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PPRP

Long-Term Electricity Report for Maryland

Reference Case Update

May 2013

MARYLAND POWER PLANT RESEARCH PROGRAM

Martin O'Malley, Governor
Anthony G. Brown, lt. Governor

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***Joseph P. Gill**, Secretary*
Maryland Department of Natural Resources

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Long-Term Electricity Report for Maryland

Reference Case Update

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May 2013

ABSTRACT

On July 23, 2010, Governor Martin O'Malley signed Executive Order 01.01.2010.16 ("EO") directing the Maryland Department of Natural Resources' Power Plant Research Program ("PPRP") to develop a long-term electricity report for the State of Maryland. The central purpose of the Long-term Electricity Report ("LTER") was to provide a comprehensive assessment of approaches to meet the long-term electricity needs of Marylanders through clean, reliable, and affordable power. In the two years since the LTER assumptions were formulated, more recent information has become available that suggests that some of the assumptions relied upon in the LTER warrant revision. The LTER Reference Case Update ("RCU") incorporates a reduced natural gas price, the increased number of announced power plant retirements, the addition of the Mt. Storm to Doubs transmission line upgrade and the Competitive Power Ventures St. Charles natural gas generation project. The RCU uses the PJM 2013 Load Forecast, which projects slightly lower electricity usage through 2020 but a slightly higher growth rate in demand during the last ten years of the study period as compared to the 2011 PJM Forecast that was used in the LTER Reference Case ("RC"). The RCU results reflect the changes in demand and the reduction in the natural gas price projections. RCU energy prices are lower than the energy price projections in the RC by between $15 and $25 per MWh in real terms throughout the forecast period, and capacity prices tend to be higher. Very little generic natural gas capacity is constructed in Maryland, as increased transmission capacity allows the State to meet a larger portion of its energy needs through increased imports. Additionally, Maryland and Delaware are now the only states in PJM that belong to the Regional Greenhouse Gas Initiative ("RGGI"); New Jersey withdrew in 2011. Therefore, the RGGI allowance prices affect both Maryland generic builds and coal generation, which is reduced in the RCU compared to the RC. Emissions of SO_2, NO_x, and CO_2 from Maryland power plants are correspondingly lower than shown in the RC since coal and natural gas generation in Maryland is reduced in the RCU.

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1 Introduction

On July 23, 2010, Governor Martin O'Malley signed Executive Order 01.01.2010.16 ("EO") directing the Maryland Department of Natural Resources' Power Plant Research Program ("PPRP") to develop a long-term electricity report for the State of Maryland. The central purpose of the Long-term Electricity Report ("LTER") was to provide a comprehensive assessment of approaches to meet the long-term electricity needs of Marylanders through clean, reliable, and affordable power. The LTER provided policy-makers with the anticipated effects of both alternative policies (for example, environmental policies, renewable energy policies) and external (non-policy-related) factors such as high (and low) natural gas prices, high (and low) growth in electric loads, and climate change. To satisfy the purpose of the EO and to meet the requirements set forth therein, PPRP assessed future electricity and peak demand needs for Maryland over the 20-year period from 2010 through 2030. The LTER contained detailed results for a Reference Case and 38 alternative scenarios. The LTER was published on December 1, 2011 and can be obtained by visiting http://www.dnr.state.md.us/bay/pprp/. Pursuant to the EO, the next comprehensive update of the report will be finalized by December 1, 2016.

The assumptions relied upon in the LTER Reference Case are inherently uncertain over the course of a 20-year study period. Major areas of uncertainty include assumptions related to fuel prices; the build-out of the transmission system; future policy implementation regarding renewable energy, energy conservation, energy efficiency; emissions; load growth; and potential in-State power plant construction. Because these assumptions can significantly affect projections future energy and capacity prices, the overall generation mix, power supply price variability, and emission levels, the LTER explored these uncertainties through the alternative scenarios. For example, to address the uncertainty in natural gas price projections, a "high natural gas price" scenario and a "low natural gas price" scenario were developed in addition to the natural gas price projection contained in the Reference Case.

In the two years since the LTER assumptions were formulated, more recent information has become available that suggests that some of the assumptions relied upon in the LTER warrant revision. As a result, PPRP has undertaken this update to the LTER Reference Case ("RC") incorporating identified changes to the input assumptions. The most significant change is the natural gas price forecast. The LTER Reference Case Update ("RCU") incorporates a reduced natural gas price forecast that is a blend of forward prices and the Energy Information Administration's ("EIA's") latest natural gas price forecast as presented in the 2013 Annual Energy Outlook. This forecast is on average about 35 to 40 percent lower than the natural gas price forecast used in the RC. Another big change in the RCU is the increased number of power plant retirements that have been announced since the RC assumptions were formulated in early 2011. Other significant changes include the addition of the Mt. Storm to Doubs transmission line upgrade and the Competitive Power Ventures St. Charles natural gas generation project. The RCU uses the PJM 2013 Load Forecast, which projects slightly lower electricity usage through 2020 but a slightly higher growth rate in demand during the last ten years of the study period as compared to the 2011 PJM Forecast that was used in the LTER RC. The RCU takes these new developments into account with updated reference case assumptions.

The RCU results reflect the changes in demand and the reduction in the natural gas price projections. RCU energy prices are lower than the RC energy price projections by between $15 and $25 per MWh in real terms throughout the forecast period. Given the lower projected energy prices, capacity prices are higher in the RCU as compared to the RC.[1] Very little generic natural gas capacity is constructed in Maryland, as increased transmission capacity allows the State to meet a larger portion of its energy needs through increased imports. Additionally, Maryland and Delaware are now the only states in PJM to belong to the Regional Greenhouse Gas Initiative ("RGGI"); New Jersey withdrew in 2011. Therefore, the RGGI allowance prices affect both Maryland generic builds and coal generation, which is reduced in the RCU compared to the RC. Emissions of SO_2, NO_x, and CO_2 from Maryland power plants are correspondingly lower than shown in the RC since coal and natural gas generation in Maryland is reduced in the RCU.

Pursuant to the EO, the next comprehensive LTER analysis will be conducted not later than during 2016. The RCU is intended to help provide policy makers with insight during the interim years between 2011 and 2016. During this interim period, the 38 alternative scenarios examined for the initial LTER analysis can be utilized by evaluating the direction and the approximate magnitude of changes relative to the RC.

Chapter 1 of this report provides an overview of the EO, the changes in assumptions, and a short summary of the main RCU results. Chapter 2 discusses the Ventyx model and the assumption in detail and Chapter 3 presents the RCU results as they compare to the RC.

2 LTER Reference Case Update Inputs

The LTER Reference Case Update once again makes use of the Ventyx Midwest regional model. The LTER Reference Case was based upon Ventyx's Fall 2010 Reference Case while the RCU incorporates the Ventyx Fall 2012 Reference Case ("Fall 2012 VRC"). This chapter gives a brief description of how the Ventyx model works and then discusses the input assumptions used for the RCU model run and how they compare to the RC.

[1] This is primarily due to the way the Ventyx model projects capacity prices. Capacity prices are calculated as a "make-whole" generator payment. See section 3.4 of this report for a more detailed discussion.

2.1 The Ventyx Model

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

The IPM also simulates emissions markets, including demand outside of the electric power sector, to estimate emission allowance prices for SO_2 and NO_x. Finally, IPM estimates capacity prices based on a make-whole payment concept whereby marginal generators either delay retirement or a new generator enters and capacity prices are set such that the revenues the generator earns in the energy and capacity markets just cover its costs. See Chapter 2 of the 2011 LTER Report for a detailed description of the Ventyx model.

2.2 Input Assumptions

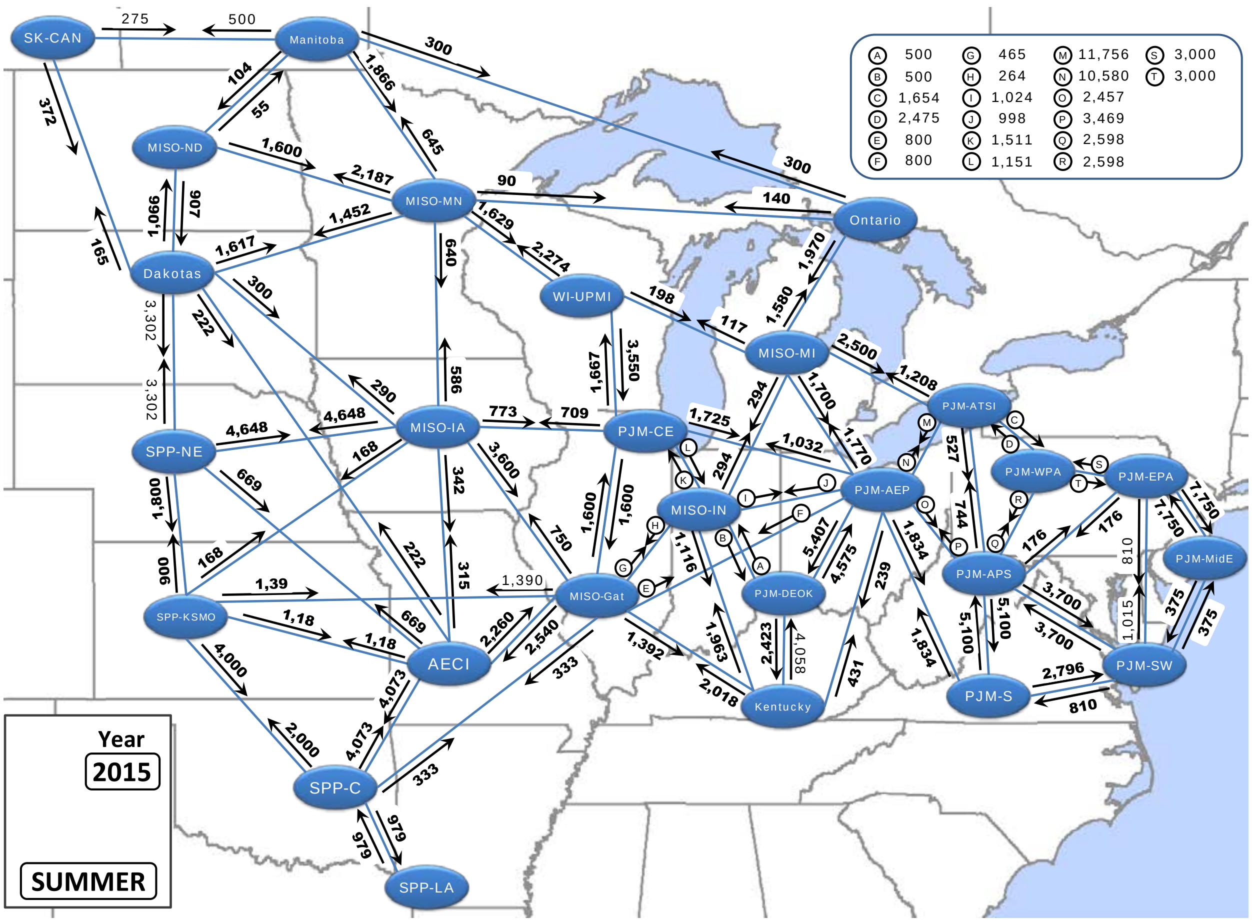
Certain modeling inputs (i.e., assumptions) originally developed for the RC have been modified for use in this update. These changes includes power plant retirements, load growth, energy efficiency and demand response impacts, environmental regulations, fuel prices, power plant capital costs, and renewable energy project development. Table 1 provides a summary and comparison of the input assumptions used in the RC and the RCU. These are discussed in greater detail later in this chapter.

