GenOn Energy, Inc.
Form 10-K
February 29, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year ended December 31, 2015.

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition period from to .

GenOn Energy, Inc.
(Exact name of registrant as specified in its charter)
75-0655566 (I.R.S. Employer Identification No.)
Commission File Number: 001-16455

GenOn Americas Generation, LLC
(Exact name of registrant as specified in its charter)
51-0390520 (I.R.S. Employer Identification No.)
Commission File Number: 333-63240

GenOn Mid-Atlantic, LLC
(Exact name of registrant as specified in its charter)
58-2574140 (I.R.S. Employer Identification No.)
Commission File Number: 333-61668

Delaware
(State or other jurisdiction of incorporation or organization)

211 Carnegie Center Princeton, New Jersey	08540
(Address of principal executive offices)	(Zip Code)

(609) 524-4500
(Registrants' telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:
None
Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act.

GenOn Energy, Inc.	o Yes þ No
GenOn Americas Generation, LLC	o Yes þ No
GenOn Mid-Atlantic, LLC	o Yes þ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

GenOn Energy, Inc.	þ Yes	o No
GenOn Americas Generation, LLC	þ Yes	o No
GenOn Mid-Atlantic, LLC	þ Yes	o No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. (As a voluntary filer not subject to filing requirements, the registrant nevertheless filed all reports which would have been required to be filed by Section 15(d) of the Exchange Act during the preceding 12 months had the registrant been required to file reports pursuant to Section 15(d) of the Securities Exchange Act of 1934 solely as a result of having registered debt securities under the Securities Act of 1933.)

GenOn Energy, Inc.	o Yes o No
GenOn Americas Generation, LLC	o Yes o No
GenOn Mid-Atlantic, LLC	o Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

GenOn Energy, Inc.	þ Yes o No
GenOn Americas Generation, LLC	þ Yes o No
GenOn Mid-Atlantic, LLC	þ Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

GenOn Energy, Inc.	þ
GenOn Americas Generation, LLC	þ
GenOn Mid-Atlantic, LLC	þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b 2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
GenOn Energy, Inc.	o	o	þ	o
GenOn Americas Generation, LLC	o	o	þ	o
GenOn Mid-Atlantic, LLC	o	o	þ	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b 2 of the Act).

GenOn Energy, Inc.	o Yes þ No
GenOn Americas Generation, LLC	o Yes þ No
GenOn Mid-Atlantic, LLC	o Yes þ No

Each Registrant's outstanding equity interests are held by its respective parent and there are no equity interests held by nonaffiliates.

Registrant	Parent
GenOn Energy, Inc.	NRG Energy, Inc.
GenOn Americas Generation, LLC	NRG Americas, Inc.
GenOn Mid-Atlantic, LLC	NRG North America, LLC

This combined Form 10-K is separately filed by GenOn Energy, Inc., GenOn Americas Generation, LLC and GenOn Mid-Atlantic, LLC. Information contained in this combined Form 10-K relating to GenOn Energy, Inc., GenOn Americas Generation, LLC and GenOn Mid-Atlantic, LLC is filed by such registrant on its own behalf and each registrant makes no representation as to information relating to registrants other than itself.

The registrants have not incorporated by reference any information into this Form 10-K from any annual report to securities holders, proxy statement or prospectus filed pursuant to 424(b) or (c) of the Securities Act.

NOTE: WHEREAS GENON ENERGY, INC., GENON AMERICAS GENERATION, LLC AND GENON MID-ATLANTIC, LLC MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K, THIS COMBINED FORM 10-K IS BEING FILED WITH THE REDUCED DISCLOSURE FORMAT PURSUANT TO GENERAL INSTRUCTION I(2).

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Glossary of Terms

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

ARO	Asset Retirement Obligation
ASC	The FASB Accounting Standards Codification, which the FASB established as the source of authoritative U.S. GAAP
ASU	Accounting Standards Updates – updates to the ASC
Average realized prices	Volume-weighted average power prices, net of average fuel costs and reflecting the impact of settled hedges
Bankruptcy Court	United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division
Baseload	Units expected to satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CenterPoint	CenterPoint Energy, Inc. and its subsidiaries, on and after August 31, 2002, and Reliant Energy, Incorporated and its subsidiaries, prior to August 31, 2002
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
Deactivation	Includes retirement, mothballing and long-term protective layup. In each instance, the deactivated unit cannot be currently called upon to generate electricity.
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Economic gross margin	Sum of energy revenue, capacity revenue and other revenue, less cost of sales
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GenOn	GenOn Energy, Inc. and, except where the context indicates otherwise, its subsidiaries
GenOn Americas Generation	GenOn Americas Generation, LLC and, except where the context indicates otherwise, its subsidiaries
GenOn Energy Holdings	GenOn Energy Holdings, Inc. and, except where the context indicates otherwise, its subsidiaries
GenOn Energy Management	GenOn Energy Management, LLC
GenOn Mid-Atlantic	GenOn Mid-Atlantic, LLC and, except where the context indicates otherwise, its subsidiaries, which include the coal generation units at two generating facilities under operating leases
GenOn Plans	Collectively, the NRG GenOn LTIP, The GenOn Energy, Inc. 2002 Long-Term Incentive Plan, the GenOn Energy, Inc. 2002 Stock Plan and the Mirant Corporation 2005 Omnibus Incentive Compensation Plan
GHG	Greenhouse Gases
HAPs	Hazardous Air Pollutants
ICAP	New York Installed Capacity

IRC	Internal Revenue Code of 1986, as amended
IRC §	IRC Section
ISO	Independent System Operator, also referred to as RTO

ISO-NE	ISO New England Inc.
kWh	Kilowatt-hour
LIBOR	London Inter-Bank Offered Rate
Marsh Landing	NRG Marsh Landing project
MATS	Mercury and Air Toxics Standards
MC Asset Recovery	MC Asset Recovery, LLC
MDE	Maryland Department of the Environment
Merit Order	A term used for the ranking of power stations in order of ascending marginal cost
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries
Mirant/RRI Merger	The merger completed on December 3, 2010 pursuant to the Mirant/RRI Merger Agreement
Mirant Debtors	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and certain of its subsidiaries
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MOPR	Minimum Offer Price Rule
Mothballed	The unit has been removed from service and is unavailable for service, but has been laid up in a manner such that it can be brought back into service with an appropriate amount of notification, typically weeks or months
MW	Megawatt
MWh	Saleable megawatt hour net of internal/parasitic load megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEPGA	New England Power Generators Association
Net Exposure	Counterparty credit exposure to GenOn, GenOn Americas Generation or GenOn Mid-Atlantic, as applicable, net of collateral
Net Generation	The net amount of electricity produced, expressed in kWhs or MWhs, that is the total amount of electricity generated (gross) minus the amount of electricity used during generation.
NERC	North American Electric Reliability Corporation
NextEra	NextEra Energy Resources, LLC
NOL	Net Operating Loss
NOV	Notice of Violation
NO_x	Nitrogen Oxide
NPDES	National Pollution Discharge Elimination System
NPNS	Normal Purchase Normal Sale
NRG	NRG Energy, Inc. and, except where the context indicates otherwise, its subsidiaries
NRG Americas	NRG Americas, Inc. (formerly known as GenOn Americas, Inc.)
NRG GenOn LTIP	NRG 2010 Stock Plan for GenOn employees
NRG Merger	The merger completed on December 14, 2012 pursuant to the NRG Merger Agreement
NRG Merger Agreement	The agreement by and among NRG, GenOn and Plus Merger Corporation (a direct wholly-owned subsidiary of NRG) dated as of July 20, 2012
NRG Merger Exchange Ratio	The right of GenOn Energy, Inc. stockholders to receive 0.1216 shares of common stock of NRG Energy, Inc. in the NRG Merger
NSPS	New Source Performance Standards
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSPSC	New York State Public Service Commission

OCI	Other Comprehensive Income/ (Loss)
PADEP	Pennsylvania Department of Environmental Protection

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Peaking	Units expected to satisfy demand requirements during the periods of greatest or peak load on the system
PJM	PJM Interconnection, LLC
Plan	The plan of reorganization that was approved in conjunction with Mirant Corporation's emergence from bankruptcy protection on January 3, 2006
PPM	Parts Per Million
PSCs	Public Service Commissions
PUHCA	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act of 1976
Registrants	GenOn, GenOn Americas Generation and GenOn Mid-Atlantic, collectively
REMA	NRG REMA LLC (formerly known as GenOn REMA, LLC)
Repowering	Technologies utilized to replace, rebuild, or redevelop major portions of an existing electrical generating facility, not only to achieve a substantial emission reduction, but also to increase facility capacity, and improve system efficiency
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RRI Energy	RRI Energy, Inc.
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SEC	U.S. Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
SO_2	Sulfur Dioxide
SSR	System Support Resource
U.S.	United States of America
U.S. GAAP	Accounting principles generally accepted in the U.S.

PART I

Item 1 — Business (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

General

The Registrants are wholesale power generation subsidiaries of NRG, which is a competitive power company that produces, sells and delivers energy and energy services, primarily in major competitive power markets in the U.S. GenOn is an indirect wholly-owned subsidiary of NRG. GenOn was incorporated as a Delaware corporation on August 9, 2000, under the name Reliant Energy Unregco, Inc. GenOn Americas Generation and GenOn Mid-Atlantic are indirect wholly owned subsidiaries of GenOn. GenOn Americas Generation was formed as a Delaware limited liability company on November 1, 2001, under the name Mirant Americas Generation, LLC. GenOn Mid-Atlantic was formed as a Delaware limited liability company on July 12, 2000, under the name Southern Energy Mid-Atlantic, LLC. GenOn Mid-Atlantic is a wholly-owned subsidiary of NRG North America and an indirect wholly owned subsidiary of GenOn Americas Generation. The Registrants are engaged in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services.

The Registrants' generation facilities are located in the U.S. and comprise generation facilities across the merit order. The sale of capacity and power from baseload and intermediate generation facilities accounts for a majority of the Registrants' generation revenues. In addition, the Registrants' generation portfolio provides each with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products, and providing ancillary services to support system reliability.

The following table summarizes the generation portfolio as of December 31, 2015, by Registrant:

	(In MW)		
Generation Type	GenOn	GenOn Americas Generation	GenOn Mid-Atlantic
Natural gas[(a)]	10,763	4,118	1,942
Coal[(b)]	5,143	2,433	2,433
Oil[(c)]	1,847	1,434	308
Total generation capacity	17,753	7,985	4,683

(a) GenOn's natural gas generation portfolio does not include 463 MW related to Osceola, which was mothballed on January 1, 2015, 636 MW related to Coolwater, which was retired on January 1, 2015, 160 MW related to Glen Gardner, which was retired on May 1, 2015, and 98 MW related to Gilbert, which was retired on May 1, 2015.

(b) GenOn's coal generation portfolio does not included 597 MW related to Shawville, which was mothballed on May 31, 2015, and 401 MW related to Portland, which was deactivated on December 1, 2015.

(c) GenOn's oil generation portfolio does not included 212 MW related to Werner, which was retired on May 1, 2015.

Seasonality and Price Volatility

Annual and quarterly operating results of the Registrants' wholesale power generation segments can be significantly affected by weather and energy commodity price volatility. Significant other events, such as the demand for natural gas, interruptions in fuel supply infrastructure and relative levels of hydroelectric capacity can increase seasonal fuel and power price volatility. The preceding factors related to seasonality and price volatility are fairly uniform across the Registrants' wholesale generation business.

Competition

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. The Registrants compete on the basis of the location of their plants and ownership of portfolios of plants in various regions, which increases the stability and reliability of their energy revenues. Wholesale power generation is a regional business that is currently highly fragmented and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identity of the companies the Registrants compete with depending on the market. Competitors include regulated utilities, other independent power producers, and power marketers or trading companies, including those owned by financial institutions, municipalities and cooperatives.

Competitive Strengths

The Registrants’ power generation assets are diversified by fuel-type, dispatch level and region, which helps mitigate the risks associated with fuel price volatility and market demand cycles. The Registrants' baseload and intermediate facilities provide each with a significant source of cash flow, while the peaking facilities provide the Registrants with opportunities to capture upside potential that can arise from time to time during periods of high demand.

Many of the Registrants’ generation assets are located within densely populated areas, which tend to have more robust wholesale pricing as a result of relatively favorable local supply-demand balance. The Registrants have generation assets located in or near the New York City, Washington, D.C., Baltimore, Pittsburgh, Los Angeles and San Francisco metropolitan areas and New Jersey. These facilities are often ideally situated for repowering or the addition of new capacity, because their location and existing infrastructure provide significant advantages over undeveloped sites.

