Vest, Lisa A. (DNREC)

From:	Gary Myers <garyamyers@yahoo.com>
Sent:	Friday, December 12, 2014 6:34 PM
o:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC)
Subject:	REPSA COST CAP PROVISIONS NOPR: 18 DE Reg. 432 (Dec. 1, 2014)
Attachments:	2014 Cost Cap NOPR - MYERS Initial Submission.pdf; FINAL IRP - CONFIDENTIAL (unsealed on 3-1.8.13) Version.pdf; Bloom Annual Report 63014.pdf; NREL 2014 RPS Survey Costs and Benefits.pdf; Debate062210Senate.jp_Final.pdf; Debate062910House-4.jp_F.pdf; REPSA Cost Cap comments cover letter.pdf; REPSA Cost Cap Comments - MYERS.pdf; DPLRPS2013Complinance Rpt.pdf

Dear Hearing Officer Vest:

Because I have not received any response to my earlier letter seeking procedural guidance on what has been carried over in this 2014 NOPR from the 2013 NOPR, I am now moving ahead and making an initial submission of materials to be included in the 2014 NOPR record.

Attached (in .pdf format) is a listing of the materials included in my initial submission. As you can see from that document, four items are "new." I intend to refer to them in my later legal brief/comments which I hope to submit before the public hearing. I am filing them now in case other commenters might want to comment on those documents or refer to them.

The second batch of materials are items that were in the 2013 NOPR and which I am now resubmitting for inclusion 'n the 2014 record.

Again, I plan to later file a legal brief/comments concerning the revised proposed regulations.

The public notice allows comments to be filed electronically. I assume materials can be also be filed electronically. Electronic copies of the materials in my listing are also attached. If you require paper copies, please let me know.

Can you please acknowledge receipt of the listing and materials attached and confirm that they will be included in the record complied in this NOPR. Please also include this e-mail in the record.

Thank you.

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(302) 227-2775

102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions (NOPR: 18 DE Reg. 432 (Dec. 1, 2014))

Dec. 12, 2014

Gary Myers' Initial Submission of Materials - Electronic Format

1. Delmarva Power & Light Co., *2012 Integrated Resource Plan* (as unsealed March 18, 2013) (PSC Dckt. No. 12-544)
   <Final IRP - Confidential (unsealed on 3-1.8.13) Version.pdf>

2. Delmarva Power & Light Co., *Annual Supplier RPS Report Pursuant to Delaware Code, Title 26, Subchapter III-A* (filed with DE PSC Oct. 1, 2014)
   <DPLRPS 2013 Compliance Rpt.pdf>

3. Bloom Energy and Diamond State Generation, *2014 Annual Report* (filed with DE PSC June, 2014)
   <Bloom Annual Report 2014 63014.pdf>

4. Hester, *et al.*, *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards* (Technical Report, National Renewable Energy Laboratory & Lawrence Berkeley National Laboratory May, 2014)
   <NREL 2014 RPS Survey Costs and Benefits.pdf>

Gary Myers' Re-submission of Materials from 102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions (NOPR: 17 DE Reg. 600 (Dec. 1, 2013)) - Electronic Format

5. Transcript, 145th General Assembly, Senate Floor Debates, Sen. Sub. No. 1 for Sen. Bill 119 (June 22, 2010) (Wilcox & Fetzer)
   <Debate 062210Senate.jp_F>

6. Transcript, 145th General Assembly, House of Representative Floor Debates, Sen. Sub. No. 1 for Sen. Bill 119 (June 29, 2010) (Wilcox & Fetzer)
   <Debate 0629House-4.jp_F>

7. Cover letter and Initial Comments of Gary Myers in NOPR: 17 DE Reg. 600 (Dec. 1, 2013) (filed Jan. 22, 2014)
   <REPSA Cost Cap comments cover letter.pdf>
   <REPSA Cost Cap Comments - MYERS.pdf>

So submitted,

/s/ GAM

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~~**Confidential-Sealed Version**~~
(UNSEALED BY DPL REQUEST 3/8/13)

Filed Pursuant to Rule 11 of the Commission Rules of Practice and Procedure

Delmarva Power & Light Company 2012 Integrated Resource Plan

Filed: December 6, 2012

Table of Contents

(* indicates that section has confidential information)

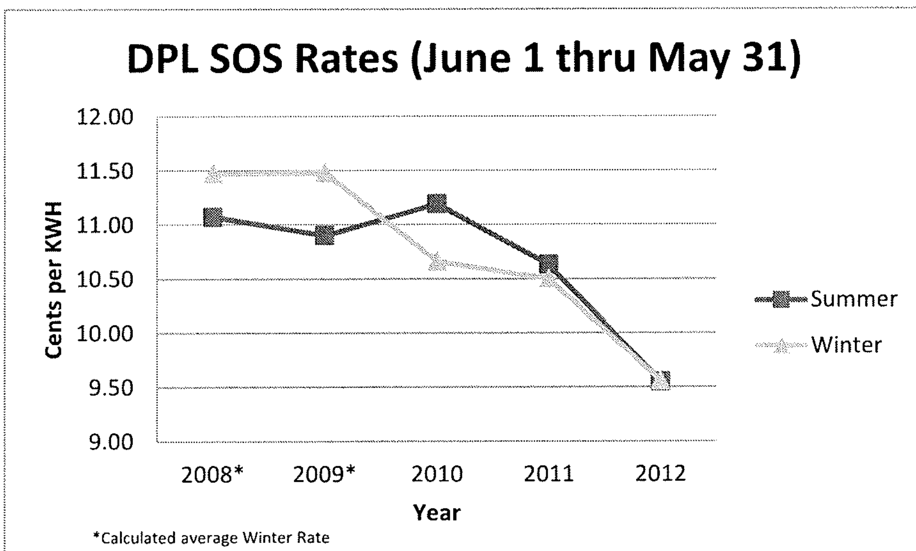
Appendices

I. IRP EXECUTIVE SUMMARY

A. Summary of Integrated Resource Plan Findings

The development and preparation of the Delmarva Power & Light Company (Delmarva, Delmarva Power) 2012 Integrated Resource Plan (IRP) greatly benefitted from the collaborative IRP Working Group process. The IRP Working Group is an effective way for stakeholders to share information in a transparent manner and for Delmarva Power to obtain stakeholder input into the development of the IRP. While Delmarva is responsible for the content of the IRP, the IRP is a more valuable due to the efforts of the participants in the Working Group.

The retail energy supply rates experienced by Delmarva Power's Standard Offer Service (SOS) customers have been stable and decreasing since the last IRP was prepared in 2010. Since 2006, residential SOS customer energy supply rates for the summer period have fallen from 11.07 cents/kwh to 9.55 cents/kwh in 2012. This is shown in the chart below:



It is expected that the combination of available generation resources and transmission import capability into the PJM DPL Zone under PJM base case assumptions will be sufficient to meet PJM reliability requirements through 2022. This result is made more secure by the implementation of demand response programs designed to reduce customer demand during peak load periods. The Delaware Public Service Commission has recently approved a Dynamic

Pricing Program and a Residential Direct Load Control Program that supports this planning objective.

Air quality in Delaware and the Mid-Atlantic Region is expected to improve over the period 2012-2022. Based on US EPA evaluation models, the impact of this improvement in air quality is estimated to range from $980 million to $2.2 billion for Delaware and $13 to $29 billion for the Mid-Atlantic Region. These results are attributable to a number of factors including new regulations controlling air emissions from coal fired power plants, the increased use of natural gas fired power generation, the increased penetration of renewable generation resources and reductions in air emissions from other sectors, such as transportation.

Delmarva Power has assembled a diverse portfolio of renewable resources in order to comply with the State's Renewable Energy Portfolio Standard Act (REPSA). The expected "un-netted" impact on average SOS customer bills of meeting the REPSA standards ranges from $6.60 /month in 2013 to $15.15/month in 2022. Renewable generation, however, avoids the creation emissions of carbon dioxide, sulfur dioxide, and nitrous oxide, and the estimated health benefits of these avoided emissions can be significant.[1]

Sensitivity analyses indicates that adding an off shore wind resource to Delmarva Power's renewable portfolio will be very expensive and does not appear needed at this time. Sensitivity analyses for adding a gas-fired combined cycle generation unit indicate that such facilities may warrant additional consideration and discussion through the IRP Working Group process.

B. Background

This Integrated Resource Plan describes Delmarva's plan to procure the electrical energy requirements for its SOS customers for the 10 year planning period 2011 – 2020. This IRP is filed pursuant to Title 26, Section 1007 (c) (1) of the Delaware Code, which provides, in part:

> [Delmarva] is required to conduct integrated resource planning.... In its IRP, [Delmarva] shall systematically evaluate all available supply options during a 10-

[1] DNREC is currently in the process of promulgating rules for calculating the cost of renewable energy and may include the benefits of avoided air emissions in the calculation.

> year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost. The IRP shall set forth [Delmarva's] supply and demand forecast for the next 10-year period, and shall set forth the resource mix with which [Delmarva] proposes to meet its supply obligations for that 10-year period....

The legislation makes clear that while the IRP must investigate all potential opportunities for a diverse and reliable supply, including those that would create environmental benefits for Delaware, it must do so with a careful eye on costs. The legislation specifically provides that in developing the IRP, Delmarva must seek to meet its customer's energy supply needs "at the lowest reasonable cost"[2] and "at a minimal cost".[3] As such, the principal objectives of Delmarva Power's plan are to secure for SOS customers a reliable energy supply at a reasonable cost, maintain price stability and, at the same time, provide environmental benefits consistent with reasonable cost and price stability.

C. Delmarva Power

Delmarva Power is a public utility company serving electric and gas customers in Delaware and the portions of Maryland. In Delaware, the company serves over 301,000 electric energy customers, of which about 267,600 are residential customers. Delmarva also serves over 123,750 natural gas customers, all of whom reside in New Castle County. The IRP focuses only on electric customers.

With respect to delivery, Delmarva is an electric delivery company, focusing on the transmission and distribution of electricity to its customers. Delmarva does not generate any electricity or own any generation plants. Delmarva's Delaware operations are managed out of four in-state offices, one each in Wilmington, New Castle, Millsboro and Harrington. Among Delmarva's assets in Delaware are almost 860 miles of high voltage (69kV and higher) transmission lines and 71 distribution and transmission substations.

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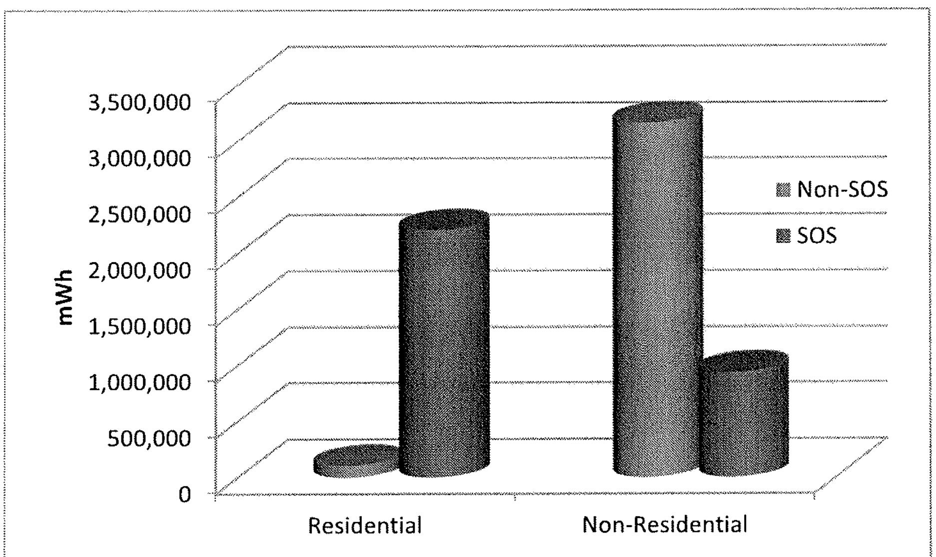
[2] 25 *Del.C.*§1007(c)(1)(b).
[3] 25 *Del.C.*§1007(c)(1).

Under Delaware's electricity deregulation laws, Delaware customers can choose their own electric energy supplier. Those customers who do not choose a supplier are supplied by Delmarva through its SOS offering. As of September 28, 2012 about 96 % of Delmarva's residential customers are supplied under the SOS offering, and about 72% of non-residential usage is provided by competitive suppliers. This IRP is focused on the procurement of the energy supply requirements of the SOS customers only.

The breakdown of energy usage by residential and non-residential customers, for SOS and non-SOS service, for 2012 through September is shown in the following chart:

Figure 1 – Energy Usage (2012 through September)



D. **Load Forecast**

The following tables summarize the baseline load forecast for the IRP planning period 2013 – 2022:

Table 1 – Delmarva Total Baseline Forecast

Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware		2018 Delmarva Delaware		2022 Delmarva Delaware	
	MW	MWh	MW	MWh	MW	MWh
Residential	1,033	2,916,121	1,133	2,853,290	1,204	2,910,224
Small Commercial	28	188,233	31	195,355	33	197,783
Large Commercial & Light Industrial	844	5,622,711	935	5,835,427	994	5,907,981
Street Lights	0	37,768	0	38,464	0	39,031
Total	**1,905**	**8,764,833**	**2,099**	**8,922,536**	**2,231**	**9,055,019**

Table 2 – Delmarva SOS Baseline Forecast

Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware SOS		2018 Delmarva Delaware SOS		2022 Delmarva Delaware SOS	
	MW	MWh	MW	MWh	MW	MWh
Residential	996	2,810,730	1,092	2,750,170	1,161	2,805,046
Small Commercial	23	150,448	25	156,140	27	158,081
Large Commercial & Light Industrial	190	1,262,540	210	1,310,303	223	1,326,595
Street Lights	0	27,643	0	28,153	0	28,568
Total	**1,209**	**4,251,361**	**1,327**	**4,244,766**	**1,411**	**4,318,290**

The Load Forecast is described in more detail in Section IV of the IRP. Appendix 4 provides more detailed documentation of the forecast preparation.

E. Price and Price Stability

Table 3 below shows the expected mean energy prices for the Reference Case for Residential and Small Commercial (RSCI) and Large Commercial (LC) customers compared with the sensitivity cases for selected planning years. The sensitivity cases include a low and high gas case reflecting a range of possible natural gas prices. The CC case represents the addition of a hypothetical 300 Mw gas fired combined cycle generating facility in Delaware.

Table 3 Expected SOS Supply Costs RSCI and LC SOS Customers (Confidential Version)

Average Costs and Risks of Electricity Procurement for DPL as Expected in August 2012		
	RSCI Total Average Costs ($/MWh)	**LC Total Average Costs ($/MWh)**
Planning Year 2013		
Reference Case	$96.93	$67.34
Reference Case - High Gas	$102.05	$82.66
Reference Case - Low Gas	$91.81	$52.03
Planning Year 2015		
Reference Case	$94.00	$69.71
Reference Case - High Gas	$109.84	$85.04
Reference Case - Low Gas	$78.15	$54.39
Planning Year 2017		
Reference Case	$122.06	$84.67
Reference Case - High Gas	$139.83	$102.34
Reference Case - Low Gas	$104.29	$67.01
Reference Case and CC	$111.16	$76.83
Planning Year 2019		
Reference Case	$141.22	$96.20
Reference Case - High Gas	$160.92	$115.78
Reference Case - Low Gas	$121.53	$76.63
Reference Case and CC	$124.35	$84.01
Planning Year 2022		
Reference Case	$161.96	$106.74
Reference Case - High Gas	$183.18	$127.70
Reference Case - Low Gas	$140.75	$85.78
Reference Case and CC	$140.94	$91.57

Table 3 indicates that for RSCI SOS customers under the Reference Case, energy supply prices are expected to rise after 2015 after falling from 2013 to 2015. For RSCI SOS customers under the Reference Case, the 2013 expected supply cost is $96.93 per MWH which is projected to rise to $161.96 in 2022. For LC SOS customers, the corresponding supply prices are $67.34 and $106.74 respectively. A primary reason for this increase in energy prices is the expected increase of natural gas prices in the later years of the IRP planning period. Within this Table, the combined cycle sensitivity case improves the performance of the Reference Case portfolio.

Table 4 presents a projection of retail customer energy supply rates for Residential and MGT customers for the period 2013 through 2018. The projections are based on the Reference Case in nominal dollars.

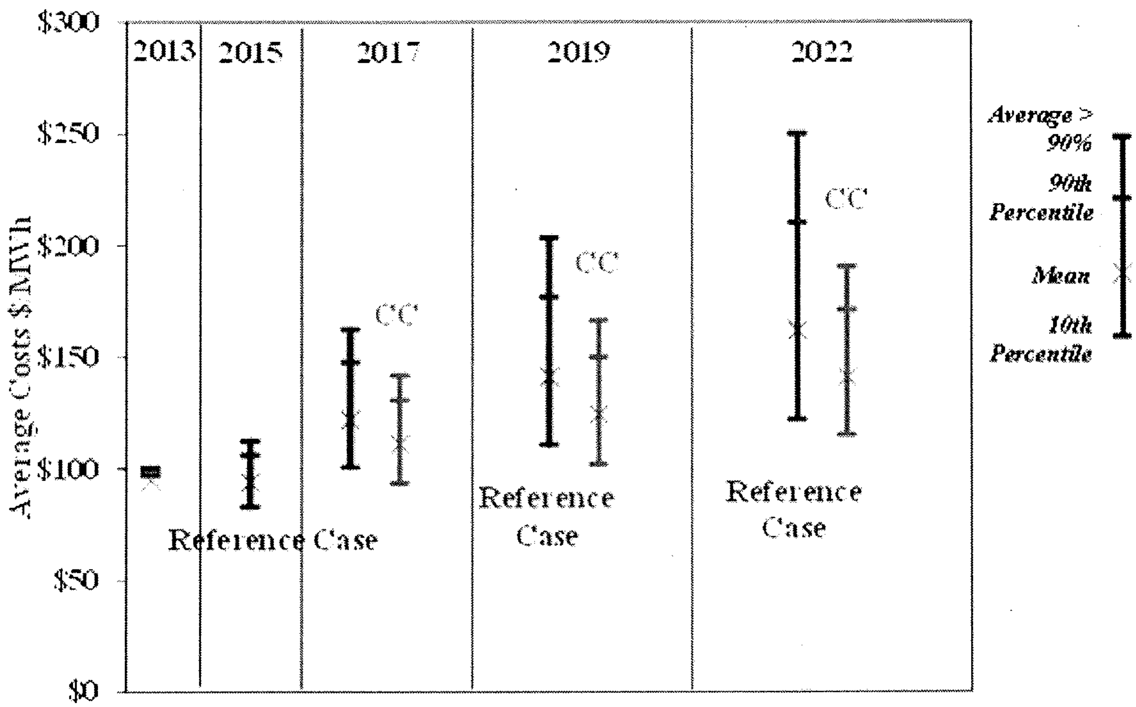
Table 4: Customer Energy Supply Rate Projections

(Confidential Version)

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-	9.24	9.31	10.9	6.7	3.76	4.52
2014/15	-	-	11.11	11.06	11.2	6.9	3.84	4.62
2015/16	-	-	11.10	11.07	11.5	7.1	3.93	4.73
2016/17	-	-	11.53	11.47	12.7	7.8	4.31	5.19
2017/18	-	-	12.45	12.34	13.8	8.5	4.68	5.64

In order to evaluate price stability, Delmarva prepared an analysis showing the expected range of prices for the Reference Case and the sensitivity cases over the planning period. Figure 2 below shows a graphical comparison of the results of this analysis.

Figure 2
Risk Ranges for RSCI FSA, With and Without CCs



In Figure 2, 10% of the possible price outcomes for that case occur above the "top" of each line and 10% occur below the "bottom" of the line. The cross mark in between the top and bottom shows the average across all potential outcomes. Figure 2 shows that the expected range of prices is increasing over time for the Reference Case.

Additional analysis of new offshore wind or new utility scale PV generation in Delaware was performed. Neither an offshore wind plant nor an additional solar project would be economically useful to the Reference Supply Portfolio costs and would add significantly to the cost of supply.

F. Environmental

i. Emissions

As part of the IRP, Delmarva prepared an analysis of the expected power plant emissions occurring over time for the Reference Case. The following charts (Figures 3 through 5) depict the emission levels of carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrous oxide (NO_X)

expected from power plants in the PJM Delmarva zone for every other year from 2012 through 2022.

Figure 3

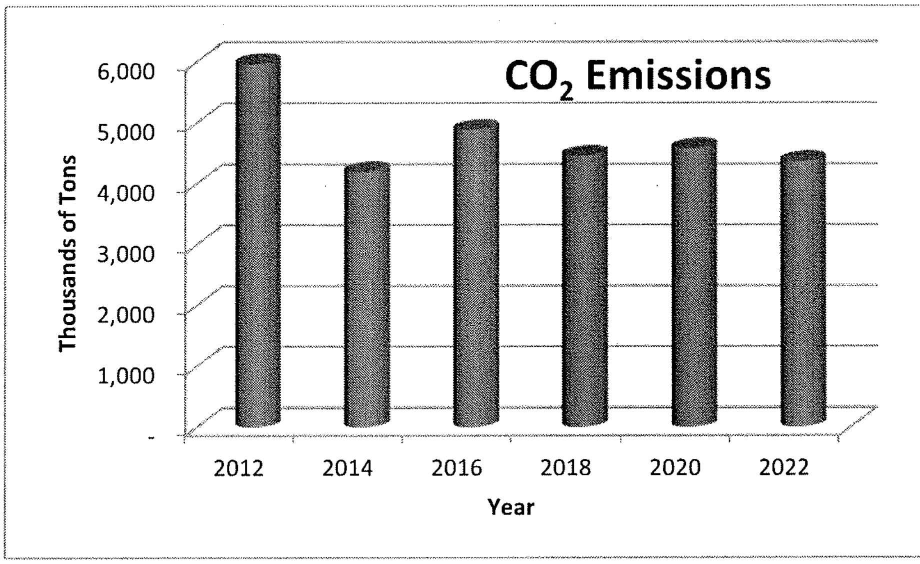


Figure 4

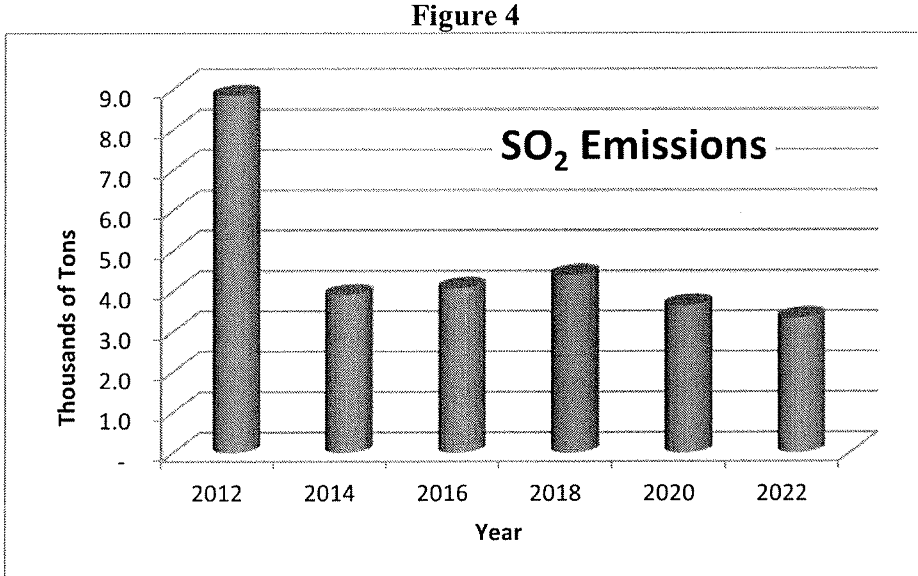
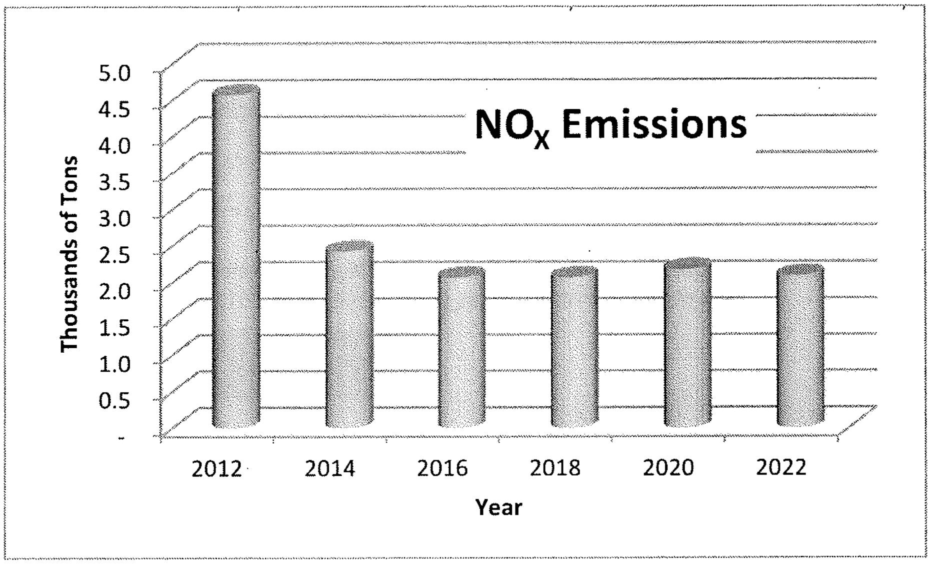


Figure 5



These charts indicate that the Reference Case emissions of CO_2, SO_2 and NO_X are expected to decline significantly in the Delmarva zone during the ten-year planning period as compared to 2012 levels. These projections reflect tightening federal and regional clean air standards, generation retirements and additions, as well as actions that Delaware has taken to increase renewable generation, reduce electric energy consumption and demand, and provide better emission controls for electric generation from coal resources. Collectively, these federal, regional and local actions are expected to improve air quality in the State.

ii. Impact on Human Health

The change in power plant emissions over time can be used to evaluate the change in ozone and particulate matter that affects air quality and impacts human health in Delaware. Using environmental modeling tools developed by the US Environmental Protection Agency (EPA) and available in the public domain, the IRP provides an estimate of the human health impacts for the Reference Case comparing changes in air quality between 2013 and 2022. The methods and procedures of the analysis are described in Section IX and Appendix 8 of the IRP.

Due to the uncertainty surrounding the preparation of the estimated impact of changes in air quality on human health, the estimates are presented as a range of values as opposed to a single value. Table 5 below shows the estimated range of monetized human health benefits as derived from the EPA models that are expected to occur for Delaware resulting from improvement in air quality in the Reference Case from 2013 to 2022.

Table 5

Total BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$ and Ozone (Millions $2010 U.S. Dollars/Year) Associated with the Changes in Air Quality from 2013 to 2022.

	Delaware	
	High End	Low End
2013–2022		
PM-Mortality (Laden, 3% discount rate)	1,800	
PM-Mortality (Pope, 7% discount rate)		630
PM-Morbidity	45	45
Ozone-Mortality (Levy)	300	300
Ozone-Morbidity	6	6
Total	*2,151*	*981*
Total (2 significant figures)	2,200	980

More detailed PM-Mortality estimates are presented in Appendix 8 based upon a number of expert studies. In Table 5 only the highest value (Laden) and lowest value (Pope) are presented.

The estimated human health benefits arising from the Reference Case by 2022 shown in Table 5 are very significant. These results are affected by the expected changes in power plant emissions that can be attributed to a number of factors including:

- The expected operation of over 12 GW of new gas fired generation and retirement of about 2 GW of coal fired resources in PJM by 2022,
- Expected reductions in emissions from remaining coal generation,
- Increases in the expected implementation of renewable resources within Delaware and other Mid-Atlantic regions (including Delmarva's renewable resource portfolio),
- Ongoing demand side management activity including the implementation of smart grid technology and associated dynamic pricing and load control programs.

These factors, as well as other factors not related to power generation resources, contribute to improving air quality and human health over the 10 year planning horizon. More details on this analysis are in a detailed technical summary report provided as Appendix 8.

G. Renewable Energy

i. RPS Compliance

In 2011, Delmarva Power became responsible for obtaining Renewable Energy Credits (RECs) to comply with the State RPS standards for all distribution customers.[4] Delmarva Power has created a portfolio of renewable resources that when supplemented with REC and SREC offsets from the Bloom energy project and spot market purchases, will assure compliance with RPS. Renewable resources in Delmarva Power's portfolio include contracts with:

- AES Armenia Mountain for up to 50Mw of wind resources
- Gestamp Roth Rock for up to 40 Mw of wind resources
- enXco Chestnut Flats for up to 38 Mw of wind resources
- Dover Sun Park for 70% of the 10 Mw of solar resources
- Delaware SREC Procurement Pilot Program for up to 7.68 Mw of solar resources secured through the SEU.

ii. Impact on Customer Bills

Securing RECs and SRECs needed to comply with REPSA is forecast to affect a typical 1,000 kWh residential monthly bill on a "non-netted" basis by $6.60 in compliance year 2013.[5] This impact is expected to increase to $15.15 a month in compliance year 2022. However, as described in this IRP, the monetized human health impacts of cleaner air are significant. DNREC is currently in the process of developing rules for calculating the cost of compliance with REPSA and these rules may include provisions for "netting" the costs that are avoided by renewable energy resources (such as external health costs). Netting the external health cost and other cost avoidance benefits of renewable energy may significantly reduce the impact on customer bills.

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[4] Certain larger industrial customers may "opt out" of this requirement.
[5] "Compliance" year 2013 is the period June 1, 2013 – May 31, 2014.

H. IRP Planning Objectives and Action Plans

Delmarva Power has six planning objectives for its procurement of SOS supply obligations in Delaware. For each of these six objectives, the following discussion includes objective measures, progress since the December, 2010 IRP towards meeting the objective and action plans for the future.

1. Reasonable Cost and Price Stability

Objectives:

a) Delmarva Power will evaluate generation, transmission and demand side resource options during the planning period to ensure that sufficient and reliable resources to meet customer needs are acquired at a reasonable cost.

b) Delmarva Power will seek to provide year over year price stability in the prices paid by SOS customers for their total electricity supply.

Measures:

a) Obtain Commission acknowledgement that the IRP does not appear unreasonable in meeting these objectives.

b) Annually provide the Commission information showing changes in rates and procurement cost adjustments

Progress since 2010

On January 10, 2012, the IRP filed December 1, 2010 by Delmarva Power was ratified by the Commission issuance of Order No 8083 and, as the following table illustrates, since 2010 Delmarva's Residential and Small commercial (RSCI) SOS supply process has been able to meet customer needs while lowering supply prices.

DE SOS Procurement - Rate Comparison for 12-Month Procurement Period					
2011 over 2010			2012 over 2011		
	%	¢		%	¢
Summer	-5.0%	-0.56	Summer	-10.2%	-1.08
Winter	-1.5%	-0.16	Winter	-9.0%	-0.94

Delmarva's strategy of procuring laddered, three year Full Requirements Service (FRS) contracts through a reverse auction bidding format, along with falling prices for natural gas, appear to be the primary factors for providing reasonable cost and stable-priced electricity.

Action Plan:

The following actions are expected to occur in the next five years:

a) In accordance with EURCSA, the Company will prepare and file an Integrated Resource Plan at least once every two years. The IRP will include a systematic evaluation of generation, transmission, and demand side resource options. Under this schedule, Delmarva Power will file the next IRP on or before December 1, 2014.

b) The IRP will provide an evaluation of various resource mixes showing both the expected outcome in terms of average price and the potential range of outcomes around the expected price.

2. Reliability

Objective:

- Ensure that the electric system serving Delmarva Power's customers meets all NERC, RFC, PJM, PHI and Delaware transmission electrical reliability requirements.

Measures:

a) Schedule for completing PJM approved zonal RTEP projects as listed on the "RTEP Construction Status" page on the PJM Website (www.pjm.com).

b) Reliability standards in DE PSC Docket 50 "Electric Service Reliability and Quality Standards." From Section 4 of that document, transmission "Reliability and Quality Performance Benchmarks" include:

i. Transmission CAIDI & SAIDI (excluding major events) as part of the overall system CAIDI and SAIDI

ii. Constrained hours of operation

Progress since 2010

The following table summarizes the transmission system upgrades made in the State of Delaware since November, 2010.

Table 6

Description	In-Service Date	Cost ($M)
Easton - Bozman to 69kV – Build new line	12/31/2010	$5.16
Lank - Five Points 69kV - Upgrade Conductor	6/1/2011	$1.70
Indian River Substation - Add 3rd 230/138kV Transformer	6/1/2011	$7.42
Loretto - Princess Anne 69kV - Rebuild Line	5/31/2011	$2.55
Oak Hall - Wattsville 138kV - Build new line and add a 138/69kV transformer at Wattsville	5/31/2011	$13.97
Darley - Silverside 69kV Reconductor	12/31/2011	$1.31
Indian River - Bishop 138kV - New Line	6/2/2012	$19.30
Add two additional breakers at Keeney 500 kV	6/1/2012	$5.06
Easton 69kV Substation Reconfiguration	6/1/2012	$1.13
Kenney 69kV - Establish Ring Bus	6/20/2012	$2.73
Indian River 230kV SVC - Install Reactors	6/15/2012	$2.35
Bishop - Ocean Bay 138kV Relay Upgrade	6/15/2012	$0.28
Nelson 138kV SVC - Install Reactors	6/29/2012	$2.26
Edgemoor AT-20 230/138kV - Replace Transformer	7/5/2012	$3.30
Keeney - Steele 230kv Relay Upgrade	4/31/2012	$0.20
Wattsville and Piney Grove 69kV - Install Relays for Kenney Sub	5/31/2012	$0.32

In addition, in April 2012, Delmarva Power provided updates to the Commission as part of the annual Docket 50 transmission standards targets.

Action Plan:

The following are expected to occur annually for the next five years:

a) Complete all approved PJM RTEP Delmarva Zone projects by required in-service dates.

b) Provide updates for annual Docket 50 transmission standards targets (in "Reliability Planning and Studies Report" - submitted annually in March for the current calendar year) and performance (in "Reliability Performance Report" - submitted annually in April for the previous calendar year).

3. Renewable Energy

Objectives:

a) Obtain Renewable Energy through a diverse portfolio of renewable energy resources at reasonable cost.
b) Prepare a plan to obtain Renewable Energy Credits (RECs) from renewable energy resources over the planning period sufficient to meet the requirements as specified by the Delaware Renewable Energy Portfolio Standards Act (REPSA) for its SOS customers.
c) Prepare a plan to obtain sufficient solar resources to meet the State of Delaware's RPS requirements for solar photovoltaic resources.
d) Avoid alternative compliance payments under the State RPS.
e) Consistent with regulations currently being promulgated by DNREC, provide cost of RPS compliance information if needed.

Measures:

a) Meet the annual RPS requirements for SOS customers through a portfolio of contracted wind and solar resources, offsets from Qualified Fuel Cell Providers, SRECs purchased from the SEU, and balanced with purchases from competitive short-term markets.
b) Minimize compliance payment requirements.
c) As may be required by forthcoming regulation, provide information needed to determine the cost of RPS compliance.