Table 1 Summary of Input Assumptions			
Item	**2011 LTER RC**	**2013 LTER RCU**	**Comments**
Load growth	2011 PJM Forecast with adjustments for energy efficiency programs in PJM states	2013 PJM Forecast with adjustments for energy efficiency programs in PJM states	Largely applying the same methodology but updating the underlying state energy efficiency and PJM Forecasts
Callable Demand Response	DR projected to be developed in PJM by 2015	Callable DR cleared in 2012 PJM RPM Auction	RCU represents a slight decrease in DR
Natural gas prices	Ventyx's Fall 2010 Reference Case natural gas price forecast	Hybrid between near-term NYMEX forwards and the EIA's 2013 Annual Energy Outlook	Near-term natural gas futures are the best-indicators of market expectations of near-term natural gas prices. The EIA's AEO natural gas price forecast is a publically available, well-documented and commonly relied upon forecast
Coal prices	Ventyx Fall 2010 Reference Case	Ventyx Fall 2012 Reference Case	
Other fuel prices	Ventyx Fall 2010 Reference Case	Ventyx Fall 2012 Reference Case	
Generic biomass capacity constructed in Maryland by 2030	40 MW	82 MW	Increased to include additional poultry litter capacity on Maryland's Eastern Shore
Generic landfill gas capacity constructed in Maryland by 2030	80 MW	80 MW	
Generic land-based wind capacity constructed in Maryland by 2030	80 MW	250 MW	Increased land-based wind capacity to reflect two utility-scale Maryland wind projects in PJM Interconnection Queue
Generic off-shore wind capacity constructed in Maryland by 2030	0 MW	200 MW	Increased to reflect expected enactment of off-shore wind incentive legislation
Generic solar PV capacity constructed in Maryland by 2030	498 MW	515 MW	Adjusted for projected load growth to meet 50% of Maryland's solar RPS by 2020
Solar RPS achievement in Maryland	50%	50%	
Wind capacity factor	30%	30%	
Solar PV capacity factor	15%	14%	New capacity factor is consistent with MEA's estimates
Overnight construction costs for new renewable generation	Ventyx Fall 2010 Reference Case except for land-based and off-shore wind	Ventyx Fall 2012 Reference Case and EIA 2013 Annual Energy Outlook estimates	Some of the Ventyx's overnight construction cost estimates for renewable capacity (solar, biomass, and wind) differed from other industry estimates. EIA estimates or an average of the EIA and Ventyx estimates were used instead.
Overnight construction costs for new non-renewable generation	Ventyx Fall 2010 Reference Case	Ventyx Fall 2012 Reference Case	
RGGI Prices	$2/ton through 2030	$2/ton through 2030	
EPA SO_2 and NO_x rules	Cross-State Air Pollution Rule	Clean Air Interstate Rule	US Federal Court of Appeals vacated the Cross-State Air Pollution Rule in August 2012

2.2.1 Transmission Topology

The Ventyx model has undergone certain changes since 2010 including the addition of new transmission capacity to account for new transmission line development. Most notable for Maryland is the inclusion of the Mt. Storm to Doubs transmission upgrade project, which increases the transfer capacity between zones in Western and Eastern Maryland (denoted by PJM-APS and PJM-SW, respectively, by Ventyx). Figure 1 shows the Fall 2012 VRC Summer 2015 transmission topology for the Midwest region.

Figure 1 Ventyx 2012 Fall Reference Case Transmission Topology



In 2012, Duke Energy Kentucky, Duke Energy Ohio, and East Kentucky Power Cooperative joined PJM, therefore, the pricing zones defined by Ventyx have also changed slightly. The 2010 model contained a Cinergy hub for PJM. This has now been replaced by a price zone called PJM-DEOK that includes the new Kentucky and Ohio territories. PJM is represented by ten zones in the Ventyx model. Table 2 lists the ten PJM zones along with the utility service territories included within each zone.

Table 2 PJM Zones in the Ventyx Model	
Zone	**Utility Territories Covered**
PJM-AEP	American Electric Power, Dayton Power & Light
PJM-APS	Allegheny Power
PJM-ATSI	FirstEnergy American Transmission Systems
PJM-CE	Commonwealth Edison
PJM-DEOK	Duke Energy Kentucky, Duke Energy Ohio, East Kentucky Power Cooperative
PJM-S	Virginia Power Company
PJM-MidE	Atlantic Electric, Delmarva Power & Light ("DPL"), Jersey Central Power & Light, PECO Energy, Public Service Electric & Gas, Rockland Electric
PJM-EPA	Metropolitan Edison, Pennsylvania Power & Light, UGI Corporation
PJM-SW	Baltimore Gas & Electric and Potomac Electric Power Company
PJM-WPA	Pennsylvania Electric

The 2011 LTER examined an alternative scenario as an addendum which included a new natural gas plant in PJM-SW to explore the impact of a potential Maryland Public Service Commission ("PSC") Request for Proposals ("RFP") to supply new generation capacity within Maryland. The PSC ultimately issued an RFP and selected Competitive Power Ventures ("CPV") to build a combined cycle natural gas unit in Charles County. This plant has been included in the RCU with an expected online date of January 2017.

2.2.2 Power Plant Retirements

Announced power plant retirements have increased since the Fall 2010 Ventyx Reference Case was developed. The RCU projects 35 GW of generation unit retirements in PJM by 2030, compared to the 21 GW of retirements in the RC. The majority of the retirements (59 percent) are coal units, followed by petroleum units (20 percent), natural gas (15 percent), and nuclear (7 percent). RCU retirements are summarized in the top panel of Table 3, below. The capacity-weighted average age of the retired plants is 53 years, implying an average online year of 1959.

Table 3 PJM Cumulative Retirements by Fuel Type (MW)						
	Natural Gas	Petroleum	Coal	Nuclear	Biomass	Total
2013 LTER RC Update						
2015	3,403	1,885	17,990	0	16	23,294
2020	4,329	3,955	18,317	0	16	26,617
2025	4,863	7,021	18,337	0	16	30,237
2030	5,185	7,045	20,685	2,364	16	35,295
2011 LTER RC						
2015	719	1,206	3,601	0	0	5,526
2020	2,874	3,607	4,294	0	0	10,775
2025	3,731	6,243	5,031	0	0	15,005
2030	3,909	6,379	9,635	1,451	0	21,374

Sixty five percent (23.2 GW) of the cumulative PJM retirements by 2030 are announced retirements; 12 GW of the PJM retirements are age-based retirements, which means that the generation unit is automatically retired due to age, and 184 MW (less than one percent) of the capacity is retired due to the Mercury Air Toxics Standard ("MATS") rule. The bottom panel of Table 3 summarizes retirement projections from the RC. The RC included just over 21 GW of retirements in PJM by 2030.[2] The RCU projects just over 35 GW of retirements by 2030, therefore, projected PJM retirements have increased by 13.9 GW, or 65 percent. The majority of the "new" retirements in the RCU are coal units (20.7 GW), with the RCU projecting the retirement of an additional 11 GW of coal capacity compared to the RC.

Table 4, below, summarizes the total retirements for the RC and RCU in PJM and Midwest Independent Transmission System Operator ("MISO"), which exports power to PJM. The RCU projects total PJM and MISO retirements of 54.6 GW by 2030, compared to 32.9 GW in the RC. Thus, projected PJM and MISO retirements have increased by 21.7 GW, or 66 percent. New PJM retirements account for 13.9 GW of this increase and new MISO retirements account for 7.8 GW.

[2] See Table 4.3 of the 2011 LTER Report for further details.

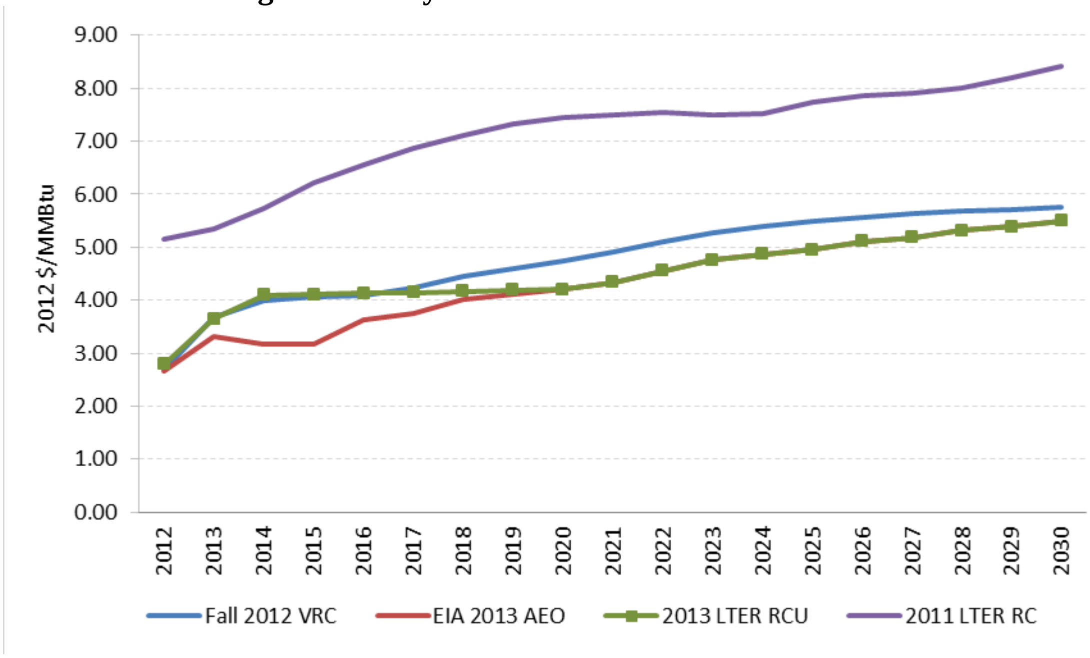
Table 4 Cumulative Retirements in PJM and MISO (MW)			
2013 LTER RC Update			
	PJM	MISO	Total
2015	23,294	7,068	30,362
2020	26,617	10,611	37,228
2025	30,237	14,497	44,734
2030	35,295	19,308	54,603
2011 LTER RC			
	PJM	MISO	Total
2015	5,526	1,988	7,514
2020	10,775	4,833	15,608
2025	15,005	8,385	23,390
2030	21,374	11,541	32,915

2.2.3 Fuel Costs and Capital Costs

The revised assumptions about future natural gas prices have a large impact on the RCU results. The natural gas price forecast is lower than was forecast two years ago. Both Ventyx and the Energy Information Administration's 2013 Annual Energy Outlook ("AEO") project that low natural gas prices will persist throughout the 20 year forecast period.[3] Short-term natural gas projections in the RCU are based on NYMEX futures contracts while the longer-term forecasts are based on the 2013 AEO Reference Case. Figure 2 compares the natural gas price forecasts used in the RC and RCU and also includes the 2013 AEO and Ventyx Fall 2012 Reference Case projections for purposes of comparison.

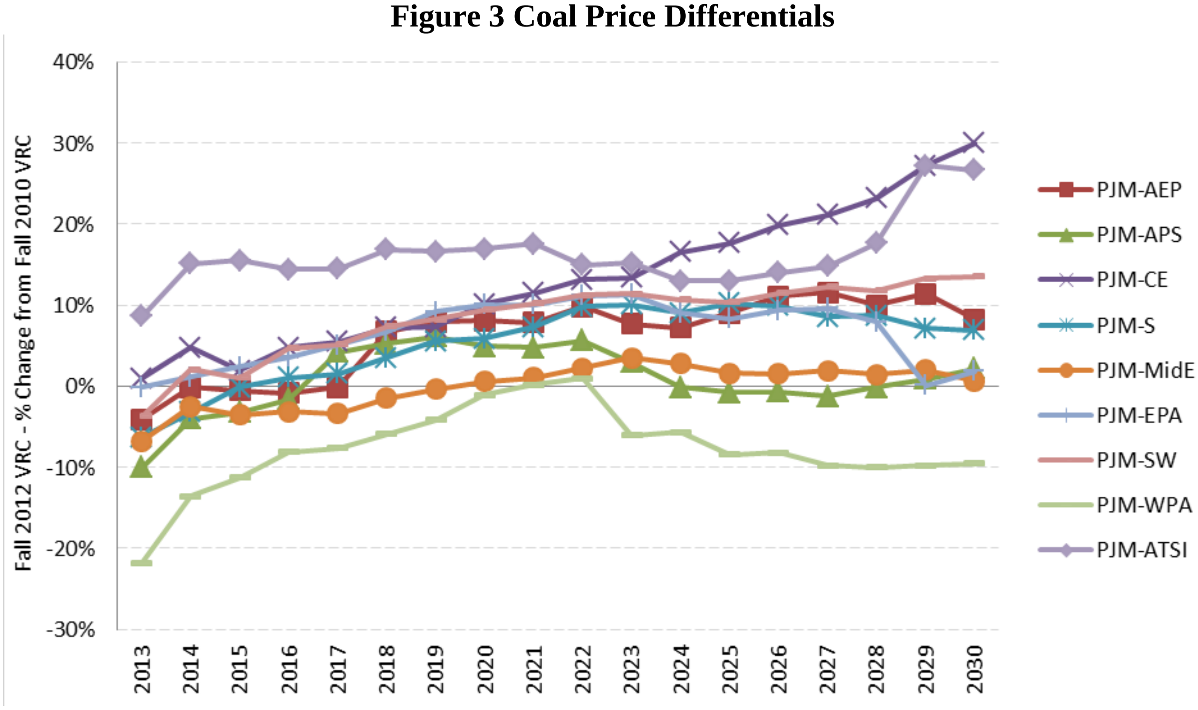
[3] The 2013 AEO Reference Case natural gas projections were provided in the EIA's Early Release Reference Case in Table 13 of that document, "Natural Gas Supply, Disposition, and Prices."

Figure 2 Henry Hub Natural Gas Price Forecast



The coal price forecasts have also changed in the update, with some regions experiencing higher prices and some lower (see Figure 3, below). The relationship between coal prices and natural gas prices affect the dispatch order of some plants and consequently, the projected capacity factors of the plants.

