DYNEGY INC.
Form 10-K
February 25, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý 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 ________

DYNEGY INC.
(Exact name of registrant as specified in its charter)

Commission File Number	State of Incorporation	I.R.S. Employer Identification No.
001-33443	Delaware	20-5653152

601 Travis, Suite 1400 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 507-6400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section12(b) of the Act:

Title of each class	Name of each exchange on which registered
Dynegy's common stock, $0.01 par value	New York Stock Exchange
Dynegy's 5.375% Series A Mandatory Convertible Preferred Stock, $0.01 par value	New York Stock Exchange
Dynegy's warrants, exercisable for common stock at an exercise price of $40 per share	New York Stock Exchange

Securities registered pursuant to Section12(g) of the Act:
None
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

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. Yes o No ý

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. Yes x No ¨

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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). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. x

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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

No x

As of June 30, 2015, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $3,478,775,830 based on the closing sale price as reported on the New York Stock Exchange.

Indicate by check mark whether the registrant filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

Number of shares outstanding of Dynegy Inc.'s class of common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 116,903,586 shares outstanding as of February 8, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant's 2016 Annual Meeting of Stockholders, which the registrant intends to file no later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, Items 10, 11, 12, 13 and 14 will be filed as part of an amendment to this Form 10-K no later than the end of the 120-day period.

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PART I

DEFINITIONS

Unless the context indicates otherwise, throughout this report, the terms “Dynegy,” “the Company,” “we,” “us,” “our,” and “ou
are used to refer to Dynegy Inc. and its direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy, Legacy Dynegy or Dynegy Holdings, LLC (“DH”) are clearly noted in such sections or areas and specific defined terms may be introduced for use only in those sections or areas. Further, as used in this Form 10-K, the abbreviations contained herein have the meanings set forth below.

CAA	Clean Air Act
CAISO	California Independent System Operator
CT	Combustion Turbine
CPUC	California Public Utility Commission
DNE	Dynegy Northeast Generation, Inc.
EGU	Electric Generating Units
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
HAPs	Hazardous Air Pollutants, as defined by the Clean Air Act
ICR	Installed Capacity Requirement
IMA	In Market Availability
IPCB	Illinois Pollution Control Board
IPH	IPH, LLC (formerly known as Illinois Power Holdings, LLC)
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MSCI	Morgan Stanley Capital International
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NM	Not Meaningful
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OTC	Over-The-Counter
PJM	PJM Interconnection, LLC
PRIDE	Producing Results through Innovation by Dynegy Employees
RCRA	Resource Conservation and Recovery Act of 1976
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	U.S. Securities and Exchange Commission

VaR	Value at Risk

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Item 1. Business

THE COMPANY

Dynegy began operations in 1984 and became incorporated in the State of Delaware in 2007. We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our primary business is the production and sale of electric energy, capacity and ancillary services from our fleet of 35 power plants in eight states totaling approximately 26,000 MW of generating capacity.

We operate a portfolio of generation assets that is diversified in terms of dispatch profile, fuel type and geography. Our Coal and IPH segments are fleets of baseload coal facilities, located in the Midwest and Massachusetts. Our Gas segment operates both intermediate and peaking natural gas plants, located in the Midwest, Northeast and California. The inherent cycling and dispatch characteristics of our intermediate combined cycle units allow us to take advantage of the volatility in market pricing in the day-ahead and hourly markets. This flexibility allows us to optimize our assets and provide incremental value. Peaking facilities are generally dispatched to serve load only during the highest periods of power demand, such as hot summer and cold winter days, or for local reliability needs. In addition to generating power, our generating facilities also receive capacity revenues through structured markets or bilateral tolling agreements, as local utilities and ISOs seek to ensure sufficient generation capacity is available to meet future market demands.

We sell electric energy, capacity and ancillary services primarily on a wholesale basis from our power generation facilities. We also serve residential, municipal, commercial and industrial customers primarily in MISO and PJM through our Homefield Energy and Dynegy Energy Services retail businesses, through which we provide retail electricity to approximately 931,000 residential customers and approximately 41,000 commercial, industrial and municipal customers in Illinois, Ohio and Pennsylvania. Wholesale electricity customers will primarily contract for rights to capacity from generating units for reliability reasons and to meet regulatory requirements. Ancillary services support the transmission grid operation, follow real-time changes in load and provide emergency reserves for major changes to the balance of generation and load. Retail electricity customers purchase energy and these related services in the deregulated retail energy market. We sell these products individually or in combination to our customers for various lengths of time from hourly to multi-year transactions.