Progress since 2010

The Dover Sun Park, one of the largest solar installations in the Mid-Atlantic region, became commercially operational during the Summer of 2011. Delmarva has a 20 year contract to purchase 70% of the SRECs created by this facility. Accompanying this contract, Delmarva signed an agreement with the Delaware Sustainable Energy Utility (SEU) which allows the SEU to purchase a portion of the SRECs generated by the Sun Park during its first two years of operation for the purpose of preserving the life of excess SRECs.

Gestamp Roth Rock, a wind farm located in Western Maryland which provides up to 40 MW of wind energy under contract to Delmarva Power, became operational in August 2011. The enXco Chestnut Flats wind farm located in Central Pennsylvania provides up to 38 Mw of wind energy began service in December 2011.

The Delaware PSC approved an SREC Procurement Pilot Program in 2011 that authorized the SEU to conduct a competitive solicitation for Solar RECs that would then be sold through long term contracts to Delmarva Power. In 2012, the SEU awarded 166 twenty year contracts for Delaware-sited solar systems totaling 7.68 MW of Capacity.

Action Plan:

The following are expected to take place over the next five years:

1. Continue receiving energy and REC's from the following executed and approved contracts from land-based wind generators:
   a. AES Armenia Mountain Wind Energy
   b. Gestamp Roth Rock Wind Energy
   c. enXco Chestnut Flats Wind Energy
2. Continue receiving SREC's from the following approved contracts from solar providers:
   a. The Dover Sun Park
   b. The Solar REC Procurement Pilot Program

3. Incorporate REC and SREC offsets derived from the Bloom Energy Project to help meet the State RPS.

4. Demand Response

Objective: Implement utility provided, technically feasible, and cost effective demand response programs with a focus on contributing towards meeting the peak demand reduction goals of 15% by 2015 of the Energy Conservation and Efficiency Act of 2009. Utility provided new demand response programs are expected to be enabled by Delmarva Power's deployment of an Advanced Meter Infrastructure (AMI) in Delaware.

Measure: Peak demand reduction capability and achievements will be measured each year beginning in 2013.

Progress since 2010:

1. Advanced Metering Infrastructure for over 99% of Delmarva Power electricity customers in Delaware have been installed.
2. An education campaign to inform customers about the additional information available as a result of the AMI installation is well in progress.
   - Presented detailed energy use information through monthly electricity bills.
   - Presented detailed energy use information through Delmarva Power's internet based My Account.
3. Initiated the operation of dynamic pricing during the summer of 2012.
4. Received Commission approval on November 5, 2012 for a new residential direct load control program. Delmarva Power continued operation of legacy direct load control programs throughout 2010, 2011 and 2012.
5. Held quarterly meetings with SEU representatives to discuss DSM initiatives.

Action Plan

Over the next two years:

Residential Demand Response Programs

1. Conduct residential dynamic pricing and direct load control program education efforts beginning the first quarter of 2013.
2. Enroll customers in the new direct load control program and install equipment beginning in 2013.
3. Conduct program load reduction events beginning during the summer of 2013.

Non-Residential Demand Response Programs

1. Implement non-residential phase-in of dynamic pricing for AMI Field Acceptance Test SOS customers.
2. Prepare and file testimony seeking Commission authorization to establish a non-residential direct load control program for air conditioning systems.

Delmarva Power will monitor and evaluate the impacts of these programs and request program revisions and improvements as needed over the next 5 years.

5. Energy Efficiency

Objective: Collaborate with the SEU on the implementation of SEU selected programs. SEU selected programs will contribute towards meeting the Energy Conservation and Efficiency Act of 2009 savings targets of 2% of the 2007 electricity consumption by 2011, increasing to 15% by 2015.

Measures: Achieved energy reductions will be measured beginning in 2011 by the SEU.

The Delaware Legislature created the Delaware Sustainable Energy Utility ("SEU") in 2007 to coordinate and promote the sustainable use of energy in Delaware. The SEU was given responsibility for implementing energy efficiency and conservation programs in Delaware.

Progress since 2010:

1. The SEU planned and designed energy efficiency and conservation programs.
2. The SEU implemented selected programs. A large number of these programs have been concluded.
3. The SEU has met with Delmarva Power on a quarterly basis to discuss planned activities.

Action Plan:

1. Delmarva Power will continue to discuss program savings opportunities with the SEU on a quarterly basis.
2. The SEU selects its specific mix of programs, savings measures and targeted market sectors.
3. The SEU will implement its selected programs and savings measures.

6. Utility Provided Energy Efficiency Programs

Objective: Implement utility energy efficiency initiatives (transmission improvements, street lighting, and possibly a Combined Heat and Power (CHP) program)

Measure: Provide annual achieved energy savings beginning 2013.

Progress since 2010:

1. Installed high efficiency transformers and replaced transmission conductors.
2. Installed distribution line capacitors, which resulted in lower losses on the system.
3. Replaced Mercury Vapor (MV) streetlights with High Pressure Sodium (HPS) streetlights.
4. Evaluated LED street lighting technology potential future LED street lighting conversions)

Action Plans:

1. Implement transmission and distribution improvement measures as described in the RTEP.

2. Continue installation of high efficiency transformers.
3. Continue streetlight improvement plan.
4. Work with SEU to determine CHP or other program utility implementation opportunities.

1. Recommended Path Forward

The IRP Working Group provides an effective way to share information in a collaborative and transparent manner among stakeholders. Delmarva Power recommends that the IRP Working Group process continue.

Delmarva's current procurement strategy, which has been developed and refined on an on-going basis over the years, has been to:

1. Through a reverse auction process, procure a series of laddered three year contracts for Full Service Requirements Agreements (FSA) for Residential and Small Commercial SOS customers and one year FSAs for Large Commercial SOS customers,
2. Construct a portfolio of renewable energy resources to provide for the needs of Delmarva Power's customers which increases in size over time consistent with the requirements of the Delaware Renewable Portfolio Standards (RPS), and,
3. Bundle the renewable portfolio together, including any applicable offsets from the Bloom Energy fuel cells, with the FSA's to complete the procurement of electrical requirements for SOS customers.

This strategy has provided SOS customers with reasonable and stable energy prices and should be continued. In addition, as markets change, Delmarva Power can discuss these changes and appropriate responsive actions with the IRP Working Group. Moreover, each year Delmarva, the Public Advocate, Commission Staff, and numerous other stakeholders engage in a process overseen by the Commission designed to review and, where necessary, improve the SOS bidding process. That annual process has resulted in improvements, such as the reverse auction bidding process and changes to the FSA's. These annual SOS process improvement workshops will continue.

Further, the reduction in power plant emissions expected under the Reference Case between 2013 and 2022 provides significant improvements in air quality and health benefits for the State of Delaware. Based upon EPA models of air quality, the range of expected health benefits under the Reference Case occurring in 2022 relative to 2013 in Delaware is $980 million to $2.2 billion Delmarva's current procurement strategy provides an appropriate balance to secure reliable and reasonable cost energy supply, provide price stability and environmental benefits and should be continued.

In the Fall of 2012, the Delaware Public Service Commission approved Delmarva Power's application for a Dynamic Pricing Program and for a Residential Load Control Program. The reduction in energy usage and peak demand expected from the implementation of these programs will supplement Delmarva's procurement practices.

II. Summary Historical IRP Background

Pursuant to the Electric Utility Retail Customer Supply Act ("EURCSA"), which was enacted in 2006, Delmarva Power is required to prepare and file an Integrated Resource Plan every two years.[6] The IRP is designed to provide a comprehensive review of Delmarva Power's plans to procure energy for SOS customers for the next ten years after the filing.[7]

Prior to the 2012 IRP, the most recent IRP prepared by Delmarva Power was submitted to the Commission and State Agencies on December 1, 2010. The 2010 IRP was the first to be submitted under the regulations adopted by the Commission on December 8, 2009, by Order No. 7693 in PSC Regulation Docket No. 60. On January 10, 2012 the Commission issued Order No. 8083 in which the 2010 IRP was ratified. The Commission further approved most of the "Proposed Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP"): Joint Proposal to Ratify PSC Docket No 10-2."[8] Copies of the Path Forward and Order No 8083 are provided in Appendix 3.

Events since the last IRP

Upon approval of the Path Forward, Delmarva Power and other parties began a series of workshops and collaborative discussions regarding the planning and development of the 2012 IRP. Topics discussed at these workshops included Load Forecasting, Demand Side Management, Transmission Planning, Generation Interconnection, IRP model assumptions, and Scenario/Sensitivity Analysis. Numerous parties participated in some or all of these discussions including, but not necessarily limited to, Delmarva Power, Commission Staff, DNREC, DPA, Caesar Rodney Institute, the Mid Atlantic Renewable Energy Coalition (MAREC), the Delaware SEU, Calpine and NRG.

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[6] 26 *Del C.* §1007(c)(1).
[7] *Id.*
[8] The Commission did not approve Section 4 of the Path Forward that suggested that Delmarva may not be required to submit an IRP every two years (See Order 8083, item 2, pp 3)

One of the challenges of preparing an IRP is to keep the planning assumptions underlying the resource analysis as current and accurate as can be reasonably expected given the time and resource requirements of developing an IRP. Since December 2010 when the last IRP was filed, a number of events have occurred that impact the preparation and development of Delmarva Power's IRP. The 2012 IRP incorporates these events into the resource planning analysis to the extent such information was available before the analysis for the IRP needed to begin in order to meet the December 2012 filing requirement. Brief descriptions of the more important events that have occurred from a resource planning perspective since the 2010 IRP was submitted are described below.

Bluewater Wind Power Purchase Agreement

In 2008, Delmarva Power entered into a power purchase agreement with Bluewater Wind for up to 200 MW of offshore wind energy from an offshore wind farm to be constructed 10 to 11 miles off the Delaware coast. The Bluewater Wind project was scheduled to begin operation in 2015 and was included as a renewable generation resource in the 2010 IRP. However, in January 2012, NRG, the parent company of Bluewater Wind, terminated the power purchase agreement with Delmarva Power and announced that active development of its offshore wind projects would be placed on hold. Consequently, the Bluewater offshore wind project is no longer included as a resource in Delmarva's 2012 IRP. Although the Bluewater Wind project is no longer modeled as part of the IRP Reference Case, the 2012 IRP includes a sensitivity analysis of a generic offshore wind facility.

May 2012 PJM Capacity Auction

As part of the PJM Capacity market that takes place in May of each year, a Base Residual Auction (BRA) is held for electrical capacity to be provided three years in the future. Resources which clear the BRA are considered firmly committed to provide this future capacity. In May of 2012, the yet to be constructed Calpine Garrison Energy Project, a 309 MW gas fueled combined cycle facility, cleared the BRA for the capacity year 2015.[9] This plant, which cleared the BRA

[9] PJM Capacity year 2015 is June 1, 2015 – May 31, 2016.

without any guarantee of ratepayer subsidy, is located near Dover and is included as a resource in Delmarva Power's 2012 IRP beginning in 2015.

Mid Atlantic Power Pathway (MAPP)

Delmarva Power has long supported the construction of the **Mid-Atlantic Power Pathway** (MAPP), a high voltage transmission line that would run from Possum Point in Virginia through Chalk Point and Calvert Cliffs in Maryland and across the Chesapeake Bay to Vienna, MD and then to Indian River Delaware. During the summer of 2012 the PJM Board decided to remove the MAPP from PJM's regional transmission plans. According to PJM, this decision was based on a reduced load forecast, increased demand response and new generation resources. The 2012 IRP does not include the MAPP project as a transmission resource in the analysis.

Delmarva Power Becomes Responsible for RPS Compliance for all Distribution Customers

In July, 2011, changes to the Renewable Portfolio Standard (RPS) enabling legislation were enacted that greatly expanded Delmarva Power's role in complying with RPS. Prior to these changes, Delmarva Power was responsible for procuring Renewable Energy Credits (RECS) in the amounts specified in the RPS legislation for its Standard Offer Service (SOS) customers only. The July 2011 changes expanded the scope of Delmarva Power's RPS compliance efforts to include *all* distribution customers,[10] not just SOS customers. Because RPS compliance is based on annual MWH sales, Delmarva Power must procure much larger amounts of RECs each year to remain in compliance. As discussed further in this IRP, this has a significant impact on Delmarva Power's longer term plans to procure RECs to maintain compliance with the RPS.

SREC Procurement Pilot Program

Amendments to the state-wide RPS legislation enacted in 2010 established a Renewable Energy Task Force. In 2011, the Renewable Energy Task Force recommended that the Delaware Public

[10] As discussed elsewhere in this IRP, there is a provision in the legislation for certain larger industrial customers to become exempt from RPS compliance.

Service Commission approve a Solar Renewable Energy Credit (SREC) Procurement Pilot Program. Under the Procurement Pilot Program, the Delaware Sustainable Energy Utility (SEU) would conduct competitive solicitations to obtain SRECs that would then be sold to Delmarva Power. The SREC Pilot Program was approved by the Commission in DPSC Order No 8093. In April 2012, the Delaware Sustainable Electric Utility (SEU) conducted the first round of the SREC Procurement Pilot Program and, as a result, awarded twenty-year SREC contracts to 166 Delaware sited qualifying solar systems totaling 7.68 MW of electrical capacity. The SRECs now being produced by these facilities are purchased by Delmarva Power and are used by the Company to help meet its solar RPS obligations.

Qualified Fuel Cell Provider Program

In July 2011, the Governor of the State of Delaware signed legislation that establishes that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider") is an eligible resource for RECs under the Renewable Portfolio Standards Act. The legislation further requires that the Delaware Public Service Commission adopt a tariff under which Delmarva Power would be an agent that collects payments from its customers and disburses the amounts collected to a qualified fuel cell provider that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility. The legislation further stipulates that the payments from customers be offset by the market revenues received by the qualified fuel cell provider from its selling of capacity and energy into the wholesale market netted against its cost of fuel. The legislation also provides for a reduction in Delmarva Power's REC and solar REC requirements based upon the actual energy output of the 30-megawatt generation facility. In October 2011, through Order No. 8062, the Commission approved the tariff submitted by Delmarva Power in response to the legislation.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as the fuel cell provider. Bloom plans to construct a fuel cell facility at two locations in Delaware. The first site, a 3 MW fuel cell facility at Brookside, went into commercial operation on June 18, 2012. The second site, a 27 MW facility located near Red Lion, is to be phased into operations on or before September 30, 2014.

US EPA Air Pollution Rules

On July 6, 2011, the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR requires upwind states to reduce power plant emissions that contribute to ozone and/or fine particle pollution in other downwind states. Later in 2011 however, the CSAPR Rule was challenged in the U.S. Court of Appeals.

On August 21, 2012, a three judge panel the U.S. Court of Appeals for the District of Columbia court struck down the Environmental Protection Agency's CSAPR. On October 5, 2012 EPA filed an appeal of the August 12 decision seeking a re-hearing of the case before the entire US Appeals Court for the District of Columbia. Delaware was included in the group of 10 states and various cities petitioning in favor of the re-hearing.

At the time of the CSAPR decision, the IRP analysis was already well underway and the resource planning and air quality modeling could not be started anew if Delmarva were to meet the December 2012 IRP filing requirement. Due to the potential impact of CSAPR on the future resource mix, prices and air emissions, Delmarva Power has prepared and included within this IRP a sensitivity case on the expected resource mix and air emissions with and without CSAPR.

Advanced Metering Infrastructure

Delmarva Power began deploying Advanced Metering Infrastructure (AMI) following the Commission's approval in Order No. 7420. Significantly for the IRP, AMI enables the implementation of Dynamic Pricing. Since December, 2010, Delmarva Power has essentially completed the installation of AMI smart meters for its approximately 300,000 residential and small business electric customers in its Delaware service territory.

Dynamic Pricing

On March 23, 2011, Delmarva Power filed an Application to Implement and Advanced Metering Enabled Dynamic Pricing Plan and Dynamic Pricing Rider DP. On January 31, 2012 the

Delaware Public Service Commission approved the Settlement Agreement entered into by Delmarva Power, Commission Staff and the Division of Public Advocate, approving the proposed phase-in implementation of its AMI enabled Dynamic Pricing Program for its Standard Offer Service customers. The approved rate is structured as a default Critical Peak Rebate ("CPR") rate with the ability for the customer to opt-out of the rate. The program, branded as the "Peak Energy Savings Credit," applies to Delmarva Power's residential and small and medium non-residential customers.

The program began implementation in June 2012 with approximately 7,000 residential customers who participated in the AMI Field Acceptance Test, which took place in 2009. This part of the Phase-in concluded on September 29, 2012 and is in the process of a Phase I Assessment, whereby the program will incorporate results and improvements obtained from the experience gained from the application of the program to this first group of customers.

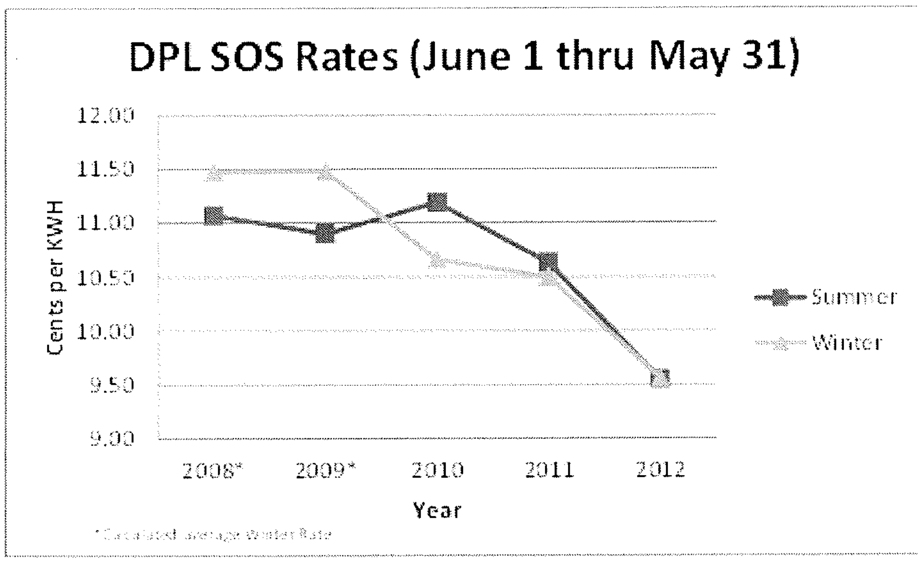
Residential Direct Load Control

On July 28, 2011, Delmarva Power filed an Application to establish a new Residential Air Conditioning Cycling Program through the Residential Direct Load Control Rider "R-DLC" with the Delaware Public Service Commission. The Department of Natural Resources intervened in the proceeding. Several workshops were held with Commission Staff and the Public Advocate in attendance, and informal exchanges of questions and answers occurred during the Spring, Summer and Fall of 2012.

On October 17, 2012, Commission Staff issued their Report overall in support of the program. On November 5, 2011 the Commission approved the program which will be marketed to Delmarva Power's customers as the Energy Wise Rewards program.

Low Natural Gas Prices

Finally, the development of shale gas resources including the Marcellus Shale region in the Mid Atlantic/New York area and the expansion of gas transportation resources has greatly increased the availability of natural gas and driven down prices to ten-year lows. This has impacted the expected generation resource mix in the region and placed downward pressure on energy prices generally including electricity. In fact, since the last IRP was submitted in December 2010, the energy component of Delmarva Power's retail customer electric rates has continued to decrease. This is shown in the chart below.



III. Overview of IRP Analysis and Modeling Structure

This Section of the IRP describes the overall analytical approach and major modeling tools used in the analysis. This is followed by six subsections describing in more detail the key components of the IRP and Delmarva Power's energy procurement strategy. These subsections include discussions of the following:

1. The Load Forecast
2. Demand Side Management (DSM)
3. Transmission
4. Supply Resources
5. Environmental Externalities
6. Renewable Resources

The intent of Delmarva Power's Integrated Resource Plan is to provide Delmarva's customers and regulators with a road map of how, at the time this plan was filed, the Company intends to procure electric energy for our Standard Offer Service customers for the next ten years in a way that balances cost, price stability and environmental benefits. Delmarva's overall approach to developing the IRP is based upon the following general analytical approach:

1. Begin by preparing a detailed view of the future from 2013 – 2022 for an expected or "Reference" Case. The preparation of the Reference Case requires an intensive modeling effort employing generation system planning models, portfolio analysis models, and environmental analysis models. The results of the Reference Case provide the expected view of future prices, price stability, and environmental benefits for Delmarva's customers.
2. After completion of the Reference Case, sensitivity analysis is performed around several key planning assumptions to gain a better understanding of the risk associated with some of the critical assumptions underlying the Reference Case.
3. Provide the Public Service Commission with the results of the IRP analysis in a clear and concise manner for their consideration under the current IRP Docket.

In order to prepare a plan that meets the broad objectives of the IRP, it is necessary to use several separate but related planning models. The following narrative describes how the various planning tools included in the technical analysis are aligned to provide the information needed to determine a preferred energy procurement strategy, while meeting the Commission's approved IRP regulations.

The following key planning tools were used in developing the IRP Reference Case:

- The Integrated Planning Model (IPM®) developed by ICF. IPM® is a resource planning model that considers supply, demand and transmission resources. IPM® also provides information on power plant emissions.
- The Portfolio Model (PM) developed by the Brattle Group. This model is used to evaluate price stability of the Reference and Scenario cases.
- The Community Multi-scale Air Quality (CMAQ) and Benefits Mapping and Analysis Program (BenMAP) models developed by the US Environmental Protection Agency. These models are used to translate the change in air emissions between the initial planning year and 2022 into quantified estimates of the effect of these changes on air quality and human health.

Each of these models performs specific tasks related to Delmarva's IRP requirements. The remainder of this section describes each of these models, their functions, capabilities and interrelationship with one another.[11]

a. The IPM® model

The IPM® is the first analytical processor in the Delmarva IRP development chain. IPM® is a multi-regional generation planning and production cost model. For Delmarva's IRP, the model is focused on the Delmarva Zone and PJM. The Delmarva Zone includes all of Delaware and the Maryland and Virginia portions of the Delmarva Peninsula. The model provides a detailed look at the expected future state of generation resources over the planning period 2013 - 2022. The key inputs into IPM® include the load forecast, fuel costs, PJM RTEP approved transmission

[11] More technical descriptions of each of these models are provided in the Appendices of this IRP.

investments, energy efficiency programs and goals, demand reduction programs and targets, renewable energy requirements, and prevailing and expected environmental regulations at the State, Regional, and Federal levels.

In order to provide the picture of future generation markets for Delmarva's planning period of 2013 – 2022, the model comprehensively evaluates a large number of supply side and demand side resources to produce the least cost solution of existing and future generation resources. The evaluation produces a forecast of new generation facilities that will be economic, resources that will be retired, how much energy is produced by each available generation resource, what emissions are created by each generation resource, and expected capacity and energy prices for the DPL zone and PJM.

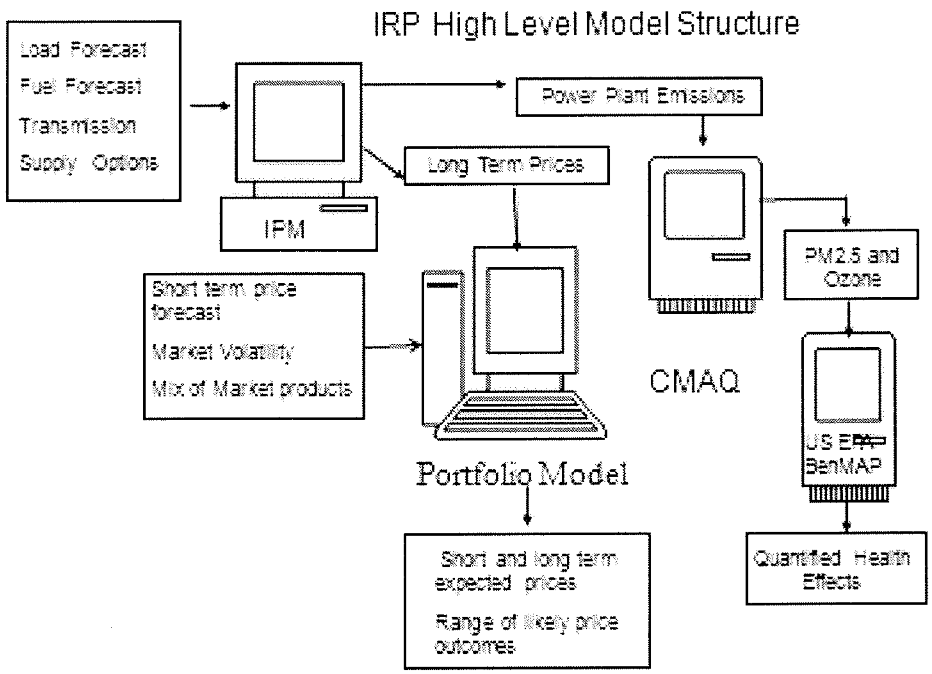
The generation resources evaluated by IPM® include the following:

- Traditional fossil fueled generation
    - Gas fired combustion turbines
    - Gas fired combined cycle facilities
    - Traditional and super-critical coal fired facilities
    - Integrated Gasification Combined Cycle
    - Oil fired facilities
- Nuclear generation
- Renewable resources
    - Off-shore wind
    - Land based wind
    - Solar
    - Biomass
    - Land-fill gas.
    - Fuel Cell Technology

A more detailed listing and specific information on the assumed cost and performance characteristics of these resources may be found in Technical Appendix 4.

The outputs of the IPM® provide key information for the other planning tools used in the IRP. The energy and capacity price forecasts are passed onto the Portfolio Model for an evaluation of future prices and price stability. Power plant emission data for criteria pollutants nitrous oxides (NO_x), sulphur dioxide (SO_2), mercury (Hg) and carbon dioxide (CO_2) are passed on to the CMAQ and BenMAP models which are used in the evaluation of human health effects. A high level overview of this process is shown in Figure 1.

Figure 1



b. <u>The Portfolio Model</u>

The Portfolio Model (PM) is a stochastic model used primarily to evaluate the price stability of various planning options. The model is also used to perform risk analysis and review the sensitivity of the results to various planning assumptions. The PM relies on the output from the IPM® to obtain estimates of longer term energy and capacity prices. In the shorter term, the PM relies on market data from electric and gas markets to generate forward electricity price curves. In order to simulate electricity prices in future years, PM requires the additional input of current market price volatility information and the terms of the pricing related to Delmarva's renewable energy contracts and Full Service Agreements.

Using the forward price information, hourly SOS customer load data, the contract price information and expected output of wind, solar resources and the Bloom energy project, and forward price volatility, the PM uses Monte Carlo Techniques to simulate a range of future energy prices for SOS customers.[12] The price ranges produced by the PM analysis can be depicted by various percentage ranges.

In this IRP, the PM is used to evaluate the price and price stability characteristics of the Reference Case. The PM is also used to evaluate various sensitivity cases around the Reference Case including changes in expected natural gas prices. More detailed descriptions of the sensitivities analyzed by the Portfolio Model are provided in Appendix 6.

c. Environmental Models

The CMAQ and BenMAP models are analytical tools used in the evaluation of the effect of power plant emissions on human health. Both CMAQ and BenMAP were developed by the US Environmental Protection Agency and are available in the public domain. The CMAQ model takes the inventory of air emissions from all sources, including power plant air emissions data from the IPM®, and along with detailed meteorological information, calculates expected changes to ambient air quality for the pollutants of interest. For this IRP, the CMAQ model performs these detailed calculations over a four kilometer grid covering most of the PJM footprint in the Mid-Atlantic States. This process is quite computationally intensive and time consuming. BenMAP uses the output from CMAQ to estimate the impacts on human health in dollar terms associated with the changes in air quality simulated by CMAQ.

Delmarva is also required by regulation to provide appropriate life-cycle analysis of resource alternatives in the IRP. However, the Commission indicated in Order 8083 when discussing the

[12] A more detailed description of the Portfolio Model is provided in Technical Appendix 6.

frequency of filing an IRP, that Delmarva may use existing models and studies if they are still relevant and accurate. Delmarva prepared and submitted a life-cycle analysis in the IRP filed December 1, 2010. The 2010 life-cycle analysis is both relevant and accurate and is incorporated by reference into this IRP.

IV. Load Forecast

Delmarva's ten year energy procurement plan to provide the electrical requirements for SOS customers is based on an internally prepared load forecast covering the planning period through 2022. Section 4 of the IRP regulations provides detailed requirements for preparing a range of load forecasts as well a review of historical load data. Detailed documentation of Delmarva's load forecasts and its forecasting methods, intended to meet these requirements, is attached as Appendix 4. For the IRP, Delmarva prepares both a " baseline" forecast and a Reference Case forecast. The baseline forecast is derived from econometric modeling techniques but does not include the effects of future DSM programs. When both the expected impacts of future DSM programs, which are estimated separately from the econometric baseline forecast, and expected hourly SOS customer loads are subtracted from the baseline forecast, the result is termed the Reference Case Forecast. A summary of the major forecast results is provided below.

Baseline Forecast

The following table summarizes the baseline forecast for summer peak demand (MW) and energy throughput (MWh) for 2013, the initial year of the IRP planning period, and 2022, the last year of the IRP planning period, for Delmarva Delaware's three major categories of customers (with street lights added as a fourth category for energy throughput). The table also provides the summer peak demand and energy throughput for the SOS component of each category for the same two years.

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Baseline Forecast – Peak Demand (MW) & Energy Throughput (MWh)

a. Delmarva Delaware Total - 2013 & 2022

Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware		2018 Delmarva Delaware		2022 Delmarva Delaware	
	MW	MWh	MW	MWh	MW	MWh
Residential	1,033	2,916,121	1,133	2,853,290	1,204	2,910,224
Small Commercial	28	188,233	31	195,355	33	197,783
Large Commercial & Light Industrial	844	5,622,711	935	5,835,427	994	5,907,981
Street Lights	0	37,768	0	38,464	0	39,031
Total	**1,905**	**8,764,833**	**2,099**	**8,922,536**	**2,231**	**9,055,019**

b. Delmarva Delaware SOS - 2013 & 2022

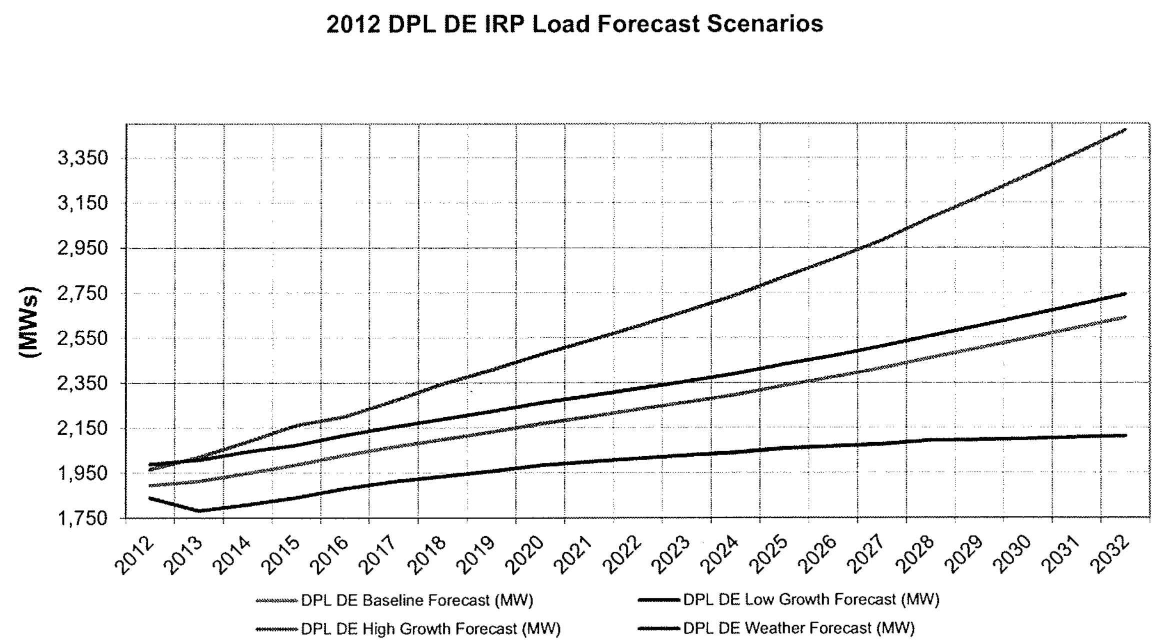
Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware SOS		2018 Delmarva Delaware SOS		2022 Delmarva Delaware SOS	
	MW	MWh	MW	MWh	MW	MWh
Residential	996	2,810,730	1,092	2,750,170	1,161	2,805,046
Small Commercial	23	150,448	25	156,140	27	158,081
Large Commercial & Light Industrial	190	1,262,540	210	1,310,303	223	1,326,595
Street Lights	0	27,643	0	28,153	0	28,568
Total	**1,209**	**4,251,361**	**1,327**	**4,244,766**	**1,411**	**4,318,290**

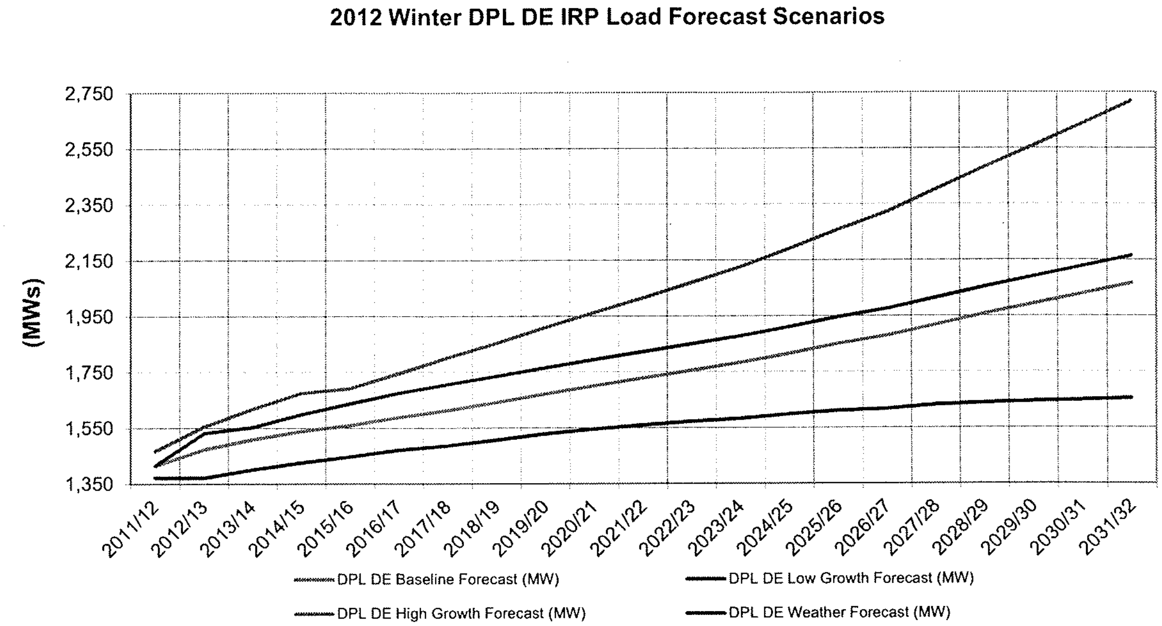
Load Growth Scenarios

In addition to providing a "baseline" forecast, the IRP regulations require Delmarva to prepare a range of load growth forecasts for a number of different assumptions. The range of forecasts can be used in the IRP sensitivity analyses. The following tables present, for differing assumptions, the Company's forecast for the unrestricted summer and winter peak demand, as well as the forecast for MWh , for all Delmarva Delaware customers over the ten year IRP planning period.