Figure 3 Coal Price Differentials



Certain plant characteristics in the Ventyx model have also changed since the Fall 2010 LTER. Table 5, below, shows the assumptions for new conventional power plant characteristics used in the RCU. Ventyx now includes different classes of combined-cycle ("CC") natural gas units to account for new, more efficient turbine technologies (classes F, G, and H). From 2020 onwards, all of the generic CC natural gas plant additions consist of the more efficient H class. Construction costs and O&M costs have also been updated. Renewable energy plant characteristics have similarly been updated. For the RCU, some of the assumptions used are from the Fall 2012 VRC and some were drawn from the latest EIA data. Table 6 shows the renewable energy plant characteristics adopted for the RCU. For purposes of comparison, the 2011 RC assumptions are included in Table 7, escalated to 2012 dollars.[4]

Table 5 Conventional Plant Characteristics Fall 2012 VRC

Unit Characteristics	Units	Gas Turbine	CC F Class	CC G Glass	CC H Class	Nuclear
Online Year		2014	2014	2014	2020	2018
Summer Capacity	MW	160	450	350	400	1,000
Winter Capacity	MW	180	490	375	425	1,000
Full Load Heat Rate	HHV, Btu/kWh	10,500	6,800	6,625	6,400	10,400
SO_2 Emission Rate	(lb/MMBtu)	0	0	0	0	0
NO_X Emission Rate	(lb/MMBtu)	0.03	0.01	0.01	0.01	0
CO_2 Emission Rate	(lb/MMBtu)	120	120	120	120	0
Fixed O&M	2012 $/kW-yr	11.67	12.96	13.07	13.17	99.77
Variable O&M	2012 $/MWh	3.51	2.21	2.15	2.01	0.55
Forced Outage Rate	%	3.60%	5.50%	5.20%	5.00%	3.80%
Maintenance Outage Rate	%	4.10%	9.70%	9.60%	9.50%	6.10%
Overnight Construction Cost	2012 $/kW	680	1,010	1,025	1,035	6,000

Source: Ventyx.

[4] In the 2011 LTER, construction costs were presented in constant 2010 dollars.

Table 6 New Renewable Energy Plant Characteristics

Unit Characteristics	Units	Geothermal Steam Turbine	Landfill Gas	Biomass	Photo-voltaic	Land-Based Wind Turbine	Off-Shore Wind Turbine
Full Load Heat Rate	HHV, Btu/kWh	0	8,910	13,648	0	0	0
SO_2 Emission Rate	(lb/MMBtu)	0	0	0	0	0	0
NO_x Emission Rate	(lb/MMBtu)	0	0	0	0	0	0
CO_2 Emission Rate	(lb/MMBtu)	0	0	0	0	0	0
Fixed O&M	2012 $/kW-yr	53.35	54.00	103.01	22.00	28.77	28.77
Variable O&M	2012 $/MWh	0	3.19	1.54	0	0	0
Forced Outage Rate	%	20.00%	30.00%	30.00%	0.00%	0.00%	0.00%
Maintenance Outage Rate	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Overnight Construction Cost	2012 $/kW	4,245	2,950	3,772	3,709	1,770	4,482

Sources: Ventyx, 2013 EIA Annual Energy Outlook.

Table 7 LTER RC Plant Characteristics

Unit Type	Fixed O&M	Variable O&M	Fuel Costs	Overnight Construction Cost
	(2012 $/kW-yr)	(2012 $/MWh)	(2012 $/MWh)	(2012 $/kW)
Pulverized Coal Steam Turbine	$28.35	$4.21	$22.79-$23.85	$2,798
Combustion Gas Turbine	$13.26	$3.95	$49.27-$88.48	$694
Aero derivative Gas Turbine	$11.52	$3.47	$42.23-$75.84	$1,073
Combined Cycle Natural Gas	$13.68	$2.26	$31.91-$57.30	$1,020
Integrated Coal Gasification Combined Cycle	$49.76	$4.89	$22.00-$23.02	$3,535
Nuclear	$74.22	$0.58	$7.11-$8.86	$6,175
Pulverized Coal Steam Turbine with Carbon Capture and Sequestration	$33.82	$6.47	$29.68-$31.07	$5,354
Combined Cycle Natural Gas with Carbon Capture and Sequestration	$23.25	$3.31	$41.75-$75.00	$2,245
Integrated Coal Gasification CCNG with Carbon Capture and Sequestration	$59.33	$7.47	$28.61-$29.95	$5,943
Geothermal Steam Turbine	$178.68	$0.00	$0.00	$1,999
Landfill Gas	$125.95	$0.01	$0.00	$2,683
Biomass	$73.88	$7.58	$21.85-$27.65	$3,472
Photovoltaic	$13.20	$0.00	$0.00	$5,260
Wind Turbine – Land-Based (2010)	$31.09	$0.00	$0.00	$2,314
Wind Turbine – Land-Based (2011-2030)	$31.09	$0.00	$0.00	$1,894
Wind Turbine - Off-Shore	$77.72	$0.00	$0.00	$4,482

Source: Long Term Electricity Report for the State of Maryland, December 2011.

2.2.4 Environmental Assumptions

The Ventyx model inputs used to estimate the RCU have changed from those used for the 2011 LTER RC in light of new environmental regulations that govern SO_2, NO_x, and ozone emissions. The RC assumed that the Clean Air Transport Rule ("CATR"), which had been approved by the Environmental Protection Agency ("EPA"), would be implemented. However, federal courts vacated the EPA replacement for CATR, the Cross-State Air Pollution Rule ("CSAPR") in August 2012. As a result, the current rule for SO_2, NO_x, and ozone emissions is the Clean Air Interstate Rule ("CAIR"), which was the rule in place prior to CATR. Accordingly, power plant emissions in the RCU are governed by CAIR. Most states have already been in compliance with CAIR for several years, resulting in a depressed market for SO_2 and NO_x allowances. The RCU retains this assumption, however, as with the RC, Maryland power plants are subject to the Maryland Healthy Air Act ("HAA"). The HAA imposes emission restrictions on power plants more stringent than the EPA restrictions.

The RC also included the Tailoring Rule for greenhouse gases as a constraint on coal facilities. Ventyx assumed the Tailoring Rule effectively prohibited construction of, or major modifications to, coal units without CO_2 controls, therefore no new coal plants were constructed, as it was not economically feasible. This assumption also resulted in compliance with the New Source Performance Standards ("NSPS") with respect to coal plants. Ventyx reevaluated the impact of these rules along with EPA's new MATS rule for its Fall 2012 VRC and concluded that the large number of coal plant retirements, from both the increased amount of announced retirements and the plants retired by the modeling due to economic factors, effectively negates the need for imposing even more retirements from the environmental rules. No modifications to this assumption were made for the RCU.

The states that are still party to the RGGI recently announced they have agreed to lower the RGGI allowance cap by 45 percent. The previous assumption of RGGI allowance prices remaining at the floor price was maintained for the RCU, as it was unknown at the time the analysis was performed what the new RGGI budget for Maryland would be.

2.2.5 Renewable Energy Assumptions

Both the RC and the RCU assume full compliance with the Maryland Renewable Energy Portfolio Standard ("RPS") Tier 1 non-solar renewable energy requirement and 50 percent achievement of the solar set-aside by 2020. However, in-State renewable energy capacity has increased in the last two years and the Maryland legislature passed an off-shore wind energy bill in the 2013 session. This has resulted in an increase in the total renewable energy capacity assumed to be built in Maryland. The RCU includes additional biomass capacity to account for poultry litter generation on the Eastern Shore, more land-based wind, and 200 MW of off-shore wind power. Additionally, in the RCU, non-solar renewable capacity was added gradually over the study period rather than within the first few years, as was the case in the RC. Table 8 shows the cumulative generic renewable energy capacity additions (i.e., new renewable energy capacity built in the model) for the RC and the RCU. Solar energy in the RCU is slightly higher in the last decade of the study period compared to the RC due to the slightly higher load growth assumed in the PJM 2013 load forecast in that time period and the slightly lower solar capacity factor and in the RCU relative to the RC.

Table 8 Cumulative Generic Renewable Capacity Additions (MW)

Resource	2015		2020		2025		2030	
	RC	RCU	RC	RCU	RC	RCU	RC	RCU
Land-based Wind	80	100	80	200	80	250	80	250
Biomass	40	49	40	82	40	82	40	82
Landfill Gas	80		80	40	80	70	80	80
Solar	294	130	445	471	472	512	498	559
Off-shore Wind				200		200		200

Figure 4 shows the assumed total renewable energy capacity in Maryland from the RC, while Figure 5 shows the assumed total renewable capacity in Maryland in the RCU.

Figure 4 LTER RC Maryland Renewable Energy Capacity

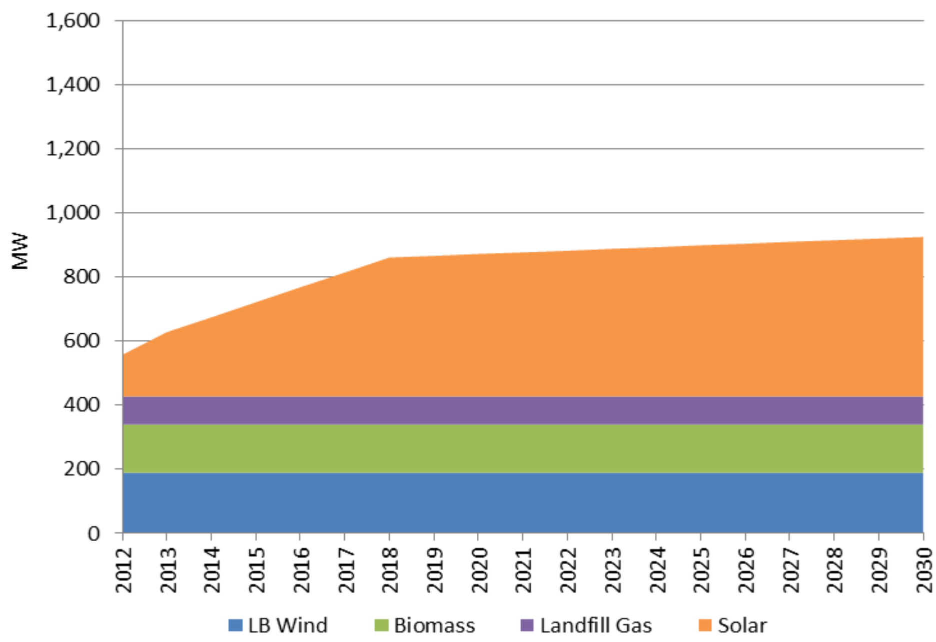
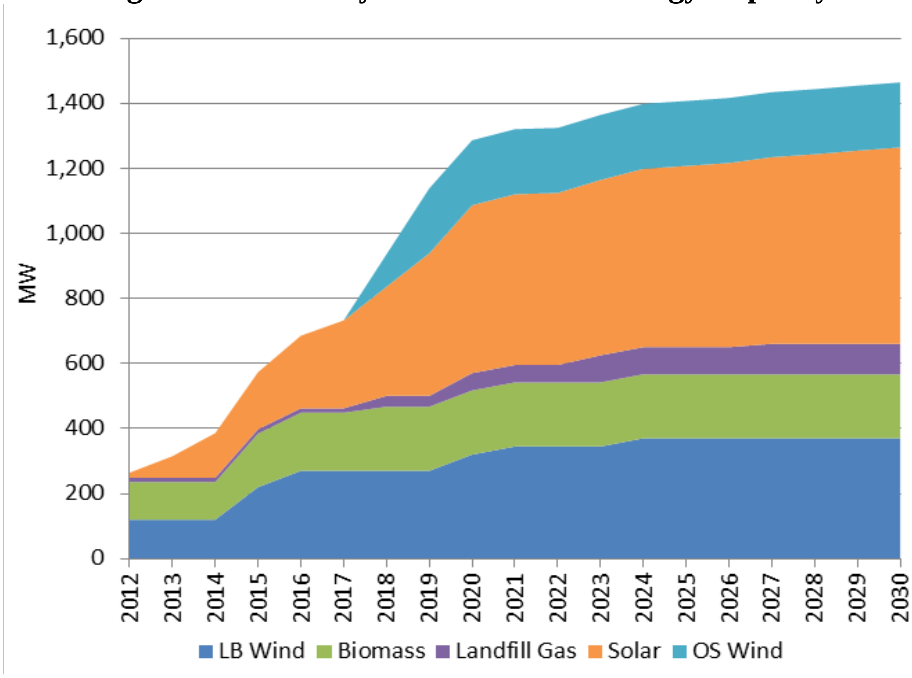


Figure 5 RCU Maryland Renewable Energy Capacity



2.2.6 Load Forecast

The RC utilized the PJM 2011 Load Forecast as its base forecast for peak demand and energy in the PJM region.[5] The RCU incorporates the latest PJM January 2013 Load Forecast. The 2013 PJM forecast of peak demand and energy is lower in the first half of the study period than the 2011 forecast, but shows a slightly higher growth rate in the later years. Figure 6 and Figure 7, below, show the unadjusted peak demand and energy for the 2011 and 2013 PJM load forecasts (including both the ATSI and DEOK zones) respectively.