We do business with a wide range of customers, including RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, power marketers, financial participants such as banks and hedge funds and residential, commercial and industrial end-users. Some of our customers, such as municipalities or integrated utilities, purchase our products for resale in order to serve their retail, commercial and industrial customers. Other customers, such as some power marketers, may buy from us to serve their own wholesale or retail customers or as a hedge against power sales they have made.

IPH and its direct and indirect subsidiaries are organized into ring-fenced groups in order to maintain corporate separateness from Dynegy and our other legal entities. Certain of the entities in the IPH segment, including Illinois Power Generating Company ("Genco"), have an independent director whose consent is required for certain corporate actions, including material transactions with affiliates. Further, entities within the IPH segment present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Furthermore, they pay liabilities from their own funds, conduct business in their own names and have restrictions on pledging their assets for the benefit of certain other persons.

Our principal executive office is located at 601 Travis Street, Suite 1400, Houston, Texas 77002, and our telephone number is (713) 507-6400. We file annual, quarterly and current reports, and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 100 F Street N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. Our SEC filings are also available to the public at the SEC's website at www.sec.gov. No information from such website is incorporated by reference herein. Our SEC filings are also available free of charge on our website at www.dynegy.com, as soon as reasonably practicable after those reports are filed with or furnished to the SEC. The contents of our website are not intended to be, and should not be considered to be, incorporated by reference into this Form 10-K.

Our Power Generation Portfolio
Our generating facilities are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	Region
Baldwin	1,815	Coal	Baseload	Baldwin, IL	MISO
Havana	434	Coal	Baseload	Havana, IL	MISO
Hennepin	294	Coal	Baseload	Hennepin, IL	MISO
Wood River (2)	465	Coal	Baseload	Alton, IL	MISO
Conesville (3)(4)	312	Coal	Baseload	Conesville, OH	PJM
Killen (3)(4)	204	Coal	Baseload	Manchester, OH	PJM
Kincaid	1,108	Coal	Baseload	Kincaid, IL	PJM
Miami Fort (3)	653	Coal	Baseload	North Bend, OH	PJM
Miami Fort CT	75	Oil	Peaking	North Bend, OH	PJM
Stuart (3)(4)	904	Coal	Baseload	Aberdeen, OH	PJM
Zimmer (3)	628	Coal	Baseload	Moscow, OH	PJM
Brayton Point (5)	1,528	Coal	Baseload	Somerset, MA	ISO-NE
Total Coal Segment	8,420				
Coffeen	915	Coal	Baseload	Coffeen, IL	MISO
Joppa/EEI (3)	802	Coal	Baseload	Joppa, IL	MISO
Joppa CT Units 1-3	165	Gas	Peaking	Joppa, IL	MISO
Joppa CT Units 4-5 (3)	56	Gas	Peaking	Joppa, IL	MISO
Newton	1,230	Coal	Baseload	Newton, IL	MISO
Duck Creek	425	Coal	Baseload	Canton, IL	MISO
E.D. Edwards (6)	585	Coal	Baseload	Bartonville, IL	MISO
Total IPH Segment (7)	4,178				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Moss Landing, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Moss Landing, CA	CAISO
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Dicks Creek	143	Gas	Peaking	Monroe, OH	PJM
Elwood (3)	788	Gas	Peaking	Elwood, IL	PJM
Fayette	696	Gas	Intermediate	Masontown, PA	PJM
Hanging Rock	1,439	Gas	Intermediate	Ironton, OH	PJM
Kendall	1,236	Gas	Intermediate	Minooka, IL	PJM
Lee	757	Gas	Peaking	Dixon, IL	PJM
Liberty	598	Gas	Intermediate	Eddystone, PA	PJM
Ontelaunee	567	Gas	Intermediate	Reading, PA	PJM
Richland	418	Gas	Peaking	Defiance, OH	PJM
Stryker	17	Oil	Peaking	Stryker, OH	PJM
Washington	678	Gas	Intermediate	Beverly, OH	PJM
Casco Bay	538	Gas	Intermediate	Veazie, ME	ISO-NE
Dighton	185	Gas	Intermediate	Dighton, MA	ISO-NE
Lake Road	857	Gas	Intermediate	Dayville, CT	ISO-NE
Masspower	280	Gas	Intermediate	Indian Orchard, MA	ISO-NE
Milford	569	Gas	Intermediate	Milford, CT	ISO-NE
Independence	1,126	Gas	Intermediate	Oswego, NY	NYISO
Total Gas Segment	13,586				
Total Fleet Capacity	26,184				