2015 Significant Events and Developments

Dispositions

In the fourth quarter of 2015, GenOn entered into two separate agreements to sell 100% of its interest in Seward Generation, LLC, or Seward, and Shelby County Energy Center, LLC, or Shelby. Seward and Shelby own and operate a 525 MW coal-fired facility and a 352 MW natural gas-fired facility, respectively. The sale of Seward was completed on February 2, 2016 and the sale of Shelby is expected to be completed during the first quarter of 2016. See Item 15 — Note 3, Dispositions, to the Consolidated Financial Statements for further discussion.

Fuel Repowerings and Conversions

The table below lists projected repowering and conversion projects at certain of the Registrants' facilities:

Facility	Net Generation Capacity (MW)	Project Type	Fuel Type	Targeted COD
New Castle Units 3, 4 and 5	325	Natural Gas Conversion	Natural Gas	Summer 2016
Shawville Units 1, 2, 3 and 4	597	Natural Gas Conversion	Natural Gas	Fall 2016
Total Fuel Repowerings and Conversions	922			

Coal Operations

The following table summarizes GenOn's U.S. coal capacity and the corresponding revenues and average natural gas prices and positions resulting from coal hedge agreements extending beyond December 31, 2015, and through 2019:

	2016	2017	2018	2019	Annual Average for 2016-2019
	(Dollars in millions unless otherwise stated)				
Net Coal Capacity (MW) [(a)]	4,409	4,198	4,198	3,492	4,074
Forecasted Coal Capacity (MW) [(b)]	2,256	2,007	1,656	1,368	1,822
Total Coal Sales (MW) [(c)]	1,827	1,153	217	—	799
Percentage Coal Capacity Sold Forward [(d)]	81 %	57 %	13 %	—	38 %
Total Forward Hedged Revenues [(e)]	$828	$439	$57	$—	
Weighted Average Hedged Price ($ per MWh) [(e)]	$51.58	$43.42	$30.19	$—	
Average Equivalent Natural Gas Price ($ per MMBtu) [(e)]	$3.29	$3.15	$2.83	$—	
Gas Price Sensitivity Up $0.50/MMBtu on Coal Units	$85	$120	$154	$123	
Gas Price Sensitivity Down $0.50/MMBtu on Coal Units	$(47)	$(79)	$(106)	$(84)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal Units	$34	$44	$66	$62	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal Units	$(27)	$(34)	$(50)	$(46)	

(a) Net coal capacity represents nominal summer net MW capacity of power generated as adjusted for the Registrants' ownership position excluding capacity from inactive/mothballed units, see Item 2 - Properties for units scheduled to be deactivated.

(b) Forecasted generation dispatch output (MWh) based on forward price curves as of December 31, 2015, which is then divided by number of hours in a given year to arrive at MW capacity. The dispatch takes into account planned and unplanned outage assumptions.

(c) Includes amounts under power sales contracts and natural gas hedges. The forward natural gas quantities are reflected in equivalent MWh based on forward market implied heat rate as of December 31, 2015, and then combined with power sales to arrive at equivalent MWh hedged which is then divided by number of hours in given year to arrive at MW hedged. The coal sales include swaps and delta of options sold which is subject to change. For detailed information on the Registrants' hedging methodology through use of derivative instruments, see discussion in Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements.

(d) Percentage hedged is based on total coal sales as described in (c) above divided by the forecasted coal capacity.

(e) Represents all U.S. coal sales, including energy revenue and demand charges, excluding revenues derived from capacity auctions.

Regulatory Matters

As owners of power plants and participants in wholesale energy markets, certain of the Registrants' subsidiaries are subject to regulation by various federal and state government agencies. These include the CFTC and FERC, as well as other public utility commissions in certain states where the Registrants' generating assets are located. In addition, the Registrants are subject to the market rules, procedures and protocols of the various ISO markets in which they participate. The Registrants must also comply with the mandatory reliability requirements imposed by NERC and the regional reliability entities in the regions where they operate.

National

U.S. Supreme Court Agrees to Consider the Constitutionality of Maryland's Generator Contracting Programs — On October 19, 2015, the U.S. Supreme Court agreed to hear a case challenging the constitutionality of certain state-directed procurements of new electric generating facilities. The case involves the authority of the Maryland Public Service Commission to direct load-serving utilities in the state to enter into long-term power purchase contracts with a generation developer to encourage the construction of new generation capacity in Maryland. The constitutionality of the long-term contracts was challenged in the U.S. District Court for the District of Maryland, which, in an October 24, 2013, decision, found that the contracts violated the Supremacy Clause of the U.S. Constitution because they were both conflict preempted and field preempted by the FPA and the authority that the FPA granted to FERC. On June 30, 2014, the U.S. Court of Appeals for the Fourth Circuit affirmed the District Court's decision. A case arising out of New Jersey and raising similar issues was decided by the U.S. Court of Appeals for the Third Circuit, which also determined that the state-mandated contracts were preempted. After the Supreme Court granted certiorari in the Maryland case, NRG filed a friend-of-the-court brief urging the Court to uphold the right of states to incentivize new generation by directing utilities in the state to enter into long-term contracts — but noted that FERC has both the authority and the statutory obligation to protect wholesale markets by requiring that bids in the wholesale markets reflect costs and by ensuring that uneconomic entry does not distort auction outcomes. The Supreme Court heard oral argument on February 24, 2016. The outcome of this litigation could have broad impacts on whether and how states require utilities to contract with new generation resources, as well as how such contracted resources interact with the FERC-jurisdictional wholesale markets.

U.S. Supreme Court Allows FERC to Retain Jurisdiction Over Demand Response — On January 25, 2016, the U.S. Supreme Court issued a 6-2 decision affirming FERC's ability to exercise jurisdiction over demand response resources seeking to voluntarily participate in the wholesale markets. Additionally, the Supreme Court upheld FERC's preferred scheme for pricing demand response in the energy market. This case arose out of a May 23, 2014, decision by the D.C. Circuit which vacated FERC's rules (known as Order No. 745) that set the compensation level for demand response resources participating in the FERC-jurisdictional energy markets. The Court of Appeals had held that the FPA does not authorize FERC to exercise jurisdiction over demand response and that instead demand response is part of the retail market over which the states have jurisdiction. With the Supreme Court's decision, FERC will resume exercising jurisdiction over demand response, which the Registrants view as a positive for their wholesale business.

East

PJM

PJM Auction Results — On August 21, 2015, PJM announced the results of its 2018/2019 Base Residual Auction, officially integrating the new Capacity Performance product into the market. GenOn cleared approximately 8,610 MWs of Capacity Performance product and 464 MWs of Base Capacity product in the 2018/2019 Base Residual Auction. GenOn's expected capacity revenues from the 2018/2019 Base Residual Auction are approximately $565 million. GenOn Americas Generation (including GenOn Mid-Atlantic) cleared approximately 3,801 MWs of Capacity Performance product and 58 MWs of Base Capacity product in the 2018/2019 Base Residual Auction. GenOn Americas Generation's (including GenOn Mid-Atlantic) expected capacity revenues from the 2018/2019 Base Residual Auction are approximately $232 million. PJM announced the results of its Transitional Capacity Auctions for the 2016/2017 and 2017/2018 delivery years, respectively, on August 31, 2015, and September 9, 2015. GenOn cleared approximately 850 MWs of Capacity Performance product in the 2016/2017 Transactional Capacity Auction, and 5,897 MWs of Capacity Performance product in the 2017/2018 Transitional Capacity Auctions. GenOn Americas Generation (including GenOn Mid-Atlantic) cleared approximately 2,501 MWs of Capacity Performance product in the 2017/2018 Transitional Capacity Auctions. GenOn and GenOn Americas Generation (including GenOn Mid-Atlantic) expect an approximate $170 million and $50 million increase in PJM capacity revenue, respectively, from 2016/2017 to 2018/2019 due to the Capacity Performance product.

The tables below provide a detailed description of the Registrant's Base Residual Auction results:

GenOn:

	Base Capacity Product		Capacity Performance Product	
Zone	Cleared Capacity (MW)(1)	Price ($/MW-day)	Cleared Capacity (MW)(1)	Price ($/MW-day)
COMED	—	$200.21	579	$215.00
EMAAC	91	$210.63	424	$225.42
MAAC	67	$149.98	6,431	$164.77
RTO	306	$149.98	1,176	$164.77
Total	464		8,610	

(1) Includes imports.

GenOn Americas Generation & GenOn Mid-Atlantic:

	Base Capacity Product		Capacity Performance Product	
Zone	Cleared Capacity (MW)(1)	Price ($/MW-day)	Cleared Capacity (MW)(1)	Price ($/MW-day)
MAAC (2)	58	$149.98	3,801	$164.77
Total	58		3,801	

(1) Includes imports.

(2) Plants that participate in the PJM auctions for GenOn Americas Generation are solely those operated by GenOn Mid-Atlantic.

Capacity Performance Rehearings — On June 9, 2015, FERC approved changes to PJM's capacity market. Major elements of the approved changes to the Capacity Performance framework include the calculation of the bid cap, elimination of the 2.5% holdback for short lead-time resources, and substantial performance penalties on Capacity Performance resources that do not perform in real time during specific periods of high demand. The rules mandate that underperformance penalties be paid to units that over perform during those periods of high demand. The Registrants' actual revenues will be the combination of the revenues based on the cleared auction MWs plus the net of any over and under performance of the Registrants' fleet. On July 9, 2015, multiple parties, including the Registrants, filed requests for rehearings at FERC regarding the framework of the new annual capacity auctions. Rehearing is pending. In addition, multiple parties sought clarification on whether demand resources could participate in the Capacity Performance Transition Auctions. On July 22, 2015, FERC issued an order allowing demand response and energy efficiency resources to participate in the Capacity Performance Transition Auctions. Rehearing is pending.

Capacity Replacement — On March 10, 2014, PJM filed at FERC to limit speculation in the forward capacity auction. Specifically, PJM proposed tariff changes that are designed to ensure that only capacity resources that are reasonably expected to be provided as a physical resource by the start of the delivery year can participate in the Base Residual Auction. These changes include the addition of a replacement capacity adjustment charge that is intended to remove the incentive to profit from replacing capacity commitments, an increase in deficiency penalties for non-performance, and a reduction in the number of incremental auctions from three to one. On May 9, 2014, FERC rejected PJM's proposed changes to address replacement capacity and incremental auction design, but established a Section 206 proceeding and technical conference to find a just-and-reasonable outcome. On August 18, 2014, PJM requested that FERC defer further action in the proceeding. Since the request, FERC has taken no action. The Section 206 proceeding and technical conference could have a material impact on future PJM capacity prices.

Reactive Power — On November 20, 2014, FERC issued an Order to Show Cause under FPA Section 206 directing PJM to either revise its tariff to provide that a generation or non-generation resource owner will no longer receive reactive power capability payments after it has deactivated its unit and to clarify the treatment of reactive power capability payments for units transferred out of a fleet or show cause why it should not be required to do so. On December 22, 2014, PJM filed proposed tariff changes, and the matter remains pending at FERC. The Registrants' reactive power revenues may change as a result of this proceeding.

Demand Response Operability — On May 9, 2014, FERC largely accepted PJM's proposed changes on demand response operability in an attempt to enhance the operational flexibility of demand response resources during the operating day. The approval of these changes will likely limit the amount of demand response resources eligible to participate in PJM. The matter is pending rehearing at FERC.

MOPR Revisions — On May 2, 2013, FERC accepted PJM's proposal to substantially revise its Minimum Offer Price Rule. Among other things, FERC approved the portions of the PJM proposal that exempt many new entrants from demonstrating that their proposed projects are economic, as well as providing a similar exemption from public power entities and certain self-supply entities. This exemption is subject to certain conditions designed to limit the financial incentive of such entities to suppress market prices. On June 3, 2013, NRG filed a request for rehearing of the FERC order and subsequently protested the manner in which PJM proposed to implement the FERC order. On October 15, 2015, FERC denied the requests for rehearing and accepted PJM's compliance filing. NRG, along with other parties, filed a petition for review of FERC's decision with the D.C. Circuit.

AEP and FirstEnergy Ohio Contracts — FirstEnergy and AEP, through their regulated Ohio utilities, have sought approval at the Public Utility Commission of Ohio of a capacity market "swap" where FirstEnergy's and AEP's "merchant" resources would recover the full costs of their generation facilities through a non-bypassable surcharge applicable to all Ohio retail customers. Evidence introduced in the Ohio proceeding suggests that these contracts could impose more than $1,000 per Ohio retail customer in excess costs over the next eight years. A coalition of consumer and supply groups are opposing the proposed contracts before the Public Utility Commission of Ohio. Additionally, NRG and numerous other coalition members have filed a complaint at FERC questioning whether FirstEnergy and AEP have the regulatory approvals necessary to enter into above-market contracts with their generation affiliates without further FERC review. That complaint is pending at FERC.