[5] While both the RC and RCU relied on PJM load forecasts, those forecasts were adjusted to account for additional factors affecting load growth, including energy conservation and efficiency programs and growth in the use of plug-in electric vehicles.

Figure 6 Unadjusted PJM Load Forecast Summer Peak Demand

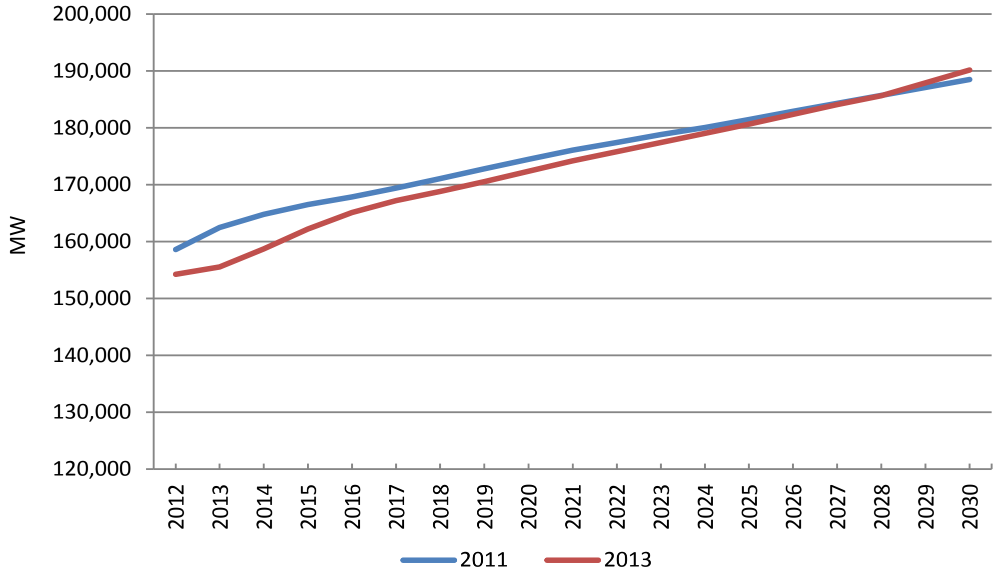
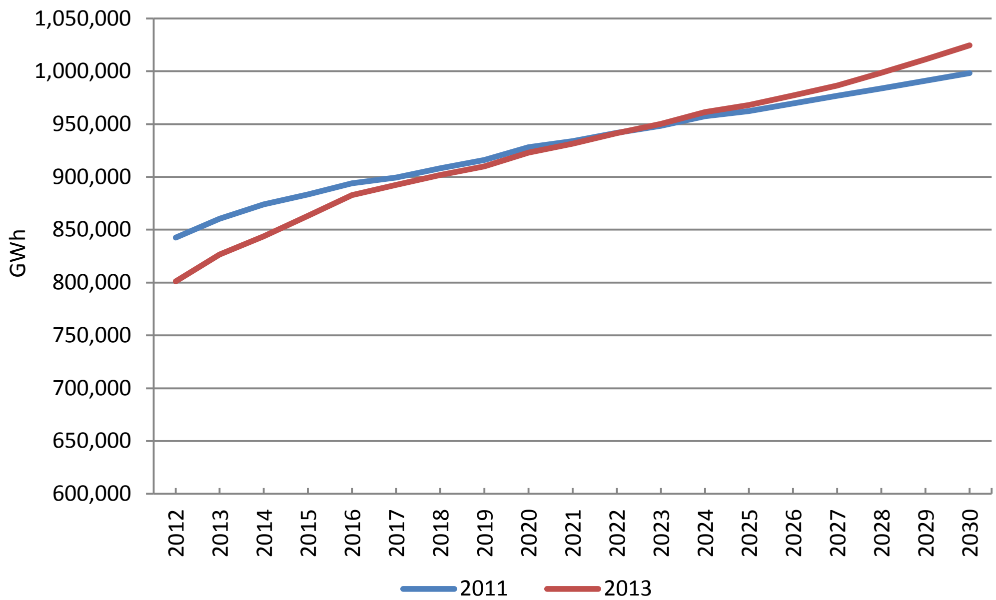


Figure 7 Unadjusted PJM Load Forecast Energy



As was done for the RC, the RCU's load forecast was adjusted to account for impacts associated with energy efficiency/conservation and plug-in electric vehicles. The EmPOWER Maryland program was in its initial stages when the RC assumptions were formulated and, therefore, the estimated projected reductions were based on relatively little actual achievement data. In developing the RCU adjustments to the PJM forecast, three years of energy and demand reduction data provide for a better estimate of what will be achieved by 2015, the current program end year. Table 9 shows actual reductions through 2012 and projected EmPOWER Maryland reductions in Maryland through 2015. The energy and peak load reductions in Table 9 were used to adjust PJM's 2013 Load Forecast along with additional information on energy efficiency and conservation for other PJM states. The 2011 RC assumption for EmPOWER Maryland energy reductions totaled four million MWh and peak demand reductions totaled 2,170 MW.[6]

Table 9 EmPOWER Maryland 2015 Cumulative Reduction Projections

Year	Projected Energy Reduction (MWh)	Projected Peak Demand Reduction (MW)
2010	628,929	715
2011	1,316,987	932
2012	1,944,247	1,142
2013	2,706,992	1,460
2014	3,553,637	1,893
2015+	4,386,963	2,361

Source: Maryland Energy Administration.

The PJM 2013 Load Forecast, as noted above, was adjusted (reduced) to account for the energy efficiency and conservation programs that have been implemented in other PJM states. Similar adjustments were made in the RC but these adjustments have been updated to reflect the last two years of achievement data. The updated energy reduction estimates used in the RCU are shown in Table 10. Total annual energy reductions (i.e., reductions from the 2011 PJM load forecast) in the other PJM states were projected to reach about 31 GWh in the RC in 2020 compared to 18 GWh in the RCU. The RCU annual reduction is lower because the projected energy usage in all PJM states is forecast to be lower (see Figure 6, above) than previously expected. Also, the PJM 2013 Load Forecast contains utility load data to 2011 and, therefore, already incorporates reductions realized to the end of 2011. The projected energy reductions from energy efficiency programs have been adjusted to reflect achievements-to-date and the overall drop in energy consumption.

[6] For both the RC and the RCU, a portion of the demand reduction is allocated to a permanent reduction in peak demand and a portion is allocated to demand response.

Table 10 Estimated Annual Energy Reductions Resulting from Energy Efficiency & Conservation Initiatives in PJM States with EE&C Programs (MWh)							
State	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021-2030**
Delaware	540,035	540,035	540,035	540,035	540,035	540,035	540,035
Illinois	1,618,415	2,274,582	2,947,927	3,628,688	4,315,143	4,315,143	4,315,143
Indiana	334,977	463,728	611,305	776,273	949,977	949,977	949,977
Michigan	103,186	129,577	156,272	182,994	182,994	182,994	182,994
New Jersey	1,517,698	1,897,123	2,276,547	2,655,972	3,035,397	3,414,821	3,414,821
North Carolina	84,112	104,986	127,211	149,182	163,076	177,382	194,347
Ohio	3,735,403	4,773,874	5,825,705	6,879,595	6,879,595	6,879,595	6,879,595
Pennsylvania	1,634,337	1,634,337	1,634,337	1,634,337	1,634,337	1,634,337	1,634,337
Total	9,568,163	11,818,242	14,119,339	16,447,076	17,700,554	18,094,284	18,111,249

Note: the annual energy reductions represent the MWh removed from PJM's 2013 Load Forecast of annual energy consumption in PJM.

Plug-in electric vehicle ("PEV") adoption rates have not changed significantly in the last two years. Therefore, the PEV assumptions in the RCU remain unchanged. Table 11 shows the PEV demand assumptions.

Table 11 Total Weekday Hourly Demand from PEVs in Maryland and PJM (MW)			
2020	Maryland	Total On-Peak	3.5
		Total Off-Peak	63
	PJM	Total On-Peak	33
		Total Off-Peak	589
2030	Maryland	Total On-Peak	23.6
		Total Off-Peak	424
	PJM	Total On-Peak	222
		Total Off-Peak	4,003

The peak demand and energy forecast used as the input to the RCU update is comprised of the PJM 2013 unadjusted Load Forecast modified to include energy and associated demand reductions from EmPOWER Maryland, energy efficiency and conservation programs in other PJM states, and the energy and demand increases from PEVs. Table 12 shows the original PJM 2013 Load Forecast and the RCU forecast of energy and peak demand through 2030.

Table 12 PJM & LTER Reference Case Forecasts				
	Base Peak Demand (MW)		Energy (GWh)	
Year	January 2013 PJM Forecast*	LTER Reference Case Update	January 2013 PJM Forecast*	LTER Reference Case Update
2012	154,235	153,361	801,302	798,173
2013	155,553	153,693	826,562	820,140
2014	158,717	153,964	843,697	834,472
2015	162,216	157,091	863,161	850,901
2016	165,128	159,472	882,669	868,363
2017	167,211	161,238	892,369	876,024
2018	168,813	162,954	901,824	883,481
2019	170,521	165,001	910,089	890,909
2020	172,368	167,264	923,064	904,014
2021	174,175	169,037	931,411	912,994
2022	175,791	170,719	941,369	923,748
2023	177,439	172,480	950,374	933,616
2024	179,042	174,457	961,429	945,689
2025	180,647	176,539	968,056	953,500
2026	182,394	178,502	977,292	964,065
2027	184,079	180,256	986,388	974,625
2028	185,671	181,860	998,488	988,306
2029	187,899	183,482	1,011,468	1,002,945
2030	190,154	185,114	1,024,617	1,017,802
Average Annual Growth Rates				
2012 - 2020	1.4%	1.1%	1.8%	1.6%
2021 - 2030	1.0%	1.0%	1.0%	1.2%
2012 - 2030	1.2%	1.1%	1.4%	1.4%

*PJM's 2013 Load Forecast extends only to 2028. For years 2029 and 2030, the forecast values were obtained through extrapolation. The values above are for the unadjusted 2013 forecast.

The RC included projected demand reductions from demand response and advanced metering initiatives ("AMI"). The RC demand response reduction estimates were based on the then-available data, taking actual amounts that had been bid into PJM Reliability Pricing Model ("RPM") capacity markets with an escalation based on what the utilities had predicted they would be able to achieve by 2015. Demand response, as a whole, has increased significantly in the PJM RPM auctions, and PJM has indicated that demand response may be reaching a limit that should not be exceeded for reliability purposes.[7] Therefore, for the RCU, the actual demand response auction data was utilized up to what was bid into the 2015/2016 RPM Base Residual Auction, and then held flat thereafter. Table 13 shows the PJM 2013 demand response bid amounts.

Table 13 PJM January 2013 Load Forecast Demand Response (MW)

Year	BGE	DPL*	PEPCO*	APS*	Total PJM
2013	1,085	292	638	644	10,739
2014	1,294	394	876	866	14,220
2015-2030	1,101	418	837	903	14,651

*Reductions for entire zone, only a portion of which is in Maryland.

As with energy efficiency programs, AMIs are now well underway compared to two years ago and more information about peak demand reductions due to AMI is available. Utilities in several PJM states have implemented peak demand reduction programs in concert with AMI to incentivize consumers to reduce demand during peak periods. Table 14 outlines the projected peak demand reductions from AMI. The Ventyx model treats both demand response and AMI as dispatchable supply-side resources that are included in the supply stack and, therefore, though both ultimately serve to reduce demand, they are not treated as adjustments to the load forecast.

[7] See PJM Markets Implementation Committee, Demand Response Saturation Analysis.