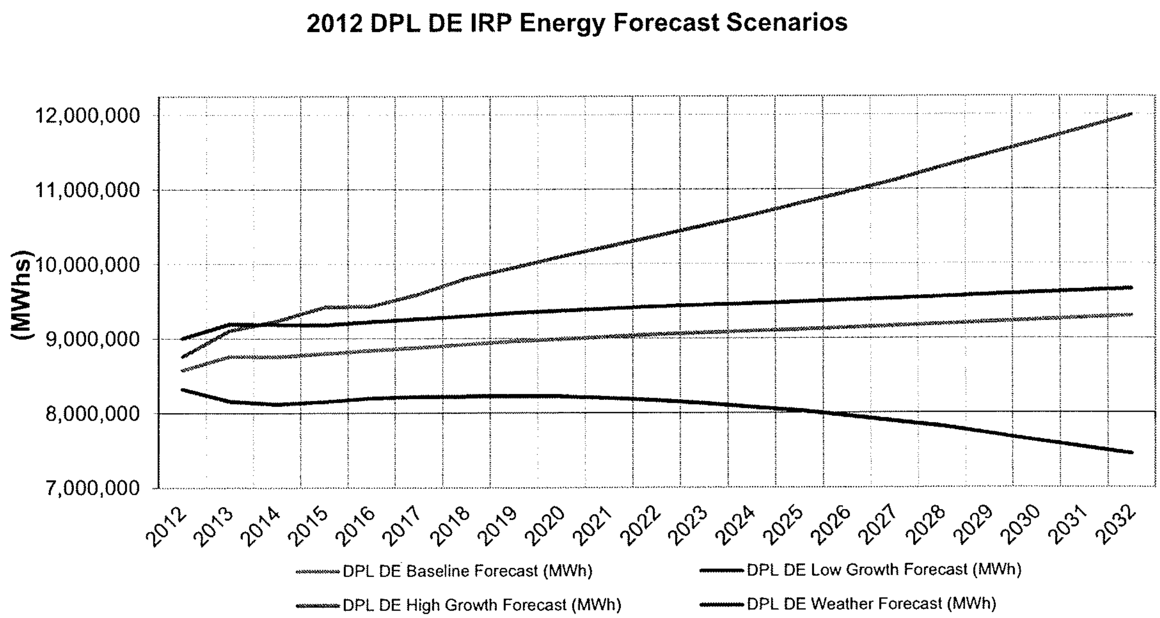
DPL Delaware Jurisdictional Summer Peak Demand (MWs)



DPL Delaware Jurisdictional Winter Peak Demand (MWs)



DPL DE Jurisdictional Energy Throughput MWH



In the tables above, the heavy green line represents the Baseline Scenario; it is assumed that 50% of the possible future outcomes will be above this forecast and 50% will be below. The red and blue lines represent, respectively, High and Low Economic growth Scenarios. It is assumed that

10% of the possible outcomes will lie above the High Economic Forecast and 10% will lie below the Low Economic forecast.

Finally, the purple line represents the Extreme Weather Scenario. This case is meant to reflect climate change potential for the region. Extreme Weather is represented by calculating the average and standard deviation of heating and cooling degree days for each month of the year. In the Extreme Weather Scenario, monthly heating and cooling degree days are set equal to their historical average plus two standard deviations.

IRP Load Forecast Requirements

Technical Appendix 4 includes a discussion of the methodology used in developing these forecasts and provides further information on these forecasts including:

- Historical data and future estimates of:
  - Five year historical loads, current year-end estimate and 10 year weather adjusted forecast
  - DPL – DE and DPL DE SOS load forecasts aggregated and by customer category, including capacity (MW) and energy (MWh) data
- Winter and summer peak demand for total DPL DE load and DPL DE SOS load by customer class
- Weather adjustments including consideration of climate change potential
- A description of the process used to develop the forecast, probability of occurrence and how well the model predicted past load data for five years.

SOS Reference Forecast

As mentioned earlier, the Baseline Forecast described above does not include the effects of future DSM programs. For purposes of procuring a portfolio to provide SOS customer energy requirements, the expected energy savings from DSM programs needs to be subtracted from the Baseline Forecast of SOS customer energy to arrive at the amount of annual energy expected to be procured for SOS customers in the Reference Case. In addition, the loads of expected Hourly Supply customers also need to be subtracted.

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The Reference Portfolio Forecast represents the expected Delaware jurisdictional SOS load for which Delmarva is obligated to make contractual arrangements for energy supply.

The following table summarizes the calculation for the reference portfolio load.

SOS Reference Portfolio Forecast

Delaware SOS Customer MWH

	2013	2014	2016	2018	2020	2022
Baseline SOS	4,251,361	4,155,052	4,200,299	4,244,766	4,284,939	4,318,290
less Hourly SOS	351,678	359,183	362,475	364,982	367,543	369,520
Less SOS DSM	411,724	554,751	727,997	795,087	975,199	1,066,782
SOS Reference Case	3,487,960	3,241,118	3,109,827	3,084,697	2,942,198	2,881,989

V. DEMAND SIDE MANAGEMENT ANALYSIS

The Delmarva Power IRP evaluates demand side management (DSM) programs as potential resource options for meeting Delmarva Power Delaware customer energy and capacity requirements. In contrast to supply side options such as new generating units, DSM options reflect potential savings in either the total consumption of electrical energy, reduction of system demand during peak periods or both. Demand Side Resources were examined to support energy efficiency, conservation, and demand response in compliance with the Delaware Energy Conservation & Efficiency Act of 2009.

The Delaware Energy Conservation & Efficiency Act of 2009[13] (The Act) designates energy efficiency as the first energy supply resource to be considered before any increase or expansion of traditional energy supplies. The Act created an Energy Efficiency Resource Standard (EERS) requiring each Affected Electric Energy Provider[14] to achieve, at a minimum, energy savings equivalent to 15% of the Provider's 2007 electricity consumption, and a coincident peak demand reduction that is equivalent to 15% of the Provider's 2007 peak demand by 2015.[15] Pursuant to *29 Del. C. §8059,* the Delaware Sustainable Energy Utility is tasked with coordinating and promoting the sustainable use of energy in Delaware. The SEU is responsible for implementing energy efficiency and conservation programs in Delaware while Delmarva Power is responsible for implementing Demand Response (DR) programs. The Act requires that Delmarva Power achieve the demand and energy reduction goals in coordination with the SEU and the Delaware Weatherization Assistance Program (WAP).[16] Additionally, the current regulations[17] governing the preparation of this and future IRP states that it shall include:

> "...a detailed description of energy efficiency activities in accordance with 26 *Del. C.* §1020."

[13] 26 *Del. C.* §§1500-1507.
[14] An "Affected Electric Energy Provider" is defined as an electric distribution company, rural electric cooperative or municipal electric company serving Energy Customers in Delaware. 26 *Del. C.* §1501(1).
[15] *Id.* at 1502(a)(1).
[16] The Delaware Division of Energy and Climate also offers renewable energy and energy conservation programs for residential and non-residential customers.
[17] In the Matter of the Investigation Into the Adoption of Proposed Rules and Regulations to Accomplish Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company under 26 *DEL. C.* § 1007(c) & (d) (Opened August 7, 2007). PSC Regulation Docket No. 60.

26 *Del. C.* § 1020 states:

> "IRPs filed with the Commission pursuant to §1007 of this Chapter shall include a detailed description of energy efficiency activities. Electricity demand response programs shall be directly implemented by the utility. Demand-side management and other energy efficiency activities shall be implemented by the SEU (as defined in §8059 of Title 29), in collaboration with the utility. The contributions of the utility-implemented and SEU-implemented programs shall be considered in meeting the Energy Efficiency Resource Standards required under Chapter 15 of this Title."

Delmarva Power has also examined and included an analysis of the likely energy and demand reductions that will result from code and standard improvements in projecting the total attainable demand and energy consumption savings.

In accordance with The Act, the EERS Workgroup was created to consider the various energy efficiency issues identified in the statute, including providing guidance on the interpretation of the statute's targets. Delmarva Power was an active participant in this workgroup. In June of 2011, the EERS Workgroup submitted to the Secretary of DNREC the "State of Delaware Energy Efficiency Resources Standards Workgroup Report" (EERS Report). The EERS Report, among other things, further defined the consumption and demand targets for the Affected Electric Energy Providers. The 2015 reduction goals for Delmarva Power were determined to be 284 MW for peak electricity demand and 1,329,054 MWh for annual electric energy consumption. (EERS Report, pp. 35 and 36) Although the EERS Workgroup did not establish interim year goals, for planning purposes, Delmarva Power has assumed that the interim year goals prior to 2015 can be derived based upon a straight line ramp up between 2011 and 2015. The resulting reduction targets for Delmarva Power for years 2013, 2014, and 2015 are presented in Table 1.

Table 1

DELMARVA POWER REDUCTION GOALS		
Year	Cumulative MW Reduction for that Year	Cumulative MWh Reduction for that Year
2013	137	762,606
2014	205	1,052,701
2015	284	1,329,054

At this time, the Act and the EERS Report do not addresses what the consumption and peak demand reduction requirements will be after 2015. In the absence of a clear directive, Delmarva Power has assumed that the goal for each successive year after 2015 would be to continue calculating the goal as 15% of the EERS Report mandated 2007 consumption and peak demand minus each following year's otherwise forecasted consumption and peak demand.

Overall DSM Cumulative Impacts

Delmarva Power, in consultation with the IRP stakeholders, has assumed for the 2012 IRP Reference Case that the state prescribed 2015 electric energy and demand goals will be achieved. At stakeholders' request, the Company has conducted a sensitivity analysis to explore the impact of not achieving these goals. This analysis is discussed later in section..

The assumed DSM Reference Case cumulative impacts for the Delmarva Power, the SEU, and WAP DSM initiatives for the IRP planning horizon 2013 – 2022 are shown numerically in Tables 2 and 3.

Table 2

Reference Case Energy Savings Estimates

(All Delmarva Power Delaware Distribution Customers)

Reference Case Projected Delmarva Power Cumulative DSM Energy Impacts (MWh)										
DSM Initiative	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
AMI Enabled Reductions	33,000	34,000	33,000	33,000	32,000	32,000	32,000	31,000	31,000	32,000
Distribution Efficiency Improvements	12,392	16,523	20,654	24,785	28,916	33,047	37,177	41,308	45,439	49,570
Transmission Efficiency Improvements	5,614	5,855	6,096	6,342	6,594	6,850	7,110	7,374	7,642	7,914
Combined Heat & Power	61,503	95,335	129,167	162,999	196,831	251,191	305,552	359,912	414,272	468,633
Street Lighting Improvements	2,557	2,670	2,783	2,896	2,896	2,896	2,896	2,896	2,896	2,896
Delaware Weatherization Assistance Program	2,654	3,539	4,424	5,308	6,193	7,078	7,962	8,847	9,732	10,617
Residential Direct Load Control	2,156	5,823	9,418	11,865	11,865	11,865	11,865	11,865	11,865	11,865
Non-Residential Direct Load Control	-	102	732	1,260	1,289	1,316	1,345	1,367	1,391	1,412
Improved Codes and Standards	110,386	147,181	183,977	220,772	257,567	294,363	331,158	367,953	395,125	422,297
SEU Residential EE Programs	124,073	169,144	210,734	218,559	226,708	222,062	240,431	253,843	253,843	253,843
SEU C/I EE Programs	408,270	572,529	728,070	641,268	558,196	484,881	559,199	634,340	634,340	634,340
Total Cumulative Energy Impact (MWh)	762,606	1,052,701	1,329,054	1,329,054	1,329,054	1,347,549	1,536,695	1,720,705	1,807,546	1,895,387
Cumulative Energy Goal Achievement	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table 3

Reference Case Demand Savings Estimates

(All Distribution Customers)

Reference Case Projected Delmarva Power Cumulative DSM Demand Impacts (MW)										
DSM Initiative	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
AMI Enabled Dynamic Pricing	84	120	116	113	110	108	106	104	105	107
Distribution Efficiency Improvements	1	2	2	3	3	4	4	5	5	6
Transmission Efficiency Improvements	2	2	2	2	2	2	2	2	2	2
Combined Heat & Power	9	14	18	23	28	36	44	52	60	68
Street Lighting Improvements	-	-	-	-	-	-	-	-	-	-
Delaware Weatherization Assistance Program	1	1	1	1	2	2	2	2	3	3
Residential Direct Load Control	21	35	41	61	61	61	61	61	61	61
Non-Residential Direct Load Control	-	2	15	26	27	27	28	28	29	29
Improved Codes and Standards	29	39	48	58	67	77	87	96	103	110
SEU Residential EE Programs	33	45	57	59	61	60	65	68	68	68
SEU C/I EE Programs	105	147	186	161	136	114	131	149	149	149
Total Cumulative Demand Impact (MW)	284	406	487	507	497	491	530	568	585	603
Cumulative Demand Goal Achievement	207%	198%	172%	178%	175%	173%	187%	200%	206%	212%

Energy Efficiency and Conservation

In earlier IRPs prior to 2010, Delmarva Power employed an energy efficiency impacts evaluation process which involved the analysis of potential individual efficiency measures where each measure was evaluated for cost-effectiveness using the Total Resource Cost Test (TRC). This process required energy and demand impacts for cost-effective measures to be calculated. This was conducted as part of a more traditional IRP process where the screening assesses the economic performance of measures through standard cost-benefit tests with the intent to select the most economically efficient and cost-effective portfolio, since utility ratepayer funds would be used to implement the programs. At this time, the SEU is responsible for determining:

1. The energy savings measures to be targeted by the SEU.
2. The screening criteria to be used by the SEU to select measures and programs.

The SEU is charged with implementing programs that address efficiency in electricity, natural gas, and other fuels throughout the State, however, the impacts of the SEU activities in the Company's IRP include only electricity savings estimates within the Delmarva Power service territory.[18] The SEU program selection process is not constrained by the traditional utility cost-effectiveness screening process for several reasons:

1. The SEU's programs do not currently use ratepayer funds, and therefore have no direct impact on rates.
2. Over time, the SEU expects to move away from direct rebates that were funded by the American Recovery and Reinvestment Act (ARRA) towards self-sustaining financing and performance contracting. The TRC and other conventional cost-benefit tests typically assume that rebates are the primary method to encourage participation.
3. Since the SEU's programs include electricity, natural gas and other fuels, screening is based more on insuring the availability of programs for all market segments and that all fuels are addressed.

The Delaware Sustainable Energy Utility

As of October 2012, the SEU has developed and implemented a variety of energy efficiency and conservation (EE&C) programs, a portion of which are no longer in operation due to completion of funding available from the ARRA. At this time the SEU is continuing to identify and evaluate the appropriate mix of programs going forward. This work is ongoing and, therefore, specific program initiatives are not available from the SEU at this time. SEU sponsored programs have included programs targeting savings opportunities in all market sectors across a wide range of end use measures.[19] All programs relied primarily upon federal stimulus funding except for the

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[18] The SEU's activities are not subject to Delaware Commission oversight. Delmarva Power representatives meet with SEU representatives periodically to exchange information. Delmarva Power invited the SEU to identify any program plans for inclusion with the IRP.

[19] According to the draft report provided by the SEU, titled "Delaware Energy Efficiency Program Evaluation, Measurement, and Verification Report," the SEU sponsored programs have achieved an annual electric energy savings of 47,559 MWh in the Delmarva Power Delaware area. The Delmarva Power Delaware specific savings were estimated based upon the ratio of annual electricity sales in Delmarva Power compared with other Delaware distribution utilities. An additional 11,493 MWh of annual electric energy savings have been achieved through the SEU's energy performance contracts in the Delmarva Power Delaware area.

Performance Contracting Program which uses tax-exempt bonds and other private sources.[20] The types of programs implemented by the SEU are described below to provide an indication of the types of programs that might be offered in the future.

Programs offered prior to December 2010:

1. ENERGY STAR® Residential Appliance Rebate Program – This program offered Delaware residents up to $200 on certain ENERGY STAR qualified clothes washers, dishwashers, room air conditioners, or gas water heaters. Rebates were supported in part by funds from the American Reinvestment and Recovery Act. *This program was terminated as planned on August 31, 2010.*

Programs offered since December, 2010:

1. Efficiency Plus Homes –
    a. Efficient Home Lighting Program – *Program concluded in August 2011*
    b. ENERGY STAR qualified Heating and Cooling Rebate Program– *Program concluded in December 2010.*
    c. Home Performance with ENERGY STAR (existing homes) – *Program concluded in March 2012.*
    d. Green for Green Program (new construction) – *Program concluded in March 2012.*
2. Efficiency Plus Program for Business – Offered prescriptive and custom equipment incentives and financing. - *Program concluded in September 2011.*
3. Efficiency Plus Program for Institutions and Non-Profits – Offered prescriptive and custom equipment incentives and financing. – *Program concluded in September 2011.*
4. Low Income Multi-Family Housing Loan Program – *Single project and completed.*

[20] Additional program funding was provided from auction proceeds from Delaware's participation in the Regional Greenhouse Gas Initiative ("RGGI").

5. Performance Contracting for Institutions and Non-Profits – *Currently the only program offered. Funded through tax-exempt bonds and other private financing sources.*

At this time the SEU is continuing the Performance Contracting for Institutions and Non-Profits and the SEU plans to re-implement their Green for Green Program. The SEU has budgeted $2.5 million dollars for its Energize Delaware programs in 2013 and is actively planning to bring new programs on in addition to the Green for Green Program. Additional SEU programs are needed at this time to achieve the electric energy and demand reduction goals. If funding is available, any of the above listed programs could be offered in the future.

Potential SEU Energy Efficiency Programs that have not been offered in the past

In addition to the programs previously offered by the SEU, Delmarva Power has prepared a list of potential EE&C programs that are representative of the typical types of EE&C programs implemented in other jurisdictions or have been previously identified by the SEU. These programs typically are cost-effective using a traditional TRC test and could be implemented by the SEU in the future if sufficient funding becomes available.

Potential Residential Programs:

1. Expanded Residential Home Retrofits – Expansion of the previously offered Home Performance with ENERGY STAR. Customers could be eligible for low-interest financing from the SEU. Many of the recommendations are expected to provide sufficient bill savings (from energy bills) to cover the costs of the improvements over the life of the loan.
2. Appliance Recycling – This program encourages customers to recycle old inefficient appliances to ensure that are they removed from the electric grid and disposed of in an environmentally safe way. The appliances must be in working condition at the time of pickup in order to ensure that energy is being saved from their disposal. In exchange for each old electrical appliance, a customer receives a complimentary haul-away and a monetary reward.

3. Quick Home Energy Check-up - This program provides residential customers with a quick energy audit and the installation of free energy savings measures such as CFL and/or LED light bulbs, smart strips and faucet aerators.
4. Behavior Based Program – Under this program comparative billing reports would be created and mailed to residential customers. The reports provide comparative energy use information and tips regarding energy savings techniques. Typically the reports also refer customers to energy efficiency or demand response program participation opportunities. Programs such as this one have achieved proven behavioral based reductions in energy use.

Potential Non-Residential Programs:

1. Expanded Commercial/Industrial Energy Efficiency Programs – Expansion of the SEU's Efficiency Plus for Business Program. Customers would be eligible for low interest financing from the SEU for pre-approved measures and custom measures meeting program criteria for payback. Many of the recommendations will provide enough bill savings (from energy bills) to cover the costs of the improvement over the life of the loan.
2. Retro Commissioning – This program is a systematic process that improves the overall energy efficiency in an existing building by ensuring the equipment and control systems are operating properly. In addition to reducing operational inefficiencies that would result in energy savings, the Retro Commissioning process provides additional benefits in the form of improved comfort, enhanced air quality and reduced occupant complaints.
3. New Construction programs for Commercial buildings - This program would be similar to the residential "Green for Green" program offered by the SEU for commercial buildings.
4. Combined Heat and Power Program – This program provides financial incentives to encourage the installation of distributed generation to meet the electricity requirements of commercial and industrial customers. Please see the additional discussion of this program in the following section for further program information
5. Small commercial program to provide targeted assistance for the installation of high efficiency measures.

Potential Combined Residential and Non-Residential Programs:

1. Sustainable Communities Program – This SEU program would be a community-level development effort (as compared to individual participants) – a neighborhood, group of businesses, participants in a geographic area, etc. who would recommend to the SEU the installation of specific energy efficiency measures and distributed renewables. The program could be divided into two markets segments:

    a. Large Commercial & Industrial ("C&I") Energy Efficiency Program – This program would promote energy efficiency and distributed renewables in the private large commercial and industrial sectors using a performance contracting approach.
    b. Residential, Commercial, and Industrial Efficiency Program – This program would help to promote energy efficiency and distributed renewables in the residential sector (at a minimum) and possibly extending to other sectors.

The Delaware Weatherization Assistance Program (WAP)

WAP installs energy efficiency improvements in low-income households. Specifically, WAP provides for the installation of such measures as: air sealing, insulation, window and door replacement, and furnace repair and replacement. Based on an analysis prepared several years ago on electrically-heated homes by the University of Delaware's Center for Energy and Environmental Policy, WAP estimates KWh savings of 22% on average per household. In program year 2009 (4/1/09 – 3/31/10) the program served a total of 1,221 homes statewide. WAP plans to serve approximately 1,100 homes during each program year going forward.[21]

[21] Information provided by Ken Davis, Manager, Weatherization Assistance Program. Phil Cherry, Administrator of the Program, has confirmed that these are the best available assumptions at this time.

Combined Heat and Power Potential

The Act states that there shall be established requirements to include procedures for counting combined heat and power savings towards the energy and demand savings goals.[22] Delmarva Power conducted a separate study during 2010 of Combined Heat and Power ("CHP") potential in the Delmarva Power service territory of Delaware. The results of this study remain applicable for the current IRP analysis, although savings achievements will be shifted further out in time because the program has not been implemented. (Please refer to the Delmarva Power & Light Company 2010 Integrated Resource Plan, Attachment 1 to Exhibit B titled "Combined Heat and Power Market Assessment for Delmarva Power", May 2010, prepared by ICF International.)

CHP offers a potentially efficient and clean approach to generating electricity or mechanical power and supplying useful thermal energy from a single fuel source at the point of use. Instead of purchasing electricity and also burning fuel in an on-site furnace or boiler to produce thermal energy, an industrial or commercial facility can use CHP to provide these energy services in one energy-efficient step. As a result, CHP can provide significant energy efficiency and environmental advantages over separate heat and power supplies. CHP systems are located at or near end-users, and therefore lessen or defer the need to construct new transmission and distribution (T&D) infrastructure. While the traditional method of producing separate heat and power has a typical combined efficiency of 45%, new CHP systems can operate at efficiency levels as high as 80%. CHP's high efficiency results in less fuel use and lower levels of greenhouse gases emissions.

To estimate the potential for CHP in Delmarva's Delaware service territory, Delmarva Power used the *ICF CHP Market Model.* This model estimates cumulative CHP market penetration as a function of competing CHP system specifications, current and future energy prices, and electric

[22] It is not clear at this time whether the SEU will be pursuing implementation of a CHP program. In the event that the SEU chooses not to do so, Delmarva Power may propose a plan for approval by the Public Service Commission to design and implement a CHP program.

and thermal load characteristics for target markets. The CHP analysis included the following four steps:

- Estimate CHP Technical Market Potential – An estimate of the technically suitable CHP applications by size and by industry. This estimate was derived from the screening of customer data based on application and size characteristics that were used to estimate groups of facilities with appropriate electric and thermal load characteristics conducive to CHP.

- CHP Technology Characterization – For each market size range, a set of applicable CHP technologies were selected for evaluation. These technologies were characterized in terms of their capital cost, heat rate, non-fuel operating and maintenance costs, and available thermal energy for process use on-site.

- Estimate of Energy Price Projections – Present and future fuel and electricity prices were estimated to provide inputs into the CHP net cost calculation.

- Estimate of CHP Market Penetration – Within each customer size, the competition among applicable CHP technologies was evaluated. Based on this competition, the economic market potential was estimated and shared among competing CHP technologies. The rate of market penetration by technology was then estimated using a market diffusion model.

CHP Market Penetration Results

CHP market penetration was analyzed for two alternative sets of input assumptions:

- Base Case – existing federal incentives for CHP with no assumed supplemental SEU or utility provided incentives.

- Incentive Case – a 20% reduction in the capital cost was assumed in addition to existing federal tax credits.

The resulting difference between these two cases provides the estimated energy and peak demand grid savings.

CHP Incentive Case – 20% Capital Cost Reduction

An incentive scenario representing a 20% capital cost reduction for CHP was evaluated to measure the increase in market penetration. This is a potential incentive program that Delmarva Power or the SEU could establish to increase the adoption of CHP in its service territory.[23] The gas and electric pricing and all other assumptions are the same as the *Base Case* assumptions.

In the Base Case (what would be expected without incentives), the projected CHP market penetration in the next five years is 16.6 MW out of an economic potential of 39.5 MW. Addition of the 20% capital cost reduction incentive increases the five year market penetration to 26.5 MW out of an economic potential of 62.9 MW. By 2025, the cumulative market penetration in the Base Case is 59.1 MW. The 20% capital cost reduction is estimated to increase this market penetration by 28.4 MW to a total of 87.4 MW – a 48% increase in the market size.

Demand Response Programs

Delmarva Power is responsible for implementing demand response programs within its service territory, although additional demand savings will result from the SEU's energy efficiency and conservation programs and all other energy savings sources with the exception of street-lighting improvements. Consequently, Delmarva Power has two programs currently approved which are being phased-in in 2012 and 2013 and has developed demand response potential projections for one other program. These three combined programs address all customer market segments for Delmarva Power Delaware. The approved and projected programs have been designed specifically to participate in available demand response market opportunities within the PJM capacity and energy markets.[24] Participation in these markets provides a potential revenue stream to offset a portion of program costs, provides PJM dispatchers demand response programs that can be used to help maintain system reliability during high load periods, and helps to

[23] The Delaware Energy Efficiency Investment Fund that is managed by the Delaware Division of Energy and Climate has expressed an interest in pursuing CHP opportunities as well.
[24] PJM market demand response rules are evolving and therefore existing rules will change over time. Delmarva Power participates in the PJM stakeholder process related to these market rule changes.

mitigate high regional electricity market capacity and energy prices. The programs can also be used by Delmarva Power to help manage localized distribution system problems depending upon their location and scale. Demand Response Programs help to defer the need to construct additional generation resources, transmission facilities, and distribution facilities. The programs can also assist with the integration of renewable generation sources, such as wind power, due to its uncertain availability during periods of high electricity demand. Finally the programs offer consumers a direct method of reducing their monthly electricity bills through both various incentives for participating in each program and the reduction of energy consumption during specific periods of time.

Dynamic Pricing – "Peak Energy Savings Credit"

On March 23, 2011, Delmarva filed an Application to Implement and Advanced Metering Enabled Dynamic Pricing Plan and Dynamic Pricing Rider DP. On December 20, 2011, the Commission approved the Settlement Agreement entered into by Delmarva, Commission Staff and the Division of Public Advocate, and on January 31, 2012, issued its Final Findings, Opinion and Order (Order No. 8105) approving the proposed phase-in implementation of its Advanced Metering Infrastructure enabled Dynamic Pricing Program for its Standard Offer Service customers. The approved rate is structured as a default Critical Peak Rebate rate with the ability for the customer to opt-out of the program. The program will be offered to all Delmarva Power residential SOS customers and all Delmarva Power small and medium non-residential SOS customers. The program is currently titled the "Peak Energy Savings Credit Program."

The program provided dynamic pricing signals beginning in June 2012 to approximately 7,000 residential customers who participated in the AMI Field Acceptance Test (FAT) which took place in 2009. This part of the residential dynamic pricing phase-in concluded on September 29, 2012. Delmarva Power is incorporating the lessons learned from the phase-in to further improve and refine the program during 2013.

In June 2013, the second phase of the program will begin with the remaining Delmarva Power residential SOS customers being defaulted to the dynamic pricing rate. In addition, approximately 240 small and medium non-residential FAT will be moved to the moved to the rate. The final phase of program implementation will begin in June 2014 where all Delmarva Power residential and small and medium non-residential SOS customers will be placed on the dynamic pricing rate.

Delmarva Power and the Brattle Group have performed a detailed study of the projected energy and demand savings attributable to dynamic pricing in the Company's Delaware service territory based upon load reduction impacts from available comparable industry studies – the ongoing Baltimore Gas & Electric Company's (BGE) dynamic pricing pilot, and the California statewide pricing pilot. The residential impacts of dynamic pricing programs in Delaware were estimated by adapting the Pricing Impact Simulation Model (PRISM) developed through the California smart meter pilot studies to the price elasticities that were estimated through the BGE study. Non-residential customer price elasticities were based upon results from the comprehensive California dynamic pricing pilots. All pricing estimates were adjusted for Delaware load shapes and weather conditions.

The dynamic pricing impact study excluded the load impacts of Delmarva Power's existing and planned direct load control program, the projected energy efficiency and conservation savings expected to be achieved by the SEU, and energy and demand savings from other identified sources. These adjustments lessen the estimated demand savings that will be achieved by dynamic pricing programs; therefore, if reductions from other sources are not achieved, demand reductions from dynamic pricing are expected to be higher. Dynamic pricing is expected to provide 116 MW of peak demand reduction by 2015. In the event that PJM wholesale electricity market conditions for the Delmarva Power Delaware region change, dynamic pricing incentives can be adjusted to reflect those changes.

Delmarva Power's AMI deployment has enabled the Company to provide additional detailed electric energy use information to all residential and small commercial customers. The additional energy usage information is now available through Delmarva Power's monthly electricity bills and its "My Account" web portal. Delmarva Power provides energy savings tips through the My Account web portal and via its call center through its Energy Advisors.

Delmarva Power has estimated that residential customers will reduce their energy consumption by 1.5% annually due to the availability of detailed energy use information to Delmarva Power customers.[25]

Delmarva Power's specific projected programs include:

- A residential air conditioner direct load control program consisting of a choice of smart thermostats or outdoor switches.
- A small commercial customer packaged air conditioner direct load control program consisting of a choice of smart thermostats or outdoor switches.

Table 4 contains the results of Delmarva Power's recent cost-effectiveness screening for the Company's approved residential direct load control program. The presented cost-effectiveness calculation is conservative and it does not include capacity and energy price mitigation benefits. Both programs are expected to be very cost-effective under the Total Resource Cost Test.

Table 4

Residential Direct Load Control Cost Effectiveness Results

Total Resource Cost Test (All $ Values in $1,000,000)		
Costs	Benefits	Ratio
$ 26.38	$ 65.31	2.48

Residential Direct Load Control

On November 5, 2012, Delmarva Power received Public Service Commission approval of its proposed Residential Direct Load Control Program ("DLC"). The new DLC program is titled the Energy Wise Rewards™ Program. The DLC program is a voluntary customer program designed to update, expand, and over time, replace the legacy Energy For Tomorrow central air conditioning/heat pump load control program with newer technology. The new program will

[25] See also a paper by Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence", *Energy: The International Journal,* April 2010.

provide a voluntary and simple method for residential consumers with central air conditioning or heat pump systems to automatically reduce peak electricity demand during peak usage periods and to reduce overall air conditioning and heating system energy consumption. The program will accomplish this through the installation of either a remotely controllable smart thermostat or direct load control switch. (Participating customers will have the option of choosing either of the devices.) These devices will reduce the air conditioner load on the electric system after receipt of a Delmarva Power command signal. The smart thermostats will be capable of being programmed to automatically vary temperature settings, thereby providing added energy savings opportunities for Delmarva's customers. The planned program will be integrated with Delmarva Power's AMI system. This will permit the Company to rely upon the two-way communication capability of the AMI system and participant credits will be based upon the dynamic pricing rebate rate.

As shown in Table 3, available peak demand reduction capability for the Residential DLC Program is projected to be 41 MW by the 2015 summer. Associated energy savings are estimated to exceed 9,000 MWh by year-end 2015.

Non-Residential Direct Load Control

The primary objective of the voluntary Non-Residential Load Control Program is to provide a simple method for non-residential consumers with central air conditioning or heat pump systems to automatically reduce peak electricity demand during peak usage periods and to also reduce their overall electricity consumption. Similar to Delmarva Power's residential direct load control program, this program will provide the installation of either a remotely controllable smart thermostat or a direct load control switch. (Participating customers will have the option of choosing either of the devices.) Available peak demand reduction impacts for the Non-Residential Direct Load control are projected to be 15.2 MW by 2015. Projected energy savings are estimated to exceed 700 MWh annually by year-end 2015. These savings estimates are included within Table 9 in the non-residential program figures. Delmarva Power will seek Commission approval of this program later in 2013 after the residential direct load control program implementation has begun.

Transmission and Distribution Efficiency Improvements

The Act defines Energy Efficiency to include "the reduction in transmission and distribution losses associated with the design and operation of the electrical system."

Transmission Loss Reductions

Delmarva Power's transmission system is continually being upgraded. These upgrades are a result of the PJM Regional Transmission Expansion Process which has the responsibility of ordering new transmission facilities to be built in order to meet all applicable reliability criteria. PJM has the responsibility for planning and operating the transmission system. Each year, PJM takes a detailed forward look to make sure that the transmission system that is required to supply future load growth meets the appropriate reliability criteria. PJM then determines what additions to new transmission facilities or upgrades to existing transmission facilities are required. Besides increasing the reliability of the transmission system, these system upgrades have the added benefit of reducing system losses. Adding new facilities or upgrading existing facilities in many cases reduces the impedance of the system and allows the transmission system to function more efficiently, meaning that more of the power generated or imported is used to serve the distribution system rather than being consumed on the system as transmission line and transformer losses.

A study was performed to compare the 2012 transmission topology with the topology that is expected to exist in 2017 with all of the transmission upgrades required between 2013 and 2017 included in the analysis. The results of these added upgrades are expected to reduce the transmission system losses by 0.3% annually. Using the Delmarva Power FERC Form No. 1 from 2011/Q4, this translates to an approximate savings of 2,280 MWh on an annual basis. The transmission system additions and upgrades that are presently part of the PJM Regional Transmission Expansion Plan for the period 2013 to 2017 are shown in Table 6.

The reduction in transmission losses from Year 2013 through 2022 for Delaware electric customers are expected to be 1.8 MW's and 4,631 MWh over that time period. Table 5 contains the projected incremental savings for each year. The savings through Year 2022 may be higher if the PJM RTEP process determines that there is a need to reinforce the system through additional transmission upgrades. The PJM RTEP results have only been fully evaluated through the 2016/2017 PJM planning year. These studies are re-evaluated every year and the results may alter future transmission improvements.