New England (GenOn and GenOn Americas Generation)

Performance Incentive Proposal — On January 17, 2014, ISO-NE filed at FERC to revise its forward capacity market, or FCM, by making a resource’s forward capacity market compensation dependent on resource output during short intervals of operating reserve scarcity. The ISO-NE proposal would replace the existing shortage event penalty structure with a new performance incentive, or PI, mechanism, resulting in capacity payments to resources that would be the combination of two components: (1) a base capacity payment and (2) a performance payment or charge. The performance payment or charge would be entirely dependent upon the resource’s delivery of energy or operating reserves during scarcity conditions, and could be larger than the base payment.

On May 30, 2014, FERC found that most of the provisions in the ISO-NE proposal, with modifications, together with an increase to the reserve constraint penalty factors, provided a just and reasonable structure. FERC instituted a proceeding for further hearings and required ISO-NE to make a compliance filing to modify its proposal and adopt the increases to the reserve constraint penalty factors. FERC denied rehearing. The New England Power Generators Association filed a petition for review of FERC's decision with the D.C. Circuit.

FCM Rules for 2014 Forward Capacity Auction — On February 28, 2014, ISO-NE filed with FERC the results of Forward Capacity Auction 8. On September 16, 2014, FERC issued a notice stating that the Forward Capacity Auction 8 results would go into effect by operation of law. Several parties requested rehearing of FERC’s notice. FERC rejected those requests on legal and procedural grounds. A petition for review of FERC's decision was filed with the D.C. Circuit. NRG, along with other parties, filed a brief in support of FERC. An adverse decision could call into question the capacity revenues associated with the 2017/2018 delivery year.

Sloped Demand Curve Filing — On May 30, 2014, FERC accepted the proposed tariff revisions discussed in the April 1, 2014 ISO-NE filing at FERC regarding the establishment of a sloped demand curve for use in the ISO-NE Forward Capacity Market. The accepted tariff changes include extending the period during which a market participant can lock-in the capacity price for a new resource from five to seven years, establishing a limited exemption for the buyer-side market mitigation rules for a set amount of renewable resources, and eliminating the administrative pricing rules. The shift away from the current vertical demand curve and accompanying proposed changes could have a material impact on the capacity prices in future auctions as well as an impact on resources that have a price lock-in. FERC denied rehearing. NRG, along with other generators, filed a petition for review of FERC's decision with the D.C. Circuit.

In December 2015, FERC voluntarily requested a remand from the D.C. Circuit. FERC also instituted a FPA Section 206 proceeding, directing ISO-NE to submit tariff revisions by March 31, 2016, providing for zonal sloped demand curves to be implemented beginning in Forward Capacity Auction 11. The ultimate outcome of this proceeding will affect the market design governing future capacity auctions in New England.

New York

Competitive Entry Exemption to Buyer-Side Mitigation Rules — On December 4, 2014, pursuant to Section 206 of the FPA, a group of New York transmission owners filed a complaint seeking a competitive entry exemption to the current NYISO buyer-side mitigation rules. On December 16, 2014, TDI USA Holdings Corporation filed a complaint under Section 206 of the FPA against the NYISO claiming that the NYISO’s application of the Mitigation Exemption Test under the buyer-side mitigation rules to TDI’s Champlain Hudson 1,000 MW transmission line project is unjust and unreasonable and seeks an exemption from the Mitigation Exemption Test. On February 26, 2015, FERC granted the complaint filed by the New York transmission owners and directed the NYISO to adopt a competitive entry exemption into its tariff within 30 days. In a companion order issued on the same day, FERC rejected the TDI complaint on the grounds that TDI’s concerns were adequately addressed by FERC’s first order. On March 30, 2015, NRG filed a request for rehearing. On August 4, 2015, FERC granted in part and denied in part the rehearing requests and conditionally accepted NYISO's compliance filing subject to revisions clarifying that the competitive entry exemption is not available for generator or unforced capacity deliverability rights projects that are members of the completed class years.

Revisions to the Buyer-Side Mitigation Rules — On May 8, 2015, several New York entities, including the NYSPSC, filed a complaint against the NYISO under Section 206 of the FPA seeking revisions to the buyer-side market power mitigation measures of the NYISO tariff. The parties requested FERC to find that the current buyer-side mitigation rules are unjust and unreasonable because they prevent the ICAP market from functioning properly and that the rules should apply only to a limited subset of generation facilities. NRG protested the complaint. On October 9, 2015, FERC held that certain renewables and self-supply resources should be exempt from buyer-side mitigation rules and ordered the NYISO to submit a compliance filing. On February 5, 2016, FERC denied rehearing. The NYISO has yet to issue its compliance filing addressing FERC's order to develop exemptions for certain renewables and self-supply resources. The eventual disposition of this case could impact the ability of uneconomic resources to enter the New York market.

Independent Power Producers of New York (IPPNY) Complaint — On May 10, 2013, as amended on March 25, 2014, a generator trade association in New York filed a complaint at FERC against the NYISO. The generators asked FERC to direct the NYISO to require that capacity from existing generation resources that would have exited the market but for out-of-market payments under RMR-type agreements be excluded from the capacity market altogether or be offered at levels no lower than the resources' going-forward costs. The complaints point to the recent reliability services agreements entered into between the NYSPSC and generators as evidence that capacity market prices are being influenced by non-market considerations.

On March 19, 2015, FERC denied IPPNY’s complaint and directed NYISO to establish a stakeholder process to consider whether there are circumstances that warrant the adoption of buyer-side mitigation rules in the rest-of-state, and whether mitigation measures would need to be in place to address any price suppressing effects of repowering agreements. On June 17, 2015, NYISO filed its compliance report describing the outcome of the stakeholder process on concluding that buyer-side mitigation measures in the rest-of-state are not warranted. On November 16, 2015, FERC directed the NYISO to provide additional information. On December 16, 2015, NYISO filed responses to FERC's request. Rehearing is pending. Failure to implement buyer-side mitigation measures could result in uneconomic entry, which artificially decreases capacity prices below competitive market levels.

Gulf Coast

MISO (GenOn)

Complaints regarding the 2015/2016 Planning Resource Auction — In May 2015, the Illinois Attorney General, Public Citizen, Inc., and Southwestern Electric Cooperative, Inc. filed complaints against MISO on the grounds that the results of the MISO 2015/2016 Planning Resource Auction resulted in unjust and unreasonable prices, specifically the auction clearing price in Zone 4. NRG, on behalf of itself and GenOn, filed comments providing its view on the rationale for the market outcome.

On June 30, 2015, the Illinois Energy Consumers filed a complaint with FERC under Section 206 of the FPA regarding MISO’s Planning Resource Auction tariff provisions, stating that the current MISO tariff does not produce just and reasonable results. The complaint suggests specific tariff modifications to address these alleged deficiencies, particularly as to the initial reference level price and the failure of the MISO tariff to count capacity sold in neighboring capacity markets toward meeting local clearing requirements in effect for the zones where capacity is physically located. On October 20, 2015, FERC held a technical conference on MISO's Planning Resource Auction, which in part addressed changes to MISO's auction design.

On December 31, 2015, FERC issued an order directing MISO to change key portions of its capacity market tariff, including restricting the ability of suppliers to place offers up to a MISO-developed opportunity cost. FERC mandated several changes to the auction, to be in place before the next planning resource auction in 2016. MISO is pursuing its own stakeholder reforms process to create different rules and implement price formation reforms as to its restructured retail market zones, including Zone 4. FERC expressly declined to rule on the portion of the complaint addressing the outcome of the 2015 Zone 4 auction, and instead stated that its investigation into the conduct of the auction remained pending. Rehearing is pending.

Revisions to MISO Capacity Construct — On November 20, 2015, FERC issued a final order denying the NRG’s request for rehearing of a 2012 FERC order approving the MISO capacity construct. NRG filed a petition for review of FERC’s decision with the D.C. Circuit on the grounds that FERC’s order denies merchant generators in MISO’s footprint any reasonable opportunity to recover their fixed costs. The eventual outcome of this proceeding could impact MISO’s attempts to redesign its capacity markets and thereby affect the value of NRG’s uncontracted assets within the MISO footprint.

Environmental Matters

The Registrants are subject to a wide range of environmental laws in the development, construction, ownership and operation of projects. These laws generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental laws have become increasingly stringent and the Registrants expect this trend to continue. The electric generation industry is facing new requirements regarding GHGs, combustion byproducts, water discharge and use, and threatened and endangered species. Future laws may require the addition of emissions controls or other environmental controls or impose restrictions on the operations of the Registrants' facilities, which could have a material effect on the Registrants' operations. Complying with environmental laws involves significant capital and operating expenses. The Registrants decide to invest capital for environmental controls based on the relative certainty of the requirements, an evaluation of compliance options, and the expected economic returns on capital.

A number of regulations with the potential to affect the Registrants and their facilities are in development, under review or have been recently promulgated by the EPA, including ESPS/NSPS for GHGs, NAAQS revisions and implementation and effluent guidelines. The Registrants are currently reviewing the outcome and any resulting impact of recently promulgated regulations and cannot fully predict such impact until legal challenges are resolved.

Ozone NAAQS — On October 26, 2015, the EPA promulgated a rule that reduces the ozone NAAQS to 0.070 ppm. This more stringent NAAQS will obligate the states to develop plans to reduce NO_x (an ozone precursor), which could affect some of the Registrants' units.

Clean Power Plan — The national and international attention (including the Paris Agreement) in recent years on GHG emissions has resulted in federal and state legislative and regulatory action. In October 2015, the EPA finalized the Clean Power Plan, or CPP, addressing GHG emissions from existing EGUs. The CPP rule faces numerous legal challenges that likely will take several years to resolve. On February 9, 2016, the U.S. Supreme Court stayed the CPP.
Effluent Limitations Guidelines — In November 2015, the EPA promulgated a rule revising the Effluent Limitations Guidelines for Steam Electric Generating Facilities, which will impose more stringent requirements (as individual permits are renewed) for wastewater streams from flue gas desulfurization, fly ash, bottom ash, and flue gas mercury control. The Registrants estimate that it would cost approximately $50 million over the next six years to comply with this rule at the Registrants' coal-fired plants. This regulation has been challenged and is subject to legal uncertainty. The Registrants decide to invest capital for environmental controls based on: the certainty of regulations; evaluation of different technologies; options to convert to gas; and the expected economic returns on the capital. Over the next several years, the Registrants will decide whether to proceed with these investments at each of the plants as permits are renewed based on, among other things, the legal certainty of the regulation and market conditions at that time.

See Item 15 — Note 16, Regulatory Matters, Note 17, Environmental Matters, and Note 18, Guarantees, to the Consolidated Financial Statements.

East

Maryland Environmental Regulations — In December 2014, MDE proposed a regulation regarding NO_x emissions from coal-fired electric generating units, which had it been finalized would have required by 2020 the Registrants (at each of the three Dickerson coal-fired units and the Chalk Point coal-fired unit that does not have an SCR) to either (1) install and operate an SCR; (2) retire the unit; or (3) convert the fuel source from coal to natural gas. In early 2015, the State of Maryland decided not to finalize the regulation as proposed. In November 2015, MDE finalized revised regulations to address future NO_x reductions, which although more stringent than previous regulations, will not cause the Registrants to spend capital to comply. As a result of the new regulations, on February 29, 2016, the Registrants notified PJM that they were withdrawing the standing deactivation notices for Dickerson Units 1, 2 and 3 and Chalk Point Units 1 and 2.

RGGI — The Registrants operate generating units in Maryland, Massachusetts and New York that are subject to RGGI, which is a regional cap and trade system. In 2013, each of these states finalized a rule that reduced and will continue to reduce the number of allowances, which the Registrants believe will increase the price of each allowance. The nine RGGI states are re-evaluating the program and may alter the rules to further reduce the number of allowances. The 2013 rules and/or revisions being currently contemplated could adversely impact the Registrants' results of operations, financial condition and cash flows.

Environmental Capital Expenditures

GenOn estimates that environmental capital expenditures from 2016 through 2020 required to comply with environmental laws will be approximately $68 million for GenOn, which includes $12 million for GenOn Americas Generation. The estimate for GenOn Americas Generation includes $9 million for GenOn Mid-Atlantic. The majority of these costs will be expended by the end of 2016.

See Item 15 — Note 8, Retirements or Mothballing of Generating Facilities, to the Consolidated Financial Statements.

Employees

As of December 31, 2015, GenOn had 1,689 employees of which 595 employees were part of GenOn Americas Generation and 440 employees were part of GenOn Mid-Atlantic, approximately 64.8%, 68.9% and 70.9% respectively, of whom were covered by bargaining agreements. During 2015, the Registrants did not experience any labor stoppages or labor disputes at any of their facilities.

Available Information

The Registrants’ annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to section 13(a) or 15(d) of the Exchange Act are available free of charge through NRG's website, www.nrg.com, as soon as reasonably practicable after they are electronically filed with, or furnished to the SEC.