Table 14 Cumulative Demand Reductions from Advanced Metering Initiatives (MW)				
State	**2015**	**2020**	**2025**	**2030**
DC	139	212	223	233
DE	142	147	151	155
IL	34	159	168	177
IN	7	36	38	40
MD	388	705	734	761
MI	3	7	7	7
NC	75	276	286	296
NJ	3	35	37	39
OH	59	487	508	530
PA	188	382	402	422
VA	49	349	372	394
WV	13	95	99	103
Total	1,100	2,890	3,025	3,157

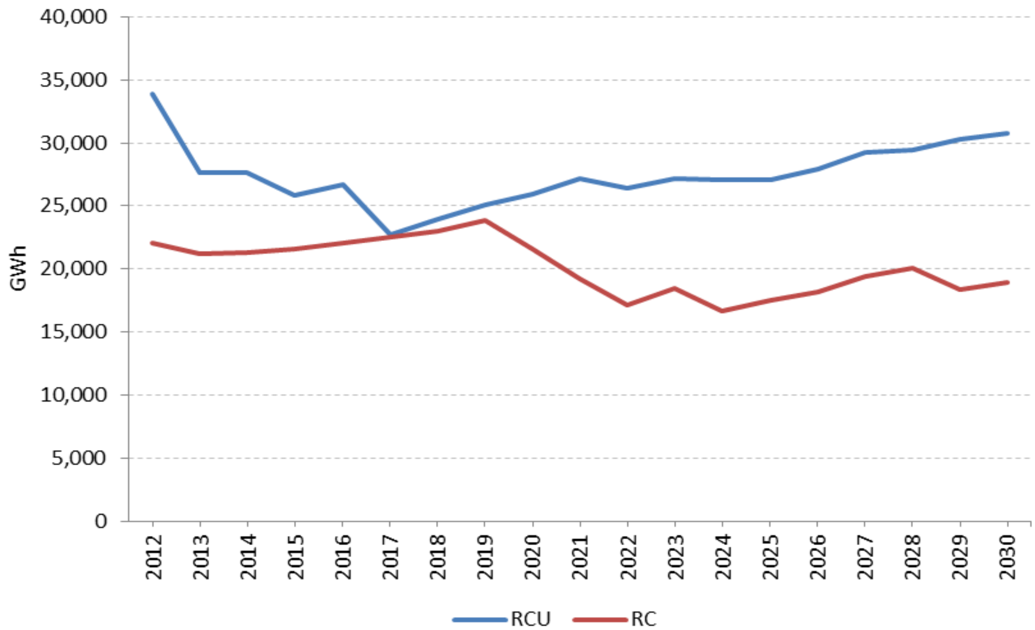
3 Reference Case Update Results

The Ventyx model has three zones that contain parts of Maryland: PJM-SW, PJM-MidE, and PJM-APS. PJM-SW is comprised of the service territories of BGE and Pepco and, therefore, also includes the District of Columbia. PJM-MidE includes all of the Delmarva Peninsula including Delaware, all of New Jersey, and Philadelphia. As such, Maryland's DPL territory is only a very small portion of the zone. Similarly, PJM-APS includes all of Allegheny Power, of which Maryland is only a small portion.

3.1 Generic Power Plant Builds and Net Imports

To satisfy the demand in a zone, the Ventyx model either imports energy from other zones or builds generic power plants based on least-cost principles. Maryland has historically been a large importer of energy and has imported approximately 30 to 40 percent of its energy requirements in recent years. Maryland is also a relatively high-priced zone for power plant construction, compared to some of the other PJM zones. Power plant operating costs in Maryland are also higher than in most other PJM states since Maryland and Delaware are the only states in PJM that are a party to RGGI (New Jersey withdrew in 2011). Accordingly, the Ventyx model builds power plants outside Maryland (PJM-SW in particular) and the PJM-SW zone imports energy from other zones in PJM. This effect can be observed in Figure 8 which shows that net imports into PJM-SW are higher in the RCU compared to the RC. The greater volume of imports is facilitated by the addition of the Mount Storm to Doubs transmission upgrade. The temporary drop in imports between 2017 and 2018 is due to the CPV power plant (located in Charles County in Maryland) coming on-line.

Figure 8 PJM-SW Net Imports



Total new generic natural gas capacity builds in PJM as a whole reach 40,547 MW by 2030. This is a significant increase over the 30,101 MW built in PJM in the RC. The increase is mainly to compensate for the greater number of power plant retirements in the RCU relative to the RC. As noted earlier, PJM-SW is now one of the higher-priced power plant construction zones and coupled with the increased transfer capacity from the new transmission, very little generic capacity is built in the zone. Figure 9 shows the generic natural gas capacity additions for the three Maryland zones in the RCU.

Figure 9 RCU Generic Natural Gas Capacity Additions

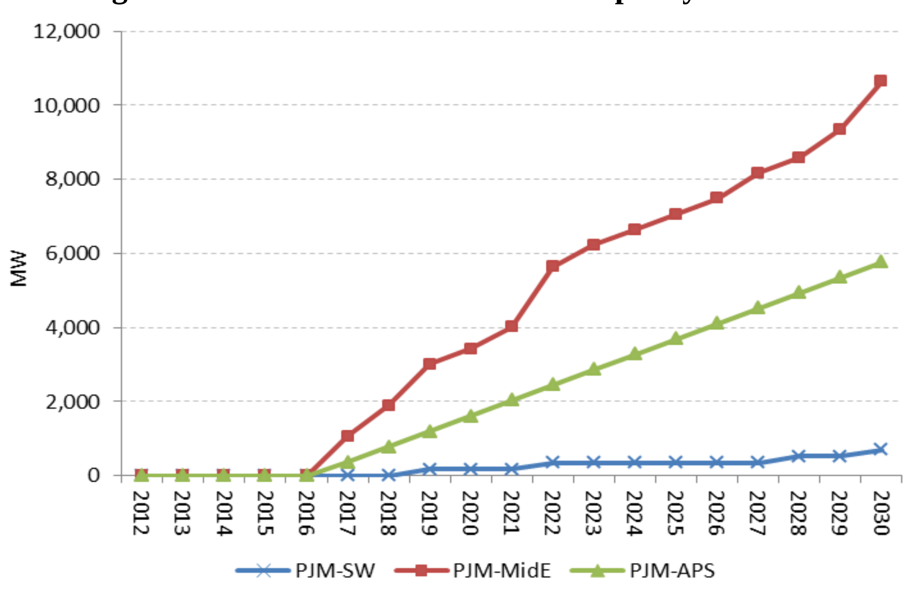
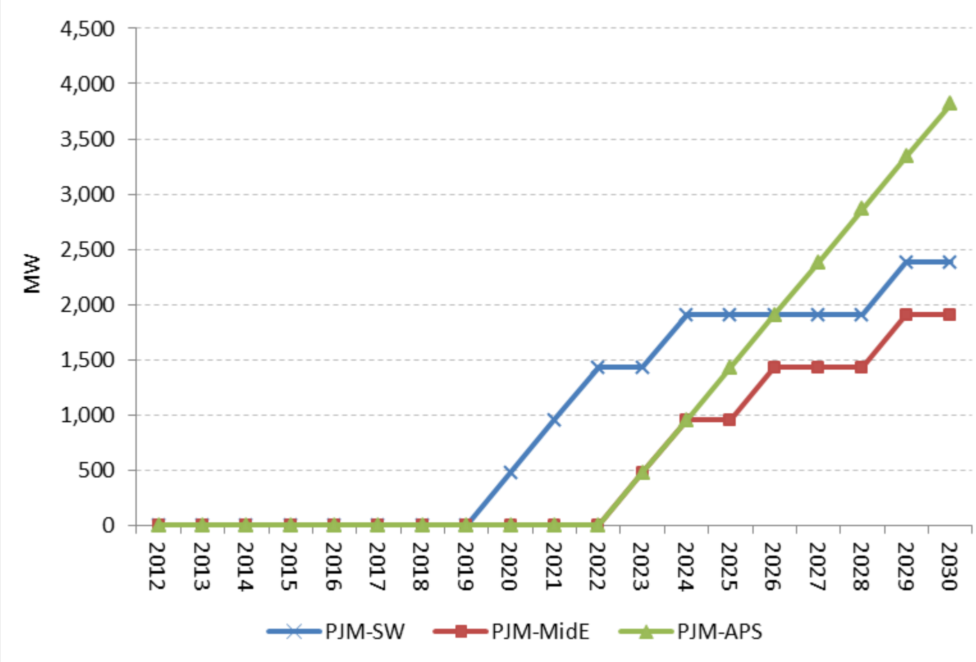


Figure 10 shows the generic natural gas capacity additions that were added to the Maryland zones in the RC. Only 696 MW are added in PJM-SW in the RCU compared to the 2,385 MW added to the zone in the RC. The zone with the largest increase in capacity additions is PJM-MidE, where 10,644 MW are added in the RCU compared to the 1,908 MW in the RC. This is largely attributable to New Jersey's withdrawal from RGGI, which makes the zone preferential for capacity additions to serve eastern loads.

Figure 10 RC Generic Natural Gas Capacity Additions



3.2 Generation Mix

Generation mix is a function of how much electricity the various types of generation (e.g., coal, natural gas, nuclear, wind, etc.) generate within a given time period. Figure 11 and Figure 12 show the projected generation mix in Maryland for the RCU and RC, respectively. Projected natural gas generation in Maryland was higher in the RC than the RCU because more generic natural gas plants were added in Maryland in the RC (plants in PJM-MidE are assumed to be constructed in New Jersey). Very few natural gas plants are built in Maryland in the RCU. The increase in natural gas generation in 2017 in the RCU is due to the CPV power plant coming on-line, but it slowly reduces output as imports rise in the last decade of the forecast period. Coal generation is also lower in the RCU compared to the RC, as imports are serving more of Maryland's energy requirements.

Figure 11 RCU Generation Mix in Maryland

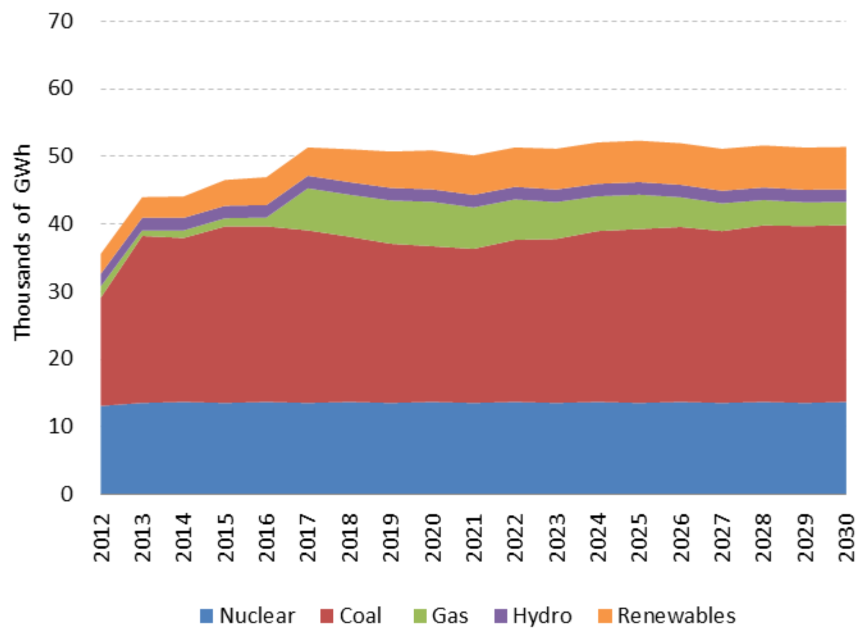
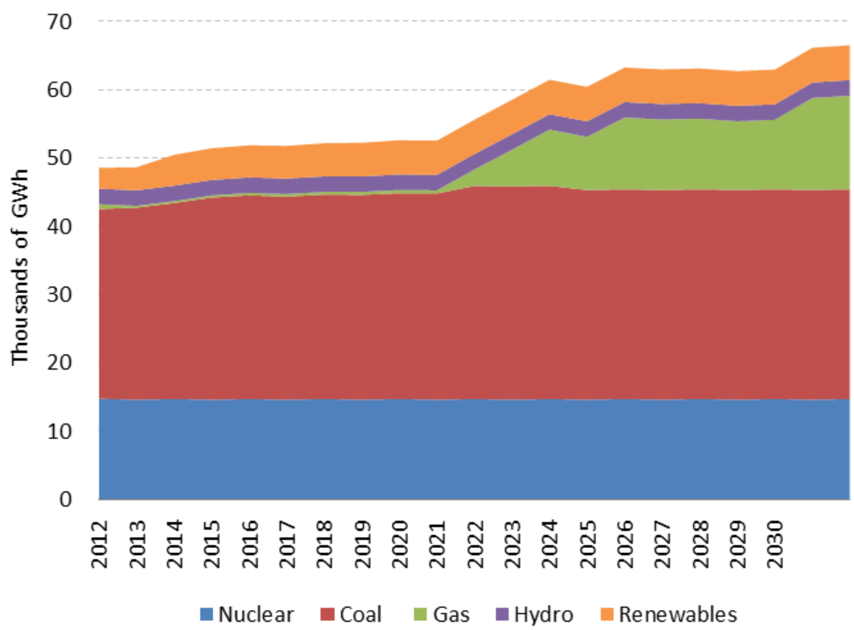


Figure 12 RC Generation Mix in Maryland



Total renewable energy generation in Maryland is higher in the RCU compared to the RC as more renewable capacity has been developed in the State. Figure 13 and Figure 14 show the total renewable energy generation in Maryland in the RC and the RCU, respectively.