Table 5

Incremental Reductions in Transmission Losses Due to System Upgrades

Years 2013 – 2022

Incremental Reductions in Transmission Losses Due to System Upgrades from Year 2013 - 2022										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
MW	0.5	0	0.4	0	0.1	0.1	0.1	0.2	0.2	0.2
MWh	1528	0	1223	0	306	309	312	317	318	318

Notes:

1. The MW value represents the savings in transmission losses for Delmarva (Delaware customers only)
2. The MWHr numbers were calculated based on loading factors from the FERC Form 1 "Energy Sales" 2011 Q4
3. The data past Year 2017 was based on Demand growth for MW and Energy growth for MWHr

Capacitor Control Program

Delmarva Power plans to implement a new Distribution VAR Dispatch (DVD) System. This System will have two-way communication with capacitors controlled by a centralized computer system integrated with an Energy Management System. The System will also include local voltage override on each bank and a stand-alone operation mode that will serve as a voltage controlled capacitor bank in the event that communication is lost.

The concept and equipment for this program were selected as part of the PHI Blueprint for the Future initiative. This system will also have the capability to remotely operate capacitor banks by the system operators should a situation arise. Current plans are to install controllers on capacitor banks tied together with two-way communication via the installed Silver Spring AMI Network and having a centralized control algorithm integrated with the EMS. The DVD System will have the capability to maintain unity power factor at the substation and on the individual distribution feeders. Implementation of this system is expected to begin in year 2013 with savings ramping up as the project progresses.

Energy Savings from Higher Efficiency Transformers
Compared to Industry Minimum Efficiency Levels

Electric distribution transformers are evaluated consistently throughout the PHI utility companies using the minimum efficiency tables contained in NEMA TP1-2002, Section 4. At the time that the U.S. Department of Energy (DOE) issued their Final Ruling in 2007 to establish more stringent minimum efficiency levels, Delmarva Power was already investigating methods to increase the minimum efficiency levels. Beginning in 2008, Delmarva Power purchased transformers consistent with DOE's pending TSL-2 level efficiency criteria. Consistent with moving forward with this effort, Delmarva Power is now evaluating transformers using the Total Owning Cost (TOC) Methodology as specified in NEMA TP1-2002, Section 2.

Near the end of 2009, Delmarva Power, through its parent Company, PHI, awarded a multi-year contract for the purchase of liquid immersed distribution transformers to several manufacturers based on the TOC Methodology for evaluating transformers. In order to meet the DOE recently-implemented (January 2010) high efficiency transformer specifications, some transformer manufacturers chose to quote their bids using amorphous metal steel for core construction in their units.

Amorphous Metal (AM) is a unique alloy structured of atoms that occur in random patterns. Conventional grain oriented steel (silicon steel) has an organized crystalline structure with much higher resistance to magnetization, which leads to higher core losses. AM is a metallic alloy with no crystalline structure due to the use of Boron in the alloy. Lower losses in AM transformers are a direct result of the lower loss in the base material. The absence of the crystalline structure leads to lower hysteresis losses in the core, and the higher resistivity and lower thickness of the metal leads to lower eddy current losses in the core. This results in total losses for AM at about one third of those found in silicon steel transformers.

Delmarva Power awarded one transformer manufacturer a contract to supply both single and three-phase pad mount transformers and that the manufacturer will also supply AM units. Other manufacturers chose to supply silicon steel transformers built to the new DOE efficiency levels. The successful manufacturer for single phase pole type transformers will be supplying silicon steel for core construction for all but eight stock transformer types. The remaining eight will be constructed with AM. These three types of transformers, the pole-type and both pad mount-types, account for the vast majority of the transformers to be used in Delaware.

As both AM units and higher efficiency silicon steel units are delivered, they will be used in new construction after existing inventories are depleted. Manufacturers and utilities alike recognize the high potential to save energy by installing low loss transformers for new construction. In addition, as older transformers are replaced, these higher efficiency units will be used. Even higher energy savings can be realized by replacing old high loss transformers with new low loss designs, including both amorphous and DOE efficiency units.

Table 6 contains the expected annual average demand reduction, in kilowatts, resulting from the reduction in losses of new higher efficiency transformers when compared to the DOE minimum efficiency levels implemented January 1, 2010. The table also indicates the expected annual energy savings due to the use of AM and silicon steel transformers when purchased using the TOC methodology as compared to the DOE minimum efficiency levels. Since the DOE minimum efficiency levels are the current standard in the industry effective 2010, Delmarva Power will achieve this energy savings as these units are installed.

Table 6

Average Demand & Energy Savings over Industry Minimum Efficiency

Average Demand & Energy Savings Over Industry Minimum Efficiency

Transformer Type & Core Construction	Estimated Annual Quantities (Units)	Total Aggregate Nameplate KVA	Expected Annual Avg. Demand over DOE (kW)	Expected Annual Energy Savings (MWh)
1-Phase Pad Amorphous	813	53,307	181	1,587
3-Phase Pad Amorphous	129	53,875	164	1,433
1-Phase Pole Amorphous	875	29,025	97	851
1-Phase Pole Silicon Steel	576	33,168	30	260
Total	2,393	169,375	472	4,131

Table 7 below contains both the cumulative annual average demand (in kW) and the cumulative annual energy savings (in MWh) that will be realized through the purchase of higher efficiency transformers as a result of evaluating using the Total Owning Cost Methodology of NEMA TP1-2002, Section 2.

Table 7

Cumulative Expected Annual Energy Savings from Transformer Purchases by TOC Methodology

Cumulative Expected Annual Energy Savings from Transformer Purchases by TOC Methodology

Higher Efficiency Transformers Purchased for Delaware	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Estimated Annual Quantities (Units Installed)	2,393	2,393	2,393	2,393	2,393	2,393	2,393	2,393	2,393	2,393
Cumulative Annual Average Demand Savings (kW)	1,415	1,886	2,358	2,829	3,301	3,772	4,244	4,716	5,187	5,659
Cumulative Annual Energy Savings (MWh)	12,392	16,523	20,654	24,785	28,916	33,047	37,177	41,308	45,439	49,570

Assumptions:
1. Transformer usage will be flat for next several years based on forecasted URD and housing construction.
2. All transformers purchased within each year will be installed within that year.

Savings from Mercury Vapor to High Pressure Sodium Streetlight Replacements

As a result of EPACT 2005, the Federal Government banned the manufacture and importation of Mercury Vapor (MV) streetlight ballasts, effective January 1, 2008. After a review of options, PHI implemented a plan to proactively replace MV streetlights over a five year period with High Pressure Sodium (HPS" streetlights throughout its three regional utility companies, including Delmarva Power.

There are several advantages for converting to HPS from MV technology. Both sources are in the High Intensity Discharge (HID) family of lighting products, where gas vapors are held captive in an arc tube and, when a current is applied, the gas particles are excited and result in the production of an intense light. MV is the oldest form and least efficient (lowest efficacy) of the HID lighting choices. HPS offers a level of performance that is acceptable to many users, and improvements have been made over the years to develop the product to where it provides advantages over the MV source. Both HPS and MV lighting technologies have the same average life of 24,000 hours of operation for a standard lamp. HPS lamps also provide a softer, warmer color of light when transitioning from areas of complete darkness. While all HID lamps contain a specific level of Mercury, HPS lamps contain less mercury than MV and other HID sources. HPS also has better "lumen maintenance" than MV technology. Basically, an HPS lamp maintains its lumen output longer than an MV lamp while approaching its end of life. An HPS lamp will remain brighter for the same life span when compared to an MV lamp. On average, when both lamps are replaced after 5-1/2 years, the MV lamp will look visually dimmer than the HPS lamp.

Delmarva Power will reduce the energy consumption of current MV lamp users by offering increased lumen output of light for the customer at a lower power consumption value (wattage) by replacement of existing lamps with HPS lamps. For example, customers presently using a 175W MV lamp receive approximately 7,900 lumens of light. Delmarva Power will provide a 100W HPS lamp and increase the customer's lumen output by approximately 25% to 10,000 lumens. These types of improvements can be made because HPS offers an efficacy of 120 lumens per watt when compared to the 50 lumens per watt output of MV. Given the same power output, HPS provides more than twice as many lumens as MV.

Table 8 contains the annual energy savings (in MWh) that will be realized through the MV to HPS Group Replacement Program for the Delmarva region which began in 2008.

Table 8

High Efficiency Street Lighting Savings

Delaware MV to HPS Conversion Project	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Fixtures/Lamps to be Replaced (number)	450	450	450	450	0	0	0	0	0	0
Cumulative Annual Energy Savings (MWh)	2,557	2,670	2,783	2,896	2,896	2,896	2,896	2,896	2,896	2,896

Demand and Energy Savings from Delmarva Power Initiatives Only

The projected cumulative impacts of the combined Delmarva Power's DSM initiatives for the IRP Reference Case are shown in Table 9 below.[26]

Table 9

Reference Case Projected Delmarva Power Cumulative DSM Impacts

	Reference Case Projected Delmarva Cumulative DSM Impacts (2012 IRP)									
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy Impacts (MWh)										
Residential Load Control	2,156	5,823	9,418	11,865	11,865	11,865	11,865	11,865	11,865	11,865
Non-Residential Load Control	0	102	732	1,260	1,289	1,316	1,345	1,367	1,391	1,412
T&D Efficiency Improvements	20,563	25,048	29,533	34,023	38,406	42,793	47,183	51,578	55,977	60,380
CHP Potential Savings	61,503	95,335	129,167	162,999	196,831	251,191	305,552	359,912	414,272	468,633
AMI Enabled Reductions	33,000	34,000	33,000	33,000	32,000	32,000	32,000	31,000	32,000	32,000
Total Energy Impact	117,222	160,307	201,850	243,147	280,390	339,165	397,945	455,722	515,506	574,290
Demand Impacts (MW)										
Residential Load Control	20.9	35.3	41.2	61.2	61.2	61.2	61.2	61.2	61.2	61.2
Non-Residential Load Control	0.0	2.1	15.2	26.2	26.8	27.4	28.0	28.5	29.0	29.4
T&D Efficiency Improvements	3.0	3.6	4.1	4.7	5.2	5.8	6.3	6.9	7.4	8.0
CHP Potential Savings	8.8	13.6	18.5	23.3	28.2	36.1	44.0	51.9	59.8	67.6
AMI Enabled Dynamic Pricing	84.0	120.0	116.0	113.0	110.0	108.0	106.0	104.0	105.0	107.0
Total Demand Impact	116.7	174.6	195.0	228.4	231.4	238.4	245.5	252.4	262.3	273.2

[26] The exact implementation schedule of these and other programs will depend on the final Delaware Sustainable Energy Utility implementation timing and the timing of any required regulatory approvals for utility provided programs. Third party vendor capability, equipment availability, and program market receptivity will also affect the timing of initiatives. Savings estimates were developed based upon information available to Delmarva Power as of May 2010. The CHP incentive program identified in the table could be offered by either Delmarva Power or the Delaware Sustainable Energy Utility.

Impacts on Savings from Changes in Codes and Standards

The Act further states that there shall be requirements to establish methods for calculating codes and standards savings, including the use of verified compliance rates. Delmarva Power has also considered the potential savings impact of code and standard improvements in Delaware in calculating the total attainable demand and energy consumption savings. The major impacts from codes and standards that are currently in effect and are not already captured in the load forecasting are air conditioning minimum efficiency requirements and Federal lighting efficiency requirements which went into effect beginning in 2011. Since the SEU energy efficiency programs are likely to contain residential and non-residential lighting efforts that extend through 2017 separately, the codes and standards impacts of the lighting efficiency requirements could result in potential double counting of savings. Therefore, only the impact of the air conditioning minimum efficiency requirements that are not captured by either load forecasting or the identified SEU programs was estimated.

The basis for the analysis is that there are energy savings that are not captured in energy efficiency programs which result from the higher minimum efficiency requirements. When an air conditioner is replaced, the current minimum efficiency is significantly higher than the original unit that was replaced. Since an efficiency program only claims savings that are above the required minimum efficiency, any savings resulting from reaching the minimum efficiency levels are not accounted for in the efficiency program impacts. Likewise, the load forecasts only account for the savings that have been recognized from new equipment which has been installed, not what will be installed in the future. An analysis was performed to estimate the impacts resulting from the higher minimum efficiencies required for residential and non-residential air conditioning replacement. The results of the analysis are shown in Table 10.

Table 10

Codes and Standards Impacts

Estimated Cumulative Codes and Standards Energy Impacts (MWh)										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	61,210	81,613	102,017	122,420	142,823	163,227	183,630	204,033	214,813	225,593
Non-Residential	49,176	65,568	81,960	98,352	114,744	131,136	147,528	163,920	180,312	196,704
Total	110,386	147,181	183,977	220,772	257,567	294,363	331,158	367,953	395,125	422,297

Modeling Assumptions

Demand Side Management Impacts Aggregation and Goal Contributions

In order to prepare the energy and demand impacts of the various demand side efforts described above for use in the IPM modeling process, the impacts were aggregated to achieve the goals identified in Table 1. To reach the identified goals, impacts from the approved SEU Programs, Residential and Non-Residential Load Control, T&D Efficiency Improvements, CHP, AMI Enabled Dynamic Pricing and codes and standards were totaled. In years 2013 – 2022, where the impacts from these DSM initiatives did not reach the goals identified in Table 1, impacts sufficient to reach the goals were included from the prospective SEU programs. When impacts from the prospective SEU programs were included, the residential and C/I program contributions are in the same proportion as residential and C&I shares of the total projected SEU Prospective Program impacts.

Initiative Savings for Legislatively Established Target Year 2015

Charts 11 and 12 graphically represent the mix of initiatives selected to achieve the energy and demand savings for year 2015.

Chart 11

2015 Energy Saving Sources

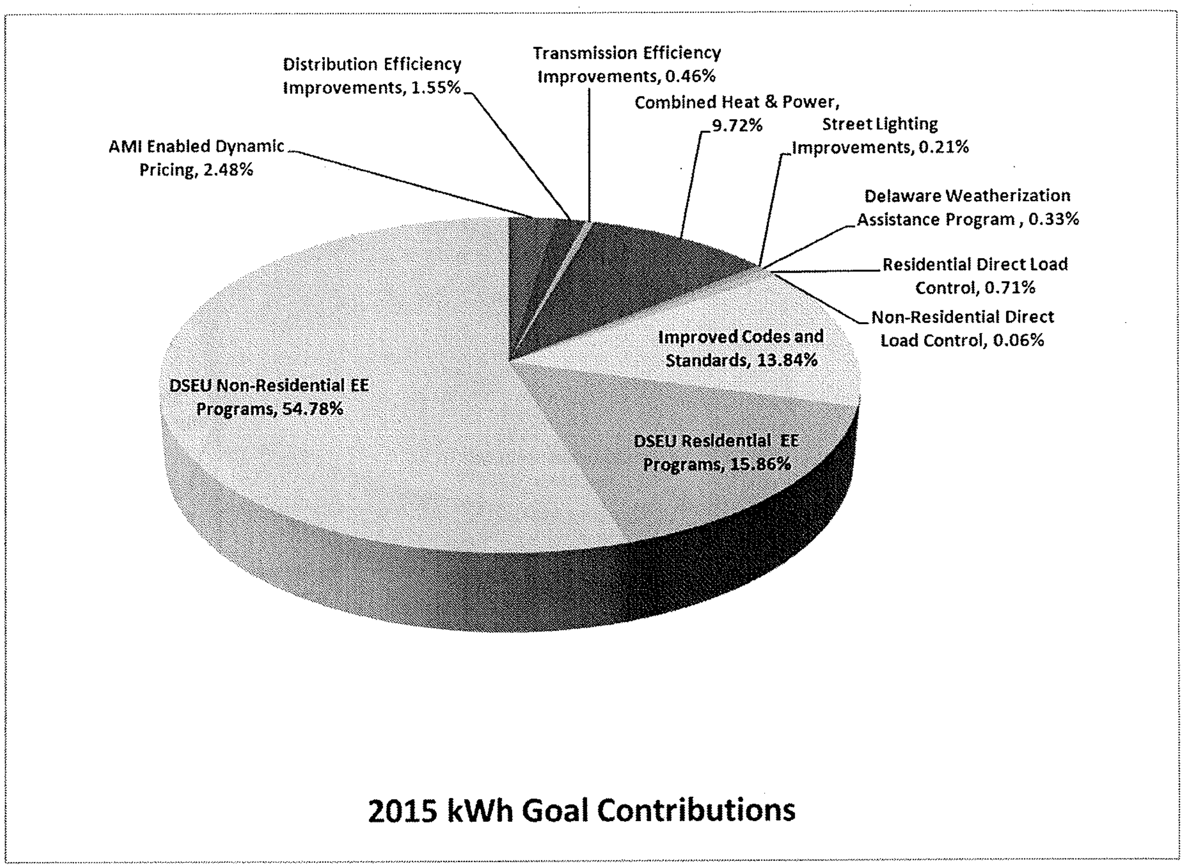
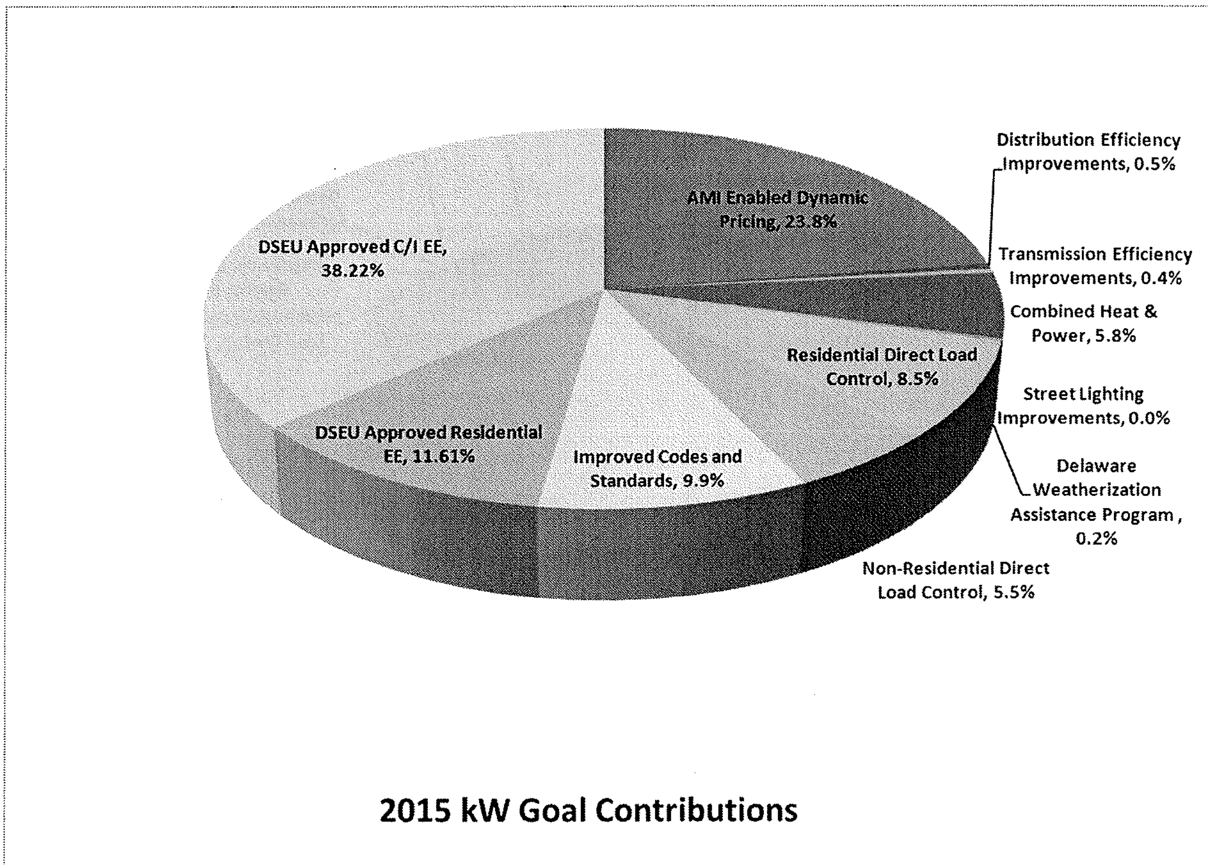


Chart 12

2015 Peak Demand Savings Sources



Allocation of Impacts Across Hours

To prepare the demand side energy impacts for use in the IPM model, it is necessary to create an hourly impact load shape. Since the energy impacts provided by the SEU and other entities were not created using hourly modeling, the necessary load shapes could not be developed directly from the available data. An alternative methodology was employed which used hourly information from the ICF Energy Efficiency Planning Model library to create a representative hourly load shape from the annual energy impacts described above.

The library planning model selected for use was the South Atlantic North (SAN) census region model. The SAN model is an energy efficiency potential model for the states of Delaware, Maryland, Virginia and West Virginia. The SAN model was selected because of its relevance to Delaware and the similarity of the efficiency measure groups which were analyzed and the measures likely to be included in the SEU programs, which comprise a large share of the energy efficiency impacts. The efficiency measure groups that are considered in the SAN model are shown in Table 12.

Table 12

SAN Model Efficiency Measure Groups

SAN Model Efficiency Measure Groups	
RES Efficient Windows	COM Efficient HVAC
RES Efficient Insulation	COM Efficient Boilers
RES Reduced Infiltration	COM Efficient Ducts
RES Efficient Ducts	COM Fluorescent Lighting
RES Efficient Space Cooling Equipment	COM Metal Halide Lighting
RES Efficient Space Heating Equipment	COM Solid State Lighting
RES Efficient Electric Water Heating	COM ENERGY STAR Appliances
RES Incandescent to Fluorescent Lighting	COM CPU Power Management
RES Halogen to Fluorescent Lighting	COM Efficient Refrigeration
RES Solid State Lighting	COM LEED Certification
RES Efficient Refrigerators	COM Building Retro-Commissioning
RES Efficient Clotheswashers	COM Building Commissioning

The hourly load shapes were developed in a three-step process. The first step was to develop hourly factors for total residential and non-residential measures in the model which represent an individual hour's contribution to each annual kWh of residential and non-residential savings. The second step was to aggregate the annual incremental energy-efficiency impacts for residential and non-residential initiatives. The final step was to multiply the appropriate residential or non-residential hourly factor by the total annual impact to calculate each hour's annual contribution. This calculation was performed for each year from 2013 – 2037.

Hourly load shapes are not required for the analysis of load control impacts in the IPM Model. For load control impacts the annual residential and non-residential impacts are utilized.

Contingency Planning

In section 3.2.7 of the new rules governing the preparation of future IRPs, there is a requirement that there be a contingency plan "should one of the supply, demand, or transmission options be either delayed or not realized."

The Act contains a requirement in 26 *Del. C.* § 1502(b) stating that "Affected Electric Energy Providers shall submit to the State Energy Coordinator a report on April 1, for the prior year, demonstrating that it, in cooperation with the SEU and the Weatherization Assistance Program, has achieved cumulative Energy Savings in the previous year that are at least equal to the Energy Savings required by regulations adopted by the Secretary pursuant to 1502(a) of this Chapter."

Several factors could impact when and if Delmarva Power's planned demand response programs or the SEU's energy efficiency programs realize the projected savings. For the Delmarva Power demand reduction programs, timing of receipt of Commission approval of the non-residential direct load control program is a key variable. For the SEU, insufficient funding or other factors could delay or prevent the implementation of energy efficiency and conservation programs and/or limit their operation. Additionally, both Delmarva Power demand response programs and SEU energy efficiency programs are subject to impacts caused by the Delaware economy. Program market receptivity will impact the timing and quantity of achieved electric energy and electric demand reductions.

In the event that any of the DSM programs do not attain the expected savings impacts and it is reflected in the required annual report that Delmarva Power has not achieved the energy savings required for the given year, the Act permits an additional Energy Efficiency Charge to be created on Delmarva Power's utility bills and it states that "...[s]hould an Affected Energy Provider determine that an energy efficiency charge is necessary to achieve the goals, they may make such a recommendation in the Workgroup study...." This Energy Efficiency Charge could then be used to directly fund additional DSM activities within Delmarva Power's service territory. Additionally, if savings are not achieved by 2015, the Company will initiate working groups with all stakeholders, including the SEU, to discuss possible revisions to program plans and other alternatives. During these meetings, the Company will offer alternative programs and approaches to achieving energy and demand savings.[27]

Sensitivity Analysis

In the Reference Case, Delmarva Power assumes that the energy reduction targets defined by the Energy Efficiency Act of 2009 are achieved. These goals include a 15% reduction from 2007 energy consumption levels by 2015 and the IRP Reference Case assumes that this target will be met on schedule. The following sensitivity analysis examines the impact assuming that the energy efficiency savings goal was met in 2022 rather than in 2015. In this scenario it was assumed that in 2015 25% of the energy efficiency and conservation program reduction set forth in the Reference Case[28] goal would be met and that a ramp up of programs would occur until the original 2015 electric energy savings goal is achieved in 2022. A comparison of the reference case to the sensitivity analysis is shown in Graph 1. The economic value of the area between the two lines represents the "lost opportunities" of the later achievement of this goal for Delmarva Power customers.

[27] The SEU is free to develop whatever supplemental initiatives or energy efficiency programs it determines appropriate.
[28] Delmarva Power IRP, Demand Side Management Analysis Table 2.

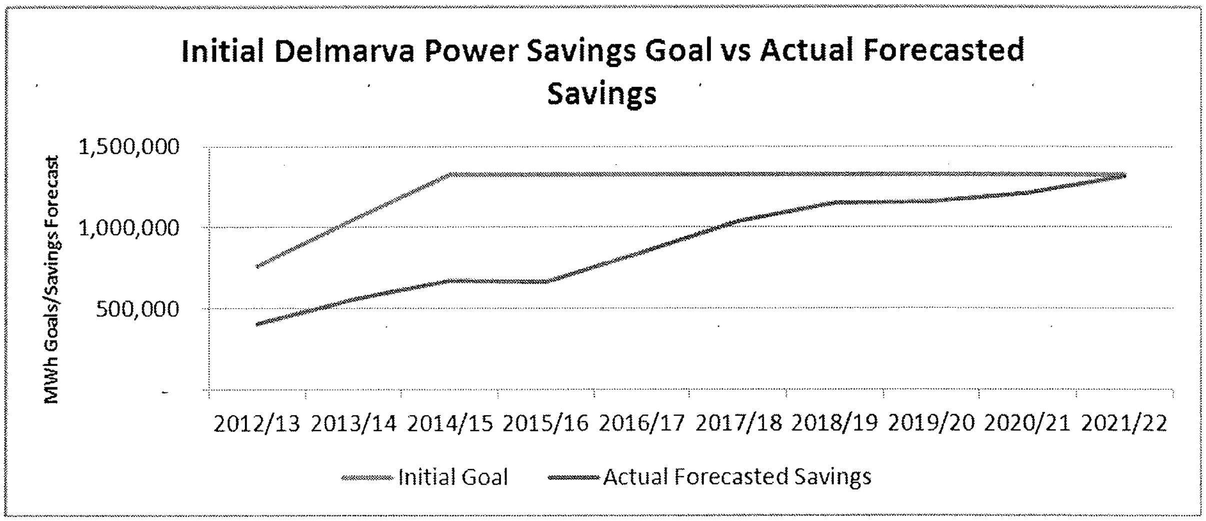


Table 2 below shows the lost opportunity in electric energy and peak demand reduction that are not achieved under this sensitivity. In this sensitivity analysis, the initial shortfall in 2015 represents 75% of the expected energy and demand savings that was forecast in the Reference Case for energy efficiency and conservation programs. This shortfall gradually diminishes and is eliminated at the end of 2022.[29]

Table 2

Lost Opportunities Measured in MWh and MW per PJM Planning Period

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
MWh Lost Opportunity	354,171	492,464	654,840	667,008	478,544	291,175	177,298	167,111	115,258	8,649
MW Lost Opportunity	110	153	193	140	89	37	33	28	0	-27

Table 3 shows the calculated lost wholesale opportunity costs associated with this scenario. There are several types of costs that were quantified in this analysis. These include the cost of energy that would have been avoided in the Reference Case, the cost of additional capacity required as a result of the energy efficiency shortfall and the cost of additional Renewable Energy Credits that Delmarva Power would have to purchase as a result of the increased energy consumption increasing the amount of RECs needed to comply with the state Renewable Portfolio Standards requirement. These costs are valued based on the output of the IPM® model.

[29] The majority of the additional energy efficiency savings would be provided by the Delaware Sustainable Energy Utility (SEU).

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As shown below the annual lost opportunity cost could be significant in a number of years. The overall lost opportunity cost is over $230 Million on a cumulative basis.

Table 3

Value of Lost Opportunity Cost in Millions of Dollars per PJM Planning Period

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
MWh Lost Opportunity $	$ 13,551	$ 21,429	$ 29,990	$ 32,241	$ 23,605	$ 15,847	$ 10,346	$ 10,110	$ 7,200	$ 555
MW Lost Opportunity $	$ 7,442	$ 13,650	$ 9,612	$ 8,586	$ 7,558	$ 3,786	$ 3,773	$ 3,245	$ 28	$ (3,410)
RPS Additional Cost	$ 129	$ 583	$ 813	$ 1,854	$ 2,196	$ 1,721	$ 1,278	$ 1,425	$ 1,168	$ 100
Total Lost Opportunity Cost	$ 21,122	$ 35,662	$ 40,415	$ 42,680	$ 33,359	$ 21,354	$ 15,398	$ 14,780	$ 8,396	$ (2,755)

If these numbers were adjusted to the retail or customer level the lost opportunity costs would increase due to line losses and required RECs as well as supplier hedge premiums. In addition, energy and capacity price mitigation impacts will be lost. This will result in higher PJM market prices for both capacity and energy for all Delaware customers for a period of time. Other lost benefits that are associated with this scenario include a loss of environmental benefits and positive reliability impacts.

VI. Transmission

Delmarva Power's transmission facilities are located within the PJM Regional Transmission Organization (RTO). Delmarva Power works with PJM to ensure that reliability standards are met and that the necessary transmission facilities are built to meet the short and long term needs of the Delmarva Peninsula.

PJM, as the RTO, is responsible for ensuring:

- Adequate generation or demand side resources across the entire region.
- Adequate transmission capacity to reliably and efficiently deliver the generation capacity where it is needed.

PJM meets these objectives by administering competitive markets that encourage merchant generation, transmission and demand-side resources. In addition, PJM, as the regional planner, identifies violations of the PJM planning criteria and works with Delmarva Power's Transmission Planning Department to verify the accuracy of the violations and determine the most appropriate system upgrades to mitigate those violations. The selected upgrades are ultimately included in the PJM Regional Transmission Expansion Plan (RTEP).

PJM's planning process is a rigorous 24-month process, which uses a 15-year horizon, as outlined in PJM Manual 14-B, available on the PJM web site. The 24-month planning process is made up of two similar 12-month planning cycles to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. The planning process takes into account the requirement that the future transmission system must meet all applicable reliability criteria including North American Electricity Reliability Council (NERC), Reliability First Corporation (RFC), PJM and Delmarva local planning criteria. PJM tests the system under both expected normal peak conditions and extreme conditions where peak loads are higher than forecasted and there are more generating units out of service than would be expected under normal peak conditions. Based on this analysis, PJM, with support from Delmarva, develops a detailed near-term and long-range plan to ensure that the transmission system has sufficient capability to serve the load and that generation resources within PJM are deliverable. The transmission system plans that are developed include upgrades and additions to the transmission system, as well as new reactive sources, to assure adequate transmission system voltages are maintained under all tested conditions. The load flow cases on which the plan is based include all assumptions about the expected load forecasts, the Demand Response programs, and the proposed generation available. For example, the load flow cases that were used for 2017 planning year assumed that Indian River units #1, #2, and #3 were all retired.

The table below lists pending individual transmission system upgrades that comprise the near-term plan for projects in Delaware. A short description of each project as well as the PJM project identification number, expected in-service date and estimated project cost are provided in the table. The information listed is also available on the PJM web site. PJM will finalize a complete list of projects by the end of the year that will be used as part of the 2012 RTEP report which will be issued by February 2013.

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Table 1– Transmission System Planned Upgrades

Upgrade ID#	Project Description	In-Service Date	Estimated Cost ($M)
B0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, remove relay limits on Cecil-Colora 230 kV line & Cecil-Glasgow 138 kV line, and operate the 34 kV bus normally open	6/1/2013	$10.80
B0725	Steele Sub - Add 3rd 230/138kV Transformer	6/1/2013	$9.75
B0733	Harmony Sub - Add 2nd 230/138kV Transformer	6/1/2013	$14.82
B0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line and upgrades necessary substation equipment to bring the normal rating to 298 MVA and the emergency rating to 333 MVA	6/1/2013	$16.34
B0873	Build 2nd Glasgow-Mt Pleasant 138 kV line	6/1/2013	$12.76
B0732	Rebuild Vaughn-Wells 69 kV line	6/1/2013	$1.20
B0752	Reybold - Lums Pond 138 kV: Replace two circuit breakers to bring the emergency rating up to 348 MVA	6/1/2013	$1.00
B0874	Reconfigure Brandywine substation	6/1/2013	$16.98
B1899.2	Install new variable reactors at Cedar Creek 230 kV	12/31/2013	$2.86
B1246	Re-build the Townsend - Church 138 kV circuit	6/1/2014	$14.42
B1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV	12/31/2014	$5.35
B1247	Re-build the Glasgow - Cecil 138 kV circuit	6/1/2015	$6.80
B1249	Reconfigure the existing Sussex 69 kV capacitor	6/1/2015	$1.27
[redacted]			

Table 2 below shows the Delaware RTEP projects that were constructed by year since the last Delaware Integrated Resource Plan was submitted. The projects addressed reliability concerns and were identified to resolve violations flagged by PJM in their RTEP process. In addition, these projects helped mitigate economic concerns by lowering congestion hours for all Delaware customers.