Item 1A — Risk Factors
The Registrants are subject to the following factors that could have a material adverse effect on their future performance, results of operations, financial condition and cash flows. In addition, such factors could affect their ability to service indebtedness and other obligations, to raise capital and could affect their future growth opportunities. Also, see Cautionary Statement Regarding Forward Looking Information and Item 7 — Management's Narrative Analysis of the Results of Operations and Financial Condition of this Form 10-K.
Risks Related to the Operation of the Registrants' Businesses
GenOn is a wholly-owned subsidiary of NRG and is highly dependent on NRG for services under a master services agreement.
GenOn relies on NRG for its administrative and management functions and services including human resources-related functions, accounting, tax administration, information systems, legal services, treasury and planning, operations and asset management, risk and commercial operations, and other support services under a management services agreement. GenOn anticipates continuing to rely upon NRG to provide many of these services. If NRG terminates the management services agreement or defaults in the performance of its obligations under the agreement, GenOn may be unable to contract with a substitute service provider on similar terms or at all, and the costs of substituting service providers may be substantial. In addition, in light of NRG's familiarity with GenOn's assets, a substitute service provider may not be able to provide the same level of service due to lack of preexisting synergies. If GenOn cannot locate a service provider that is able to provide it with substantially similar services as NRG does under the management services agreement on similar terms, it would likely have a material adverse effect on GenOn's business, financial condition, results of operation and cash flows.
The interests of NRG as GenOn's equity holder may conflict with the interests of holders of debt.
GenOn is owned and controlled by NRG. The interests of NRG may not in all cases be aligned with the interests of the holders of GenOn's debt or the debt and lease obligations of GenOn's subsidiaries. If GenOn encounters financial difficulties or becomes unable to pay its debts as they mature, NRG does not have any liability for any obligations under the GenOn notes or the notes and lease obligations of the GenOn subsidiaries. In addition, NRG may have an interest in pursuing acquisitions, divestitures, financings or other transactions that, in its judgment, could enhance its equity investments, even though such transactions might involve risks to GenOn's business or the holders of GenOn's and its subsidiaries' debt. Furthermore, NRG may own businesses that directly or indirectly compete with GenOn. NRG also may pursue acquisition opportunities that may be complementary to NRG's business, and as a result, those acquisition opportunities may not be available to GenOn.
The Registrants' financial results are unpredictable because most of their generating facilities operate without long-term power sales agreements, and their revenues and results of operations depend on market and competitive forces that are beyond their control.

The Registrants provide energy, capacity, ancillary and other energy services from their generating facilities in a variety of markets and to bi-lateral counterparties, including participating in wholesale energy markets, entering into tolling agreements, sales of resource adequacy and participation in capacity auctions. The Registrants' revenues from selling capacity are a significant part of their overall revenues. The Registrants are not guaranteed recovery of their costs or any return on their capital investments through mandated rates.

The market for wholesale electric energy and energy services reflects various market conditions beyond the Registrants' control, including the balance of supply and demand, transmission congestion, competitors' marginal and long-term costs of production, the price of fuel, and the effect of market regulation. The price at which the Registrants can sell their output may fluctuate on a day-to-day basis, and their ability to transact may be affected by the overall liquidity in the markets in which the Registrants operate. These markets remain subject to regulations that limit their ability to raise prices during periods of shortage to the degree that would occur in a fully deregulated market. In addition, unlike most other commodities, electric energy can be stored only on a very limited basis and generally must be produced at the time of use. As a result, the wholesale power markets are subject to substantial price fluctuations over relatively short periods of time and can be unpredictable.

The Registrants' revenues, results of operations and cash flows are influenced by factors that are beyond their control, including those set forth above, as well as:

- the failure of market regulators to develop and maintain efficient mechanisms to compensate merchant generators for the value of providing capacity needed to meet demand;
- actions by regulators, ISOs, RTOs and other bodies that may artificially modify supply and demand levels and prevent capacity and energy prices from rising to the level necessary for recovery of the Registrants' costs, investment and an adequate return on investment;

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- environmental regulations and legislation;
- legal and political challenges to or changes in the rules used to calculate capacity payments in the markets in which the Registrants operate or the establishment of bifurcated markets, incentives, other market design changes or bidding requirements that give preferential treatment to new generating facilities over existing generating facilities or otherwise reduce capacity payments to existing generating facilities;
- the ability of wholesale purchasers of power to make timely payment for energy or capacity, which may be adversely affected by factors such as retail rate caps, refusals by regulators to allow utilities to recover fully their wholesale power costs and investments through rates, catastrophic losses and losses from investments by utilities in unregulated businesses;
- increases in prevailing market prices for fuel oil, coal, natural gas and emission allowances that may not be reflected in prices the Registrants receive for sales of energy;
- increases in electricity supply as a result of actions of the Registrants' current competitors or new market entrants, including the development of new generating facilities or alternative energy sources that may be able to produce electricity less expensively than the Registrants' generating facilities and improvements in transmission that allow additional supply to reach their markets;
- increases in credit standards, margin requirements, market volatility or other market conditions that could increase the Registrants' obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of future OTC regulations adopted pursuant to the Dodd-Frank Act;
- decreases in energy consumption resulting from demand-side management programs such as automated demand response, which may alter the amount and timing of consumer energy use;
- the competitive advantages of certain competitors, including continued operation of older power facilities in strategic locations after recovery of historic capital costs from ratepayers;
- existing or future regulation of the markets in which the Registrants operate by FERC, ISOs and RTOs, including any price limitations, non-performance penalties and other mechanisms to address some of the price volatility or illiquidity in these markets or the physical stability of the system;
- the Registrants' obligation under any default sharing mechanisms in RTO and ISO markets, such mechanisms exist to spread the risk of defaults by transmission owning companies or other RTO members across all market participants;
- regulatory policies of state agencies that affect the willingness of the Registrants' customers to enter into long-term contracts generally, and contracts for capacity in particular;
- access to contractors and equipment;
- changes in the rate of growth in electricity usage as a result of such factors as national and regional economic conditions and implementation of conservation programs;
- seasonal variations in energy and natural gas prices, and capacity payments; and
- seasonal fluctuations in weather, in particular abnormal weather conditions.

As discussed above, the market for wholesale electric energy and energy services reflects various market conditions beyond the Registrants' control, including the balance of supply and demand, the Registrants' competitors' marginal and long-term costs of production, and the effect of market regulation. The Registrants cannot ensure that higher earnings or price increases will result from industry retirements of coal-fired generating facilities or that higher earnings from their remaining facilities will offset or more than offset reduced earnings from facility deactivations.

Changes in the wholesale energy markets or in the Registrants' generating facility operations could result in impairments or other charges.

If the ongoing evaluation of the Registrants' business results in decisions to deactivate or dispose of additional facilities, the Registrants could have impairments or other charges. These evaluations involve significant judgments about the future. Actual future market prices, project costs and other factors could be materially different from current estimates.

The Registrants are exposed to the risk of fuel cost volatility because they must pre-purchase coal and oil.

Most of the Registrants' fuel contracts are at fixed prices with terms of two years or less. Although the Registrants purchase coal and oil based on expected requirements, they still face the risks of fuel price volatility if they require more or less fuel than expected.

The Registrants' cost of fuel may not reflect changes in energy and fuel prices in part because they must pre-purchase inventories of coal and oil for reliability and dispatch requirements, and thus the price of fuel may have been determined at an earlier date than the price of energy generated from the fuel. Similarly, the price the Registrants can obtain from the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel costs.

The Registrants are exposed to the risk of their fuel providers and fuel transportation providers failing to perform.

The Registrants purchase most of their coal from a limited number of suppliers. Because of a variety of operational issues, the Registrants' coal suppliers may not provide the contractual quantities on the dates specified within the agreements, or the deliveries may be carried over to future periods. Also, interruptions to planned or contracted deliveries to the Registrants' generating facilities can result from a lack of, or constraints in, coal transportation because of rail, river or road system disruptions, adverse weather conditions and other factors.

If the Registrants' coal suppliers do not perform in accordance with the agreements, the Registrants may have to procure higher priced coal in the market to meet their needs, or higher priced power in the market to meet their obligations. In addition, generally the Registrants' coal suppliers do not have investment grade credit ratings nor do they post collateral with the Registrants and, accordingly, the Registrants may have limited ability to collect damages in the event of default by such suppliers.

For the Registrants' oil-fired generating facilities, the Registrants typically purchase fuel from a limited number of suppliers. If the Registrants' oil suppliers do not perform in accordance with the agreements, the Registrants may have to procure higher priced oil in the market to meet their needs, or higher priced power in the market to meet their obligations. For the Registrants' gas-fired generating facilities, any curtailments or interruptions on transporting pipelines could result in curtailment of operations or increased fuel supply costs.

The Operation of the Registrants' generating facilities involves risks that could result in disruption, curtailment or inefficiencies in their operations.

The operation of the Registrants' generating facilities involves various operating risks, including, but not limited to:

- the output and efficiency levels at which those generating facilities perform;
- interruptions in fuel supply and quality of available fuel;
- disruptions in the delivery of electricity;
- adverse zoning;
- breakdowns or equipment failures (whether a result of age or otherwise);
- violations of permit requirements or changes in the terms of, or revocation of, permits;
- releases of pollutants to air, soil, surface water or groundwater;
- ability to transport and dispose of coal ash at reasonable prices;
- curtailments or other interruptions in natural gas supply;
- shortages of equipment or spare parts;
- labor disputes, including strikes, work stoppages and slowdowns;
- the aging workforce at many of the Registrants' facilities;
- operator errors;
- curtailment of operations because of transmission constraints;
- failures in the electricity transmission system, which may cause large energy blackouts;
- implementation of unproven technologies in connection with environmental improvements; and
- catastrophic events such as fires, explosions, floods, earthquakes, hurricanes or other similar occurrences.

These factors could result in a material decrease, or the elimination of, the revenues generated by the Registrants' facilities or a material increase in the Registrants' costs of operations.

The Registrants operate in a limited number of markets and a significant portion of revenues are derived from the PJM market. The effect of adverse developments in the markets, especially the PJM market, may be greater on the Registrants than on more geographically diversified competitors.

As of December 31, 2015, GenOn's generating capacity is 59% in PJM, 21% in CAISO, 12% in NYISO and ISO-NE and 6% in MISO, and GenOn Americas Generation's generating capacity is 59% in PJM, 13% in CAISO and 28% in NYISO and ISO-NE. As of December 31, 2015, all of GenOn Mid-Atlantic's generating capacity is in PJM. Adverse developments in these regions, especially in the PJM market, may adversely affect the Registrants. Further, the effect of such adverse regional developments may be greater on the Registrants than on more geographically diversified competitors.

The integration of the Capacity Performance product into the PJM market could lead to substantial changes in capacity income and non-performance penalties, which could have a material adverse effect on the Registrants' results of operations, financial condition and cash flows.

On June 9, 2015, FERC approved changes to PJM’s capacity market. Major elements of the approved changes to the Capacity Performance framework include the calculation of the bid cap, elimination of the 2.5% holdback for short lead-time resources, and substantial performance penalties on Capacity Performance resources that do not perform in real time during specific periods of high demand. The Registrants' Capacity Performance resources may not perform as planned, and the Registrants may experience substantial changes in capacity income and non-performance penalties, which could have a material adverse effect on the Registrants' results of operations, financial condition and cash flows.

The Registrants are exposed to possible losses that may occur from the failure of a counterparty to perform according to the terms of a contractual arrangement, particularly in connection with non-collateralized power hedges with financial institutions.

Failure of a counterparty to perform according to the terms of a contractual arrangement may result in losses to the Registrants. Specifically, GenOn Mid-Atlantic's credit exposures on power and gas hedges with financial institutions in excess of applicable collateral thresholds are senior unsecured obligations of such counterparties. Deterioration in the financial condition of such counterparties could result in their failure to pay amounts owed to GenOn Mid-Atlantic or to perform obligations or services owed to GenOn Mid-Atlantic beyond collateral posted.

Changes in technology may significantly affect the Registrants' generating business by making their generating facilities less competitive.

The Registrants generate electricity using fossil fuels at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in those technologies, or governmental incentives for renewable energies, will reduce their costs to levels that are equal to or below that of most central station electricity production.

The expected decommissioning and/or site remediation obligations of certain of the Registrants' generating facilities may negatively affect their cash flows.

Some of the Registrants' generating facilities and related properties are subject to decommissioning and/or site remediation obligations that may require material expenditures. Furthermore, laws and regulations may change to impose material additional decommissioning and remediation obligations on the Registrants in the future.

Terrorist attacks and/or cyber-attacks may result in the Registrants' inability to operate and fulfill their obligations, and could result in material repair costs.

As power generators, the Registrants face heightened risk of terrorism, including cyber terrorism, either by a direct act against one or more of their generating facilities or an act against the transmission and distribution infrastructure that is used to transport the power. Although the entire industry is exposed to these risks, the Registrants' generating facilities and the transmission and distribution infrastructure located in the PJM market are particularly at risk because of the proximity to major population centers, including governmental and commerce centers.