Figure 13 LTER RC Maryland Renewable Energy Generation

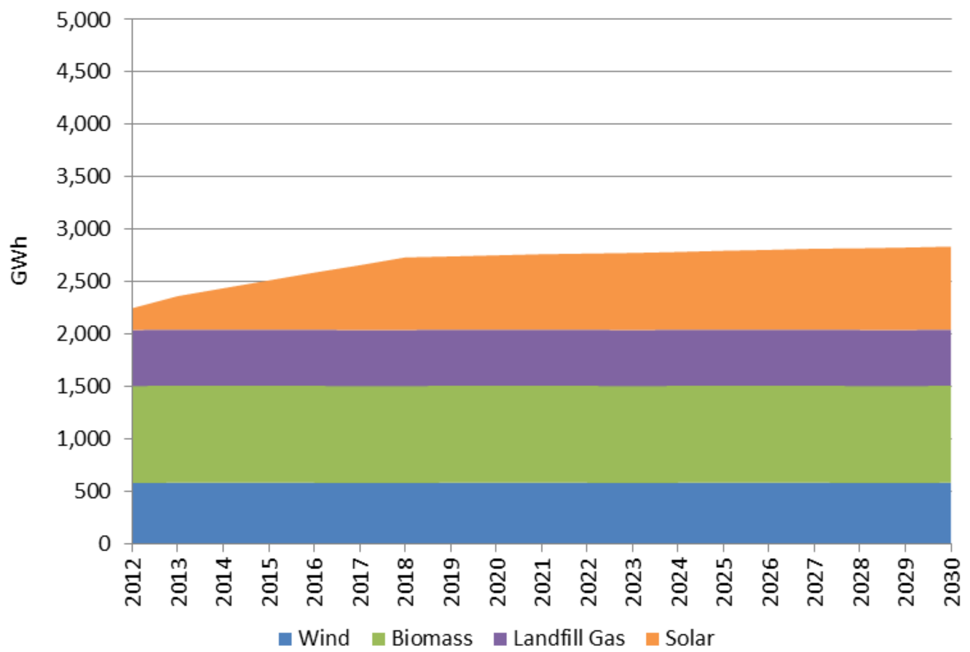
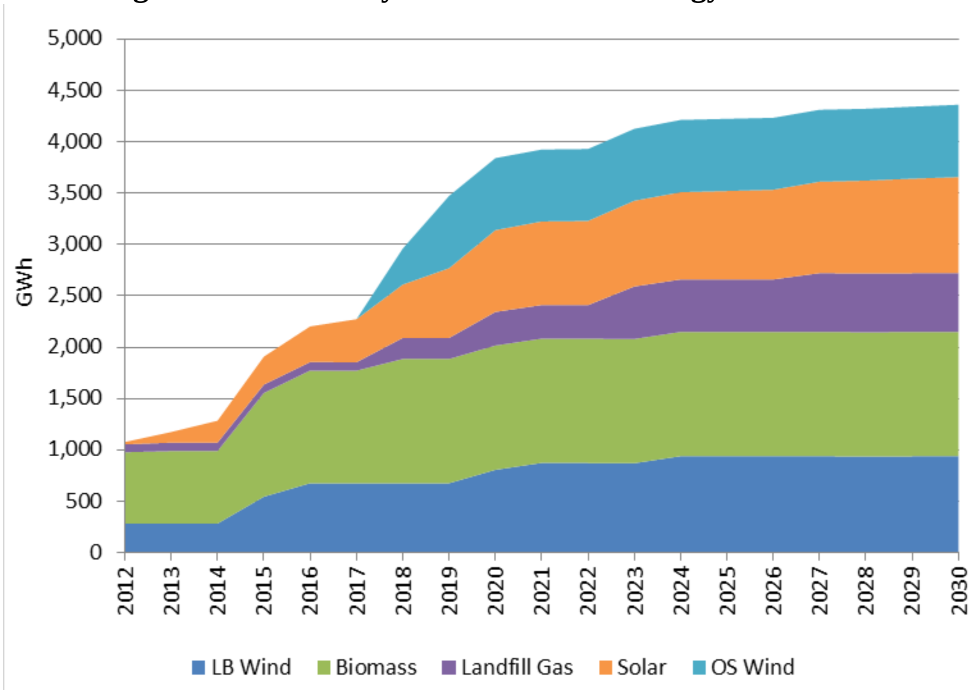


Figure 14 RCU Maryland Renewable Energy Generation



3.3 Energy Prices

Natural gas prices are the dominant driver of projected energy prices. With the lower natural gas price forecast, energy prices in the RCU (see Figure 16) are significantly lower throughout the analysis period compared to the RC (see Figure 15). There is also much less regional differential in energy prices in the RCU, with the eastern and western zones being closely aligned. This likely results from natural gas units setting the price (i.e., natural gas units being on the margin) more often in both the coal-heavy western zones of PJM and the eastern zones.

Figure 15 RC Energy Prices

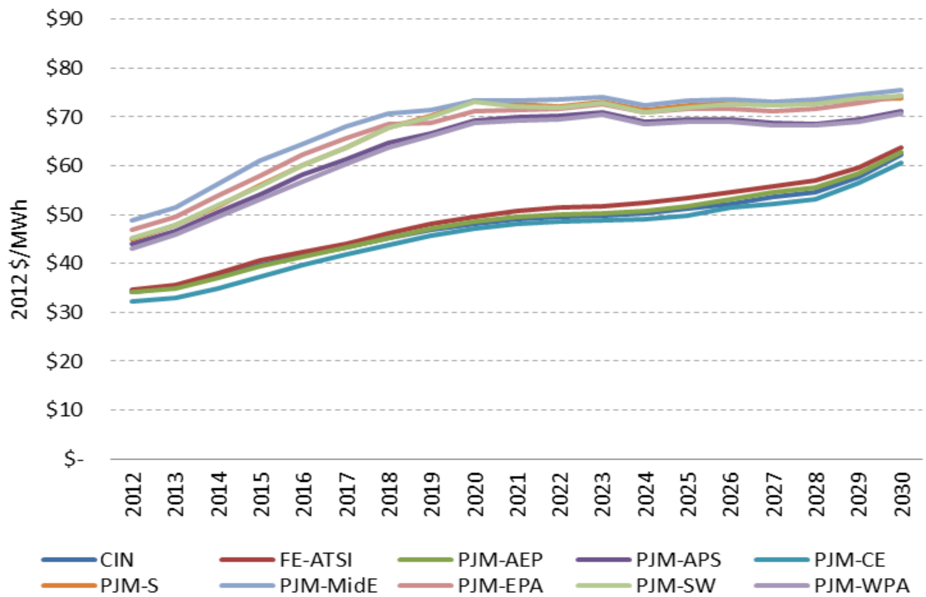
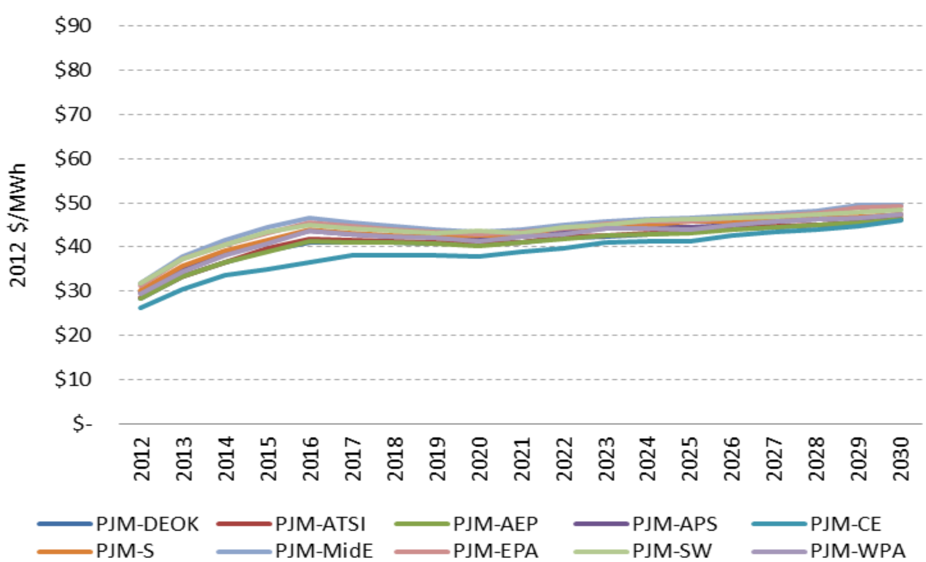


Figure 16 RCU Energy Prices

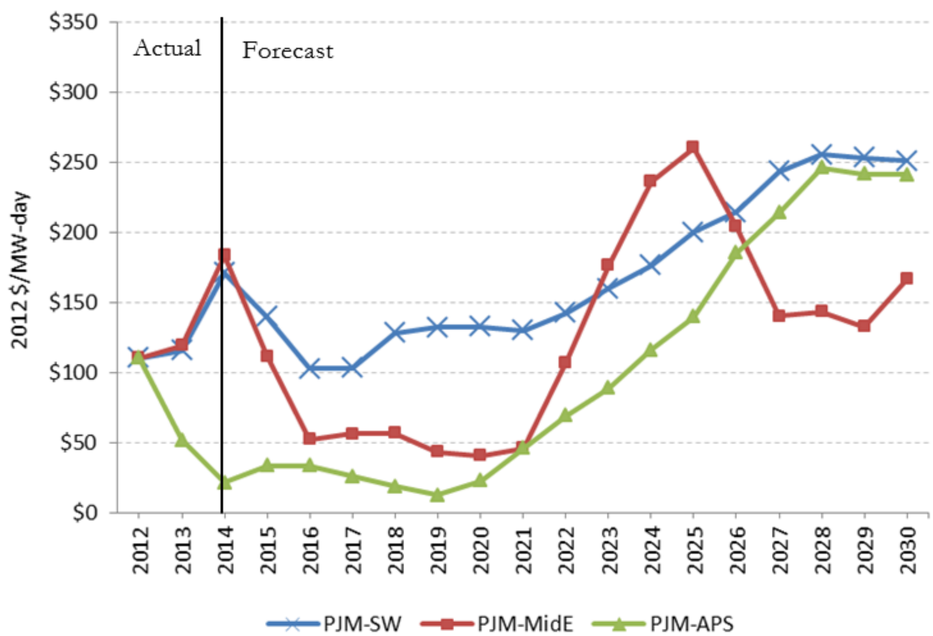


3.4 Capacity Prices

RCU incorporates actual PJM RPM capacity prices through 2016 whereas the RC estimated prices after 2013 because the 2014 and 2015 RPM auctions were held after the LTER report was released. While PJM is in a supply surplus overall, capacity prices in the Ventyx model are estimated as "make-whole" payments for the marginal unit until load growth requires new generation additions. As new generation is built, capacity prices can be calculated by the model using a cost-of-entry variable and thus capacity costs adjust to levels more in line with the cost of new entry. The capacity prices generated by the Ventyx model can vary significantly from year to year and are highly sensitive to new generation, transmission system expansion, and load levels.

Capacity prices in the first decade of the RC were relatively low because PJM had excess generating capacity (see Figure 17) and energy revenues were providing a major portion of funding to the marginal units. As new generation was required to maintain reliability, capacity prices in PJM were projected to increase.

Figure 17 RC Capacity Prices



Capacity prices in the RCU, however, remain consistently high throughout the analysis period (see Figure 18). This is principally due to the lower energy prices providing less revenue to generation units, therefore requiring higher capacity revenues in order for the marginal generation unit to be "made whole." The capacity price differential between the RC and the RCU narrows in the last five years of the study period for PJM-SW and PJM-APS zones because these zones no longer have excess supply in either the RC or the RCU (see Figure 19).