Table 2 – Transmission Projects completed in Delaware 2011-2012

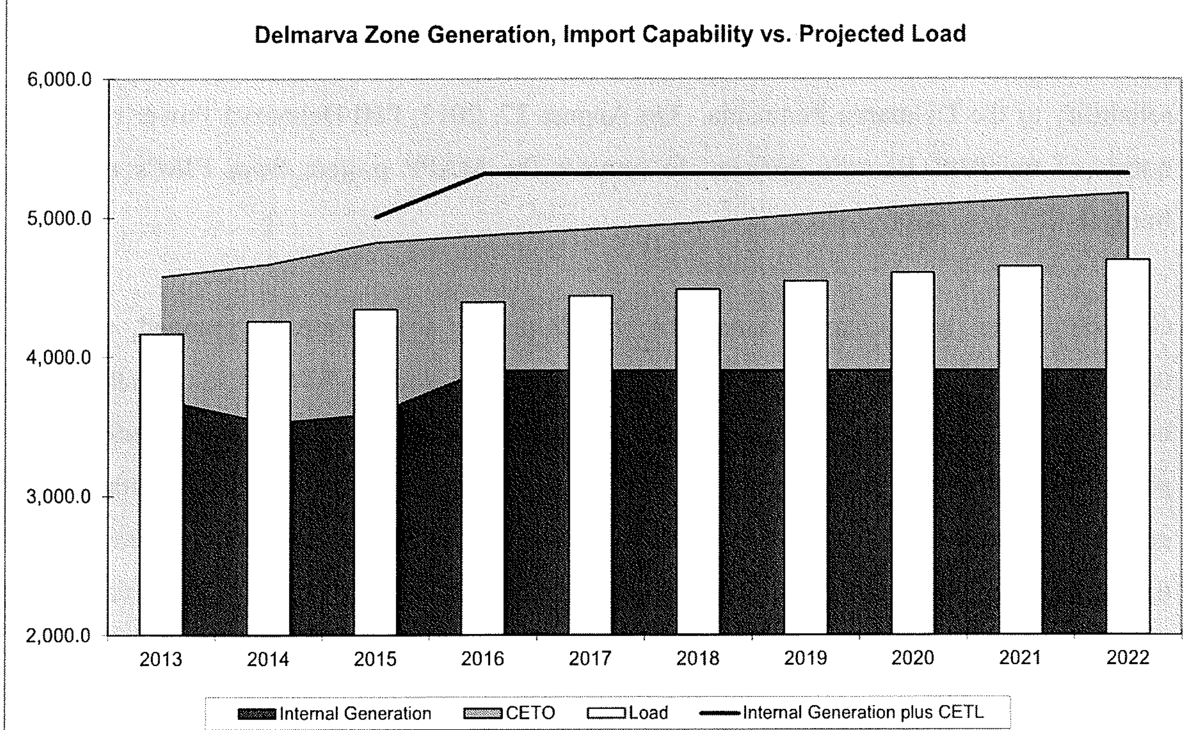
Upgrade ID#	Project Description	In-Service Year
B0568	Add third Indian River 230/138 kV transformer	2011
B0480	Rebuild Lank - Five Points 69 kV	2011
B0481	Replace wave trap at Indian River 138kV on the Omar - Indian River 138kV circuit	2011
B1899.1	Install new variable reactors at Indian River and Nelson 138 kV	2012
B0751	Add two additional breakers at Keeney 500 kV	2012
B0737	Build a new Indian River-Bishop 138 kV line	2012

As previously noted, in addition to the detailed plans developed for the next five years, PJM also works with stakeholders, including Delmarva Power, to develop a 15-year plan which addresses the need for new major backbone transmission projects at higher voltages. PHI/Delmarva Power previously identified the Mid-Atlantic Power Pathway as a major 500kV backbone transmission project which would provide additional capacity and reliability to the Delmarva Peninsula. On August 27, 2012, PHI/Delmarva Power received notice of the PJM Board's decision to remove the MAPP project from PJM's regional transmission expansion plans.

Grid conditions have changed since the MAPP project was originally planned, and the updated analysis performed by the transmission planning staff at PJM no longer showed a need for the MAPP project to maintain grid reliability during the planning period. In particular, lower load projections resulting from a slower economy, coupled with recent generation additions and increased demand response, are the factors that reduced the need for this project. As a result of PJM's decision to cancel the MAPP project, PHI/Delmarva Power does not have any backbone transmission projects in PJM's 15-year plan. Currently, there are no planned major backbone transmission projects in Delaware.

The graphical data in Figure 4 below shows the import capability into the Delmarva zone with respect to the zonal load. The Capacity Emergency Transfer Objective (CETO) target was calculated and published by PJM for study year 2015. CETO values for years prior to and after were extrapolated based on the 2015 value and the yearly change in the forecasted load. The Capacity Emergency Transfer Limit (CETL) target was calculated and published by PJM for study year 2015. PJM plans for a minimum CETL to CETO ratio of 115%. The chart above conservatively holds CETL values for years 2016 – 2023 constant. The rise in the "Increased Generation plus CETL" value in 2016 is attributed to increased generation on the Delmarva system. Based on PJM's published CETL to CETO value of greater than 115% for Delmarva in 2015, it is not anticipated that the CETO value will exceed the CETL value within the Delmarva zone over the planning horizon. The data presented in Figure 4 illustrates that over the IRP planning period, it is expected that there will be sufficient generation and transmission resources to meet projected zonal load and PJM planning objectives.

Figure 4 – Delmarva Zone Generation, Import Capability vs. Projected Load



Capacity Emergency Transfer Objective (CETO) - is the targeted import capability objective into the area to meet established regional reliability margins. Capacity Emergency Transfer Limit (CETL) - is the estimated/calculated import capability into the area. 2015 CETL values as listed in PJM 2015/2016 BRA documentation. CETL conservatively held flat for future years.

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Contingency Plan

The PJM RTEP considers the near-term (five years out) and long-term (15 years out) needs of the regional transmission system and is updated on an annual basis. As new decisions are made during the RTEP process, Delmarva Power updates its plans accordingly.

Changes to the RTEP process

As per the requirements of The Federal Energy Regulatory Commission (FERC) Order 1000 issued on July 21, 2011 requiring changes to the Transmission Planning and Cost Allocation processes, PJM and stakeholders have been working through the PJM Regional Planning Process Task Force (RPPTF) to revise the affected PJM planning protocols to align them with the requirements outlined in the Order. The Order can be reviewed in its entirety, along with the subsequent FERC Order 1000-A on the FERC website (http://www.ferc.gov/). The order addresses the following topics: Planning Requirements inclusive of local, regional and interregional transmission planning processes, Public Policy Requirements advising consideration of transmission needs driven by Public Policy, the Right of First Refusal including the development of transmission facilities by non-incumbent developers, and Cost Allocation Requirements specific to transmission cost allocation policies. The content of PJM stakeholder meetings can be viewed via the RPPTF link on the PJM website.

VII. Supply Side Resources

This Section of the IRP discusses the generation supply options analyzed in this study.

SUPPLY-SIDE RESOURCE OPTIONS CONSIDERED

In order to optimize the resource mix overtime, the analysis considered alternative power supply options. The optimization was based on a discounted cash flow and cost minimization decision process endogenous to the IPM®. The generation addition options which were characterized within IPM® and considered as possible options include:

Natural Gas-Fired Combined Cycle – These plants use a combination of steam turbine and combustion turbine technologies and capture the waste heat from the gas turbine exhaust produced during electricity generation and reuse it to generate steam for the steam turbine to generate additional electricity. Combining these two cycles results in higher overall efficiency.

Natural Gas-Fired Peaking Combustion Turbine – This plant has lower thermal efficiency and capital costs and shorter construction lead times than Combined Cycle and Cogeneration Units. These peaking units also offer quick start capability.

Areoderivatives (LMS100s) - Similar to peaking combustion turbines, aeroderivative capacity offers short construction times, quick start capability, and have lower capital costs than combined cycles. LMS100s typically are sized at much smaller increments than combustion turbines, have a smaller footprint, can be constructed in a much shorter time, and are more thermally efficient. However, these units also have a higher capital cost than combustion turbines.

Integrated Gasification Combined Cycle (IGCC) - Instead of burning coal directly, IGCC plants convert coal into gas prior to combustion. Gasification helps in achieving lower levels of pollutant emissions. Using a combined-cycle technology, higher thermal efficiencies are achieved. IGCC plants have higher capital costs than traditional pulverized coal plants.

Supercritical Pulverized Coal (SCPC) - Nearly all U.S. coal plants are designed to use pulverized coal, and supercritical plants are designed to increase the plant's thermal efficiency. The plant is highly controlled for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg). Because this type of coal plant is actively being considered by other utilities, it is modeled as an option for other northeastern U.S. utilities.

Nuclear – Nuclear generation is currently the second largest generation source in the U.S. New nuclear facilities face a number of hurdles prior to any future development largely due to siting concerns. The potential for newly constructed units and uprates at existing facilities are directly accounted for in this analysis.

Solar – Central and rooftop/distributed generation options are considered.

Wind – On- and off-shore wind facilities are considered. Wind resources are generally the dominant source of generation expected to meet requirements under Renewable Portfolio Standard programs. The analysis considers the potential for new wind resources to be added throughout PJM and the US. On-shore resources are characterized at three distinct tiers of units based on the combination of the expected facility performance and the construction costs of units. The Step 1 resources have the lowest capital costs while the Step 3 resources have the highest. Each Step may achieve varying output levels (capacity factor) depending on the ambient conditions which are defined by wind classes; each step has 4 associated wind classes which are modeled, Class 3, 4, 5, and 6. Capacity factor is 32% for Class 3, 34% for Class 4, 38% for Class 5, and 40% or higher for Class 6 resources. In addition, off-shore units are also considered in the analysis within coastal market areas and have a distinct cost and performance characteristics.

Biomass - Biomass plants use organic materials such as wood, agricultural and animal waste. Biomass resources are considered a renewable resource. Within this analysis, Biomass resources are also typically considered as carbon neutral.

Landfill Gas - Landfill gas plants use the gas (methane) naturally produced by the decomposing garbage in the landfill to generate electricity. Landfill Gas resources are considered to be renewable resources.

Power Purchases and Sales Reflecting Short-Term Market Conditions – Wholesale power import and export options are modeled in each hour. For the peak, capacity or reliability transactions are modeled.

Demand Side Resources – Demand response and energy efficiency programs have been used by the utilities to lower levels of peak and energy demand. In recent years, the most notable development has been the increase in DSM qualifying for the PJM capacity auction. Given the treatment in PJM of demand side options as a capacity resource, they are treated on a like basis in the overall analysis for generic options. For Delmarva, the specific program planned and projections have been input to this analysis as given.

Exhibits 2.1 and 2.2 present a summary of the assumptions related to new conventional resource options for Delaware. Exhibit 2.3 presents costs and characteristics for renewable resources. The capital cost assumptions reflect ambient conditions in Delaware and demonstrate regional variances depending on the cost of labor and construction material in those regions. All costs are in 2010 dollars.

Exhibit 2.1: Delaware Conventional Resource Options Capital Cost Assumptions

Resource Type	Earliest Online Year	Capital Cost (2010$/kW)	Forced Outage Rate
Peaking Units (LMS100 and Combustion Turbine)	2013	~950	2.4%
Combined Cycle	2015	~1,400	1.3%
Aeroderivatives (LMS100)	2013	~1,300	1.3%
Supercritical Pulverized Coal	2018	~3,000	6.3%
Integrated Gasification Combined Cycle	2019	~3,800	6.3%
Nuclear	2021	~6,500	3.5%

A typical combined cycle unit requires a lead time of 36 months or more prior to coming on-line. A typical coal plant requires an even longer lead time of 4 to 5 years. Given the longer lead-time required for a combined cycle unit versus a combustion turbine unit, we assume that no new combined cycle units are possible before the summer of 2015 unless they are already under construction. New coal plants including IGCC plants are assumed to be available after 2019, unless in an advanced stage of development. New nuclear options become available in 2021. However, upratings to existing facilities are available during the IRP study period.

The capital costs are expected to decline in real terms at about 1 percent annually on average as a result of expected technological advancements. Technological improvements also enhance plant efficiencies reflected by improvements in heat rates over time. Combined cycle technology is assumed to improve to greater levels of efficiency from roughly a 7,100 BTU/kWh lifetime heat rate for through version 3 of the "F" technology, to levels closer to 6,800 BTU/kWh by the end of the forecast period. The lower heat rate is associated with advances in technology including movements to technologies such as version 5 of the "F" technology and the "G" technology.

Capital costs are expected to decline in real terms by about 1% annually on average as a result of expected technological advancements. Technological advancements also enhance plant efficiencies reflected by improvements in heat rates over time.

Exhibit 2.2: Higher Heating Value Heat Rate (Btu/kWh)

Year	Combined Cycle	Combustion Turbine	Jet Engine (LMS 100)	Coal IGCC CCS
2014	-	10,905	9,468	-
2016	6,800	10,905	9,468	-
2018	6,800	10,905	9,468	-
2020	6,800	10,905	9,468	10,156
2022	6,800	10,905	9,468	10,156

Exhibit 2.3 presents the capital expenses for renewable technologies considered in modeling.

Exhibit 2.3: Delaware Renewable Resource Options Assumptions Summary

Resource Type	Earliest Online Year	Capital Cost (2010$/kW)
Onshore Wind Step 1	2013	~2,000
Onshore Wind Step 2	2013	~2,500
Onshore Wind Step 3	2013	~3,100
Offshore Wind	2016	~4,000
Solar Photovoltaic-Distributed	2013	~4,000
Biomass	2016	~6,000
Landfill Gas	2013	~2,800

1. Regional adjustment factors are applied to the costs above to reflect regional variations in labor and materials markets and altitude/temperature differentials on gas-fired technologies. Capital costs include interconnection costs.
2. Capital cost includes EPC, Soft Costs, AFUDC and generic transmission upgrades.
3. Wind development options are modeled based on geographically determined potential for higher end wind classes. Large scale development is typically class 3 or above. Class 3 capacity factors roughly 32% while class 6 is roughly 40%. Wind development costs are differentiated by site conditions primarily tied to the proximity to the transmission network. Delaware onshore potential is primarily class 3 or below and is concentrated on the coast line. Delaware also has offshore potential which is included as a development option.

The federal government offers production tax credits (PTC) and Investment Tax Credits (ITC) to encourage wind and other renewable generation development. The modeling assumption utilized for PTC reflects 2.2 cents/kWh for wind 1.1 cents/kWh for non-wind renewables through the end of 2012 for wind units and 2013 for other eligible technologies. The ITC (30%) is available through 2016 at full value and it is phased out gradually over the next four years. Any applicable credits will be accounted for in modeling.

Onshore wind options are considered in various configurations to reflect the characteristics to construct and the operational output capabilities at alternate locations. In this analysis we consider three steps of on-shore wind and a single off-shore wind option. In addition to the varying cost steps which reflect the difficulty in constructing facilities (for example, Step 3 reflects a facility in a remote location which would require extensive upgrades such as roadway clearing and lengthy transmission interconnection to come on-line while Step 1 reflects a relatively accessible location requiring typical site and interconnection investment), each step reflects the potential to build wind class 4, 5, and 6 facilities. Wind classes reflect the wind speed and height of the turbines which translate into varying and improving capacity factors at the higher classes. Based on the geographic characteristics of the area, the onshore wind potential in Delaware is extremely limited to only the lowest wind classes which tend to have high costs and lower capacity factors. As such, wind options modeled within Delaware are consistent with this limited amount of onshore resource.

Offshore wind facilities are thought to offer several advantages over on-shore facilities. The major advantages are:

1. Wind speeds are generally stronger; a 25-40 percent gain in wind speed is typical at a few miles off-shore.
2. The potential for large contiguous development areas exists.
3. Offshore wind tends to be less turbulent, translating into less wear and tear on the turbines.
4. Offshore wind shear is lower than on-shore. This means that the boundary layer of slower moving air near the sea surface is thinner than the comparable area on land. This phenomenon allows for use of shorter towers to reach the desired hub-height average wind speed for turbine operation.

However, offshore facilities also have several disadvantages compared to onshore wind units. Among the disadvantages are the higher costs, the extremely limited experience in constructing, permitting, operating, and maintaining the facilities and their platforms. Further, due to the limited experience, the impact on the marine environment, the impact on other environmental issues, and the construction and maintenance requirements and costs also have a high degree of uncertainty surrounding them.

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FINANCING ASSUMPTIONS FOR NEW RESOURCE OPTIONS

The following table illustrates the financial assumptions used for new resources in Delaware.

Exhibit 2.4: New Resource Options Financing Assumptions for Delaware

Financial Assumptions	Combustion Turbine	Combined Cycle/Cogeneration	Coal/Nuclear Average	Intermittent Renewables
Debt/Equity Ratio (%)	55/45			
Nominal Debt Rate (%)	5.8			
Nominal After Tax Return on Equity (%)	10.8			
Income Taxes[1]	40.6			
Other Taxes[2] (%)	0.8			
General Inflation Rate (%)	2.5			
Debt Life (years)	15	20	20	15
Levelized Real Capital Charge Rate (%)	9.4	9.3	9.1	8.9

Note: Financing assumptions are identical for all areas of the country, but taxes vary regionally.

1. Includes federal and state taxes.
2. Includes property taxes and insurance.

For additional capacity needed over and above the firm commitments identified as having broken ground, the model adds capacity based on the resource options described in Exhibits 2.1 and 2.2 above.

VIII. Renewable Energy Resources

As part of the Renewable Energy Portfolio Standards Act (REPSA), the State of Delaware requires that Delmarva Power purchase an increasing amount of Renewable Energy Credits (RECs) from qualified renewable energy sources through 2025. Compliance with this requirement over the IRP planning horizon of 2013 – 2022 is an important focus of the 2012 IRP. To demonstrate compliance with the RPS legislation, Delmarva Power must provide to the State documentation that RECs meeting the requirement have been retired. In general, one REC is created for every MWh generated by an eligible renewable energy resource.[30] There is also a requirement for a minimum percentage of RECs to be generated from solar photovoltaic resources. For simplicity, RECs generated by solar facilities are often referred to as "SRECs". Table 1 below shows the minimum percentage of Delmarva Power customer's annual energy supply that must be supplied from renewable sources as amended by the Delaware General Assembly in June, 2010.[31] The percentages shown in the Table can be applied to Delmarva Power's forecast annual MWH sales to determine Delmarva Power's expected annual quantity of RECs to ensure RPS compliance.

Table 1

Delaware Eligible Renewable Energy Requirements

Complinace Year	Minimum Cumulative % from Eligible Energy Resources	Minimum Cumulative % from Eligible Solar Resources
2013/14	10.0%	0.60%
2014/15	11.5%	0.80%
2015/16	13.0%	1.00%
2016/17	14.5%	1.25%
2017/18	16.0%	1.50%
2018/19	17.5%	1.75%
2019/20	19.0%	2.00%
2020/21	20.0%	2.25%
2021/22	21.0%	2.50%
2022/23	22.0%	2.75%

[30] An exception is related to the impacts of each MWH generated by a Qualified Fuel Cell Project (QFCP). While a QFCP does not produce RECs directly, each MWH produced from a Qualified Fuel Cell can be used to offset Delmarva's RPS obligations.

[31] 26 *Del.C.* § 354.

As indicated in Table 1, in 2013, the first plan year in this IRP, Delmarva Power is required to procure 10% of its supply requirements from renewable resources, including at least 0.6% from solar resources. By planning year 2022/23, the percentage increases to 22% for all qualifying resources, with at least 2.75% from solar resources. The percentages in Table 1 can be applied to the Reference Case MWH forecast for all Delmarva Power distribution customers adjusted for: 1.) larger industrial customers that have chosen, as allowed by legislation, to not participate in the Delaware RPS; and, 2.) REC requirements for customers whose RPS requirements are meet by their third-party supplier through existing contracts phased out as Delmarva Power transitions to meeting the REC requirements of all distribution customers. The forecast REC requirements for all distribution customers indicating the expected RECs needed for RPS compliance by year for both solar and non-solar eligible resources are shown in Table 2.

Table 2

REC and SREC Expected Annual Requirements

Complinace Year	RPS Load Obligaton (MWH)	Tier 1 Requirement (RECs)	Solar Carve-Out (SRECs)
2013/14	6,348,943	634,894	38,093
2014/15	6,290,994	723,464	50,327
2015/16	6,053,684	786,979	60,536
2016/17	5,952,527	863,116	74,406
2017/18	5,982,907	957,265	89,743
2018/19	5,927,171	1,037,255	103,725
2019/20	5,766,151	1,095,569	115,323
2020/21	5,646,117	1,129,223	127,037
2021/22	5,583,251	1,172,483	139,581
2022/23	5,525,832	1,215,683	151,960

The forecast REC and SREC requirements shown in Table 2 are equal to the eligible distribution customer MWH forecast multiplied by the appropriate percentage from Table 1. The results shown in Table 2 will change depending on the load forecast used and assumptions regarding the level of energy efficiency and conservation achieved.

As explained in more detail below, Delmarva Power anticipates securing RECs and SRECs in sufficient quantity to maintain compliance with the REPSA requirements. Delmarva Power plans to do this through a combination of:

- Contracted Resources;
- Bloom Energy Offsets; and,
- Spot Purchases.

A. Contracted Resources

As a result of REPSA, and as approved by the Delaware PSC, Delmarva Power has already contracted for a portfolio of wind and solar resources to help meet the renewable energy requirements for its eligible distribution customers. The specific contracts are listed below in the order that they have or are expected to begin producing RECs to support Delmarva Power's compliance with REPSA.

1. AES Armenia Mountain: This 100 MW [nameplate capacity] wind project is located in North Central Pennsylvania. Delmarva Power has entered into a 15-year power purchase agreement (PPA) with AES to purchase up to 50 MW of the wind energy and RECs from this project. This project is expected to generate approximately 129,000 MWH of renewable energy and RECs annually. This facility became operational in December 2009.
2. Dover Sun Park: Delmarva Power agreed to a 20 year contract to purchase 70% of the SRECs created by the 10 MW [nameplate capacity] Solar Park constructed in Dover by White Oak Solar Energy, LLC, an affiliate of LS Power. The Dover Sun Park is one of the largest solar installations in the Mid-Atlantic region and became commercially operational during the Summer of 2011. Accompanying this contract, Delmarva Power signed an agreement with the Delaware Sustainable Energy Utility (SEU) which allows the SEU to purchase a portion of the SRECs generated by the Sun Park during its first two years of operation for the purpose of preserving the life of excess SRECs. Under

the terms of the SEU/Delmarva Power agreement, the SEU will return the preserved[32] SRECs to Delmarva Power in later years when the RPS solar requirements are greater.

3. Gestamp Roth Rock: Delmarva Power has entered into a PPA with Gestamp to provide RECs and energy from a 40 MW wind farm located in Western Maryland [nameplate capacity]. The wind farm became operational in August 2011 and contract purchases began in August of 2011.
4. enXco Chestnut Flats: Delmarva Power entered into a PPA with enXco to provide RECs and energy from a 38 MW wind project located in Central Pennsylvania. This project began service in December 2011.
5. Delaware SREC Procurement Pilot Program: Under the SREC Procurement Pilot Program approved by the Delaware PSC in 2011, the Delaware SEU conducted a competitive solicitation for SRECs from customer sited facilities in April 2012. As a result, the SEU awarded 166 twenty year contracts for Delaware-sited solar systems totaling 7.68 MW of Capacity. As part of the SREC Procurement Pilot Program, Delmarva Power has a contract with the SEU to purchase the SRECs that the SEU secured through the Pilot Program. SRECs from the contract agreement with the SEU began to be available in Summer 2012.
6. Delaware 2013 SREC Procurement Program: Delmarva Power is preparing a filing with the Commission to seek approval of a next round of SREC solicitation. This filing is based on the recommendation of the Delaware Renewable Energy Task Force and, if successful, would result in the procurement of approximately 7,000 SRECS per year from customer-sited facilities beginning in compliance year 2013/14.

The five current RPS eligible projects and programs represent a total of 128 MW of wind generation and 17.68 MW of solar generation resources. This diverse portfolio of renewable energy resources establishes a strong foundation for Delmarva Power's compliance with the Delaware RPS requirements. Over the period 2013-2022, these projects will create a renewable resource "supply stack" of RECs and SRECs that, along with spot market purchases, will allow Delmarva Power to meet its customers' needs. Table 3 below shows the projected REC and

[32] RECs and SRECs normally expire if not used with 3 years after the month of generation, when SRECs are in the possession of the SEU this time frame is extended.

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SREC[33] supply from Delmarva Power's contracted renewable resources over the planning period:

Table 3

Projection of RECs Created by Existing Contracts

Complinace Year	AES Armenia Wind (RECs)	Gestamp - Roth Rock (RECs)	Gamesa - Chestnut Flats (RECs)	Dover SunPark (SRECs)	SREC Financing Pilot Program (SRECs)
2013/14	129,210	105,120	99,864	14,126	11,472
2014/15	129,210	105,120	99,864	17,025	11,415
2015/16	129,210	105,120	99,864	17,835	11,358
2016/17	129,210	105,120	99,864	18,865	11,301
2017/18	129,210	105,120	99,864	13,845	11,245
2018/19	129,210	105,120	99,864	13,776	11,188
2019/20	129,210	105,120	99,864	13,707	11,132
2020/21	129,210	105,120	99,864	13,639	11,077
2021/22	129,210	105,120	99,864	13,571	11,021
2022/23	129,210	105,120	99,864	13,503	10,966

Table 4 below shows how Delmarva Power's "supply stack" of SRECs obtained from contracted resources is currently expected to match up with the projected RPS requirements over the 2013- 2022 planning period.

Table 4

Contracted Resources Position vs. Projected REPSA Requirement

Complinace Year	Solar Carve-Out Requirement (SRECs)	Contracted SREC Supply (SRECs)	Net Position (SRECs)	Tier 1 Requirement (RECs)	Contracted REC Supply (RECs)	Net Position (RECs)
2013/14	38,093	25,598	-12,495	634,894	359,792	-275,102
2014/15	50,327	28,440	-21,887	723,464	362,634	-360,830
2015/16	60,536	29,193	-31,343	786,979	363,387	-423,592
2016/17	74,406	30,166	-44,240	863,116	364,360	-498,756
2017/18	89,743	25,090	-64,653	957,265	359,284	-597,981
2018/19	103,725	24,964	-78,761	1,037,255	359,158	-678,097
2019/20	115,323	24,840	-90,483	1,095,569	359,034	-736,535
2020/21	127,037	24,715	-102,322	1,129,223	358,909	-770,314
2021/22	139,581	24,592	-114,989	1,172,483	358,786	-813,697
2022/23	151,960	24,469	-127,491	1,215,683	358,663	-857,020

[33] The SRECs from contracted resources are adjusted to reflect the impact of multipliers for in-state labor and parts within REPSA. SRECs from the Dover SunPark include those held by the SEU as they are expected to be resold to Delmarva Power.

As shown in Table 4, based on existing contracted wind resources alone, Delmarva Power is in a net "short" position. In the 2010 IRP, Delmarva Power did not expect to be short. However, a change in REPSA occurred in 2011 that required Delmarva Power to procure RECs for all distribution customers, rather than just Delmarva's SOS customers, beginning in compliance year 2012/13. This change significantly expanded Delmarva Power's need for additional RECs. However, as discussed in the next section, additional amendments to REPSA create a provision that the output from fuel cells manufactured and installed in Delaware to reduce or "Offset" part of Delmarva Power's RPS obligations (both solar and non-solar).

B. Qualified Fuel Cell Provider Program

In July 2011, the Governor of the State of Delaware signed legislation that establishes that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider") is an eligible resource for RECs under the Renewable Energy Portfolio Standards Act (REPSA). The legislation further requires that the Delaware Public Service Commission (the "Commission") adopt a tariff under which Delmarva Power would be an agent that collects payments from its customers and disburses the amounts collected to a qualified fuel cell provider that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility and that the payments from customers be offset by the market revenues received by the Qualified Fuel Cell Provider from its selling of capacity and energy into the wholesale market netted against its cost of fuel. The legislation also provides for a reduction in Delmarva Power's REC and SREC requirements based upon the actual energy output of the 30-megawatt generation facility. In October 2011, in Order No. 8062, the Commission approved the tariff submitted by Delmarva Power in response to the legislation.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as the Qualified Fuel Cell Provider. Bloom plans to construct fuel cell generation facilities at two locations in Delaware. The first site, a 3 MW fuel cell facility at Delmarva Power's Brookside substation, went into operations on June 18, 2012. The 2nd site, a 27 MW facility located near Delmarva Power's Red Lion Substation, is to be phased into operations on or before September 30, 2014.

Bloom uses natural gas to generate electricity through a fuel cell. While this process creates some CO2, there are virtually no other air emissions from the fuel cell. A major difference between the Bloom Energy fuel cell and wind and solar resources is that Bloom is not an intermittent resource. In fact, the Bloom facilities are expected to operate at very high capacity factors (96%) on an annual basis. Consequently, virtually every MW of Capacity obtained from the Bloom project is capable of and expected to produce.

The amendments to REPSA provide that each MWH produced by a Qualified Fuel Cell Project (QFCP) allow Delmarva Power to offset its RPS obligations. Essentially, the output of the Bloom facilities, as a QFCP, will reduce the non-solar REC and SREC requirements that would otherwise be needed to satisfy REPSA.

Delmarva Power assumed that each MWH of Bloom would be used to offset either 1/6 of an SREC or 2 RECs, depending which was projected to be most cost-effective each year.[34] Although the Department of Natural Resources and Environmental Control (DNREC) will be responsible for determining the actual RPS offsets each year, Delmarva Power made the assumptions stated above based on testimony presented by DNREC in the Qualified Fuel Cell Provider Tariff approval process. Although the output of the QFCP will be used to offset Delmarva Power's RPS Obligation, for ease of presentation, these offsets are expressed as equivalent RECs (ERECS) and equivalent SRECS (ESRECS) in this report.

Table 5 below shows the projected amount of the non-solar REC and SREC offsets expected to be created from the Bloom fuel cells that will help offset Delmarva Power's REPSA requirements.

[34] In addition, the Bloom offsets are limited to 25% of the solar requirements through compliance year 2016/17 and 30% for the remainder of the IRP study period.

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Table 5

Bloom Energy

Non Solar and Solar REC Offsets

Complinace Year	Projected Bloom Generation (MWH)	SREC Offsets (ESRECs)	REC Offsets (ERECs)
2013/14	166,230	9,523	218,181
2014/15	252,288	12,582	353,595
2015/16	252,288	0	504,576
2016/17	252,288	0	504,576
2017/18	252,288	0	504,576
2018/19	252,288	0	504,576
2019/20	252,288	0	504,576
2020/21	252,288	0	504,576
2021/22	252,288	0	504,576
2022/23	252,288	0	504,576

Tables 6 and 7 below show Delmarva Power's projected net position adjusted to reflect the expected impact of the Bloom fuel cells on Delmarva Power's RPS obligations. For both tables, a negative net position indicates that Delmarva Power is "short" or will need to purchase more RECs (or SRECs) if projections are accurate. A positive net position indicates that additional RECs are available to be "banked" and used in a future year.

Table 6

Bloom Impact on Delmarva Power's Projected Net Solar Position

Complinace Year	SREC Requirement	Bloom ESRECs	Contracted SREC Supply	Net Position
2013/14	38,093	9,523	25,598	-2,972
2014/15	50,327	12,582	28,440	-9,305
2015/16	60,536	0	29,193	-31,343
2016/17	74,406	0	30,166	-44,240
2017/18	89,743	0	25,090	-64,653
2018/19	103,725	0	24,964	-78,761
2019/20	115,323	0	24,840	-90,483
2020/21	127,037	0	24,715	-102,322
2021/22	139,581	0	24,592	-114,989
2022/23	151,960	0	24,469	-127,491

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Table 7

Bloom Impact on Delmarva Power's Projected Net RPS Position

Complinace Year	REC Requirement	Bloom ERECs	Contracted REC Supply	Net Position
2013/14	634,894	218,181	359,792	-56,922
2014/15	723,464	353,595	362,634	-7,235
2015/16	786,979	504,576	363,387	80,984
2016/17	863,116	504,576	364,360	86,803
2017/18	957,265	504,576	359,284	-6,602
2018/19	1,037,255	504,576	359,158	-173,521
2019/20	1,095,569	504,576	359,034	-231,959
2020/21	1,129,223	504,576	358,909	-265,738
2021/22	1,172,483	504,576	358,786	-309,121
2022/23	1,215,683	504,576	358,663	-352,444

C. Spot Purchases

As mentioned earlier, both RECs and SRECs can be purchased from the spot market to satisfy any shortfall in the amount of RECs and SRECs Delmarva Power may need to ensure compliance with REPSA. Tables 6 and 7 above show that Delmarva Power expects to participate in the spot market for both RECs and SRECs over the period 2013-2022 unless additional contracts are sought and brought forward for approval by the Public Service Commission. Given relative low prices currently available in the respective spot markets, Delmarva Power anticipates purchasing RECs and SRECs from the spot markets until the Renewable Energy Taskforce makes alternative recommendations and the rule-making process with respect to the 1% solar and 3% total cost limit provisions of REPSA are finalized.

D. RPS Compliance Costs

The following tables present the projected "non-netted" costs of RPS compliance given Delmarva Power's contracted resources and the forecast of spot market prices produced by

ICF[35]. The term "non-netted" refers to the monetary costs that will be incorporated into a Delmarva Power customer bill. However, as subsequent material appearing in the section under the heading of "Non-price Impacts of RPS Compliance on Customer Bills" makes clear, there are significant human health benefits associated with the improvement in air quality that may be attributable to the implementation of the Delaware RPS.[36] While the IRP shows these quantified externality impacts for all sources from improving air quality, they are not reflected on the Delmarva Power bill. As described below, the quantified externality benefits are significant.

Table 8 represents the projected non-netted cost for Delmarva Power to meet the Solar Carve-out. The cost of solar compliance is projected to increase from approximately $6 million to $29 M over the planning period with a slight dip in compliance year 2015/16 when offsets from the Bloom fuel cell are projected to switch from offsetting solar to tier 1 obligations.

Table 8

Projection of the Cost to Comply with the RPS' Solar Carve-Out

Compliance Year	2013/14	2015/16	2017/18	2019/20	2022/23
Projected SREC by Source (SRECs)					
Dover SunPark	14,126	17,835	13,845	13,707	13,503
SREC Financing Pilot Program	11,472	11,358	11,245	11,132	10,966
Bloom Offsets	9,523	0	0	0	0
Spot-Solar	2,972	31,343	64,653	90,483	127,491
Total SRECs	38,093	60,536	89,743	115,323	151,960
SREC Cost (k$)					
Dover SunPark	$2,530	$3,242	$2,480	$2,455	$2,418
SREC Financing Pilot Program	$2,393	$2,376	$2,359	$2,344	$776
Bloom Offsets	$925	$0	$0	$0	$0
Spot-Solar	$357	$3,230	$8,883	$15,060	$25,817
Total Solar Complinace Costs (k$)	$6,205	$8,848	$13,722	$19,859	$29,011

[35] The compliance costs for the Bloom fuel cell and the wind contracts include the net revenue from market sales of energy and capacity (Bloom Only).

[36] The total health benefits occurring from improved air quality over the period 2013 to 2022 and shown in Section IX and Appendix 8 of the IRP are derived from the Reference Case and other publically available sources using US EPA models.

Table 9 presents the projected non-netted total cost to comply with the total RPS requirements[37]. Projected cost increase steadily across the planning period from $45.7 million for compliance year 2013/14 to $83.4 M for compliance year 2022/23.