The Registrants rely on information technology networks and systems to operate their generating facilities, engage in asset management activities, and process, transmit and store electronic information. Security breaches of this information technology infrastructure, particularly through cyber-attacks and cyber terrorism, including by computer hackers, foreign governments and cyber terrorists, could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information related to their employees, vendors and counterparties. Confidential information includes banking, vendor, counterparty and personal identity information.

Systemic damage to one or more of the Registrants' generating facilities and/or to the transmission and distribution infrastructure could result in the inability to operate in one or all of the markets the Registrants serve for an extended period of time. If the Registrants' generating facilities are shut down, they would be unable to respond to the ISOs and RTOs or fulfill their obligations under various energy and/or capacity arrangements, resulting in lost revenues and potential fines, penalties and other liabilities. Pervasive cyber-attacks across the industry could affect the ability of ISOs and RTOs to function in some regions. The cost to restore the Registrants' generating facilities after such an occurrence could be material.

The Registrants' operations are subject to hazards customary to the power generating industry. The Registrants may not have adequate insurance to cover all of these hazards.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of high-speed rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks (such as earthquake, flood, storm surge, lightning, hurricane, tornado and wind), hazards (such as fire, explosion, collapse and machinery failure) are inherent risks in the Registrants' operations. The Registrants are also susceptible to terrorist attacks, including cyber-attacks, against their generating facilities or the transmission and distribution infrastructure that is used to transport their power. These hazards can cause significant injury to personnel or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in one or more of the Registrants being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. The Registrants do not maintain specialized insurance for possible liability resulting from a cyber-attack on their systems that may shut down all or part of the transmission and distribution system. However, the Registrants maintain an amount of insurance protection that they consider adequate and customary for merchant power producers. The Registrants cannot assure that their insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which they may be subject.

Lawsuits, regulatory proceedings and tax proceedings could adversely affect the Registrants' future financial results.

From time to time, the Registrants are named as a party to, or their property is the subject of, lawsuits, regulatory proceedings or tax proceedings. The Registrants are currently involved in various proceedings which involve highly subjective matters with complex factual and legal questions. Their outcome is uncertain. Any claim that is successfully asserted against the Registrants could require significant expenditures by them. Even if the Registrants prevail, any proceedings could be costly and time-consuming, could divert the attention of management and key personnel from their business operations and could result in adverse changes in their insurance costs.

Risks Related to Economic and Financial Market Conditions

The Registrants are exposed to systemic risk of the financial markets and institutions and the risk of non-performance of the individual lenders under GenOn's undrawn credit facilities.

Maintaining sufficient liquidity in the Registrants' business for maintenance and operating expenditures, capital expenditures and collateral is crucial in order to mitigate the risk of future financial distress to the Registrants. Accordingly, GenOn maintains a revolving credit facility with NRG to manage its expected liquidity needs and contingencies.

A negative market perception of the Registrants' value could impair their ability to issue or refinance debt.

A sustained downturn in general economic conditions, including low power and commodity prices, could result in an actual or perceived weakness in the Registrants' overall financial health.

A negative market perception of the Registrants' value could result in their inability to obtain and maintain an appropriate credit rating. In this event, they may be unable to access debt markets or refinance future debt maturities, or they may be required to post additional collateral to operate their business.

Adverse economic conditions could adversely affect the Registrants' business, financial condition, results of operations and cash flows.

Adverse economic conditions and declines in wholesale energy prices, partially resulting from adverse economic conditions, may impact the Registrants' earnings. The breadth and depth of these negative economic conditions had a wide-ranging impact on the U.S. business environment, including the Registrants' businesses. In addition, adverse economic conditions also reduce the demand for energy commodities. This reduced demand continues to impact the key domestic wholesale energy markets the Registrants serve. The combination of lower demand for power and increased supply of natural gas has put downward price pressure on wholesale energy markets in general, further impacting the Registrants' results. In general, economic and commodity market conditions will continue to impact the Registrants' unhedged future energy margins, liquidity, earnings growth and overall financial condition.

As financial institutions consolidate and operate under more restrictive capital constraints and regulations, including the Dodd-Frank Act, there could be less liquidity in the energy and commodity markets for hedge transactions and fewer creditworthy counterparties.

The Registrants hedge economically a substantial portion of their PJM coal-fired generation and certain of their other generation. A significant portion of their hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral, either for initial margin or for securing exposure as a result of changes in power or natural gas prices. Global financial institutions have been active participants in these energy and commodity markets. As global financial institutions consolidate and operate under more restrictive capital constraints and regulations, including the Dodd-Frank Act, there could be less liquidity in the energy and commodity markets, which could have a material adverse effect on the Registrants' ability to hedge economically and transact with creditworthy counterparties.

Many of the factors that cause changes in commodity prices are outside the Registrants' control and may materially increase their cost of producing power or lower the price at which they are able to sell their power.

The Registrants' generating business is subject to changes in power prices and fuel and emission costs, and these commodity prices are influenced by many factors outside the Registrants' control, including weather, seasonal variation in supply and demand, market liquidity, transmission and transportation inefficiencies, availability of competitively priced alternative energy sources, demand for energy commodities, production of natural gas, coal and crude oil, natural disasters, wars, embargoes and other catastrophic events, and federal, state and environmental regulation and legislation. In addition, significant fluctuations in the price of natural gas may cause significant fluctuations in the price of electricity. Significant fluctuations in commodity prices may affect the financial results and financial position by increasing the cost of producing power and decreasing the amounts the Registrants receive from the sale of power.

The Registrants' hedging activities will not fully protect them from fluctuations in commodity prices.

The Registrants engage in hedging activities related to sales of electricity and purchases of fuel and emission allowances. The income and losses from these activities are recorded as operating revenues and cost of operations. The Registrants may use forward contracts and other derivative financial instruments to manage market risk and exposure to volatility in prices of electricity, coal, natural gas, emissions and oil. The effectiveness of these hedges is dependent upon the correlation between the forward contracts and the other derivative financial instruments used as a hedge and the market risk of the asset or assets being hedged. The Registrants cannot provide assurance that these strategies will be successful in managing their price risks, or that they will not result in net losses to the Registrants as a result of future volatility in electricity, fuel and emission markets. Actual power prices and fuel costs may differ from expectations.

The Registrants hedging activities include natural gas derivative financial instruments that they use to hedge economically power prices for their baseload generation. The effectiveness of these hedges is dependent upon the correlation between power and natural gas prices in the markets where the Registrants operate. If those prices are not sufficiently correlated, the Registrants' financial results and financial position could be adversely affected.

Additionally, GenOn and GenOn Americas Generation expect to have an open position in the market, within their established guidelines, resulting from their fuel and emissions management activities. To the extent open positions exist, fluctuating commodity prices can affect their financial results and financial position, either favorably or unfavorably. As a result of these and other factors, the Registrants cannot predict the outcome that risk management decisions may have on their business, operating results or financial position. Although management devotes considerable attention to these issues, their outcome is uncertain.

The Registrants' policies and procedures cannot eliminate the risks associated with their hedging activities.

The risk management procedures the Registrants have in place may not always be followed or may not always work as planned. If any of the employees were able to violate the system of internal controls, including the risk management policy, and engage in unauthorized hedging and related activities, it could result in significant penalties and financial losses. In addition, risk management tools and metrics such as value at risk, gross margin at risk, and stress testing are partially based on historic price movements. If price movements significantly or persistently deviate from historical behavior, risk limits may not fully protect the Registrants from significant losses.

The Registrants' hedging and GenOn Americas Generation's fuel oil management activities may increase the volatility of the Registrants' U.S. GAAP financial results.

Derivatives from the Registrants' hedging and GenOn Americas Generation's fuel oil management activities are recorded on the balance sheets at fair value pursuant to the accounting guidance for derivative financial instruments. None of the Registrants' derivatives that are recorded at fair value are designated as hedges under this guidance, and changes in their fair values currently are recognized in earnings as unrealized gains or losses. As a result, the Registrants' U.S. GAAP financial results — including gross margin, operating income and balance sheet ratios — will, at times, be volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices.

Risks Related to Governmental Regulation and Laws

Policies at the national, regional and state levels to regulate GHG emissions, as well as climate change, could adversely impact the Registrants' results of operations, financial condition and cash flows.

On October 23, 2015, the EPA promulgated the final GHG emissions rules for new and existing fossil-fuel-fired electric generating units. The impact of further legislation or regulation of GHGs on the Registrants' financial performance will depend on a number of factors, including the level of GHG standards, the extent to which mitigation is required, the applicability of offsets, and the extent to which the Registrants would be entitled to receive CO_2 emissions credits without having to purchase them in an auction or on the open market.

The Registrants operate generating units in Maryland, Massachusetts and New York that are subject to RGGI, which is a regional cap and trade system. In 2013, each of these states finalized a rule that reduced and will continue to reduce the number of allowances, which the Registrants believe will increase the price of each allowance. The nine RGGI states are re-evaluating the program and may alter the rules to further reduce the number of allowances. The 2013 rules and/or revisions being currently contemplated could adversely impact the Registrants' results of operations, financial condition and cash flows.

California has a CO_2 cap and trade program for electric generating units greater than 25 MW. The impact on the Registrants depends on the cost of the allowances and the ability to pass these costs through to customers.

On October 26, 2015, the EPA promulgated a rule that reduces the ozone NAAQS to 0.070 ppm. This more stringent NAAQS will obligate the states to develop plans to reduce NO_x (an ozone precursor), which could affect some of the Registrants' units. EPA guidance for these plans is expected in late 2016.

Hazards customary to the power production industry include the potential for unusual weather conditions, which could affect fuel pricing and availability, the Registrants' route to market or access to customers, i.e., transmission and distribution lines, or critical plant assets. To the extent that climate change contributes to the frequency or intensity of weather related events, the Registrants' operations and planning process could be affected.

The Registrants' business is subject to substantial governmental regulation and may be adversely affected by legislative or regulatory changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements.

The Registrants' electric generation business is subject to extensive U.S. federal, state and local laws and regulation. Compliance with the requirements under these various regulatory regimes may cause the Registrants to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines, and/or civil or criminal liability. Public utilities under the FPA are required to obtain FERC acceptance of their rate schedules for wholesale sales of electric energy, capacity and ancillary services. The Registrants' assets make wholesale sales of electric energy, capacity and ancillary services in interstate commerce and are public utilities for purposes of the FPA, unless otherwise exempt from such status. FERC's orders that grant market-based rate authority to wholesale power marketers reserve the right to revoke or revise that authority if FERC subsequently determines that the seller can exercise market power in transmission or generation, create barriers to entry, or engage in abusive affiliate transactions. In addition, public utilities are subject to FERC reporting requirements that impose administrative burdens and that, if violated, can expose such public utilities to criminal and civil penalties or other risks.

The Registrants' market-based sales will be subject to certain rules prohibiting manipulative or deceptive conduct, and if any of the Registrants' generating companies are deemed to have violated those rules, they will be subject to potential disgorgement of profits associated with the violation, penalties, suspension or revocation of market-based rate authority. If such generating companies were to lose their market-based rate authority, such companies would be required to obtain FERC's acceptance of a cost-of-service rate schedule and could become subject to the significant accounting, record-keeping, and reporting requirements that are imposed on utilities with cost-based rate schedules. This could have a material adverse effect on the rates the Registrants are able to charge for power from their facilities.

Most of the Registrants' assets are operating as Exempt Wholesale Generators as defined under the PUHCA, or Qualifying Facilities as defined under the PURPA, as amended, and therefore are exempt from certain regulation under the PUHCA and the PURPA. If a facility fails to maintain its status as an Exempt Wholesale Generator or a Qualifying Facility or there are legislative or regulatory changes revoking or limiting the exemptions to the PUHCA, then the Registrants may be subject to significant accounting, record-keeping, access to books and records and reporting requirements and failure to comply with such requirements could result in the imposition of penalties and additional compliance obligations.

Substantially all of the Registrants' generation assets are also subject to the reliability standards promulgated by the designated Electric Reliability Organization (currently NERC) and approved by FERC. If the Registrants fail to comply with the mandatory reliability standards, they could be subject to sanctions, including substantial monetary penalties and increased compliance obligations. The Registrants will also be affected by legislative and regulatory changes, as well as changes to market design, market rules, tariffs, cost allocations, and bidding rules that occur in the existing regional markets operated by RTOs or ISOs, such as PJM. The RTOs/ISOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, mitigation, including price limitations, offer caps, and other mechanisms to address some of the volatility and the potential exercise of market power in these markets. These types of price limitations and other regulatory mechanisms may have a material adverse effect on the profitability of the Registrants' generation facilities acquired in the future that sell energy, capacity and ancillary products into the wholesale power markets. The regulatory environment for electric generation has undergone significant changes in the last several years due to state and federal policies affecting wholesale competition and the creation of incentives for the addition of large amounts of new renewable generation and, in some cases, transmission assets. These changes are ongoing, and the Registrants cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on the Registrants' business. In addition, in some of these markets, interested parties have proposed to re-regulate the markets or require divestiture of electric generation assets by asset owners or operators to reduce their market share. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, the Registrants' business prospects and financial results could be negatively impacted.