Figure 18 RCU Capacity Prices

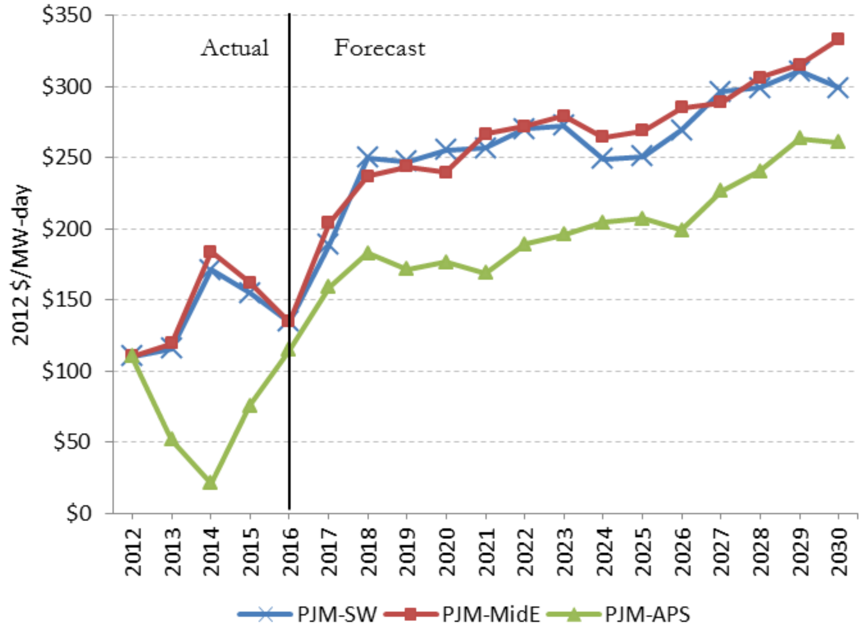
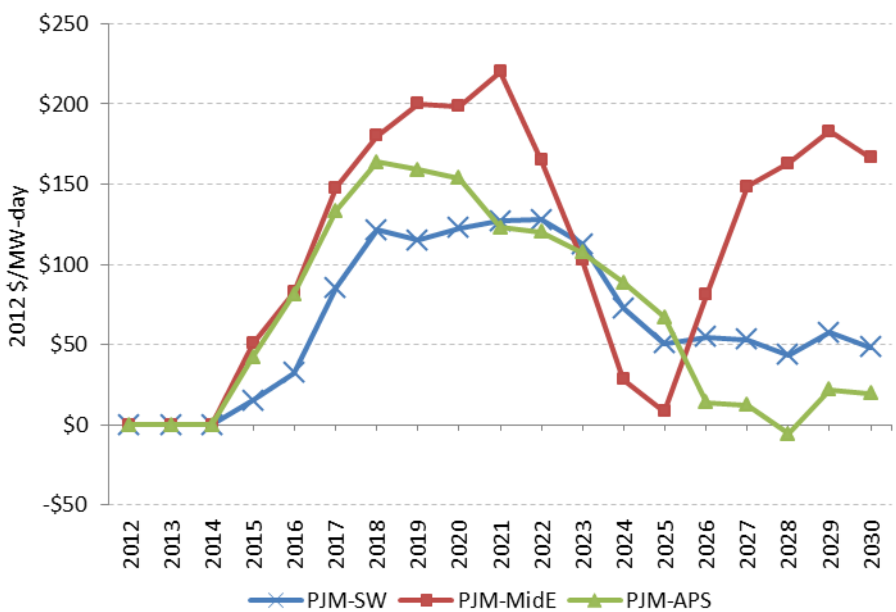


Figure 19 Capacity Price Differential RCU-RC



3.5 Emissions

Coal-fired power plants in Maryland are subject to the Maryland Healthy Air Act ("HAA"). To date, coal plants that expect to continue operation in Maryland have installed the pollution abatement technologies necessary to comply with the HAA. Since no new coal plants are projected to be built in Maryland over the course of the analysis period, emissions from existing plants remain below HAA limits throughout the study period for both the RC and the RCU. Emissions of both SO_2 and NO_x are lower in the RCU as coal generation is lower.

Figure 20 Maryland HAA Plant SO_2 Emissions

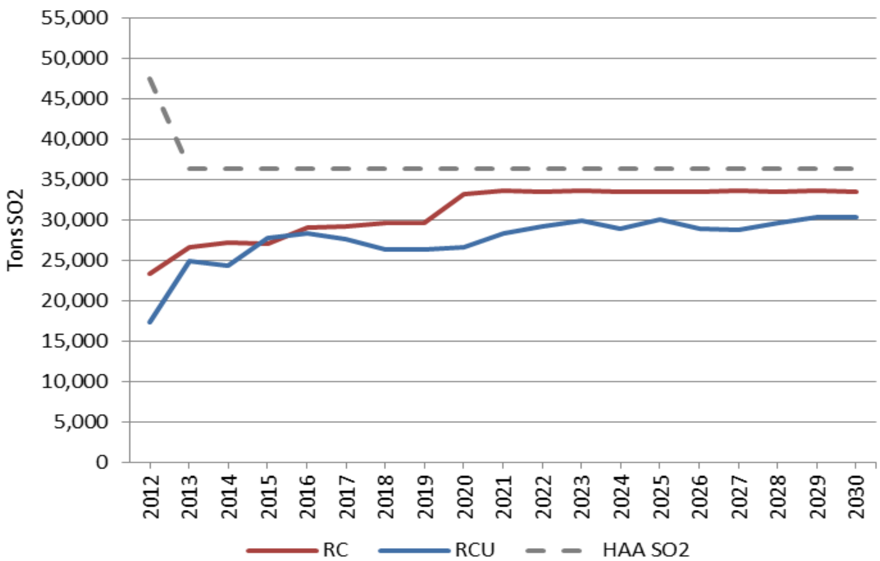
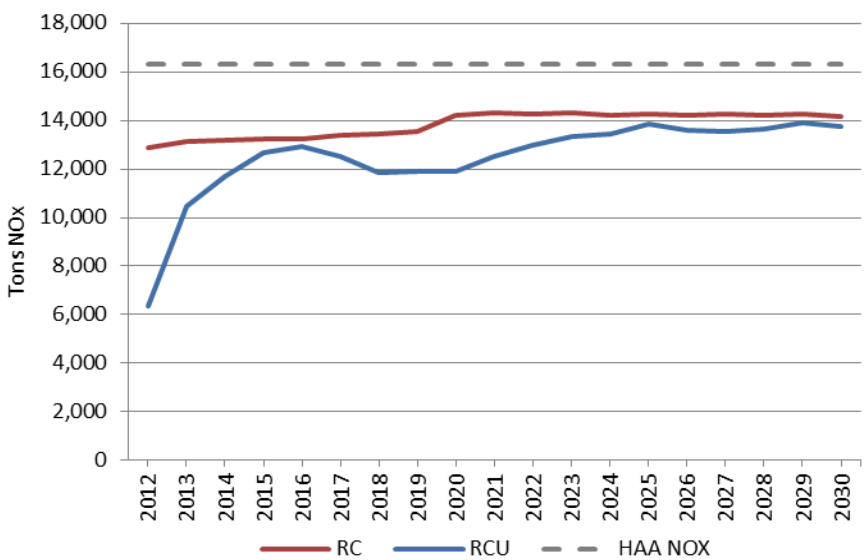
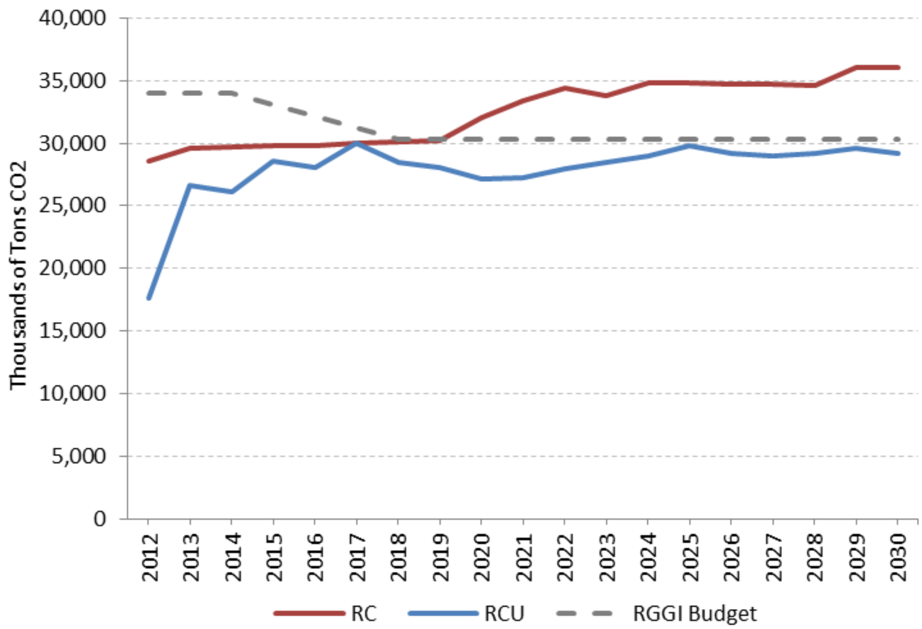


Figure 21 Maryland HAA Plant NO_x Emissions



Maryland CO_2 emissions from power plants are also lower in the RCU than in the RC and remain below the original RGGI budget throughout the study period. The increase in CO_2 emissions in the RC results from the addition of natural gas capacity built in Maryland. In the RCU, however, only a small amount of natural gas capacity is added in Maryland and, therefore, CO_2 emissions remain low (see Figure 22). Impacts of the recent modifications to the RGGI budget are discussed in Section 3.7.

Figure 22 Maryland Power Plant CO_2 Emissions



3.6 Renewable Energy Certificate Prices

The Renewable Energy Certificate ("REC") prices for the RCU were developed by determining the REC prices necessary to sustain new wind investment in Maryland.[8] The analysis is based on the principle that for a new wind facility to be economically viable, it must be able to fully recover its costs, including a return, through three revenue streams: energy market revenues, capacity market revenues, and REC revenues. The resultant REC prices for the RCU are shown below in Table 15, along with the REC prices from the LTER RC. The RC REC prices were originally developed by Ventyx, which used a different methodology. The large

[8] Wind energy is assumed to be the least-cost resource for new renewable energy facilities eligible for Tier 1 RPS compliance in Maryland.

difference in REC prices arises primarily from the new REC modeling methodology, lower installed cost assumptions for wind, and the inclusion of capacity revenues in projecting RECs prices.[9]

Table 15 REC Prices			
	Reference Case Update		LTER Reference Case
Year	(nominal $/MWh)	(2012 $/MWh)	(2012 $/MWh)
2012	3.23	3.23	3.16
2013	3.93	3.93	16.83
2014	5.24	5.08	29.46
2015	6.98	6.57	27.35
2016	9.30	8.50	26.30
2017	12.39	10.99	25.25
2018	16.50	14.23	25.25
2019	16.05	13.50	25.25
2020	15.61	12.81	26.30
2021	15.18	12.15	25.25
2022	14.76	11.53	26.30
2023	14.35	10.94	25.25
2024	13.62	10.13	23.14
2025	12.93	9.38	18.94
2026	12.27	8.68	17.88
2027	11.65	8.04	16.83
2028	11.05	7.44	14.73
2029	11.38	7.66	13.68
2030	11.72	7.89	12.62

The RCU REC price model assumes the marginal resource that establishes the Tier 1 REC price in Maryland is a 200 MW land-based wind facility with a 25-year useful life. The technical and financial assumptions used to develop REC prices in the RCU are summarized in Table 16 below. PJM allows wind facilities to bid into the capacity market but only 13 percent of installed capacity can be bid, therefore, this derate was used to estimate capacity revenues. The capacity revenue of the marginal wind plant is based on capacity prices from the RCU Ventyx

[9] For a more detailed discussion of how Ventyx derived the LTER RC REC prices see the 2011 LTER report.

model forecast for the PJM-MidE and PJM-SW zones. Energy market revenue for the wind plant is based on the average RCU on- and off-peak energy prices in the PJM-MidE, PJM-SW, and PJM-APS zones as forecast by the RCU modeling run. Based on revenue sufficiency for the year, an RCU REC price was estimated for three distinct years – 2018, 2023, and 2028. RCU REC prices outside of those years were estimated through a straight-line interpolation.

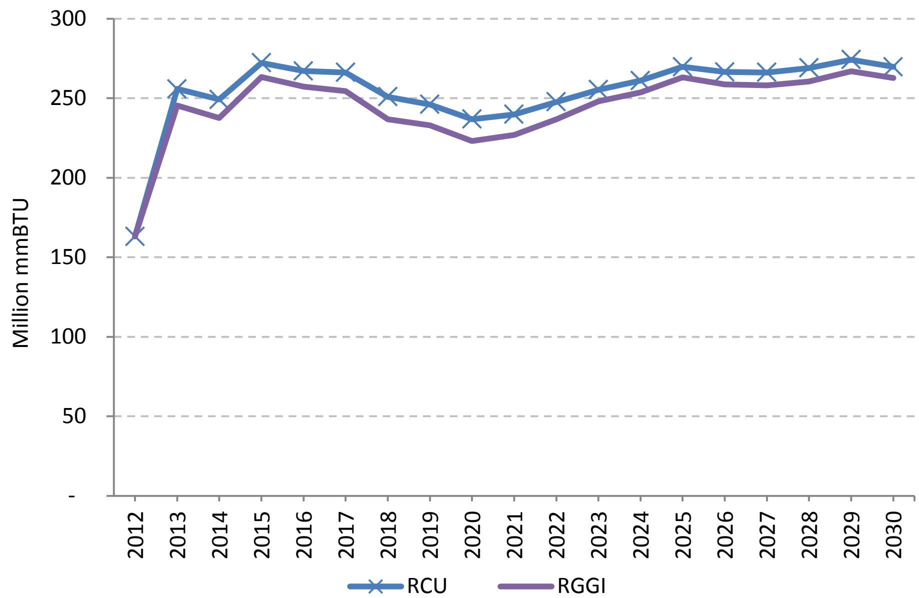
Table 16 RCU REC Model Inputs	
Technical Inputs	
Size of Wind Facility (MW)	200
Useful Life of Project (years)	25
Capacity Factor	30.0%
Annual Degradation Rate of Wind Output (after first year)	0.3%
Financial Inputs	
Rate of Inflation	2.5%
Project Costs:	
Overnight Construction Costs (2012 $/kW)	$1,740
Project Financing Parameters	
Equity Ratio	50.0%
Cost Rate of Equity	12.0%
Cost Rate of Debt	7.0%
Weighted Average Cost of Capital	9.5%
Effective Tax Rate	40.2%
Fixed O&M Costs (2012 $/kW-year)	$28.77
Variable O&M Costs (2012 $/kW-year)	$0.00
Sources of Revenues (for Developer):	
Energy Market Revenue	Average of PJM-MidE, PJM-SW, and PJM-APS energy prices
Capacity Market Revenue	Average of PJM-MidE and PJM-SW capacity prices
PJM Capacity Derate for Wind Resources	13.0%
Wind Capacity Eligible for PJM Capacity Market	26 MW

3.7 Analysis of Modified RGGI Budget

At the time of the analysis, the newly adopted revisions to the Maryland RGGI budget amount had not been announced and, therefore, are not reflected in the figures included in this report. However, the latest RGGI auction resulted in higher allowance prices due to the announcement that the cap would be reduced by 45 percent overall. A supplemental run setting the RGGI allowance price at $2.90 per ton starting in 2014 was conducted. The $2.90 per ton assumption is based on most recent reported market price data.