Table 9

Projection of the Total Cost to Comply with the RPS Requirements

Compliance Year	2013/14	2015/16	2017/18	2019/20	2022/23
Projected REC by Source (RECs)					
Solar Supply	38,093	60,536	89,743	115,323	151,960
Wind Contracts	315,132	161,331	303,118	418,009	334,194
Bloom Offsets	218,181	504,576	504,576	504,576	504,576
Existing-REC	63,489	60,536	59,829	57,661	0
Spot-REC	0	0	0	0	224,953
Total RECs	634,895	786,979	957,266	1,095,569	1,215,683
REC Costs (k$)					
Solar Supply	$6,205	$8,848	$13,722	$19,859	$29,011
Wind Contracts	$17,658	$13,125	$14,807	$16,463	$14,418
Bloom Offsets	$21,196	$32,394	$28,979	$30,339	$29,821
Existing-REC	$63	$61	$60	$58	$0
Spot-REC	$0	$0	$0	$0	$10,180
Total RPS Complinace Costs (k$)	$45,122	$54,427	$57,567	$66,718	$83,430

E. Impact of RPS Compliance on Customer Bills

As part of the Settlement in Docket No 10-2 and as later approved by the Commission in Order 8083 on January 10, 2012, Delmarva Power agreed to estimate the impact of compliance with the Delaware RPS on customer bills as part of the 2012 IRP. As described earlier, Delmarva Power is now responsible for securing the RECs and SRECs required for annual compliance with REPSA for all distribution customers[38]. In order to help fulfill this obligation, Delmarva Power is employing a three-fold renewable resource compliance plan. First, Delmarva Power has developed a portfolio of renewable resources that includes a mixture of long-term contracts for both wind and solar resources. Second, Delmarva Power is able to use the REC and SREC offsets created by the Bloom Energy project to help meet its RPS obligations. The third

[37] Through planning year 2019/2020, REPSA allows 1% of the total RPS obligation to be met with REC from "Existing" sources which were placed in-service on or before 12/31/1997.
[38] Certain large customers 1.5 Mw or over are eligible to "opt-out" of the RPS and consequently are not part of Delmarva's RPS compliance plan.

and final piece of the renewables compliance plan is to purchase RECs and SRECs from the spot market as needed to ensure the annual compliance requirements are met.. In this section of the IRP, Delmarva Power provides estimates of the annual impact over the IRP planning horizon for each of these three components of RPS compliance on customer bills for both non-solar and solar resources.

Table 10 below provides a summary of the estimated "non-netted" impact of RPS compliance on a typical Residential customer bill for the period June 2013 – May 2023 based upon the IRP Reference Case assumptions[39]. For each planning year, the "non-netted" cost of compliance for both non-solar and solar renewable resources is shown as well as the cost of Delmarva Power's existing contract obligations, the Bloom energy offsets, and spot purchases.

Table 10

Impact of RPS Compliance on Typical Residential Customer Bills[40]

Compliance Year	2013/14	2015/16	2017/18	2019/20	2022/23
Avg. Residential Customer Bill (1000 kW/Month)					
Supply Component	$89.32	$107.30	$120.30	$136.68	$151.65
Transmission Component	$6.72	$6.85	$6.99	$7.13	$7.34
Distribution Component	$30.30	$30.91	$31.53	$32.16	$33.14
Total	$125.97	$145.06	$158.82	$175.98	$192.13
Solar Compliance Impact on Typical Customer Bill					
Total SREC Compliance Cost per Avg Bill (1000 KW)	$0.91	$1.32	$2.19	$3.35	$5.27
SREC % Impact on Avg. Customer Bill	0.72%	0.91%	1.38%	1.90%	2.74%
RPS Compliance Impact on Typical Customer Bill					
Total RPS Compliance Cost per Avg Bill (1000 KW)	$6.60	$8.10	$9.18	$11.24	$15.15
RPS % Impact on Avg. Customer Bill	5.24%	5.58%	5.78%	6.39%	7.88%

In evaluating the results of Table 10 it is important to keep several things in mind. First, DNREC is currently in the process of obtaining stakeholder input into the promulgation of regulations for determining the methods for calculating costs related to RPS compliance under

[39] In table 10, the distribution component does not include RPS & Bloom charges. Both the transmission and distribution charges are assumed to escalated at 1% per year from their current levels for this calculation.
[40] The average residential customer bill includes projected generation, transmission, and distribution charges. Current transmission and distribution charges were assumed to increase at 1% per year.

26 *Del. C.* §354 (i) and (j). Because these regulations are still in the development process, they were not available for Delmarva Power to use in preparing Table 10 as part of this IRP.

Second, the expected bill impact is heightened, at least in the shorter term, in large part by forecast low natural gas prices. Low natural gas prices keep market electricity prices low but increase the relative cost of Delmarva Power's renewable contracts to customers. This occurs because Delmarva Power pays a fixed contract price for the energy output from certain of its contracted renewable resources and simultaneously liquidates the output at the current prevailing market price at the PJM interconnection point of each such renewable project. As market prices for energy fall or remain low, there is less revenue from the market received by Delmarva Power to offset the fixed contract price[41].

These results also represent a prospective, not actual, view of the impact of RPS compliance on a typical customer bill. Due to the way the RPS requirements are structured, actual RPS compliance costs and impact on customer bills can only be calculated after year end. The results in Table 10 are also based upon assumptions embedded in the IRP Reference Case. Consequently, changes in expected future electricity market prices, customer loads or the achievement of energy conservation goals will impact these results. Another variable would be whether the Production Tax Credit (PTC), which is currently scheduled to expire at the end of 2012 (as assumed in the IRP Reference Case), is further extended by Congress.

Non-price Impacts of RPS Compliance on Customer Bills.

Section 6.1.4 of the regulations governing Delmarva Power in preparing the IRP requires the evaluation of the impact of environmental externalities associated with the Delmarva Power's energy procurement plans. Further the Renewable Energy Portfolios Standards Act ("REPSA") states:

> "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."

[41] Delmarva Power's renewable contracts function as "hedges" to help provide price stability. If market prices rise the contracted resources will provide more economic benefits.

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As part of this IRP and evaluation of the Reference Case, Delmarva Power has prepared a quantitative evaluation of the impact of changes in Air Quality in the Mid-Atlantic Region and Delaware between 2013 and 2022. The results of this evaluation are presented in Section IX and Appendix 8 of this IRP. In brief, these results show human health benefits due to improvements in air quality over the period 2013 – 2022 in the range of $980 million to $2.2 billion and $13 to $29 billion for Delaware and the Mid-Atlantic Region respectively. These benefits are driven by reductions in air emissions from all sectors of the economy including power generation, industrial production, and transportation. Consequently, the externality analysis provided in Appendix 8 of the IRP does not directly identify the separate contribution of renewable resources that are part of Delmarva Power's renewable resource compliance portfolio to the overall improvement in human health.

The separate contribution of renewable resources to improving air quality could be evaluated by rerunning the IPM® and air quality models under a scenario where renewables are not included in the generation mix and comparing this to the Reference Case and then performing the resource intensive air quality analysis. Because such an analysis would be expensive, time and resource consuming, Delmarva Power has employed a simpler approach described below to help provide a range of estimates of the impact on air quality benefits provided by renewable generation.

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 (CO2), Sulfur dioxide (SO2), and Nitrous Oxide (NOX) at varying rates. Accordingly, when wind and solar resources generate power, other sources reduce their output and related air emissions.

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Determining *exactly* how much CO_2, SO_2, and NOX are displaced by wind and solar resources is made difficult because marginal changes in PJM generation emissions are different for each and every hour during the year and the hourly production of intermittent wind and solar generation over a year's time is uncertain. Consequently, exactly matching the emissions avoided by intermittent resources can be a complex undertaking. Nevertheless, making some simplifying assumptions, information provided from the IPM® Reference Case on average PJM emission rates 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 generation air emission reductions that may be attributable to Delmarva Power's RPS compliance. Based on the implied values of a ton of SO_2, NOx and CO_2 from the IRP evaluation of changes in air quality over 2013 to 2022, the range of emission reductions can then be valued in dollar terms for the potential avoided health costs.

The Air Quality analyses presented in section IX and Appendix 8 of the 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 from electric power plant emissions 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 $PM_{2.5}$ concentration and changes in $PM_{2.5}$ mortality).

Breaking this down by type of emission and based on the PPTM results, it is estimated that 63% of the overall cost is attributable to SO_2 emissions, 6% of the overall cost is attributable to NOx emissions, and 29% of the overall cost is attributable to primary $PM_{2.5}$ emissions. Considering the 2022 EGU emissions totals (as estimated using IPM ®), the cost per ton for SO_2 and NOx is estimated to be within the range of:

\$43,000 – 110,000 for SO_2, and \$9,500 – 25,000 for NOx.

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

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From the IPM® Reference Case, average annual emission rates (tons/Mwh) for SO2, Nox and CO2 can be calculated for PJM resources that create these emissions[42]. This is shown in the table below:

Table 11

Average Emission Rates (ton/MWH)

	2013	2014	2016	2018	2020	2022
PJM co2 rate	0.81870	0.80096	0.79693	0.79702	0.78294	0.77365
PJM So2 rate	0.00175	0.00110	0.00097	0.00096	0.00091	0.00088
PJM Nox rate	0.00057	0.00053	0.00043	0.00044	0.00042	0.00041

The total amount of renewable resource generation MWH enabled by Delmarva Power's renewable portfolio over 2013 - 2023 is shown in Table 12 below[43].

Table 12

Delmarva Power Renewable Resource Portfolio

Total Renewable Generation MWh

	2013	2014	2016	2018	2020	2022
Contracted Resources	359,792	362,634	364,360	359,158	358,909	358,663
Bloom	166,230	252,288	252,288	252,288	252,288	252,288
Spot Purchases	0	0	0	114,250	265,738	352,444
Total Resources	526,022	614,922	616,648	725,696	876,935	963,395

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

[42] MWH outputs from Nuclear, Wind, and Solar resources are not used in the calculation of the average emission rates for CO2. The calculation of average emission rates for SO2 and Nox also exclude the additional output from fuel cells.
[43] This table shows total MWH (not RECs) produced by the renewable portfolio.

emission rates shown above 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 shows the reduction in air emissions that would otherwise have occurred[44]:

Table 13

Tons of Emissions Avoided by DPL Renewable Portfolio Resource

(assumes 50% of PJM average emission rates)

	2013	2014	2016	2018	2020	2022
co2	147,281	145,228	145,185	188,658	244,530	275,072
so2	460	337	299	350	401	424
nox	150	162	133	158	186	199

Table 14

Tons of Emissions Avoided by DPL Renewable Portfolio Resource

(assumes 25% of PJM average emission rates)

	2013	2014	2016	2018	2020	2022
co2	73,641	72,614	72,592	94,329	122,265	137,536
so2	230	168	149	175	200	212
nox	75	81	66	79	93	100

These tons of emission reductions can be applied to the $ 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 the tables below which assume that the avoided emissions are valued at the low end of the range for avoided emission costs:

[44] Because the Bloom Energy fuel cells produce CO2, no CO2 reductions are attributed to the mwh produced by this resource.

Table 15

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

	2013	2014	2016	2018	2020	2022
CO2	$147,281.12	$145,228	$145,185	$188,658	$244,530	$275,072
SO2	$19,777,125	$14,478,834	$12,852,657	$15,040,069	$17,224,933	$18,226,921
Nox	$1,420,478	$1,540,204	$1,260,079	$1,502,449	$1,764,497	$1,894,444
Total	$21,344,884	$16,164,265	$14,257,920	$16,731,175	$19,233,959	$20,396,437

Table 16

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

	2013	2014	2016	2018	2020	2022
CO2	$73,641	$72,614	$72,592	$94,329	$122,265	$137,536
SO2	$9,888,563	$7,239,417	$6,426,329	$7,520,034	$8,612,466	$9,113,461
Nox	$710,239	$770,102	$630,039	$751,224	$882,248	$947,222
Total	$10,672,442	$8,082,132	$7,128,960	$8,365,588	$9,616,979	$10,198,219

Alternative estimates of the dollar value of the external benefits of the emissions avoided by Delmarva Power's renewable resource compliance can be obtained by further varying the assumptions around the percentage of the average PJM emission rate avoided and the costs per ton of each type of emission.

IX. Environmental Externalities

The purpose of this section of the IRP is to provide a discussion of Delmarva Power's approaches and assumptions in determining the external costs of energy production on human health. More detailed information is available in Appendix 8.

The regulations governing the preparation of Delmarva's 2010 IRP were promulgated by the Delaware Public Service Commission on August 18, 2009. The regulations constitute a complete set of standards for the IRP. Among other requirements, these governing regulations require Delmarva Power to conduct an evaluation of environmental benefits and externalities associated with the utilization of specific methods of energy production.[45]

Most of the available literature on environmental externality points to global warming and the human health effects of air emissions as dominating energy externalities. This was a primary consideration in shaping the process used by Delmarva to quantify environmental benefits and impacts.

In order to assess the externalities associated with the Reference Case, Delmarva and its contractor, ICF, estimated the overall public health benefits resulting changes in air emissions from all sources, including power generation, over the planning period 2013 to 2022. For the Reference Case, the emissions from power plants in Delaware and other nearby regions are tracked so that changes in emissions between 2013 and 2022 can be determined. The primary pollutants of interest for this assessment are particulate matter (PM), ozone, sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon dioxide (CO_2) and mercury (Hg).

[45] For purposes of this evaluation, *Environmental Benefit* means the positive environmental impact minus the negative environmental impact attained by specific actions including, but not limited to, energy generation and distribution, transmission service, conservation, customer-sited generation, DR, or DSM.

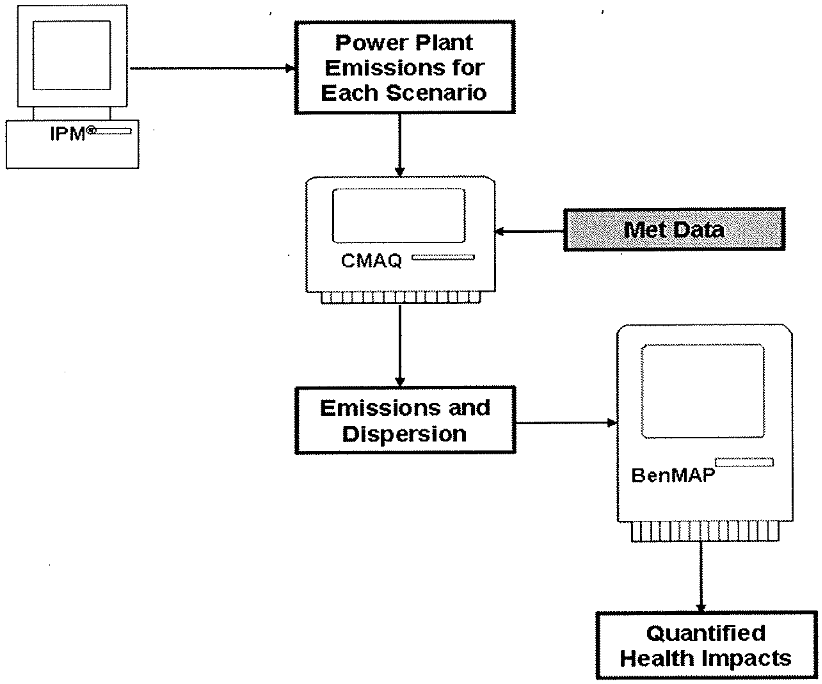
Environmental Impact means the result of an action, outcome or activity related to the IRP, on natural and physical resources including, but not limited to, wetlands, sea levels, fisheries, air quality, water quality and quantity, public health, climate impacts, land masses, and ground water.

Externalities means the social, health, environmental and/or welfare costs or benefits of energy which result from the production, delivery or reduction in use through efficiency improvements, and which are external to the transaction between the supplier (including the supplier of efficiency improvements) and the wholesale or retail customer. Externalities should be quantified and expressed in monetary terms where possible. Those externalities that cannot be quantified or expressed in monetary terms shall nonetheless be qualitatively considered.

i. Evaluation of Health Impacts of PM, Ozone, SO_2, and NO_2

The health impacts associated with PM, ozone, SO_2, and NO_2 are driven by the human inhalation of these pollutants in ambient air. Based on available health effects data, it was clear from the beginning that the health effects for human exposure to PM and ozone would be much higher than the health effects from exposure to SO_2 and NO_2 which are directly emitted from power plants and ozone which is a secondary pollutant formed in part by power plant emissions of nitrogen oxides (NO_x). As a result, the analysis of these pollutants focused on the health effects of PM and ozone exposure. To estimate impacts of PM and ozone on health and mortality (and the associated benefits of reductions in PM and ozone), changes in emissions had to be translated into changes in ambient air quality – primarily in terms of concentrations of $PM_{2.5}$ and ozone. $PM_{2.5}$ is directly emitted from coal, oil and gas-fired power plants and is also formed as a secondary product from the plant's emissions. Ozone is a secondary pollutant that is formed in the atmosphere by a series of reactions involving ultra violet (UV) radiation and precursor emissions of NO_x and volatile organic compounds (VOC). Therefore, it was necessary to account for the transport and dispersion of direct emissions of $PM_{2.5}$ as well as the chemical interactions that form secondary $PM_{2.5}$ and ozone.

The IPM® modeling provided emission estimates for Delaware of changes in emissions of SO_2, NO_x, and CO_2 from power plants that resulted from the different years of the Reference Case. The IPM® emission estimates were used as input to an air quality model, EPA's Community Multi-scale Air Quality (CMAQ) model, to calculate expected changes to ambient air quality for the pollutants of interest. Based on the CMAQ results, Delmarva/ICF then used EPA's Environmental Benefits Mapping and Analysis Program (BenMAP) program to estimate health and economic benefits for ozone and $PM_{2.5}$ and qualitative methods to estimate health and economic benefits for mercury. This approach is illustrated in the figure below:



BenMAP is a modeling system developed by EPA's Office of Air Quality Planning and Standards to estimate national and regional benefits of air quality health impacts. BenMAP is driven by estimates of $PM_{2.5}$ or ozone levels (based on air quality modeling) and provides estimates of changes in health impacts and associated costs. BenMAP includes population data at census tract level and algorithms for characterizing demographic changes (age distribution) over time through the year 2025.

BenMAP can estimate changes in a wide range of health impact "endpoints" (including mortality and morbidity) that might occur with changes in $PM_{2.5}$ exposure. Mortality endpoints include changes in "all-cause" mortality, as well as mortality due to specific causes, such as cardiovascular disease, cancer, and chronic pulmonary disease. Morbidity endpoints include specific illnesses and symptoms (for example, asthma exacerbations), events requiring medical care (emergency room visits and hospital admissions), and adverse effects that involve lost work or restricted activity days. For each scenario, health endpoints such as premature mortality, hospital admissions, chronic bronchitis, chronic asthma, acute bronchitis, induced asthma, and acute respiratory symptoms were summarized and reported (see Appendix 8).

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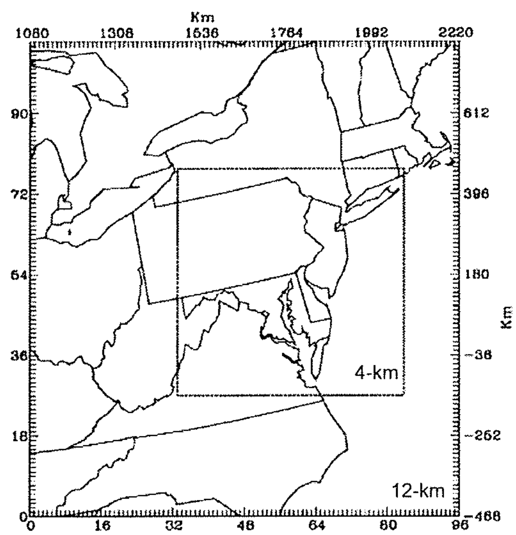
This approach included several annual applications of the CMAQ model including a 2020 baseline simulation and several alternative emissions scenarios. Version 4.6 of the CMAQ model was used for this study. The model was applied using meteorological inputs for 2001 and for the 12-kilometer resolution and four-kilometer resolution nested-grid modeling domain shown in the figure below.



Graphical and tabular summaries of the modeling results were prepared and the results were post-processed for input to the BenMAP tool. BenMAP was used to estimate the health impacts and economic benefits associated with the changes in air pollution simulated by CMAQ for each of the alternative emissions scenarios.

A full copy of the air quality and health impacts technical report is presented as Appendix 8.

ii. Evaluation of Health Impacts of CO_2 and Hg

Carbon dioxide and mercury emission changes were not evaluated in the BenMAP model. Given the complexities and uncertainties associated with any characterization of climate change and its ultimate impacts, a different, less formal approach was used to capture the health effects of CO_2. A recent National Academy of Sciences (NAS) report[46] indicated a potential range of health impacts due to CO_2 emissions ranging from $1 to $100 per tonne. As a point of reference, the NAS report used a value of $30 tonne .

For Hg, Delmarva/ICF estimated the overall changes in Hg emissions associated with different scenarios (based on outputs from IPM®) and qualitatively describe the potential impacts of these changes.

In the 2010 IRP, Delmarva Power conducted a life-cycle analysis of several resource options including land based wind, off shore wind, and gas fired generation resources. Because these life cycle evaluations remain relevant and accurate, Delmarva Power did not undertake new life cycle analyses for the 2012 IRP. The 2010 IRP life cycle evaluations are incorporated by reference into this IRP.

[46] The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, National Research Council of the National Academies, October 2009

X. The Reference Case Results

In preparing the IRP, Delmarva uses the concept of a "Reference Case" to represent Delmarva's expected view of the future procurement planning environment from 2013 - 2022. The Reference Case provides a structure for the IRP analysis and evaluations and a point of comparison with varying some of the key assumptions supporting the Reference Case.

The IRP Reference Case provides a dynamic view of the expected 2013 – 2022 future state of the electric system within Delaware and PJM. The major assumptions underlying the Reference Case reflect the current state of the overall electric system at the time the IRP modeling analysis is undertaken. For this IRP, the Reference Case reflects pertinent energy related legislation enacted by the Delaware General Assembly since the last IRP was filed in December 2010, the expected energy efficiency and conservation activities conducted by the SEU, expected Federal environmental regulations, and Commission approved renewable power purchase agreements and demand response programs.

The Reference Case provided in the 2012 IRP provides a detailed look at the results of Delmarva's expected future energy procurement practices for the period 2013 – 2022. The key data planning assumptions underlying the view of Delmarva's energy future implied by the Reference Case include the following:

1. The Delmarva load forecast (described in Section IV and Appendix 4);
2. Energy and demand response reduction targets described by the Energy Efficiency Act of 2009 (described in Section V);
3. Various PJM approved transmission system upgrades (described in Section VI);
4. The cost and operating characteristics of supply side resource options (described in Section VII and Appendix 5);
5. Delmarva's plan to procure REC's generated by renewable energy resources in sufficient quantity to meet the annual requirements of the Delaware Renewable Energy Portfolio Standards Act (described in Section VIII); and,

6. The expected implementation and timing of various environmental regulations affecting power generation. These assumptions are described in Appendix 5.

After Delmarva began the modeling efforts to complete the 2012 IRP, the Federal Cross State Air Pollution Rule (CSAPR) which had been scheduled to take effect in 2013, was vacated by the U.S. District Court. At the time that CSAPR was vacated, Delmarva could not restart the IRP modeling and still have the time and resources to meet the December 1, 2012 filing requirements of the IRP[47]. However, because of the potential importance of environmental regulations on the IRP results, Delmarva was able to prepare a sensitivity analysis of the potential impact of the changing environmental legislation. The results of this sensitivity analysis are provided later in this section and in Appendix 5. Delmarva also prepared additional sensitivity analyses around the Reference Case that are described below.

The remainder of this section presents detailed information for the Reference Case and the sensitivity analyses. Information is presented based on the IPM® results and the Portfolio Model results.

IPM® Results

The IPM® model provides detailed information about the expected state of electric power generation over the planning period including, planned generation expansion, generation output, and power plant emissions. A more technical description of IPM® is provided in Appendix 5.

Based on the IPM® analysis, Table 1 below shows the expected generation capacity by generation type in PJM under the Reference Case assumptions for the years 2013- 2022.

[47] December 1, 2012 is a Saturday so Delmarva Power actually filed the IRP on December 3, 2012.

Table 1

Expected Capacity (MW) by Resource Type
PJM RTO

Capacity (MW)	2013	2014	2016	2018	2020	2022
Coal	65,786	64,127	64,096	63,744	63,744	63,744
Combined cycle	25,359	25,924	29,525	31,162	34,928	37,962
Oil/Gas other	8,139	7,036	6,528	6,528	6,528	5,710
Hydro	7,433	7,433	7,468	7,468	7,468	7,468
Nuclear	33,707	33,707	33,707	33,707	33,057	33,057
Renewable	9,943	10,836	12,084	12,920	13,712	14,296
Biomass Gas	1	1	1	1	1	1
Biomass Residues	86	86	86	86	86	86
Biomass Solids	356	356	356	356	356	356
Cogen - Biomass	171	171	171	171	171	171
Cogen - Biomass Gas	30	30	30	30	30	30
Cogen - Landfill	20	20	50	50	50	50
Cogen - Other	109	109	109	109	109	109
Fuel Cell	18	30	30	30	30	30
Landfill	651	651	781	799	841	841
Solar PV	1,528	1,991	3,065	3,883	4,633	4,735
Steam - Other	489	489	489	489	489	489
Wind	6,482	6,901	6,915	6,915	6,915	7,397
Turbine	31,033	31,012	30,160	32,016	32,828	36,833
Total	**181,400**	**180,075**	**183,567**	**187,546**	**192,266**	**199,070**

Table 1 indicates that while the overall installed generation capacity in PJM is expected to increase by almost 18 GW from 2013- 2022, the change in the installed generation capacity by type of generation varies greatly. The amount of installed coal fired generation capacity is expected to decline by about 2 GW while the installed capacity of gas fired combined cycle (CC) technology is expected to increase over 12 GW. Land based wind generation capacity also increases by almost a GW and solar photovoltaic resources increase over 3 GW.

Corresponding to the PJM installed capacity illustrated in Table 1, Table 2 provides the expected annual energy by generation (GWH) resource type for 2013 – 2022.

Table 2

Expected Generation (MWH) by Resource Type

PJM RTO

Generation (GWh)	2013	2014	2016	2018	2020	2022
Coal	409,626	397,344	406,954	424,026	431,009	435,238
Combined cycle	127,012	137,694	151,112	154,986	180,908	199,767
Oil/Gas other	153	378	158	156	154	154
Hydro	16,339	16,544	16,884	16,969	16,969	16,969
Nuclear	261,532	261,623	259,433	257,730	255,884	254,542
Renewable	31,127	34,771	37,636	38,869	40,181	41,715
Biomass Gas	7	7	7	7	7	7
Biomass Residues	684	684	684	684	684	684
Biomass Solids	1,372	2,704	2,756	2,760	2,760	2,760
Cogen - Biomass	1,352	1,354	1,354	1,354	1,354	1,354
Cogen - Biomass Gas	237	237	237	237	237	237
Cogen - Landfill	158	158	368	368	368	368
Cogen - Other	861	861	861	861	861	861
Fuel Cell	82	242	250	250	250	250
Landfill	4,589	4,589	5,645	5,793	6,137	6,137
Solar PV	1,970	2,573	4,073	5,154	6,121	6,267
Steam - Other	3,869	3,869	3,869	3,869	3,869	3,869
Wind	15,947	17,494	17,533	17,533	17,533	18,921
Turbine	5,686	7,211	6,564	7,472	8,213	8,243
	-	-	-	-	-	-
Total	**851,475**	**855,566**	**878,741**	**900,207**	**933,317**	**956,628**

Total generation in PJM is expected to increase about 105,000 GWh over the planning period. Most of this increase comes from gas fired combined cycle generation (over 73,000 GWh), coal (almost 16,000 GWh) and renewables (over 10 GWh). While coal *capacity* decreases in PJM over the planning period due to retirement of older less efficient units, the remaining environmentally compliant units produce more *energy.*

Tables 3 and 4 below show the expected capacity (MW) and generation (GWH) for the Delmarva Zone for 2013 – 2022.

Table 3

DPL Zone Expected MW Capacity by Resource Type 2013 – 2022

DPL Zone

Capacity (MW)	2013	2014	2016	2018	2020	2022
Coal	601	436	436	436	436	436
Combined cycle	1,090	1,090	1,399	1,399	1,399	1,399
Oil/Gas other	734	734	734	734	734	734
Renewable	66	119	195	245	292	298
Fuel Cell	18	30	30	30	30	30
Landfill	16	16	29	29	29	29
Solar PV	32	57	107	157	202	208
Land Based Wind	-	16	30	30	30	30
Turbine	1,037	1,037	1,037	1,037	1,037	1,037
Other (Including Steam Turbines)	-	-	-	-	-	-
Total	**3,528**	**3,415**	**3,801**	**3,851**	**3,897**	**3,903**

Table 4

DPL Zone Expected GWH Generation by Resource Type 2013 – 2022

DPL Zone

DPL Zone Generation (GWh)	2013	2014	2016	2018	2020	2022
Coal	2,682	2,014	2,090	2,266	2,325	2,372
Combined cycle	2,898	2,901	3,946	3,937	3,933	3,403
Oil/Gas other	-	217	-	-	-	-
Renewable	234	472	688	753	818	826
Fuel Cell	82	242	250	250	250	250
Landfill	111	111	215	215	222	222
Solar PV	41	72	137	201	260	268
Land Based Wind	-	47	86	86	86	86
Turbine	1,082	1,126	735	695	818	771
Other (Including Steam Turbines)	-	-	-	-	-	-
Total	**6,896**	**6,731**	**7,460**	**7,652**	**7,895**	**7,371**

An attractive feature of the IPM® is that in preparing these generation forecasts, the model is able to keep track of power plant emissions. IPM® is able to track carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrous oxide (NO_x) emissions associated with each year of the Reference Case. As discussed in Section IX and Technical Appendix 8, the changes in power plant emissions between 2012 and 2023 for the Reference Case form the basis for the evaluation of environmental benefits.

Table 5 and Table 6 below show the expected total emissions for the Reference Case for both PJM and the DPL Zone based on the Reference Case.

Table 5

PJM

Emissions from Power Plants (Mtons)

	2013	2014	2016	2018	2020	2022
CO_2	468,318	459,652	476,327	493,985	511,868	523,679
SO_2	1,000	628	579	597	597	595
NO_X	325	302	257	270	277	280

Table 6

DPL

Emissions from Power Plants (Mtons)

	2013	2014	2016	2018	2020	2022
CO_2	4,691.27	4,193.34	4,882.17	4,450.71	4,571.98	4,358.14
SO_2	9.70	3.90	4.07	4.39	3.64	3.33
NO_X	3.25	2.42	2..06	2.06	2.17	2.08

As indicated in Table 5, the total amount of SO_2 and NO_x emissions created by power plants in PJM are expected to decrease significantly by 2022 in the Reference Case. The total amount of CO_2 in PJM, however, increases by about 11% over the IRP planning period in the Reference Case. Table 6 indicates that, in the DPL Zone, the total amount of SO_2 and NO_x emissions from power plants is expected to drop significantly from 2013 to 2022. Overall CO_2 emissions in the DPL Zone fall about 7% over the IRP planning period in the Reference Case.

Table 7 below shows the expected energy prices for the DPL Zone for the Reference Case.

Table 7 Expected DPL Zone Energy Prices 2013 – 2022

(Confidential)

DPL Zone

Energy Price Peak (2010$/MWh)	2013	2014	2016	2018	2020	2022
PJM-DPLN	42.81	43.51	46.00	53.49	54.70	55.08
PJM-DPLS	46.78	47.63	50.18	58.21	59.53	59.99

Energy Price Off-Peak (2010$/MWh)	2013	2014	2016	2018	2020	2022
PJM-DPLN	32.60	33.64	35.97	41.46	42.43	42.46
PJM-DPLS	36.28	37.46	39.85	45.48	46.62	46.77

Note: Peak hours start at 7:00 am and end at 10:59 pm Monday through Friday.

Portfolio Model Results

In order to evaluate expected energy prices and price stability, Delmarva Power uses a Portfolio Model with inputs from the IPM® and other sources. Based upon market volatility, the Portfolio model simulates 1,000 possible price outcomes per year for Delmarva Power's expected portfolio of full service and renewable energy projects for SOS customers over the planning period. A detailed description of the Portfolio Model is provided in Appendix 6.

Based on the results of the Portfolio Model, Table 8 below shows the expected mean energy prices in nominal dollars for Residential and Small Commercial (RSCI) and Commercial (LC) customers for the Reference Case compared with the sensitivity cases for selected planning years. The sensitivity cases include a low and high gas case reflecting a range of possible natural gas prices. The CC case represents the addition of a hypothetical 300 MW gas fired combined cycle generating facility in Delaware.

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Table 8 Expected SOS Supply Costs RSCI and LC SOS Customers (Confidential)

Average Costs and Risks of Electricity Procurement for DPL as Expected in August 2012		
	RSCI Total Average Costs ($/MWh)	**LC Total Average Costs ($/MWh)**
Planning Year 2013		
Reference Case	$96.93	$67.34
Reference Case - High Gas	$102.05	$82.66
Reference Case - Low Gas	$91.81	$52.03
Planning Year 2015		
Reference Case	$94.00	$69.71
Reference Case - High Gas	$109.84	$85.04
Reference Case - Low Gas	$78.15	$54.39
Planning Year 2017		
Reference Case	$122.06	$84.67
Reference Case - High Gas	$139.83	$102.34
Reference Case - Low Gas	$104.29	$67.01
Reference Case and CC	$111.16	$76.83
Planning Year 2019		
Reference Case	$141.22	$96.20
Reference Case - High Gas	$160.92	$115.78
Reference Case - Low Gas	$121.53	$76.63
Reference Case and CC	$124.35	$84.01
Planning Year 2022		
Reference Case	$161.96	$106.74
Reference Case - High Gas	$183.18	$127.70
Reference Case - Low Gas	$140.75	$85.78
Reference Case and CC	$140.94	$91.57

Table 8 indicates that for RSCI SOS customers under the Reference Case, energy supply prices are expected to rise after 2015 after falling from 2013 to 2015. For RSCI SOS customers under the Reference Case, the 2013 expected supply cost is $96.93 per MWH, which is projected to rise to $161.96 in 2022. For LC SOS customers, the corresponding supply prices are $67.34 and $106.74, respectively. A primary reason for this increase in energy prices is the expected increase of natural gas prices in the later years of the IRP planning period. Within this Table, the combined cycle sensitivity case improves the performance of the Reference Case portfolio.

Table 9 presents a projection of retail customer energy supply rates for Residential and MGT customers for the period 2013 through 2018. The projections are based on the Reference Case.

Table 9: Customer Energy Supply Rate Projections

(Confidential Version)

In order to evaluate price stability, Delmarva prepared an analysis using the Portfolio Model showing the expected range of prices for the Reference Case and the sensitivity cases over the planning period. Figure 1 below shows a graphical comparison of the results of this analysis.