The CFTC, among other things, has regulatory oversight authority over the trading of swaps, futures and many commodities under the Commodity Exchange Act, or CEA. Since 2010, there have been a number of reforms to the regulation of the derivatives markets, both in the U.S. and internationally. These regulations, and any further changes thereto, or adoption of additional regulations, including any regulations relating to position limits on futures and other derivatives or relating to margin for derivatives, could negatively impact the Registrants' ability to hedge their portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting the Registrants' ability to utilize non-cash collateral for derivatives transactions.

The Registrants' businesses are subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods and other climatic events, could disrupt the Registrants' operations and cause them to incur significant costs in preparing for or responding to these effects. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs. Climate change could also affect the availability of a secure and economical supply of water in some locations, which is essential for the continued operation of the Registrants' generation plants.
GHG regulation could increase the cost of electricity, particularly power generated by fossil fuels, and such increases could have a depressive effect on regional economies. Reduced economic and consumer activity in the Registrants' service areas — both generally and specific to certain industries and consumers accustomed to previously lower cost power-could reduce demand for the power the Registrants generate.
The Registrants costs of compliance with environmental laws are significant and can affect their future operations and financial results.

The Registrants are subject to extensive and evolving environmental laws, particularly in regard to their coal-fired facilities. Environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge and cooling water systems, are generally becoming more stringent, which may require the Registrants to install controls or restrict their operations. Failure to comply with environmental requirements could require the Registrants to shut down or reduce production at their facilities or create liabilities. The Registrants incur significant costs in complying with these regulations and, if they fail to comply, could incur significant penalties. The Registrants' cost estimates for environmental compliance are based on existing regulations or their view of reasonably likely regulations and their assessment of the costs of labor and materials and the state of evolving technologies. The Registrants' decision to make these investments is often subject to future market conditions. Changes to the preceding factors, new or revised environmental regulations, litigation and new legislation and/or regulations, as well as other factors, could cause their actual costs to vary outside the range of their estimates, further constrain their operations, increase their environmental compliance costs and/or make it uneconomical to operate some of their facilities.

Federal, state and regional initiatives to regulate GHG emissions could have a material impact on the Registrants' financial performance and condition. The actual impact will depend on a number of factors, including the overall level of GHG reductions required under any such regulations, the final form of the regulations or legislation, and the price and availability of emission allowances if allowances are a part of any final regulatory framework.

The Registrants are required to surrender emission allowances equal to emissions of specific substances to operate their facilities. Surrender requirements may require purchase of allowances, which may be unavailable or only available at costs that would make it uneconomical to operate their facilities.

Certain environmental laws, including the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of remediating contamination. Some of the Registrants' facilities have areas with known soil and/or groundwater contamination. The Registrants could be required to spend significant sums to remediate contamination, regardless of whether they caused such contamination, (a) if there are releases or discoveries of hazardous substances at their generating facilities, at disposal sites they currently use or have used, or at other locations for which they may be liable, or (b) if parties contractually responsible to them for contamination fail to or are unable to respond when claims or obligations regarding such contamination arise.

The Registrants' coal-fired generating units produce certain byproducts that involve extensive handling and disposal costs and are subject to government regulation. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the costs of handling and disposing of these byproducts.

As a result of the coal combustion process, the Registrants produce significant quantities of ash at their coal-fired generating units that must be beneficially used or disposed of at sites permitted to handle ash. One of the Registrants' landfills in Maryland has reached design capacity and it is expected that another site in Maryland may reach full capacity in the next few years. As a result, the Registrants are further developing existing and new ash management facilities. However, the costs associated with developing new ash management facilities could be material, and the amount of time to complete such developments could extend beyond the time when new facilities are needed. Likewise, the facility for preparing ash for beneficial uses may not operate as expected; or the ash may not be marketed and sold as expected. Additionally, costs associated with third-party ash handling and disposal are material and could have a material adverse effect on the Registrants' financial performance and condition.

The Registrants also produce gypsum as a byproduct of the SO_2 scrubbing process at their coal-fired generating facilities, much of which is sold to third parties for use in drywall production. Should their ability to sell such gypsum to third parties be restricted as a result of the lack of demand or otherwise, their gypsum disposal costs could rise materially.

In April 2015, the EPA finalized the rule regulating byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. The Registrants are evaluating the impact of the new rule on their results of operations, financial condition and cash flows and have accrued their environmental and asset retirement obligations under the rule based on current estimates as of December 31, 2015.

The Registrants' business is subject to complex government regulations. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the prices at which the Registrants are able to sell the electricity they produce, the costs of operating their generating facilities or their ability to operate their facilities.

The majority of the Registrants' generation is sold at market prices under market-based rate authority granted by FERC. If certain conditions are not met, FERC has the authority to withhold or rescind market-based rate authority and require sales to be made based on cost-of-service rates. A loss of the Registrants' market-based rate authority could have a materially negative impact on their generating business.

Even when market-based rate authority has been granted, FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, when it determines that potential market power might exist and that the public interest requires such potential market power to be mitigated. In addition to direct regulation by FERC, most of the Registrants' facilities are subject to rules and terms of participation imposed and administered by various ISOs and RTOs. Although these entities are themselves ultimately regulated by FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on the Registrants' business. For example, ISOs and RTOs may impose bidding and scheduling rules, both to curb the potential exercise of market power and to ensure market functions. Such actions may materially affect the Registrants' ability to sell and the price they receive for their energy, capacity and ancillary services.

To conduct the Registrants' business, they must obtain and periodically renew licenses, permits and approvals for their facilities. These licenses, permits and approvals can be in addition to any required environmental permits. No assurance can be provided that they will be able to obtain and comply with all necessary licenses, permits and approvals for these facilities.

Conflicts may occur between reliability needs and environmental rules, particularly with increasingly stringent environmental restrictions. Without a consent decree or adjustments to permit requirements, which require long lead times to obtain, the Registrants remain subject to environmental penalties or liabilities that may occur as a result of operating in compliance with reliability requirements. Further, the Registrants could be subject to citizen suits in these types of circumstances, even if they have received a consent decree or permit adjustment exempting them from environmental requirements.

The Registrants cannot predict whether the federal or state legislatures will adopt legislation relating to the restructuring of the energy industry. There are proposals in many jurisdictions that would either roll back or advance the movement toward competitive markets for the supply of electricity, at both the wholesale and retail levels. In addition, any future legislation favoring large, vertically integrated utilities and a concentration of ownership of such utilities could affect the Registrants' ability to compete successfully, and their business and results of operations could be adversely affected. Similarly, any regulations or laws that favor new generation over existing generation could adversely affect their business.

Risks Related to Level of Indebtedness

The Registrants' substantial indebtedness and operating lease obligations could limit their ability to react to changes in the economy or the industry and prevent them from meeting or refinancing their obligations.

At December 31, 2015, GenOn's consolidated indebtedness was $2.8 billion and GenOn Americas Generation's consolidated indebtedness was $752 million. In addition, the present values of lease payments under the respective GenOn Mid-Atlantic and REMA operating leases were approximately $672 million and $376 million, respectively (assuming a 10% and 9.4% discount rate, respectively) and the termination values of the respective GenOn Mid-Atlantic and REMA operating leases were $946 million and $649 million, respectively.

The Registrants' substantial indebtedness and operating lease obligations could have important consequences for their liquidity, results of operations, financial position and prospects, including their ability to grow in accordance with their strategies. These consequences include the following:

- they may limit their ability to obtain additional debt for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes;
- a substantial portion of their cash flows from operations must be dedicated to the payment of rent and principal and interest on their indebtedness and will not be available for other purposes, including for working capital, capital expenditures, acquisitions and other general corporate purposes;
- the debt service requirements of their indebtedness and their lease obligations could make it difficult for them to satisfy or refinance their financial obligations;
- certain of the Registrants' borrowings, including borrowings under the NRG credit agreement, are at variable rates of interest, exposing the Registrants to the risk of increased interest rates;
- they may limit their flexibility in planning for and reacting to changes in the industry;
- they may place the Registrants at a competitive disadvantage compared to other, less leveraged competitors;
- GenOn's and GenOn Americas Generation's credit agreement with NRG contains restrictive covenants that limit their ability to engage in activities that may be in their long-term best interest; and
- the Registrants may be more vulnerable in a downturn in general economic conditions or in their business and they may be unable to carry out capital expenditures that are important to their long-term growth or necessary to comply with environmental regulations.

GenOn and its subsidiaries that are holding companies, including GenOn Americas Generation, may not have access to sufficient cash to meet their obligations if their subsidiaries, in particular GenOn Mid-Atlantic, are unable to make distributions.

GenOn and certain of its subsidiaries, including GenOn Americas Generation and NRG Americas, are holding companies and, as a result, are dependent upon dividends, distributions and other payments from their operating subsidiaries to generate the funds necessary to meet their obligations. In particular, a substantial portion of the cash from their operations is generated by GenOn Mid-Atlantic. The ability of certain of their subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At December 31, 2015, GenOn Mid-Atlantic and REMA did not satisfy the restricted payments test.

Each of GenOn and GenOn Americas Generation may be unable to generate sufficient cash to service their debt and leases and to post required amounts of cash collateral necessary to hedge economically market risk.

The ability of each of GenOn or GenOn Americas Generation to pay principal and interest on their debt and the rent on their leases depends on their future operating performance. If their cash flows and capital resources are insufficient to allow them to make scheduled payments on their debt, GenOn or GenOn Americas Generation may have to reduce or delay capital expenditures, sell assets, restructure or refinance. There can be no assurance that the terms of their debt or leases will allow these alternative measures, that the financial markets will be available to them on acceptable terms or that such measures would satisfy their scheduled debt service and lease rent obligations. If either GenOn or GenOn Americas Generation do not comply with the payment and other material covenants under their debt and lease agreements, they could default under their debt or leases.

The Registrants' asset management activities may require them to post collateral either in the form of cash or letters of credit. Although the Registrants seek to structure transactions in a way that reduces their potential liquidity needs for collateral, they may be unable to execute their hedging strategy successfully if they are unable to post the amount of collateral required to enter into and support hedging contracts.

GenOn and GenOn Americas Generation are active participants in energy exchange and clearing markets, which require a per-contract initial margin to be posted. The initial margins are determined by the exchanges through the use of proprietary models that rely on a variety of inputs and factors, including market conditions. They have limited notice of any changes to the margin rates. Consequently, they are exposed to changes in the per unit margin rates required by the exchanges and could be required to post additional collateral on short notice.

The terms of the Registrants' credit facilities and leases restrict their current and future operations, particularly their ability to respond to changes or take certain actions.

The Registrants' credit facilities and leases contain a number of restrictive covenants that impose significant operating and financial restrictions on them and may limit their ability to engage in acts that may be in their long-term best interest, including restrictions on their ability to:

- incur additional indebtedness;
- pay dividends or make other distributions;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- sell assets;
- incur liens;
- enter into transactions with affiliates;
- enter into sale-leaseback transactions; and
- consolidate, merge or sell all or substantially all of their assets.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The words "believe," "project," "anticipate," "plan," "expect," "intend," "estimate" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause the Registrants' actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the following:

- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- Volatile power supply costs and demand for power;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that the Registrants may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of the Registrants' risk management policies and procedures, and the ability of the Registrants' counterparties to satisfy their financial commitments;
- Counterparties' collateral demands and other factors affecting the Registrants' liquidity position and financial condition;
- The Registrants' ability to operate their businesses efficiently, manage capital expenditures and costs tightly, and generate earnings and cash flows from their asset-based businesses in relation to their debt and other obligations;
- The Registrants' ability to enter into contracts to sell power and procure fuel on acceptable terms and prices;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Government regulation, including compliance with regulatory requirements and changes in market rules, rates, tariffs and environmental laws and increased regulation of carbon dioxide and other GHG emissions;
- Price mitigation strategies and other market structures employed by ISOs or RTOs that result in a failure to adequately compensate the Registrants' generation units for all of their costs;
- The Registrants' ability to mitigate forced outage risk as they become subject to capacity performance in PJM and new performance incentives in ISO-NE;
- The Registrants' ability to borrow additional funds and access capital markets, as well as GenOn's substantial indebtedness and the possibility that the Registrants may incur additional indebtedness going forward;
- Operating and financial restrictions placed on the Registrants and their subsidiaries that are contained in the indentures governing GenOn's outstanding notes, and in debt and other agreements of certain of the Registrants' subsidiaries and project affiliates generally;
- The Registrants' ability to implement their strategy of developing and building new power generation facilities;
- The Registrants' ability to implement their strategy of finding ways to meet the challenges of climate change, clean air and protecting natural resources while taking advantage of business opportunities;
- The Registrants' ability to implement their strategy of increasing the return on invested capital through operational performance improvements and a range of initiatives at plants and corporate offices to reduce costs or generate revenues;
- The Registrants' ability to successfully evaluate investments in new business and growth initiatives;
- The Registrants' ability to successfully integrate and manage any acquired businesses; and
- The Registrants' ability to develop and maintain successful partnering relationships.