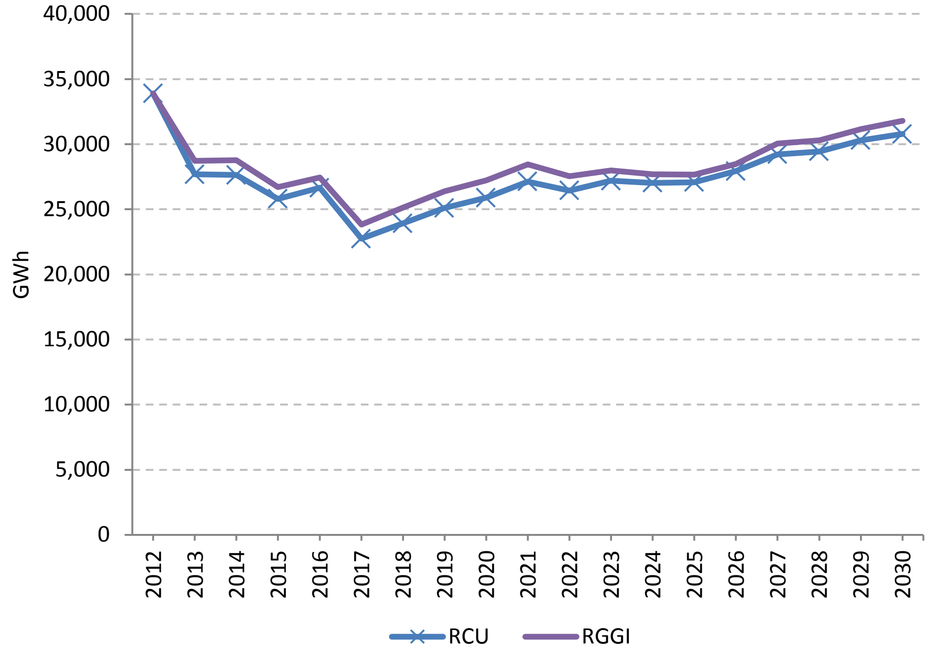
This relatively modest price change resulted in a reduction in coal generation in Maryland (see Figure 23) and a small reduction in generic natural gas power plant construction in PJM-SW: 522 MW are constructed compared to 696 MW in the RCU.

Figure 23 Coal Use in Maryland (RGGI vs. RCU)



The reduction in generation is made up for by an increase in net imports as shown in Figure 24.

Figure 24 PJM-SW Net Imports (RGGI vs. RCU)



The increased allowance price also results in slightly higher energy prices in the Maryland zones for most years (see Figure 25), while the reduction in Maryland generation reduces power sector emissions. Figure 26 shows the Maryland power plant CO_2 emissions.

Figure 25 Maryland Zone Energy Price Differentials (RGGI vs. RCU)

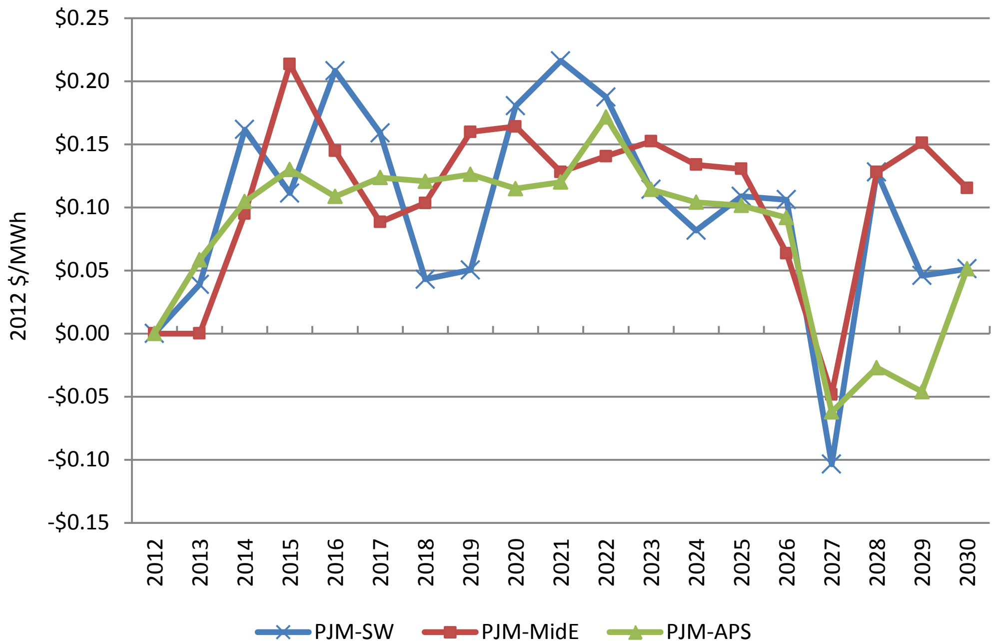
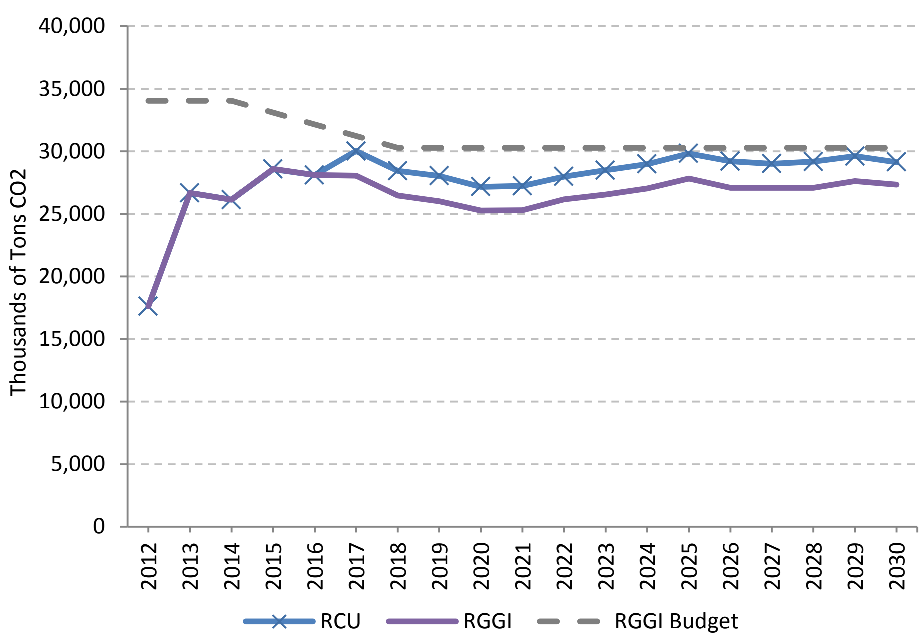
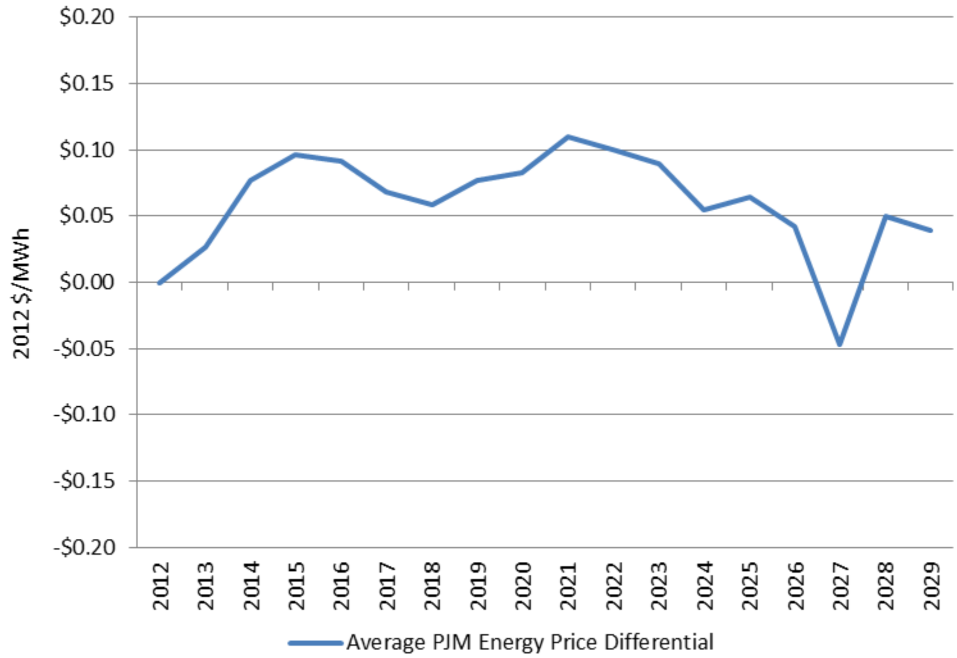


Figure 26 Maryland Power Plant CO_2 Emissions (RGGI vs. RCU)



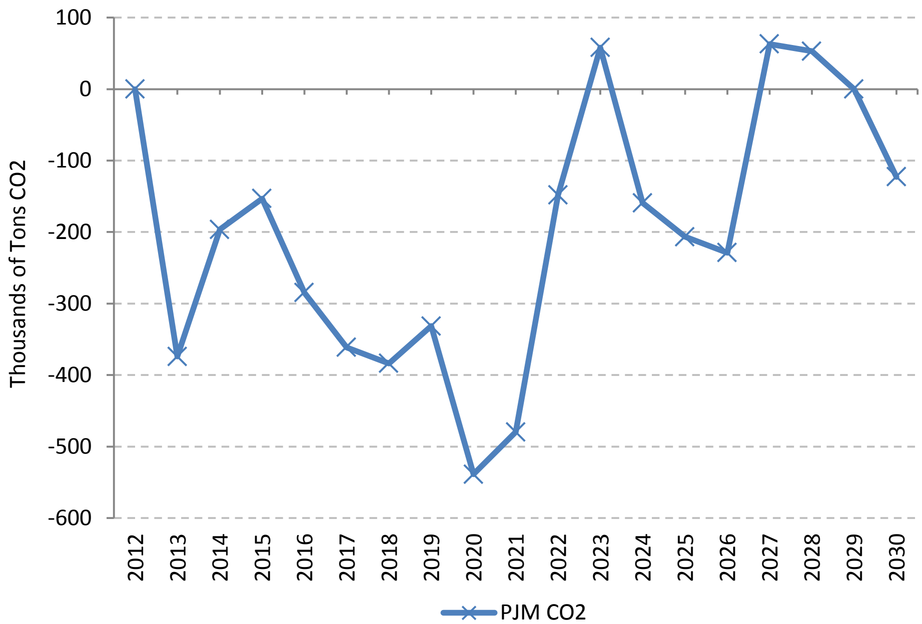
While the modeling results might indicate that Maryland's participation in RGGI is simply resulting in regional leakage where CO_2 emissions are higher in other PJM zones due to Maryland importing more of its energy, further examination of the modeling results do not show this to be the case. Figure 27 shows the average price differential for all PJM zones.

Figure 27 Average PJM Zonal Price Differential (RGGI vs. RCU)



The RGGI allowance price increase induces a slight increase in all regional power prices in most years. This causes small changes in how power plants are constructed and the dispatch order of all power plants. In PJM as a whole, coal generation is reduced. Natural gas capacity additions are slightly reduced with 40,025 MW of generic natural gas capacity being built in PJM by 2030 under the scenario that includes the updated Reference Case plus the higher RGGI prices compared to 40,547 MW in the RCU. The shortfall is met by other generation types running more often, i.e. running at higher capacity factors. Throughout the study period, PJM uses 149 million mmBtu less of coal and 194 million mmBtu more of natural gas. The end effect of these changes leads to lower CO_2 emissions in PJM as a whole in most years (see Figure 28).

Figure 28 PJM CO_2 Emissions Differential (RGGI vs. RCU)



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