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Figure 1

Risk Ranges for RSCI FSA, With and Without CCs

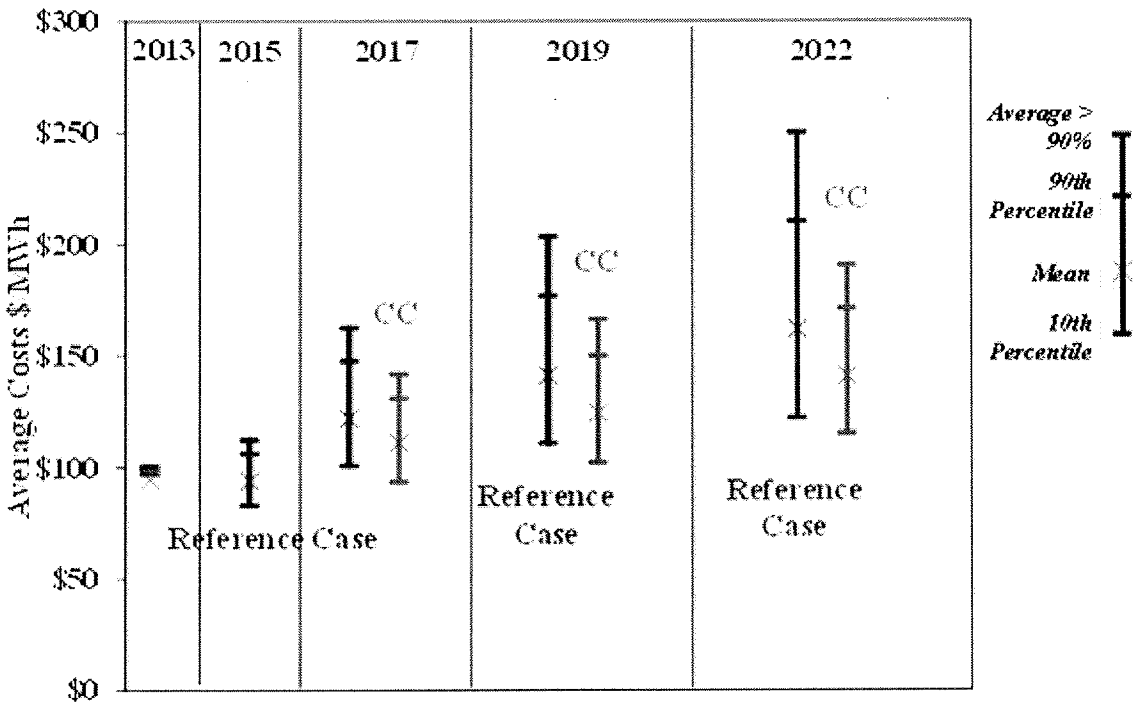

Figure 1 includes bars in red for the net costs of the FSA portfolio if a gas CC were added to the Reference Case supply portfolio, beginning in 2017. This is assumed to be a 300 MW CC with cost and performance characteristics equal to those used for a new CC in the recent PJM Net CONE study. In Figure 1, 10% of the possible price outcomes for that case occur above the "top" of each line and 10% occur below the "bottom" of the line. The cross mark in between the top and bottom shows the average across all potential outcomes. Figure 1 shows that the expected range of prices is increasing over time for the Reference Case. The lower positions and shorter lengths of the red bars (FSA with a CC) in Figure 1 indicate that the inclusion of a new CC with the FSA portfolio (under the assumed terms) drives down both the average cost and the risk range in each future year. This finding is consistent with the recent expansion of CC market development in Delaware and elsewhere in PJM.

The impact of off-shore wind on the Reference Case supply portfolio was derived from estimates of the terms of the Cape Wind project in Massachusetts.[48] This is an approximately 468 MW facility located in Nantucket Sound 4-11 miles off Cape Cod, intended to come online in 2016. It will include about 130 3.5 MW turbines, expected to cost around $5,600/kW and projected to operate at around a 37% capacity factor, with $30-$50/MWh for O&M expenses. A portion of its output is under a 15- year contract to National Grid for its Massachusetts customers, which begins at around $187/MWh in 2013 $, then grows annually at 3.5%. The levelized nominal price over the period 2013-2027 is equal to $230.40/MWh with tax credits and $261.60/MWh without[49]. The net costs are determined by starting with these gross cost and performance parameters from Massachusetts, then taking out the average energy prices and capacity value that such a plant would earn in Delaware under the projected PJM environment in the Reference Case. These net costs are $161 to $192 per MWh of expected output. Since these are well above zero, including any amount of such power in the FSA portfolio would raise its average price. For instance, if 150MW of such output was added to the FSA RSCI portfolio, these net costs of $161/MWh would add $78.6 million of annual costs, for a net increase of $33.80/MWh to the RSCI customers' average price.

A hypothetical utility-scale solar PV resource was also evaluated. It was assumed that this technology would cost around $3,500 per kW to construct and install, based on a 20 MW facility of single-axis PV panels in Delaware, capable of a 15% capacity factor. This results in revenue requirement (gross) costs that are quite high, approaching $400 to $450/MWh. About $120/MWh of these gross costs can be offset with market energy and capacity sales, but the resulting net costs, measured in REC prices needed to breakeven are still quite large – over $280/MWh. This is larger than the net costs of offshore wind. Because of this, a 20 MW facility would cause about a $3.2/MWh increase in FSA RSCI costs.

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[48] Response to the Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for approval by the Department of Public Utilities of amended power purchase agreements between National Grid and Cape Wind Associates, LLC., DPU 10-54, p. 11, 13.

[49] Idem, p. 10, 13.

Environmental Health Impacts and Benefits

Based upon the environmental health impact and benefit assessment, air quality within the Mid-Atlantic States and the State of Delaware is expected to improve from 2013 to 2022. Tables 10 and 11 present emission inventory totals for the Mid-Atlantic states and the State of Delaware, respectively, for 2013 and 2022. The expected reductions in emissions between 2013 and 2022 are due to implementation of emission control technologies required by state and federal rules, the closure of older facilities, fleet turnover of on-road motor vehicles and off-road equipment, the introduction of cleaner engine technologies, and the use of cleaner fuels, such as natural gas.

Table 10

Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the Mid-Atlantic States (New Jersey, Pennsylvania, Maryland, D.C., Delaware, and Virginia).

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU*	135,606	129,190
	Non-EGU/Point	161,304	159,026
	Non-point	162,173	161,700
	Non-road	302,452	253,926
	On-road Vehicle	448,253	167,917
SO_2	EGU	286,423	285,404
	Non-EGU/Point	201,114	195,277
	Non-point	160,541	160,472
	Non-road	35,113	37,725
	On-road Vehicle	3,998	4,004
Hg	EGU	1.8259	0.6434
	Non-EGU/Point	4.7052	5.2918
	Non-point	0.9741	1.0194

* EGU = Electric Generating Units

Table 11

Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the State of Delaware.

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU*	2,492	1,524
	Non-EGU/Point	4,678	4,678
	Non-point	3,265	3,253
	Non-road	15,144	15,173
	On-road Vehicle	11,893	4,334
SO_2	EGU	9,702	3,332
	Non-EGU/Point	11,530	11,530
	Non-point	5,797	5,796
	Non-road	3,315	3,672
	On-road Vehicle	112	110
Hg	EGU	0.0265	0.0229
	Non-EGU/Point	0.5395	0.5423
	Non-point	0.0166	0.0182

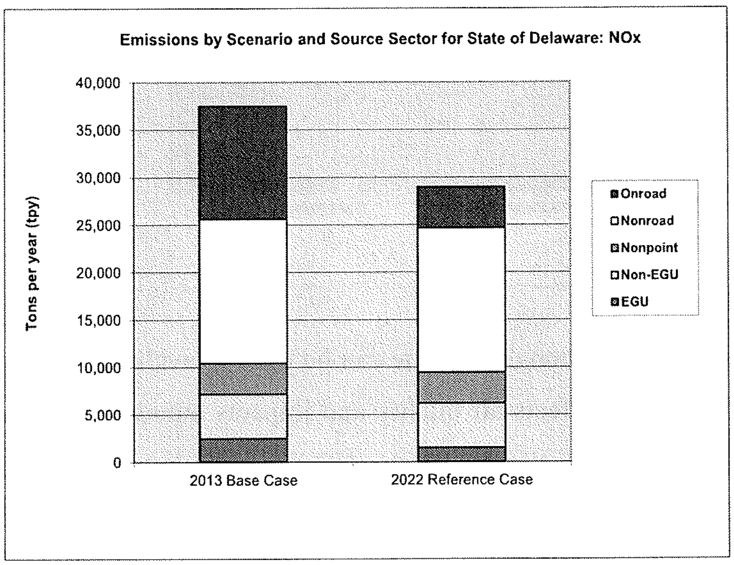
* EGU = Electric Generating Units

Figures 2a through 2c present emissions estimates by source sector for the State of Delaware for the Reference Case for NO_x, SO_2, and Hg. The figures present the expected reduction in these emissions between 2013 and 2022. They also illustrate the portion of overall emissions from the Electric Generating Units (EGU) sector.

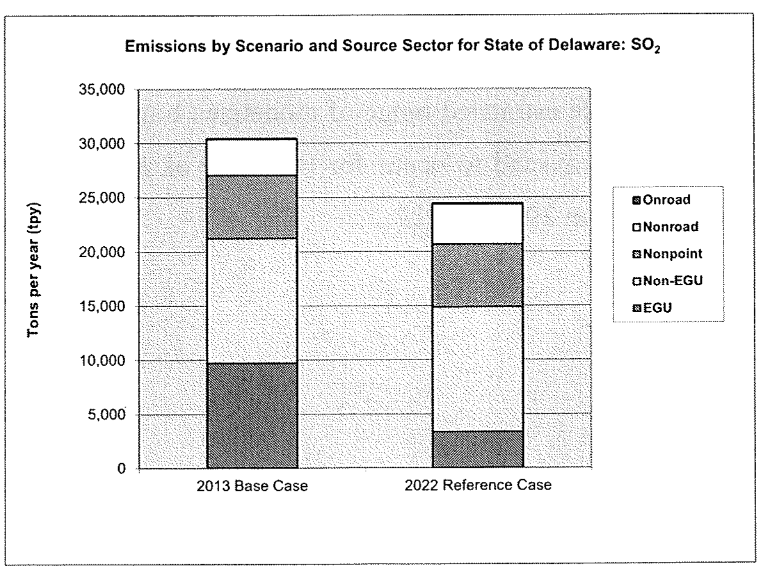
Figures 2a, 2b, 2c

Emission Totals by Source Category for the State of Delaware for the IRP Modeling Analysis
2013 Base, 2022 Reference Case,: NO_x, SO_2 and Hg
(a) NO_x (b) SO_2 (c) Hg

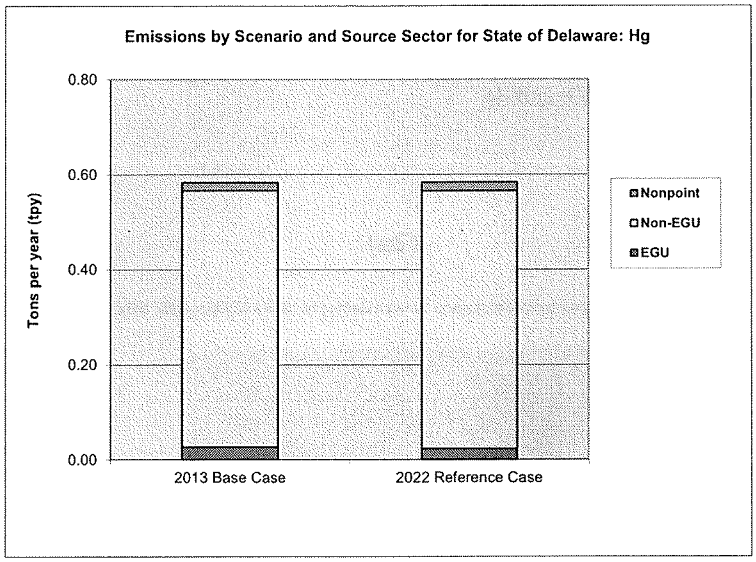
(2a)



(2b)



(2c)



The change in power plant emissions over time can be used to evaluate the change in ozone and particulate matter ($PM_{2.5}$) that affects air quality and impacts human health in Delaware. Using environmental modeling tools developed by the US Environmental Protection Agency (EPA) and available in the public domain, Delmarva Power estimated the human health impacts for the Reference Case comparing 2013 with 2022. The methods and procedures of the analysis are described in Section IX and Appendix 8 of the IRP.

Due to the uncertainty surrounding the preparation of the estimated impact of changes in air quality on human health, the estimates are presented as a range of values as opposed to a single value. Table 12 below shows the estimated range of monetized human health benefits, derived from the EPA models, that is expected to occur for Delaware as a result of the improved air quality in the Reference Case from 2013 to 2022.

Table 12

. **Total BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$ and Ozone (Millions \$2010 U.S. Dollars/Year) Associated with the Changes in Air Quality from 2013 to 2022.**

	Delaware	
	High End	Low End
2013–2022		
PM-Mortality (Laden, 3% discount rate)	1,800	
PM-Mortality (Pope, 7% discount rate)		630
PM-Morbidity	45	45
Ozone-Mortality (Levy)	300	300
Ozone-Morbidity	6	6
Total	*2,151*	*981*
Total (2 significant figures)	2,200	980

More detailed $PM_{2.5}$ Mortality estimates are presented in Appendix 8 based upon a number of expert studies. In Table 12 only the highest value (Laden) and lowest value (Pope) are presented.

The estimated human health benefits arising from the Reference Case by 2022 shown in Table 5 are very significant. These results are affected by the expected changes in power plant emissions that can be attributed to a number of factors including:

- The expected operation of over 12 GW of new gas fired generation and retirement of about 2 GW of coal fired resources in PJM by 2022,
- Expected reductions in emissions from remaining coal generation,
- Increases in the expected implementation of renewable resources within Delaware and other Mid-Atlantic regions (including Delmarva Power's renewable resource portfolio),
- Ongoing demand side management activity including the implementation of smart grid technology and associated dynamic pricing and load control programs.

These factors, as well as other factors not related to power generation resources, contribute to improving air quality and human health over the 10 year planning horizon. More details on this analysis are provided in Appendix 8.

Effect of change in US EPA Regulations

On July 6, 2011, the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR requires upwind states to reduce power plant emissions that contribute to ozone and/or fine particle pollution in other downwind states. The IRP Reference Case assumed that CSAPR would be in effect during 2013 – 2022.

However, on August 21, 2012, a three judge panel of the U.S. Court of Appeals for the District of Columbia struck down CSAPR. On October 5, 2012, EPA sought a re-hearing of the case before the entire US Appeals Court for the District of Columbia. Delaware was included in the group of 10 states and various cities petitioning in favor of the re-hearing.

At the time of the CSAPR decision, the IRP analysis was already well underway and the resource planning and air quality modeling could not be started anew if Delmarva were to meet the December 2012 IRP filing requirement. However, due to the potential impact of CSAPR on the future resource mix, prices and air emissions, Delmarva Power has prepared a sensitivity case on the expected resource mix and air emissions with and without CSAPR. Detailed results of this sensitivity are provided in Appendix 5 and the new assumed environmental regulations underlying this sensitivity are provided in Appendix 10. In the Sensitivity Case it is assumed that CAIR continues as currently designed followed by more stringent SO_2 and NO_x requirements starting in 2018.

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Table 13 presents a comparison of the expected PJM capacity (MW) while Table 14 presents the associated generation (GWH) by resource type for this Sensitivity Case.

Table 13: Expected Total Capacity (MW) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	66,627	65,186	64,136	63,736	63,736	63,736
Combined cycle	25,359	25,924	29,525	31,355	35,241	38,383
Oil/Gas other	8,139	7,036	6,528	6,528	6,528	5,710
Hydro	7,433	7,433	7,468	7,468	7,468	7,468
Nuclear	33,707	33,707	33,707	33,707	33,057	33,057
Turbine	31,033	31,012	30,160	31,992	32,729	36,959
Renewable	9,941	10,835	12,083	12,919	13,711	14,275
Wind	6,482	6,901	6,915	6,915	6,915	7,377
Solar PV	1,528	1,991	3,065	3,883	4,633	4,735
Landfill	671	671	831	849	891	891
Biomass	644	644	644	644	644	644
Other	598	598	598	598	598	598
Fuel Cell	18	30	30	30	30	30
Total	**182,239**	**181,133**	**183,607**	**187,705**	**192,470**	**199,588**

Table 14: Expected Generation (GWh) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	414,484	407,087	410,812	421,652	428,312	432,254
Combined cycle	125,461	135,004	149,815	156,879	183,554	202,894
Oil/Gas other	153	375	156	156	154	154
Hydro	16,405	16,566	16,969	16,969	16,969	16,969
Nuclear	261,532	261,623	259,433	257,730	255,884	254,542
Turbine	5,437	7,013	6,547	7,518	7,966	8,128
Renewable	31,128	34,770	37,603	38,870	40,181	41,640
Wind	15,947	17,494	17,533	17,533	17,533	18,846
Solar PV	1,970	2,573	4,073	5,154	6,121	6,267
Landfill	4,747	4747	6013	6161	6505	6505
Biomass	3652	4984	5004	5042	5042	5042
Other	4,730	4,730	4,730	4,730	4,730	4,730
Fuel Cell	82	242	250	250	250	250
Total	**854,600**	**862,438**	**881,335**	**899,774**	**933,020**	**956,581**

Overall, the impact on coal generation and capacity on a PJM-wide basis is minor in comparison to the Reference Case (see Tables 1 and 2 above). In 2013, the projections indicate a very small increase in coal generation. Although the CSAPR would have potentially had stronger near-term impact on prices, the impact on generation is somewhat mitigated by 1) the expectation of continued relatively low gas prices (i.e. strong gas on coal competition); 2) relatively low expected demand growth; and 3) the significance of the MATs ruling on the operation of continued facilities leading into the 2015/2016 period.

Table 15 presents the emissions by type in the Sensitivity Case.

Table 15: Emissions by Type (Mtons) – PJM Wide

Emissions by Type	2013	2022
CO_2 (Mtons)	472,042	521,560
NO_x (Mtons)	331	269
SO_2 (Mtons)	1,272	586

Consistent with the differences in the capacity and generation outlook, there is little change anticipated due to the vacature of CSAPR under this sensitivity. However, it is anticipated that the installation or operation of control equipment in the very near term may differ. For example, facilities may operate their SCRs at lower levels or not operate seasonally at all if under caps. In the very near-term, this has some impact on NO_x and SO_2 emissions from the facilities within PJM, however, there is negligible difference in the long-term.

Executive Summary

The past twelve months have been eventful for Diamond State Generation Partners' (DSGP's) fuel cell projects in Delaware. The projects were built out from 8.8 MW as of May 2013 to their full 30 MW nameplate capacity in November 2013. The project's Heat Rate (MMBTU gas used/KWH produced) has been better than the Target Heat Rate in the QFCP Tariff. As a result of this higher efficiency DSGP has "banked" 77,636 credits which will be used to offset lower fuel cell efficiencies as they age. The Project's capacity factor is lower than original projections 84.4% vs. 96%.

The project also completed important milestones to maximize its revenue from PJM. As a PJM Capacity Resource the project continues to sell its energy output into the PJM Day Ahead Market. The project became eligible for and received its first capacity payments in June 2013. The project also went through a months-long process to secure a stream of revenue for reactive services through an innovative filing that was the first of its kind. DSGP believes that the project is now receiving all PJM revenue for which it is eligible.

Average monthly energy payment since achieving full power: $1,261,174/month

Capacity payment will increase to $18,550/month in June 2015 they averaged $11,004 /month in 2013/14.

Reactive Services payment total $10,939/month

June 2013 through May 2014 Operating Results:

This annual report covers the second year of operations from June 2013 through May 2014.

The annual total QFCP-RC PJM revenue was $10,776,949. Table 1 below summarizes the PJM revenue on a monthly basis. Table 1 shows sharp revenue growth as the project was built out to its full capacity during 2013. The Table also shows the effects of the Polar Vortex on energy prices in the first quarter of 2014.

Table 1
Total PJM Revenue by Month

Month	PJM Revenue
Jun-13	$ 264,564.00
Jul-13	$ 467,018.00
Aug-13	$ 401,907.00
Sep-13	$ 451,393.00
Oct-13	$ 549,828.00
Nov-13	$ 628,181.00
Dec-13	$ 774,017.00
Jan-14	$ 3,018,917.00
Feb-14	$ 1,228,388.00
Mar-14	$ 1,418,292.00
Apr-14	$ 775,360.00
May-14	$ 799,084.00
Totals	$ 10,776,949.00

Table 2 presents the operating data for the year. The table includes information on the natural gas consumed, energy produced, average output, heat rate, and nameplate capacity installed. The average heat rate for the period was 7124. The average availability for the period was 84.4%. The next section of the report provides detailed information on the factors that drive the QFCP heat rate and availability.

Table 2

Fuel Cell Operating Results							
Month	MWH Generated	mmBTU Reformed	mmBTU Banked	Cumulative mmBTU Banked	Heat Rate	Avg Output, MW	Approx. Name Plate MW @ Month End
June	6,599	47,604	2,222	22,394	7,225	9.17	15
July	8,759	62,427	3,705	26,098	7,127	11.77	15
August	10,372	73,462	4,846	30,945	7,083	13.94	19
September	12,260	86,804	5,762	36,707	7,080	17.03	23
October	15,527	108,426	8,803	45,510	6,983	20.87	26
November	17,253	122,022	8,239	53,749	7,073	23.93	30
December	19,207	136,258	8,755	62,504	7,094	25.78	30
January 2014	17,844	127,594	7,129	69,633	7,151	23.98	30
February	16,649	120,402	5,298	74,931	7,232	24.77	30
March	19,116	138,492	5,832	80,763	7,245	25.73	30
April	18,583	131,989	8,313	89,076	7,103	25.81	30
May	18,988	134,625	8,732	97,808	7,090	25.52	30
Totals	181,157	1,290,105	77,636				

Total QFCP Contract payments for the period: $30,229,576.31

Plus Total Gas Cost for the period: $10,169,216.04

Minus Total PJM Revenues for the period: $10,776,949.00

Equals Total Disbursements to QFCP for the period: $29,621,843.35

Fuel Cell Availability: 84.4%; versus an originally planned availability of 96%

<u>Primary Heat Rate & Availability Variance Drivers:</u>

1. Routine Maintenance. Approximately 6% impact on availability
2. Grid voltage quality- Our systems are sensitive to grid voltage fluctuations and will enter an auto-restart mode if the voltage dips or spikes (even momentarily) beyond predetermined thresholds. We experienced a significant number of these events in over the operating year. Approximately 4% impact on availability.
3. Gas composition. When there is a substantial amount of ethane in the gas supply, our systems do not get the benefit of full heating value of the gas. The units run more process air which typically lowers efficiency by 5%.
    a. The parts required to help reform the ethane were not designed to run continuously, so they fail at a rate that is higher than expected, resulting in more down time for part replacements and system cleaning.

b. Bloom Energy continues to adapt DSGP's fuel cells to the gas conditions present at the Delaware sites. A second generation of fuel cells has been deployed at the Red Lion site, which were modified to better handle to Eastern pipeline gas composition. We expect capacity factor impacts from ethane to decline over time.

Actions taken during the year to maximize revenues:

DSGP has the duty to maximize PJM revenues in order to minimize collections from ratepayers, per the Tariff. DSGP has three streams of revenue from PJM for the QFCP project: energy, capacity, and reactive services.

Energy: DSGP has sold 100% of its energy output to date into the PJM Energy Market. Table 2 summarizes the past year's energy output. Note that a higher capacity factor would lead to higher PJM revenues but also higher collections from ratepayers; therefore, maximizing capacity factor is not seen as a method for meeting the Tariff's goal of minimizing collections from ratepayers.

Capacity: DSGP has successfully bid in all available PJM capacity auctions since March 2012. DSGP is exempt from the MOPR for all Incremental Auctions but will need to appeal through PJM for a continued exemption.

DSGP PJM Auction Results:

2014/15
For this Delivery Year, the first opportunity for DSGP was the First Incremental Auction (1IA) on 9/10/12. At that time, we entered 2.8MW at Brookside and 25.7MW at Red Lion. The auction cleared at $16.56/MWd for a total of $172,265.40. We were able to enter an additional 0.1MW into the 2IA at $56.94 for a total of $2078.31. We used an outage rate of 5% for the 1IA; however the units performed well lowering the outage rate, so we were able to enter an additional 0.1MW at Brookside and 0.9MW at Red Lion in the 3IA, which cleared at $132.20/MWd for a total of $48,253.00. The total for the year is $222,596.71.

2015/16
For this Delivery Year, Bloom was eligible for the BRA and entered 2.8MW at Brookside and 25.7MW at Red Lion using an outage rate of 5%. The BRA cleared at $167.46/MWd for a total of $1,742,002.65. In the 1IA, Brookside had 0.1MW available. The auction cleared at $166.73/MWd for a total of $6,085.65. The Year to Date total is $1,748,088.30. The 2IA is on 7/14/14 and no bids are expected. The 3IA is on 2/23/15 and if the outage rate is low again, there will be more capacity to bid into the auction.

2016/17
For this Delivery Year, Bloom entered 2.9MW at Brookside and 25.9MW at Red Lion for a total of 28.8MW. The BRA cleared at $119.13/MWd for a total of $1,252,294.56. The 1IA is on 9/8/14.

2017/18
For this Delivery Year, Bloom entered 2.9MW at Brookside and 26.5MW at Red Lion for a total of 29.4MW. The BRA cleared at $120.00 for a total of $1,287,720.00.

Table 3

RPM Auction Schedule

Delivery Year	Base Residual Auction	Incremental Auction		
		First	Second	Third
2013/14	5/3/2010	9/12/2011	7/16/2012	2/25/2013
2014/15	5/2/2011	9/10/2012	7/15/2013	2/24/2014
2015/16	5/7/2012	9/9/2013	7/14/2014	2/23/2015
2016/17	5/13/2013	9/8/2014	7/13/2015	2/29/2016

Table 4

Historical Base Residual Auction Results

Year	EMAAC
2015/16	$167.46
2016/17	$119.13
2017/18	$120.00

Table 5

Historical Incremental Auction Results

Year	EMAAC
2013/14 - 1st	$178.85
2013/14 - 2nd	$40.00
2014/15 - 1st	$16.56
2014/15 - 2nd	$56.94
2014/15 - 3rd	$132.20

Reactive Power: DSGP first investigated the economics of providing reactive power, weighing the revenue stream against the drop in efficiency that the fuel cells experience when operating at less than unity power factor. Our conclusion from speaking to other generators participating in the PJM reactive power market is that calls for reactive power are infrequent and generally total less than 100 hours per year. DSGP's analysis showed that fixed monthly payments for reactive power would provide benefits to the ratepayers well in excess of incremental gas cost from lower efficiency.

In August of 2013, DSGP engaged McNees Wallace & Nurrick LLC, a specialist law firm in this area of this type of FERC filing. McNees engaged FERC staff prior to our formal filing, as the cost-based formula to calculate reactive services payments is based on rotating machinery and is difficult to apply to inverter-based generation from fuel cells. McNees was able to clarify all issues with FERC staff, and the filing was made March 4, 2014. DSGP believes that this was the first filing of its kind. DSGP received the FERC Issuance Letter (See Attachment 1) for reactive services payments on April 25, 2014, effective May 1, 2014. The project now earns $10,939 per month from PJM for reactive services.

Attachment 1

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

Diamond State Generation Partners, LLC
Docket No. ER14-1421-000
4/25/14

McNees Wallace & Nurick LLC
Attention: Robert A. Weishaar Jr.,
Counsel for Diamond State Generation, LLC
777 North Capitol Street
Suite 401
Washington, D.C. 20426

Reference: Rate Schedule for Reactive Supply and Voltage Control from Generation Sources Service

Dear Mr. Weishaar:

On March 4, 2014, you filed on behalf of Diamond State Generation Partners, LLC (Diamond State) a Rate Schedule setting forth the cost-based revenue requirement for Reactive Supply and Voltage Control from Generation Sources Service (Reactive Power) from Diamond State's 27 MW, natural gas fired fuel cell generating facility, located in New Castle, Delaware.[1] You state that the facility is interconnected with the transmission facilities owned by Delmarva Power and Light Company (DPL) in the PJM control area.

Pursuant to the authority delegated to the Director, Division of Electric Power Regulation – East, under 18 C.F.R. §375.307, your submittal is accepted for filing, effective May1, 2014.

The filing was noticed on March 5, 2014, with comments, interventions, and protests due on or before March 25, 2014. Pursuant to Rule 214 (18 C.F.R. § 385.214 (2013), to the extent that any timely filed motions to intervene and any motion to intervene out-of-time were filed before the issuance date of this order, such interventions are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

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[1] Diamond State Generation Partners, LLC, Tariff Cost of Service, Volume 1, RSS Tariff, 0.0.0.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against Diamond State.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Jignasa Gadani, Director
Division of Electric Power
Regulation – East

Document Content(s)

A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards

J. Heeter[1], G. Barbose[2], L. Bird[1], S. Weaver[2], F. Flores-Espino[1], K. Kuskova-Burns[1], and R. Wiser[2]

[1] *National Renewable Energy Laboratory (NREL)*

[2] *Lawrence Berkeley National Laboratory (LBNL)*

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC, under contract DE-AC36-08GO28308.

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This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Technical Report
NREL/TP-6A20-61042
LBNL-6589E
May 2014

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Executive Summary

More than half of U.S. states have renewable portfolio standards (RPS) in place and have collectively deployed approximately 46,000 MW of new renewable energy capacity through year-end 2012. Most of these policies have five or more years of implementation experience, enabling an assessment of their costs and benefits. Understanding RPS benefits and costs is essential for policymakers evaluating existing RPS policies, assessing the need for modifications, and considering new policies.

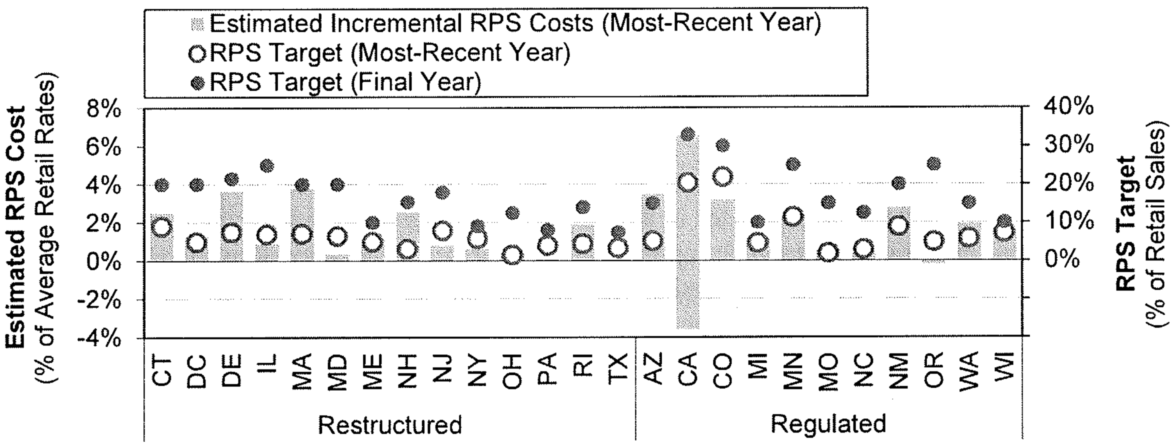
This report surveys and summarizes existing state-level RPS cost and benefit estimates and examines the various methods used to calculate such estimates. The report relies largely upon data or results reported directly by electric utilities and state regulators. As such, the estimated costs and benefits itemized in this document do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions. Because the reported values may differ from those derived through a more consistent analytical treatment, we do not provide an aggregate national estimate of RPS costs and benefits, nor do we attempt to quantify net RPS benefits at national or state levels.

The report summarizes state-level RPS costs to date and considers how those costs may evolve going forward given scheduled increases in RPS targets and cost containment mechanisms incorporated into existing policies. The report also summarizes RPS benefits estimates, based on published studies for individual states, and discusses key methodological considerations. These estimates, for example, of the social value of carbon emissions reduction and the human health impacts of reduced air emissions, are based on a variety of methodologies and assumptions. In comparison to the summary of estimated RPS costs, the summary of RPS benefits is more limited, as relatively few states have undertaken detailed benefits estimates. Further, for those states that have estimated RPS benefits, most assess only a limited number of impact types; as a consequence, some types of benefits are not reflected in this report.

RPS Costs

Our analysis focuses specifically on the *incremental* cost of meeting RPS targets, i.e., the cost above and beyond what would have been incurred absent the RPS, over the 2010-2012 period. For states with restructured markets, we derive RPS compliance costs based on the cost of renewable energy certificates (RECs) and alternative compliance payments (ACPs). For traditionally regulated states, we instead rely upon RPS cost estimates reported directly by utilities or regulators within annual compliance reports or other regulatory filings (not prospective studies), and translate those estimates into a set of common metrics for comparison. The methods used by utilities and regulators to estimate incremental compliance costs vary considerably from state to state, in some cases reflecting statutory or regulatory requirements, and a number of states are currently engaged in processes to refine and standardize their approaches to RPS cost calculation.

Importantly, the estimated RPS costs summarized within this report must be considered in light of what the underlying data represent and the limitations therein. First and foremost, the comparisons across states are imperfect, given the varying methods and assumptions used (especially among regulated states). Second, the data presented most closely correspond to the costs borne by utilities or other load serving entities; they do not represent net costs to society, nor do they necessarily represent the costs ultimately borne by ratepayers, such as in cases where ACPs or financial penalties are not passed through to rates or differences in the timing of when costs are incurred and recovered in rates. Third, depending upon the state and particular methodology used, the cost data may omit certain costs incurred by utilities (e.g., integration costs), as well as possible benefits. Other analysis has examined integration costs; for example, a number of U.S.-focused studies have found wind integration costs to be less than $5/MWh (Wiser and Bolinger 2013). Finally, the use of REC prices to compute RPS compliance costs in restructured markets is limited in some cases by a lack of REC price transparency and incomplete data on long-term contracts. In addition, REC prices can be quite volatile, with large swings from year to year, depending upon whether a given state or region is in surplus or deficit relative to its RPS obligations. As such, the calculated RPS compliance costs for restructured markets may not correspond well to trends in the underlying cost of renewable electricity.



** For most states shown, the most-recent year RPS cost and target data are for 2012; exceptions are CA (2011), MN (2010), and WI (2010). MA does not have single terminal year for its RPS; the final-year target shown is based on 2020. For CA, high and low cost estimates are shown, reflecting the alternate methodologies employed by the CPUC and utilities. Excluded from the chart are those states without available data on historical incremental RPS costs (KS, HI, IA, MT, NV). The values shown for RPS targets exclude any secondary RPS tiers (e.g., for pre-existing resources). For most regulated states, RPS targets shown for the most-recent historical year represent actual RPS procurement percentages in those years, but for MO and OR represent REC retirements (for consistency with the cost data).*

Figure ES-1. Estimated incremental RPS costs compared to recent and future RPS targets

In light of what the underlying data represent and the limitations therein, the following are key findings with respect to RPS costs.