Forward-looking statements speak only as of the date they were made, and the Registrants undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors that could cause the Registrants' actual results to differ materially from those contemplated in any forward-looking statements included in this Annual Report on Form 10-K should not be construed as exhaustive.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)
Listed below are descriptions of Registrants' interests in facilities, operations and/or projects owned or leased as of December 31, 2015. The MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the Registrants' ownership position excluding capacity from inactive/mothballed units as of December 31, 2015. The following table summarizes the Registrants' power production and cogeneration facilities by region:

Name and Location of Facility	Power Market	% Owned		Net Generation Capacity (MW) [a]	Primary Fuel-type
Chalk Point, Aquasco, MD [b]	PJM	100.00		667	Coal
Chalk Point, Aquasco, MD	PJM	100.00		1,648	Natural Gas
Chalk Point, Aquasco, MD	PJM	100.00		42	Oil
Dickerson, MD [b]	PJM	100.00	[c]	537	Coal
Dickerson, MD	PJM	100.00	[c]	294	Natural Gas
Dickerson, MD	PJM	100.00	[c]	18	Oil
Morgantown, Newburg, MD	PJM	100.00	[c]	1,229	Coal
Morgantown, Newburg, MD	PJM	100.00	[c]	248	Oil
	Total GenOn Mid-Atlantic:			4,683	
Bowline, West Haverstraw, NY	NYISO	100.00		1,147	Natural Gas
Canal, Sandwich, MA	ISO-NE	100.00		1,112	Oil
Martha's Vineyard, MA	ISO-NE	100.00		14	Oil
Pittsburg, CA	CAISO	100.00		1,029	Natural Gas
Total GenOn Americas Generation:				7,985	
Aurora, IL	PJM	100.00		878	Natural Gas
Avon Lake, OH [d]	PJM	100.00		732	Coal
Avon Lake, OH	PJM	100.00		21	Oil
Blossburg, PA	PJM	100.00		19	Natural Gas
Brunot Island, Pittsburgh, PA	PJM	100.00		244	Natural Gas
Brunot Island, Pittsburgh, PA	PJM	100.00		15	Oil
Cheswick, Springdale, PA	PJM	100.00		565	Coal
Choctaw, French Camp, MS	SERC-Entergy	100.00		800	Natural Gas
Conemaugh, New Florence, PA [e]	PJM	16.45		280	Coal
Conemaugh, New Florence, PA [e]	PJM	16.45		2	Oil
Ellwood, Goleta, CA	CAISO	100.00		54	Natural Gas
Etiwanda, Rancho Cucamonga, CA	CAISO	100.00		640	Natural Gas
Gilbert, Milford, NJ	PJM	100.00		438	Natural Gas
Hamilton, East Berlin, PA	PJM	100.00		20	Oil
Hunterstown CCGT, Gettysburg, PA	PJM	100.00		810	Natural Gas
Hunterstown CTS, Gettysburg, PA	PJM	100.00		60	Natural Gas
Keystone, Shelocta, PA [e]	PJM	16.67		283	Coal
Keystone, Shelocta, PA [e]	PJM	16.67		2	Oil
Mandalay, Oxnard, CA	CAISO	100.00		560	Natural Gas
Mountain, Mount Holly Springs, PA	PJM	100.00		40	Oil
New Castle, West Pittsburg, PA [f]	PJM	100.00		325	Coal
New Castle, West Pittsburg, PA	PJM	100.00		3	Oil

Niles, OH	PJM	100.00	25	Oil
Ormond Beach, Oxnard, CA	CAISO	100.00	1,516	Natural Gas

Orrtana, PA	PJM	100.00	20	Oil
Portland, Mount Bethel, PA (g)	PJM	100.00	169	Oil
Sayreville, NJ	PJM	100.00	217	Natural Gas
Seward, New Florence, PA (h)	PJM	100.00	525	Coal
Shawnee, East Stroudsburg, PA	PJM	100.00	20	Oil
Shawville, PA (e)(i)	PJM	100.00	6	Oil
Shelby County, Neoga, IL (h)	MISO	100.00	352	Natural Gas
Titus, Birdsboro, PA	PJM	100.00	31	Oil
Tolna, Stewartstown, PA	PJM	100.00	39	Oil
Warren, PA	PJM	100.00	57	Natural Gas
	Total GenOn:		17,753	

(a) Actual capacity can vary depending on factors including weather conditions, operational conditions, and other factors.

(b) On February 29, 2016, NRG notified PJM that it was withdrawing the standing deactivation notices for Chalk Point Units 1 and 2 and Dickerson Units 1, 2 and 3

(c) GenOn Mid-Atlantic leases 100% interests in the Dickerson and Morgantown coal generation units through facility lease agreements expiring in 2029 and 2034, respectively. GenOn Mid-Atlantic owns 312 MW and 248 MW of peaking capacity at the Dickerson and Morgantown generating facilities, respectively. GenOn Mid-Atlantic operates the Dickerson and Morgantown facilities.

(d) GenOn intends to deactivate net generation capacity at the Avon Lake Unit 7 which has net generation capacity of 94 MW in April 2016. In 2015, GenOn suspended its plans to add natural gas capabilities to the Avon Lake facility.

(e) GenOn leases 100%, 16.67% and 16.45% interests in three Pennsylvania facilities (Shawville, Keystone and Conemaugh, respectively) through facility lease agreements expiring in 2026, 2034 and 2034, respectively. GenOn operates the Shawville, Keystone and Conemaugh facilities. The table includes GenOn's net share of the capacity of these facilities.

(f) GenOn has announced its intention to continue operations at the New Castle facility, which is currently in operation. GenOn intends to add natural gas capabilities at this facility, which is expected to be completed by the summer of 2016.

(g) GenOn deactivated Portland coal Units 1 and 2 (401 MW) effective December 1, 2015.

(h) These facilities are classified as Held For Sale as of December 31, 2015. Seward was sold on February 2, 2016, and the Shelby sale is expected to close during the first quarter of 2016.

(i) GenOn mothballed the coal-fired Units 1, 2, 3 and 4 at the Shawville generating facility (597 MW) beginning in May 2015, with plans to return those units to service no later than the fall of 2016 using natural gas.

Other Properties

The Registrants own or lease oil and gas pipelines that serve its generating facilities. GenOn leases other offices. The Registrants believe that their properties are adequate for their present needs. Except for the Conemaugh and Keystone facilities, the Registrants' interest as of December 31, 2015 is 100% for each property. The Registrants have satisfactory title, rights and possession to their owned facilities, subject to exceptions, which, in their opinion, would not have a material adverse effect on the use or value of the facilities.

Item 3 — Legal Proceedings (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

See Item 15 — Note 15, Commitments and Contingencies, to the Consolidated Financial Statements for discussion of the material legal proceedings to which the Registrants are a party.

Item 4 — Mine Safety Disclosures (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

Not applicable.

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PART II

Item 5 — Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

As a result of the NRG Merger, GenOn is a wholly owned subsidiary of NRG. All of GenOn’s common stock is held by its parent, NRG, and GenOn’s common stock is not publicly traded. GenOn Americas Generation and GenOn Mid Atlantic are indirect wholly owned subsidiaries of GenOn. All of GenOn Americas Generation’s membership interests are held by its parent, NRG Americas. All of GenOn Mid Atlantic’s membership interests are held by its parent, NRG North America. GenOn Americas Generation’s and GenOn Mid Atlantic’s membership interests are not publicly traded.

Item 6 — Selected Financial Data (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

Item 6 has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Item 7 — Management's Narrative Analysis of the Results of Operations and Financial Condition (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

Reference is made to the Registrants' Consolidated Statements of Operations to this Annual Report on Form 10-K, which presents the results of the Registrants' operations for the years ended December 31, 2015, 2014, and 2013. Also refer to Item 1 to this Form 10-K for additional discussion about the Registrants' business.

Environmental Matters, Regulatory Matters and Legal Proceedings

Details of environmental matters are presented in Item 15 — Note 17, Environmental Matters, to the Consolidated Financial Statements. Details of regulatory matters are presented in Item 15 — Note 16, Regulatory Matters, to the Consolidated Financial Statements. Details of legal proceedings are presented in Item 15 — Note 15, Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information relates to costs that may be material to the Registrants' financial results.

Electricity Prices

The following tables summarize average on-peak power prices for each of the major markets in which the Registrants operate for the years ended December 31, 2015, and 2014. Average on-peak power prices decreased primarily due to the decrease in natural gas prices for the year ended December 31, 2015, as compared to the same period in 2014.

	Average on Peak Power Price ($/MWh) [a]	
	For the year ended December 31,	
	2015	2014
MISO - Louisiana Hub [b]	$34.55	$48.72
NY J/NYC	46.42	71.72
NY A/West NY	42.07	58.16
NEPOOL	48.25	75.28
PEPCO (PJM)	46.48	70.69
PJM West Hub	41.97	61.15
CAISO - NP15	35.50	49.27
CAISO - SP15	32.45	48.39

(a) Average on peak power prices based on real time settlement prices as published by the respective ISOs.

(b) Region also transacts in PJM - West Hub.

Economic Gross Margin

The Registrants evaluate their operating performance using the measure of economic gross margin, which is not a GAAP measure and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. The Registrants believe that economic gross margin is useful to investors as it is a key operational measure reviewed by the Registrants' chief operating decision maker. Economic gross margin is defined as the sum of energy revenue, capacity revenue and other revenue, less cost of sales.

The economic gross margin does not include mark-to-market gains or losses on economic hedging activities, contract amortization, emission credit amortization, or other operating costs.

Consolidated Results of Operations
GenOn
2015 Compared to 2014
The following table provides selected financial information for GenOn:

(In millions except otherwise noted)	For the Year Ended December 31, 2015	2014	Change %
Operating Revenues			
Energy revenue [(a)]	$1,637	$2,286	(28)%
Capacity revenue [(a)]	802	908	(12)%
Mark-to-market for economic hedging activities	(112)	(150)	(25)%
Other revenues [(b)]	44	46	(4)%
Total operating revenues	2,371	3,090	(23)%
Operating Costs and Expenses			
Generation cost of sales [(a)]	995	1,451	(31)%
Mark-to-market for economic hedging activities	68	(3)	N/M
Contract and emissions credit amortization	(31)	(26)	19 %
Operations and maintenance	656	671	(2)%
Other cost of operations	91	84	8 %
Total cost of operations	1,779	2,177	(18)%
Depreciation and amortization	215	245	(12)%
Impairment losses	170	82	107 %
General and administrative	194	200	(3)%
Acquisition-related transaction and integration costs	—	4	(100)%
Total operating costs and expenses	2,358	2,708	(13)%
Loss on sale of assets	—	(6)	(100)%
Operating Income	13	376	(97)%
Other Income/(Expense)			
Other income, net	6	1	N/M
Gain on sale of equity-method investment	—	18	(100)%
Interest expense	(202)	(198)	2 %
Equity in earnings of unconsolidated affiliates	—	1	(100)%
Gain on debt extinguishment	65	—	N/M
Total other expense	(131)	(178)	(26)%
(Loss)/Income before income tax expense	(118)	198	N/M
Income tax (benefit)/expense	(3)	6	(150)%
Net (Loss)/Income	$(115)	$192	N/M
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$2.66	$4.41	(40)%
MWh sold (in thousands)	29,620	34,972	(15)%
MWh generated (in thousands)	29,727	35,420	(16)%

(a) Includes realized gains and losses from financially settled transactions.
(b) Includes unrealized trading gains and losses.
N/M - Not Meaningful

Economic Gross Margin

(In millions)	Year Ended December 31, 2015	2014	Change %
Energy revenue	$1,637	$2,286	(28)%
Capacity revenue	802	908	(12)%
Other revenues	44	46	(4)%
Generation revenue	2,483	3,240	(23)%
Cost of fuel	904	1,394	(35)%
Other cost of sales	91	57	60 %
Economic gross margin	$1,488	$1,789	(17)%

Economic gross margin was $1,488 million for the year ended December 31, 2015 and $1,789 million for the year ended December 31, 2014. The changes during the period relate to:

	(In millions)
Lower gross margin due to a 14% decrease in generation due to prior year winter weather conditions in the East, partially offset by increased generation at Hunterstown, Avon Lake, Choctaw and Ormond Beach	$(116)
Lower gross margin due to a decrease in contracted capacity volumes primarily due to the retirement of Coolwater and Osceola in 2015, combined with lower contracted capacity prices in CAISO driven primarily by the expiration of certain tolling arrangements, which were replaced with lower priced resource adequacy agreements	(57)
Lower gross margin due to a 3% decrease in PJM cleared auction capacity prices and a 6% decrease in PJM cleared auction capacity volumes	(54)
Lower gross margin due to a 17% decrease in average realized energy prices, partially offset by a 49% decrease in fuel costs due to significantly lower natural gas prices in 2015	(33)
Lower gross margin due to higher purchased capacity to meet capacity supply obligations for deactivated units	(26)
Lower gross margin due to the retirement of Coolwater and the sale of Kendall	(20)
Lower gross margin due to adjustments for fuel oil inventory resulting from the further decline in fuel prices through 2015	(7)
Other	12
	$(301)

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges. The breakdown of gains and losses included in operating revenues and operating costs and expenses are as follows:

(In millions)	Year Ended December 31, 2015	2014
Mark-to-market results in operating revenues		
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$(208)	$(331)
Net unrealized gains on open positions related to economic hedges	96	181
Total mark-to-market losses in operating revenues	$(112)	$(150)
Mark-to-market results in operating costs and expenses		
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	10	17
Net unrealized losses on open positions related to economic hedges	(78)	(14)
Total mark-to-market (losses)/gains in operating costs and expenses	$(68)	$3

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

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For the year ended December 31, 2015, the $112 million loss in operating revenues from economic hedge positions was driven by the reversal of previously recognized unrealized gains from electricity and natural gas contracts that settled during the period partially offset by an increase in the value of forward sales of electricity contracts as a result of decreases in power prices. The $68 million loss in operating costs and expenses from economic hedge positions was driven by a decrease in the value of forward purchases of fuel contracts as a result of decreases in forward fuel prices, partially offset by the reversal of previously recognized unrealized loss from fuel contracts that settled during the period.

For the year ended December 31, 2014, the $150 million loss in operating revenues from economic hedge positions was driven by the reversal of previously recognized unrealized gains from electricity and natural gas contracts that settled during the period, partially offset by an increase in the value of forward sales of natural gas contracts as a result of decreases in forward natural gas prices. The $3 million gain in operating costs and expenses from economic hedge positions was driven by the reversal of previously recognized unrealized losses from fuel contracts that settled during the period, partially offset by a decrease in the value of forward purchases of fuel contracts as a result of decreases in forward fuel prices.

In accordance with ASC 815, the following table represents the results of GenOn's financial and physical trading of energy commodities. The realized and unrealized financial and physical trading results are included in other operating revenues. GenOn's trading activities are subject to limits within its risk management policy.

	Year Ended December 31,	
(In millions)	2015	2014
Trading gains/(losses)		
Realized	$—	$2
Unrealized	—	(1)
Total trading gains	$—	$1

Operations and Maintenance
Operations and maintenance was $656 million for the year ended December 31, 2015, and $671 million for the year ended December 31, 2014. The decrease of $15 million was due primarily to increased outage hours at Chalk Point, New Castle and Cheswick during the prior year and the retirement of Coolwater in January of 2015, partially offset by increased outages at Bowline and Canal during the current year.

Other Cost of Operations
Other cost of operations was $91 million for the year ended December 31, 2015, and $84 million for the year ended December 31, 2014. The increase of $7 million was due primarily for favorable adjustments to AROs related to Shawville and Maryland ash in 2014 as a result in changes in estimates, partially offset by a property tax settlement received in 2015 for Morgantown and lower property tax rates for GenOn Mid-Atlantic.

Depreciation and Amortization
Depreciation and amortization expense was $215 million for the year ended December 31, 2015, and $245 million for the year ended December 31, 2014, primarily driven by accelerated depreciation expense in the prior year for assets that were deactivated in 2015.
Impairment Losses
Impairment losses of $170 million for the year ended December 31, 2015, primarily reflect an impairment of property, plant, and equipment of $134 million related to the Seward facility, $20 million related to the suspension of the oil conversion project at Portland, $8 million related to oil tanks located at the Pittsburg facility, and $8 million related to certain equipment. Impairment losses of $82 million for the year ended December 31, 2014, reflect the impairment of property, plant and equipment at the Osceola and Coolwater facilities. These losses are further described in Item 15 — Note 9, Impairments.
Gain on Sale of Equity-Method Investment
The $18 million gain on sale of equity-method investment for the year ended December 31, 2014, reflects the gain on the sale of Sabine, which was sold in December 2014.
Gain on Debt Extinguishment
The $65 million gain on debt extinguishment for the year ended December 31, 2015, is driven by the repurchase of GenOn senior notes due 2017, 2018 and 2020 and GenOn Americas Generation senior notes due 2021 and 2031 at a price below par value, combined with the write-off of unamortized premium balances. The debt reductions of senior unsecured notes executed in 2015 will result in annual future interest savings of approximately $25 million for GenOn, which includes $14 million of annual interest savings for GenOn Americas Generation.

GenOn Americas Generation

2015 Compared to 2014

The following table provides selected financial information for GenOn Americas Generation:

(In millions except otherwise noted)	For the Year Ended December 31, 2015	2014	Change %
Operating Revenues			
Energy revenue [(a)]	$1,483	$2,111	(30)%
Capacity revenue [(a)]	823	894	(8)%
Mark-to-market for economic hedging activities	(66)	(118)	(44)%
Other revenues [(b)]	25	42	(40)%
Total operating revenues	2,265	2,929	(23)%
Operating Costs and Expenses			
Generation cost of sales [(a)]	1,541	2,026	(24)%
Mark-to-market for economic hedging activities	57	6	N/M
Contract and emissions credit amortization	—	11	(100)%
Operations and maintenance	310	291	7 %
Other cost of operations	52	51	2 %
Total cost of operations	1,960	2,385	(18)%
Depreciation and amortization	74	72	3 %
Impairment losses	8	—	N/M
General and administrative	81	88	(8)%
Total operating costs and expenses	2,123	2,545	(17)%
Loss on sale of assets	—	(6)	(100)%
Operating Income	142	378	(62)%
Other Income/(Expense)			
Other income, net	2	1	100 %
Interest expense	(70)	(74)	(5)%
Gain on debt extinguishment	42	—	N/M
Total other expense	(26)	(73)	(64)%
Income before income tax expense	116	305	(62)%
Income tax	—	—	N/M
Net Income	$116	$305	(62)%
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$2.66	$4.41	(40)%
MWh sold (in thousands)	8,992	12,394	(27)%
MWh generated (in thousands)	9,094	12,440	(27)%

(a) Includes realized gains and losses from financially settled transactions.

(b) Includes unrealized trading gains and losses.

N/M - Not Meaningful

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Economic Gross Margin

	For the Year Ended December 31,		
(In millions)	2015	2014	Change %
Energy revenue	$1,483	$2,111	(30)%
Capacity revenue	823	894	(8)%
Other revenues	25	42	(40)%
Generation revenue	2,331	3,047	(23)%
Cost of fuel	474	434	9 %
Other cost of sales	1,067	1,592	(33)%
Economic gross margin	$790	$1,021	(23)%

Economic gross margin reflects the following pass-through amounts for GenOn Energy Management for services including the bidding and dispatch of the generating units, fuel procurement and the execution of contracts, including economic hedges, to reduce price risk:

	For the Year Ended December 31,	
(In millions)	2015	2014
Energy revenue	$665	$881
Capacity revenue	415	472
Other revenues	11	14
Generation revenue	1,091	1,367
Cost of fuel	(67)	198
Other cost of sales	(1,024)	(1,565)
Economic gross margin	$—	$—

Economic gross margin was $790 million for the year ended December 31, 2015, and $1,021 million for the year ended December 31, 2014. The changes during the period relate to:

	(In millions)
Lower gross margin at GenOn Mid-Atlantic due to a 31% decrease in generation as a result of prior year winter weather conditions and an increase in planned and unplanned outage hours in 2015	$(187)
Lower gross margin at GenOn Mid-Atlantic due to a 8% decrease in average realized prices, partially offset by a 25% decrease in fuel costs due to significantly lower natural gas prices in 2015	(37)
Lower gross margin due to a 6% decrease in PJM cleared auction capacity prices and a 6% decrease in PJM cleared auction capacity volumes	(35)
Lower gross margin due to a 30% decrease in generation at Canal due to increased planned outage hours in 2015	(24)
Lower gross margin due to adjustments for fuel oil inventory resulting from the further decline in fuel prices through 2015	(8)
Lower gross margin due to higher purchased capacity to meet capacity supply obligations for deactivated units	(6)
Higher gross margin due to decrease in fuel costs as natural gas prices dropped by 45% in New York and New England, partially offset by a 8% decrease in average realized prices	61
Higher gross margin due to increased capacity contracts for Bowline partially offset by a 14% decrease in contracted capacity prices in New York during 2015	10
Other	(5)
	$(231)

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges. The breakdown of gains and losses included in operating revenues and operating costs and expenses are as follows:

	For the Year Ended December 31,	
(In millions)	2015	2014
Mark-to-market results in operating revenues		
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$(205)	$(300)
Net unrealized gains on open positions related to economic hedges	139	182
Total mark-to-market losses in operating revenues	(66)	(118)
Mark-to-market results in operating costs and expenses		
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	12	12
Net unrealized losses on open positions related to economic hedges	(69)	(18)
Total mark-to-market losses in operating costs and expenses	$(57)	$(6)

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the year ended December 31, 2015, the $66 million loss in operating revenues from economic hedge positions was driven by the reversal of previously recognized unrealized gains from electricity and natural gas contracts that settled during the period partially offset by an increase in the value of forward sales of electricity contracts as a result of decreases in power prices. The $57 million loss in operating costs and expenses from economic hedge positions was driven by a decrease in the value of forward purchases of fuel contracts as a result of decreases in forward fuel prices partially offset by the reversal of previously recognized unrealized losses from fuel contracts that settled during the period.

For the year ended December 31, 2014, the $118 million loss in operating revenues from economic hedge positions was driven by the reversal of previously recognized unrealized gains from electricity and natural gas contracts that settled during the period, partially offset by an increase in the value of forward sales of natural gas contracts as a result of decreases in natural gas prices. The $6 million loss in operating costs and expenses from economic hedge positions was driven by a decrease in the value of forward purchases of fuel contracts as a result of decreases in forward fuel prices, partially offset by the reversal of previously recognized unrealized losses from fuel contracts that settled during the period.

In accordance with ASC 815, the following table represents the results of GenOn Americas Generation's financial and physical trading of energy commodities. The realized and unrealized financial and physical trading results are included in other operating revenues. GenOn Americas Generation's trading activities are subject to limits within the risk management policy.

	For the Year Ended December 31,	
(In millions)	2015	2014
Trading gains/(losses)		
Realized	$—	$2
Unrealized	—	(1)
Total trading gains	$—	$1

Operations and Maintenance

Operations and maintenance was $310 million for the year ended December 31, 2015 and $291 million for the year ended December 31, 2014. The increase of $19 million was primarily due to increased outage hours at Bowline and Canal during the current year, partially offset by decreased outage hours at Chalk Point during the current year and lower variable costs due to lower generation.

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Impairment Losses

Impairment losses of $8 million for the year ended December 31, 2015, reflect the impairment of oil tanks at the Pittsburg facility.

Gain on Debt Extinguishment

The $42 million gain on debt extinguishment for the year ended December 31, 2015, is driven by the repurchase of GenOn Americas Generation senior notes due 2021 and 2031 at a price below par value, combined with the write-off of unamortized premium balances. The debt reductions of senior unsecured notes executed in 2015 will result in annual future interest savings of approximately $14 million for GenOn Americas Generation.

GenOn Mid-Atlantic

2015 Compared to 2014

The following table provides selected financial information for GenOn Mid-Atlantic:

(In millions except otherwise noted)	Year Ended December 31, 2015	2014	Change %
Operating Revenues			
Energy revenue [(a)]	$623	$980	(36)%
Capacity revenue [(a)]	249	281	(11)%
Mark-to-market for economic hedging activities	(27)	(192)	(86)%
Other revenues	11	14	(21)%
Total operating revenues	856	1,083	(21)%
Operating Costs and Expenses			
Generation cost of sales [(a)]	325	453	(28)%
Mark-to-market for economic hedging activities	50	6	N/M
Contract and emissions credit amortization	—	10	(100)%
Operations and maintenance	212	217	(2)%
Other cost of operations	38	42	(10)%
Total cost of operations	625	728	(14)%
Depreciation and amortization	65	50	30%
General and administrative	58	64	(9)%
Total operating costs and expenses	748	842	(11)%
Operating Income	108	241	(55)%
Other Income/(Expense)			
Interest expense	(4)	(5)	(20)%
Total other expense	(4)	(5)	(20