- Over the 2010-2012 period, average estimated incremental RPS compliance costs in the United States were equivalent to 0.9% of retail electricity rates when calculated as a weighted-average (based on revenues from retail electricity sales in each RPS state) or 1.2% when calculated as a simple average, although substantial variation exists around the averages, both from year-to-year and across states. Focusing on the most recent historical year available, estimated incremental RPS compliance costs were less than 2% of average retail rates for the large majority of states (see Figure ES-1).
- Among restructured markets, estimated incremental compliance costs ranged from 0.1% to 3.8% of retail rates. Expressed in terms of the cost per unit of renewable energy required, estimated incremental RPS compliance costs in these states ranged from $2-$48/MWh.

Variation among those states reflects differences in RPS target levels, REC pricing, the composition of RPS resource tiers, and other factors.

- Among traditionally regulated states (excluding California), estimated incremental compliance costs varied from -0.2% (i.e., a net savings) to 3.5% of average retail rates. Variation among these states partly reflects differences in RPS procurement levels. In addition, relatively high estimated costs for a number of states are associated with the presence of distributed generation (DG) set-asides, for which compliance costs tend to be "front-loaded." The estimated incremental costs of meeting general RPS obligations (i.e., excluding DG or solar set-asides) ranged from -\$4 to \$44/MWh of renewable energy procured.
- Methodological differences contribute to observed variations in these compliance cost estimates, especially among regulated states. For example, in California, two different methodologies yield derived incremental compliance cost estimates ranging from a net savings equal to 3.6% of retail rates to a net cost of 6.5%, as shown in Figure ES-1.
- Utilities in eight states assess surcharges on customer bills to recoup RPS compliance costs. These utility-reported surcharges, which represent the costs borne directly by customers, ranged in 2012 from about \$0.50/month to \$4.00/month for average residential customers, and on a statewide average basis, equate to roughly 0.5% to 4% of average retail electricity rates. These customer surcharges may differ from the estimated compliance costs borne by the utility for a variety of reasons, such as differences in the timing or type of costs that can be passed through to customers.
- Estimated incremental RPS compliance costs over the historical period of our analysis reflect the RPS targets applicable during those years (the open circles in Figure ES-1). Under current policies, RPS targets are scheduled to increase significantly, eventually reaching levels represented by the closed circles. Whether and the extent to which incremental RPS costs rise in tandem depends on many factors: renewable energy technology costs trends, natural gas prices, federal tax incentives, and environmental regulations, among others.
- Future RPS compliance costs are limited by cost containment mechanisms built into most RPS policies. Among those states relying principally upon an ACP mechanism for cost containment, RPS costs are effectively capped at roughly 6-9% of average retail rates in most cases. Cost caps in most other states are considerably more stringent, often limiting compliance costs to 1-4% of average retail rates. Compliance costs in several of those states have already reached or are approaching the respective caps.

RPS Benefits

Policymakers often consider RPS costs within the context of broader social benefits beyond any direct cost savings that may accrue to utilities. Potential benefits of RPS policies include reduced emissions, water savings, fuel diversity, electricity price stability, and economic development. States have most commonly attempted to quantitatively assess avoided emissions and associated human health benefits, economic development impacts, and savings from reductions in wholesale electricity prices. In many cases, these assessments are required by the legislature or public utilities commission (PUC), filed as part of an integrated resource plan (IRP) docket, and prepared for regulatory commissions, energy boards, or public benefit corporations. In this work, we focused on analyses conducted as part of state-level RPS evaluations, but did not review the broader literature on renewable energy benefits in general. While we attempted to conduct a thorough literature review, we have likely omitted some analyses; however, this review provides an indication of the types of benefits analyses that have been conducted and the range of benefits found.

Key findings include:

- A relatively small number of RPS benefits estimates have been developed and methodologies vary considerably, which limits the ability to make comparisons and bounds the range of impacts. We identified studies for eight states that assessed the societal benefits or broader impacts of RPS policies based on our review of literature. Most studies of benefits or impacts are prospective in nature, assessing not only the current RPS impacts, but also examining future impacts, in contrast to the cost estimates previously discussed that are retrospective. Some types of benefits, such as avoided emissions, can accrue for the lifetime of the renewable energy plant, while costs are incurred typically over a shorter period.
- We identified six studies that attempted to quantify the emissions or human health benefits of state RPS policies. Most used modeling approaches to assess scenarios with and without renewable energy and some estimated the dollar values associated with emissions reductions. In some cases, emissions benefits may be captured in estimates of net incremental costs, such as if allowance prices are already embedded in wholesale electricity prices. Estimates of benefits ranged from roughly tens to hundreds of millions of dollars on an annual basis depending on the state and scenario. These estimates translate to approximately \$4-23/MWh of renewable generation, depending on the study and the cost value assumed for CO_2.
- Similarly, we identified six studies that attempted to quantify economic impacts of an RPS. Two used economic modeling approaches while the others used input-output models or simplified case study approaches. Often input-output models or simplified approaches estimate gross jobs, which do not account for shifts in employment that may occur, as opposed to new net jobs. A number of the studies examined economic development benefits annually or over the lifespan of the renewable energy projects, with benefits on the order of \$1-\$6 billion, or \$22-30/MWh of renewable generation.
- Six states estimated wholesale market price reductions that resulted from an RPS (i.e., the reduction in market clearing prices resulting from an increase in the supply of low marginal-cost renewable resources), typically using electric system modeling or applying estimates from other modeling efforts. The studies generally found wholesale price reductions of about \$1/MWh or less within specific markets (total generation), or price suppression benefits of \$2-\$50/MWh of renewable energy generation.
- Comparison of costs to benefits is challenging, even when they are reported in the same study, given that some incremental cost calculations may already take into account specific benefits, analysis time periods may differ, benefits assessments may address only particular types of benefits, and other factors. Most states for which we have identified benefits estimates did not conduct direct comparisons.

In the future, additional efforts could be undertaken to comprehensively assess the costs and benefits of state RPS policies by comparing costs and benefits directly, using similar methodologies and level of rigor. Further, additional work could be done to standardize incremental cost calculations within and among states provided that such cost calculations are often required by RPS statutes. Efforts in a few states are underway to address standardization of incremental cost calculations; states that have not examined standardization may see the issue arise in the future and be able to learn from the processes and outcomes of existing state standardization efforts.

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1 Introduction

Renewable portfolio standards (RPS) have been widely adopted by states and have reached moderate-to-advanced stages of implementation, so that there is now sufficient experience to examine implementation costs and benefits. RPS policies call for electricity providers to acquire specific amounts of renewable energy generation over time, often as a percentage of overall electricity supplied. These policies have been a significant driver of development of new renewable capacity additions in the United States, with roughly 46 GW or two-thirds of all non-hydroelectric renewable capacity additions since 1998 occurring in states with active or impending RPS targets.[1] Today, RPS policies are established in 29 states plus Washington D.C. and Puerto Rico.[2] RPS policies in 22 states have been in place for five or more years, and RPS polices in five states have been in place for more than a decade; this degree of implementation experience has led to cost and benefit assessments by utilities, states, and others.

Understanding the costs and benefits of RPS policies can be important for program evaluation, understanding policy effectiveness, consideration of new policies, and assessing potential modifications to existing RPS policies. In recent years, there has been significant legislative activity to modify RPS targets (CNEE 2012), and information on RPS implementation costs across states can be particularly important for informing legislative decisions.

Information about RPS costs is also often needed to support other regulatory and legislative processes. RPS costs, in some cases, are recovered through a dedicated surcharge or tariff rider on customer bills that is adjusted regularly and approved by the public utilities commission (PUC). In these instances, utilities must estimate the costs when requesting adjustments to the surcharge. States may also conduct occasional evaluations of their RPS programs, which may be required by statute. Such evaluations are often much broader in scope than the aforementioned administrative processes, and may include analyses of benefits, such as economic development and environmental impacts.

Many states have cost containment mechanisms in place that limit RPS compliance costs and the associated impact on ratepayers (Stockmayer et al. 2012; CPI 2012). For example, several states have developed rules precluding the cost of RPS compliance from exceeding 2-4% of retail electricity rates. As a result of these provisions, utilities and PUCs must routinely evaluate RPS program costs—typically within the context of annual compliance filings or reports to the legislature—to ensure that the compliance costs do not exceed the cost caps.

In implementing RPS cost caps, surcharges, and program evaluations, states have faced methodological issues associated with determining compliance costs. In some cases, methods for calculating such costs may be briefly specified in statute or in implementing rules by the PUC. Even in cases where the broad methods are defined, there can be significant variability in utility

[1] The 46 GW figure is intended as a rough proxy for the impact of state RPS programs on renewable energy development to date, and was derived by simply considering the date and location of renewable energy capacity additions. For the purpose of this tabulation, renewable additions are counted if and only if they are located in a state with an RPS policy and commercial operation began no more than one year before the first year of RPS compliance obligations in that state.

[2] For additional detail, see the DSIRE database: http://www.dsireusa.org/rpsdata/index.cfm.

calculations. As a result, a number of states (e.g., New Mexico, Minnesota, Washington) have recently conducted or are currently engaged in regulatory proceedings to develop consistent RPS cost calculation methods across utilities. Some of the key challenges include assessing the incremental or above-market costs of acquiring renewable generation rather than conventional generation sources and the timeframe of the cost calculation.

While most states or utilities have estimated or collected data on compliance costs, only a few have assessed benefits quantitatively. Benefits of RPS policies can include environmental benefits, such as avoided air pollutant emissions, human health effects, and reduced water consumption, as well as fuel diversity, economic development, electricity price stability, and others. Methods used to assess benefits are substantially different than for estimating costs, and these are covered separately in this report.

This analysis adds to a relatively small, but varied, literature analyzing RPS costs across states. At the national level, cost impacts of a proposed federal RPS have been studied with the use of modeling tools (Bird et al. 2011, Fischer 2010, and Wiser and Bolinger 2007). At the state level, Morey and Kirsch (2013) use regression analysis to examine the impact of various policies, including an RPS, on electricity rates, using historical data. Chen et al. (2007) examined prospective, rather than retrospective, RPS studies, the majority of which were funded by nongovernmental organizations. Of the studies reviewed by Chen et al., 21 of 30 projected a retail rate increase of less than or equal to one percent in the RPS peak target year, while nine studies predict rate impacts above 1% and two of those studies predict rate impacts of more than 5%.

While prospective RPS studies have been conducted in many cases, in some instances at the request of state legislatures, this analysis does not utilize forward looking cost studies, but rather focuses on estimates of actual incurred costs. The approach used in our analysis focuses on estimated incurred costs so as to better determine rate changes that are attributable to RPS implementation costs rather than other factors that can influence rates.

This paper examines estimated costs and benefits from RPS implementation to date and the expected costs if they continue to evolve over time to their end target. In general, the information presented in this report can be important for policymakers and other stakeholders to understand how state RPS implementation costs and benefits compare as they evaluate existing RPS policies and consider revisions going forward. The focus of this report is on estimated costs to load serving entities subject to RPS targets; we do not focus on broader societal costs (such as federal tax subsidies). Data for this report are obtained primarily from PUC compliance filings, program evaluations conducted or authorized by state commissions, and other state-commissioned studies. Section 2 assesses current methods used to evaluate RPS costs and discusses the issues and challenges associated with various approaches. Section 3 assesses estimated RPS cost data for states where information is available, discussing underlying reasons for differences across states and the impacts of policy design (for example, the presence of solar carve-outs). The potential to reach cost caps in coming years is also examined. Section 4 reviews quantitative benefits information, focusing on estimates of broader societal benefits prepared for formal evaluations of state-level RPS policies, often at the request of legislatures.

2 Methods of Determining Cost Impact

Section 2 and Section 3 of this report survey various methods used to estimate the costs of renewable portfolio standards and summarize estimates of state RPS costs to date, relying largely upon data or results reported directly by electric utilities and state regulators. As such, the estimated costs itemized in this document do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions.

Costs examined by utilities, states, and regulators may be defined as either "gross costs" or "incremental costs." Gross costs consist of the total cost of procuring renewables to meet the RPS, while incremental costs (also referred to as "net" or "above market" costs) examine the difference between gross costs and the costs that would have been borne absent the RPS. "Incremental" is sometimes defined in different ways; here we refer to incremental cost as the additional cost of renewable electricity above and beyond what would have been incurred to procure electricity in the absence of the RPS. Most states focus on calculating the incremental costs of RPS compliance, though three (California, Kansas, and Nevada) have published estimates of gross costs. RPS benefits are discussed in Section 4.

In general, the method by which costs may be determined depends on the regulatory structure of the state.[3] In traditionally regulated states, utilities commonly enter into long-term power purchase agreements (PPAs) for the electricity and renewable energy certificates (RECs) from a project, or build and own renewable generation projects directly. RECs represent the environmental attributes of renewable generation and are used to demonstrate compliance with the RPS. Because these long-term PPAs include both the electricity and the REC (referred to as a "bundled contract"), determining the "incremental" cost of the renewable energy requires a comparison to the cost of conventional generation that would otherwise have been procured. In traditionally regulated states, RPS costs are typically estimated by either the obligated utility or by the PUC. The general methodology for assessing costs has in some cases been outlined by statute or regulation; however, statutory or regulatory language can still be open to interpretation by the compliance entity, sometimes resulting in differing methodologies across utilities within a state.

In states with restructured markets, compliance entities are typically buying "unbundled" RECs, and thus, the incremental cost of RPS compliance is derived from the cost of RECs in addition to any alternative compliance payments (ACPs) made to achieve compliance. Most restructured states have ACPs that enable obligated entities to make a payment at a pre-established price in lieu of procuring renewables (e.g., \$50/MWh). These essentially establish a ceiling on the cost of compliance because obligated entities would not enter into contracts to procure renewable generation above the ACP price. Though REC prices (in combination with ACPs) can be used to

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[3] In states with restructured markets, the traditional electric utility monopoly, where the utility provides generation, transmission, and distribution, has been split. Customers in restructured states can choose which electric service company will supply their generation. In traditionally regulated states, vertically integrated utilities provide generation, transmission, and distribution service to a captive market (i.e., franchise service territory). While there is a spectrum of restructuring, for purposes of this study, we classify the following RPS jurisdictions as operating in restructured markets: Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Washington, D.C.

estimate the incremental cost of RPS compliance, it is important to note that REC prices are influenced by market supply and demand, and can fluctuate widely, thus not necessarily representing the above market costs for renewable energy, as discussed further in Section 2.2. Moreover, in addition to purchasing unbundled RECs, compliance entities in some restructured markets have begun procuring more renewables through long-term bundled PPAs, which requires a different methodology to calculate the incremental cost.

This section provides an overview of the methods used to estimate the cost impacts of an RPS; Section 3 will present the results of studies done by states as well as our calculation of RPS costs, based on REC price data, ACPs, and data from long-term contracts.

We structure the section as follows: Section 2.1 discusses methods used to estimate incremental RPS compliance costs in regulated states; Section 2.2 discusses methods used in states with restructured electricity markets; Section 2.3 discusses those states that instead report only gross costs; Section 2.4 highlights other issues that impact cost estimates; and Section 2.5 provides a summary of methodological considerations.

2.1 Methods for Estimating Incremental RPS Costs in States with Traditionally Regulated Markets

In traditionally regulated states where utilities and state agencies are estimating the incremental cost to meet the RPS, a key decision is how to determine the counterfactual scenario—absent RPS procurement, what resources would have been procured, and at what cost. After the counterfactual scenario costs are determined, they can then be subtracted from the gross RPS costs to derive an "incremental" cost of RPS compliance.

Utilities in states with traditionally regulated markets generally use one of three methods, or a combination of methods, for defining the counterfactual scenario and estimating incremental RPS costs (Table 1). In some cases, the counterfactual scenario is a particular type of conventional generator, which may be established by the Commission. In other cases, utilities use wholesale prices to determine the counterfactual scenario. Finally, many utilities use modeling approaches to determine the proxy conventional generator(s) or market prices. Table 1 outlines the primary methods for determining incremental costs in regulated markets, identifies the methods used in various regulated states, and highlights a number of key considerations within those methods, as discussed further below.

Table 1. Methods for Estimating Incremental RPS Costs

Method	States	Key Considerations	Considerations for Multiple Methods
Compare to a proxy non-renewable generator	AZ, CA, MI, OR	• What is the process for determining the conventional generator?	• Over what time period are costs calculated? • Is a carbon adder included in the non-renewable costs? • What fossil fuel prices are assumed? • What additional costs are included (e.g. capacity, transmission, or ancillary services)? • Are renewable resources that were developed before the RPS implementation included?
Compare to market price	CA, MN, WA, WI	• Is the wholesale market generation shaped to match the output of the renewable energy? • Are energy and capacity values included?	
Modeling approaches	CO, MI, MN, NM, NC	• For future scenarios, what assumptions are made about load growth, environmental regulations?	

2.1.1 Comparing to a Proxy Non-renewable Generator

Under this approach, utilities and states compare the cost of RPS resources to the levelized cost of some proxy conventional generator. The kind of proxy generator, and the set of costs included in the comparison, may be established by the commission or in statute. These costs may include (for both the renewable generation and conventional generation) those associated with fuel consumption, generation capacity, operations and maintenance, transmission, ancillary services, and emissions.

This approach takes a long-term perspective, looking at the levelized cost of a resource over its lifetime. It may also simplify the process for calculating incremental costs, compared to a modeling approach, though decisions about defining the proxy generator, timeframe of analysis, fuel costs, and other issues may complicate the process. In addition, the resulting estimated incremental costs may not represent what actually would have been used absent an RPS. This is because in practice, renewable generation could displace more than one generator type at different hours during the year, and may or may not have equal capacity value as the proxy generator. The generator type as well as the hours in which it is operated will impact the overall cost profile.

States have used different approaches to developing a proxy. Some examples include the following:

- The Michigan PUC files a report annually examining the cost of renewables procured under the RPS compared to the cost of a new, coal-fired power plant, as required by statute. The PUC report draws on data submitted in the rate-regulated electric providers' annual renewable energy plans, which must demonstrate that the "life cycle cost of renewable energy acquired, less the life cycle net savings associated with the Energy Optimization Plans, did not exceed the life cycle cost of electricity generated by a new conventional coal-fired facility (MPSC 2013, 23-24)." The PUC staff developed a guidepost for the cost of a new coal plant of $133/MWh (or $0.133/kWh), based on a 40-year life cycle and forthcoming EPA regulations.4

- In Oregon, utilities estimate incremental costs of compliance based on a combined cycle gas turbine (CCGT) proxy, unless otherwise specified by the PUC, the costs of which must be based on the most recent integrated resource plan (IRP), unless material changes have been made since then.
- Although California's cost assessment process is being revised, the historical approach for evaluating RPS costs was to compare RPS procurement to a "market price referent" (MPR). The MPR was developed by the utilities as the modeled cost to own and operate a CCGT over multiple time periods. In its most recent RPS cost report, the CPUC used a 20-year MPR of $0.101/kWh to evaluate the utilities' 2011 RPS portfolios (CPUC 2013a).

2.1.2 Comparing to Market Price

Some states and utilities are estimating incremental RPS costs by comparing the cost of renewables procurement relative to wholesale electricity spot market prices. In order to determine the market price, a number of considerations need to be weighed, including: should the wholesale market generation be shaped to match the output of the renewable energy, and are both energy and capacity market costs considered?

States and utilities have used different approaches when comparing the cost of renewables used to meet the RPS to market price. Text Box 1 describes how utilities in Minnesota have calculated incremental RPS costs, using market price as well as modeling work. Other examples using wholesale market prices as the presumed cost absent the RPS include the following:

- In Washington, the three investor-owned utilities (IOUs) are comparing the costs of renewables to the cost of purchasing an equivalent amount of energy from the wholesale market.5 As part of this process, PacifiCorp used the wholesale market price curve shaped to the output of the renewable resource. This shaping was not done by the other IOUs. Differences in methodology and other factors led to a two-fold range in reported 2012 compliance costs estimates in Washington. PacifiCorp estimated the cost of RPS compliance at $15.73/MWh while Avista's estimate was $20.35/MWh and Puget Sound Energy's estimate was $43.76/MWh (Stanfield 2013a). The Washington UTC is addressing cost standardization as it considers revisions to its RPS rules (see Docket UE-131723).
- Although California has used the MPR approach, utilities have also estimated avoided costs using a market price methodology using day-ahead market price and the cost of capacity.

[4] The PUC staff calculation of the renewable cost includes the cost of PUC approved contracts, with the exception of Detroit Edison's and Consumers Energy's solar programs, which the PUC determined to make up less than two percent of contracts approved, on a generation basis.

[5] Washington's RPS statute defines incremental costs as "the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources, where the resources being compared have the same contract length or facility life" (RCW 19.285.050(1)(b)). The Washington PUC staff commented that use of the wholesale market price does not appear to meet the language specified in statute (Washington UTC 2013).

Compared to the MPR-based avoided cost estimate of \$0.10/kWh, the utilities' estimates based on market prices were much lower, roughly \$0.03/kWh, which resulted in much higher estimates for incremental RPS costs (discussed further in Text Box 3). The PUC expressed concern with this approach, noting that the results would have prevented even low-cost hydro and nuclear resources from being determined cost-effective and that the calculations were based on short-run avoided costs (CPUC 2013a).

Text Box 1. Rate Impact Calculations in Minnesota

Utilities in Minnesota have used different methods to estimate RPS incremental costs. Xcel Energy (MN) examined the cost of the renewable resources compared to the cost of the same amount of energy and capacity in the MISO market. To determine the renewable energy costs, they included the price paid for contracted energy or annual revenue requirements at their owned facilities (Xcel Energy 2011). Xcel Energy found that the rate impact for wind resources over 2008 and 2009 was approximately 0.7% less than market prices, though biomass resources were slightly higher (0.56% and 1.16% in 2008 and 2009, respectively).

Other utilities in Minnesota had different results. Of the fourteen utilities that submitted reports, eight said that complying with the renewable standard has resulted in little or no additional costs, if not a slight savings for customers, while six utilities, including Great River Energy, reported that their efforts to comply with the policy led to increased costs for customers. Great River Energy modeled a no-RPS scenario that did not include additional non-renewable resources, then compared that with the RPS scenario in which renewable energy was added to comply with the RPS. Great River Energy found that its wind energy purchases increased retail customer bills by about 1.6%, or about \$18/year for an average homeowner.

2.1.3 Modeling Approaches

Modeling approaches can provide a system-wide look at the differences in resources built and dispatched with and without the addition of renewable energy (instead of just looking at one generator type or the wholesale market price). Key inputs to dispatch and capacity expansion planning models include the fuel prices for fossil generation, inclusion of environmental costs, and for models examining future scenarios, the availability of renewable energy tax credits. One advantage of the modeling approach is that it can provide a more comprehensive picture of what would have happened absent the RPS. Modeling approaches may also be able to better capture integration and transmission costs. However, modeling results are heavily dependent upon the key inputs, which are complex and subject to judgment.

States have taken different approaches to modeling approaches. Some examples include the following:

- In Colorado, statute requires that utilities estimate the incremental cost of the RPS through modeling work. Utilities must use scenario analysis, comparing the costs and benefits of the renewable energy standard plan to a plan that replaces the new renewable resources with new non-renewable resources reasonably available.
- In Minnesota, Xcel Energy used wholesale market prices to determine historic RPS costs, but used a long-term resource planning tool, Strategist, to estimate future costs. The model calculates the present value of revenue requirements for different expansion plans. Xcel developed two base models, one that met the RPS, and one that replaced all incremental wind resources with conventional resources. Three additional scenarios explored the impact of extending the PTC though 2020, placing a price on carbon dioxide emissions, and a high natural gas price scenario. There was minimal difference between the cases; the base case without the RPS resulted in 1.4% higher net present cost than the RPS case. The PTC extension, CO2 price, and high gas price cases resulted in 0.74%, 0.41%, and 0.98% higher net present costs, respectively, for the conventional resource plan than the RPS case (Xcel Energy 2011).
- In New Mexico, Public Service Company of New Mexico (PNM) calculates RPS costs for the following two years using production cost modeling. PNM models the total system costs with and without each existing and proposed renewable resources to determine the avoided fuel cost for each resource (PNM 2013a). PNM also develops a single avoided fuel cost figure, for all renewable resources, which it uses to validate the individual results and also in calculating the cost cap.
- In North Carolina, utilities use a hybrid of modeling and a proxy generator method. The incremental RPS costs are defined as those that "are in excess of the electric power supplier's avoided costs," where avoided costs include both energy and capacity (North Carolina G.S. 62-133.8(h)). Duke Energy uses the Commission-approved "peaker method" to determine its avoided costs. The peaker method calculates avoided costs based upon the capacity cost of a combustion turbine peaking unit plus the marginal running costs of the system, which are calculated based on simulation of Duke's system with and without the RPS resources (Duke Energy 2010).
- In Michigan, utilities use a hybrid method when seeking to recover the RPS costs. Incremental RPS costs are specified as the difference between the gross renewable energy costs and the "transfer price". The transfer price is determined by each utility and must reflect long-term capacity and energy, but does not need to be equivalent to the cost of a new coal-fired facility, determined by the PUC (DTE 2009). In practice, Consumers Energy has calculated the transfer price based on capacity values for a gas-fired combustion facility and energy values calculated using a dispatch model (Consumers 2009). DTE has used the annual average locational marginal prices and adjusted capacity payments, by technology, compared to a new gas-fired combustion turbine (DTE 2009).

2.1.4 Additional Considerations for Estimating Incremental RPS Costs in Regulated States

2.1.4.1 Timeframe of Cost Calculation

When evaluating incremental RPS costs, regardless of method, a key consideration is the timeframe to examine.

In most cases, cost calculations are made over a longer time period and then annualized to one year.[6] This recognizes that procurement to meet the RPS may be "lumpy" in nature, and that the relative cost of renewable energy to conventional alternatives will depend on future conditions, e.g., natural gas prices and environmental regulations. In states where utilities are offering an upfront solar rebate to procure supply to meet a solar carve-out, spending may be particularly front-loaded because the rebate is paying upfront for a long-term resource: for example, the utility may offer an upfront rebate per watt in exchange for the RECs produced by the system over 20 years.

For studies using the proxy generator approach, decisions will have to be made about the time over which the conventional and renewable generator costs are levelized. In Michigan, the PUC compares the costs of renewables against the 40-year life cycle cost of a coal plant. The life cycle approach and the 40-year lifetime introduce additional uncertainty into the cost of the coal plant, including uncertainty around potential future federal regulation of coal plants. For example, actual future fuel prices can differ significantly from forecasts. In addition, the costs of renewables are typically recouped over a shorter time period (15-20 years), meaning that the cost comparisons are not done over the same time period.

When examining market prices, studies consider whether to use historical market prices compared to RPS generation in each year, or to use projections of future market prices compared to the RPS resource lifetime.

On the modeling side, Missouri examines RPS compliance costs over 10 years, and then divides those costs into annual increments; if the one-year annual rate increase exceeds 1%, then the utility's RPS obligation is decreased so that rates do not exceed 1%. In order to calculate the costs over the 10-year period, the utilities estimate their cost of compliance for each year based on an RPS-case and a no-RPS case (MO CSR 240-20.100(5)).

California is in the process of developing a cost cap for its 33% RPS. As part of the process, the CPUC staff proposed using a 10-year rolling calculation. In response to the CPUC staff proposal, some parties argued that the timeframe should be longer (e.g., 20 years), in order to match the typical length of renewable energy contracts. Others argued that the cost cap should look only at procurement in an individual year.

2.1.4.2 Inclusion of a Carbon Adder

Whether using a proxy generator, wholesale market prices, or modeling tools, a carbon price could be added to the comparison scenario given that some states or utilities may have a

[6] One notable exception is in New Mexico, where rules specify that cost cap calculations shall not include annualization.

preference for procuring low-carbon resources. That is, even if there were no RPS, state regulators or utilities may have wanted to incorporate a cost of carbon when making decisions about procurement (potentially in anticipation of potential future carbon regulations). However, some argue that in markets where there is currently no carbon policy, and thus utilities are not paying a cost for carbon, adding it to the non-renewable resource cost is inappropriate.

The Colorado PUC initially required that the non-RPS scenario include a carbon adder and a capacity credit. Adding these costs to the counterfactual scenario can be contentious, as there is no existing capacity market in Colorado, nor is there a state-wide price on carbon (Stockmayer et al. 2012). In its latest RPS compliance plan, Xcel Energy (Colorado) did not include a carbon price for 2014 calculations (PSCo 2013).

California's latest MPR calculation was done in 2011, before the state's carbon cap and trade program went into effect. The CPUC determined that the market-based forward natural gas and electricity prices should be used to calculate the implied GHG price. This methodology resulted in GHG compliance costs of \$16.27/CO_2 metric tonne in 2013, increasing to \$36.64/CO_2 metric tonne in 2020 (CPUC 2011).

2.1.4.3 Inclusion of Renewable Resources Not Driven by RPS

In some cases, renewable resources that are counted towards a particular state's RPS target may have been procured independently from the RPS. The most prevalent example would be pre-existing renewable resources that were constructed or contracted prior to the RPS. Because some states allow renewable resources that were in place at the time the RPS was passed to count toward RPS compliance, a key consideration is whether the costs of those resources are included in RPS cost estimates. Because those resources would have been developed regardless of an RPS, including the costs in an incremental cost calculation would result in overestimating RPS compliance costs. In other states, pre-existing resources are not eligible to meet the RPS, so this question is not an issue.

- In Colorado, the state's largest IOU, Xcel Energy, recovers incremental costs through a surcharge on customer bills known as the RESA surcharge. The surcharge only covers the above market costs of new renewables and contracts signed after July 2, 2006 (the date of the commission order approving the RESA) (PSCO 2013c). Renewable resources that were online on or after January 1, 2004 are eligible to meet the RPS.
- In Kansas, some of the renewable projects were built prior to implementation of the RPS, but the costs are still being included in the cost calculation. For example, Kansas Electric Power Cooperative (KEPCo) is using exclusively hydropower that it has been purchasing since the 1980s in order to meet the RPS. The utility determined that the hydropower had no cost impact to ratepayers because it is the least expensive generation source (KEPCo 2013).
- In Oregon, Portland General Electric (PGE) determines an incremental cost for only one renewable resource, Bigelow Canyon. PGE owns and operates Bigelow Canyon, so it used its actual capital costs, O&M costs, capacity factor, as well as wind integration costs that were calculated as part of the IRP process to calculate the levelized cost of the wind farm, which is then compared to the life cycle costs of a combined cycle natural gas plant (PGE 2011). The rest of PGE's renewable resources have been determined to have zero incremental cost. Oregon's regulations specify that "incremental costs are deemed to be zero for qualifying

electricity from generating facilities or contracts that became operational before June 6, 2007 and for certified low-impact hydroelectric facilities under ORS 469A.025(5)" (OAR 860-083-0100(1)(i)).

- Ameren Missouri, which owns a hydro facility that is eligible to meet Missouri's RPS, values the RECs generated by that facility at zero cost. Ameren Missouri notes that the capital and operational expenses for the facility are already included in existing rates, therefore, there are no additional costs to use the generated RECs for RPS compliance (Ameren Missouri 2013a).

Another example of renewable resources that may be procured independently from an RPS are upgrades to hydroelectric facilities, which are often treated as an eligible RPS resource. This issue has arisen in Washington, where some utilities have included the cost for efficiency upgrades at hydropower facilities. Hydropower upgrades are eligible to meet the RPS, but the upgrades were required by the Federal Energy Regulatory Commission; therefore, the upgrades would have occurred even if there were no RPS in Washington. In Washington, PacifiCorp has not included hydropower upgrades in its incremental RPS cost calculation, while Avista has included the cost of hydropower upgrades (Pacific Power 2013a; Avista 2013).

2.2 Approaches for Estimating Incremental RPS Costs in States with Restructured Electricity Markets

In restructured markets, as electricity rates are not regulated, obligated entities typically do not disclose the cost to meet RPS.[7] In some restructured markets, however, information on the cost of RECs is required to be provided and these costs, along with the costs of ACPs, can be used to estimate incremental RPS costs. RECs can be purchased separately from electricity, and in such cases, it is commonly assumed that the RECs represent the incremental RPS costs, as the RECs would not have been purchased absent an RPS.[8] There are, however, a variety of limitations with this approach, most notably, REC price volatility, limited REC price transparency (especially for medium- and long-term REC price contracts), and the fact that REC prices and ACPs ignore a number of potentially important costs and benefits from renewable energy.

REC prices do not necessarily reflect the underlying cost of renewable electricity generation, because they are influenced by supply and demand in the marketplace. There is substantial variability in REC prices from year to year depending on how states are meeting their RPS targets. In oversupply situations, REC prices can fall dramatically while in shortages they can rise to the level of the ACP. Therefore, cost calculations based on REC pricing can vary considerably from year to year. In the next section, we examine costs over a three-year period to try to capture this variability.

In addition, there is a lack of transparency in REC prices. Many load-serving entities enter into multi-year contracts for RECs–usually not more than three years–to meet RPS requirements. Little publically available data are available on these contracts. Spot market transaction data are available from some brokers, and can be used as a proxy, but these prices can differ from the

[7] REC prices paid by utilities in regulated states are also often deemed confidential by the PUCs and therefore they are not made public.
[8] For additional information on RECs, see Heeter and Bird (2011).

longer-term bilateral transactions. The source of data and assumptions about REC prices can substantially influence the cost calculation.[9]

In Illinois, Maine, Maryland, New Jersey, Ohio, Pennsylvania, and Washington, D.C., data on REC pricing and use of ACPs as purchased and employed by compliance entities are publically available (Table 2).[10] Publically available data sources for these states provide information on the cost of the RECs retired, including those RECs that were procured under long-term contracts, which may be procured at a higher or lower price than is seen in the current spot market.

However, in New Jersey, only data on solar RECs are comprehensive, because the Board of Public Utilities (BPU) set up a system for collecting data on the price of solar RECs as of the last transaction before a REC is used for compliance. However, for Class I RECs[11], the same data are not collected on every transaction. As a result, in order to estimate costs, the New Jersey Office of Clean Energy relies on REC pricing information from other sources (e.g., brokers) (NJ BPU 2011).

In Delaware, Massachusetts, New Hampshire, Rhode Island, and Texas, no such publically available source on the REC prices paid by compliance entities is available. In these states, available spot market REC pricing from REC brokers can be used to approximate the cost of RPS compliance. Broker prices may represent a small volume of transactions, however, and it is uncertain how indicative they are of the average price of all RECs used for compliance by obligated entities.

[9] One example of REC price approximation comes from by New Mexico, a traditionally regulated state. Southwestern Public Service Company (SPS) used a proxy REC price to determine RPS costs associated with two bundled PPAs for wind generation. To determine a proxy REC price, SPS examined REC prices in the national, western U.S., and Texas REC markets ($0.89/MWh, $2.31/MWh, and $1/40/MWh, respectively). The proxy REC price agreed upon was $1.35/MWh, slightly less than the average of the three markets, recognizing that REC prices are decreasing and that SPS has been unable to sell existing RECs into the western U.S. REC market (NM PRC 2011).

[10] REC pricing data from Maryland have been provided upon request to the PUC. Data from other states may also be available by request.

[11] Class I RECs are for the primary RPS target.