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(1) Unit capabilities are based on winter capacity and are reflected at our net ownership interest. We have not included units that have been retired or out of operation.
(2) On November 5, 2015, we announced plans to retire the final two units of the Wood River Power Station in mid-2016, subject to the approval of MISO.
(3) Co-owned with other generation companies.
(4) Facilities not operated by Dynegy.
(5) Scheduled to be retired from service in June 2017.
(6) Reflects the retirement of Edwards Unit 1 on January 1, 2016.
(7) We have transmission rights into PJM for certain of our IPH plants and, therefore, also offer power and capacity into PJM.

Business Strategies

Our business strategy is to create value through the optimization of our generation facilities, cost structure and financial resources.

Customer Focus. Our commercial outreach focuses on the needs of the customers and constituents we serve, including the end-use and wholesale customer, our market channel partners and the government agencies and regulatory bodies that represent the public interest. The insight provided through these relationships will influence our decisions aimed at meeting customer needs while optimizing the value of our business.

Currently, our commercial strategy seeks to optimize the value of our assets by locking in near-term cash flow while preserving the ability to capture higher values long-term as power markets improve. We may hedge portions of the expected output from our facilities with the goal of stabilizing near-term earnings and cash flow while preserving upside potential should commodity prices or market factors improve. Our wholesale organization and retail marketing teams are responsible for implementation of this strategy. These teams provide access to a broad portfolio of customers with varying energy and capacity requirements. There is a significant risk reduction from the relationship between our generation and our customer load which reduces the need to transact additional financial hedging products in the market. We expect to expand our retail load in areas in which our generation is located, thereby further reducing our risk profile and the need to transact additional financial hedging products.

Our wholesale origination efforts focus on marketing energy and capacity and providing certain associated services through structured transactions that are designed to meet our customers’ operating, financial and risk requirements while simultaneously compensating Dynegy appropriately. Additionally, we seek to capture the intrinsic and extrinsic value of our generation portfolios. We use a wide range of products and contracts such as tolling agreements, fuel supply contracts, capacity auctions, bilateral capacity contracts, power and natural gas swap agreements and other financial instruments to meet this objective.

Our retail marketing efforts focus on offering end-use customers energy products that range from fixed price and full requirements to flexible price and volume structures. Our goal is to deliver value beyond price by leveraging our experience in the energy markets to provide products that help customers make sound energy decisions. Establishing and maintaining strong relationships with retail energy channel partners is another key focus where personal service and transparent communication further build our retail brands as trusted suppliers. Our objective is to maximize the benefit to both Dynegy and our customers.

Dynegy operates in a complex and highly-regulated environment with multiple federal, state and local stakeholders, such as legislators, government agencies, industry groups, consumers and environmental advocates. Dynegy works with these stakeholders to encourage reasonable regulations, constructive market designs and balanced environmental policies. Our regulatory strategy includes a continuous process of advocacy, visibility, education and engagement. The ultimate goal is to find solutions that provide adequate cost recovery and incentivize investment, while providing safe, reliable, cost-effective and environmentally-compliant generation for the communities we serve.

Continuous Improvement. We are committed to operating all of our facilities in a safe, reliable, cost-efficient and environmentally compliant manner. We will continue to invest across all segments to maintain and improve the safety, reliability and efficiency of the fleet. The recent Acquisitions (as discussed below) are consistent with our commitment to operating safe, reliable, cost efficient and environmentally compliant power generation facilities, as these facilities have benefited from ongoing capital investment, preventative maintenance and rigorous inspection programs.

We continue to employ our cost and performance improvement initiative launched in 2011, known as PRIDE, which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. We launched “PRIDE Reloaded” in 2013 with a three-year target of

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$135 million in operating improvements, and $165 million in balance sheet efficiencies, and subsequently accelerated our original three-year target from 2016 to the end of 2015 - a full year ahead of schedule. In 2015, we exceeded our balance sheet target of $73 million by $81 million, and met our earnings before interest, taxes, depreciation and amortization ("EBITDA") target of $45 million.

On September 29, 2015, Dynegy announced "PRIDE Energized" - the next iteration of the Company's PRIDE program - targeted to deliver an incremental $250 million in EBITDA and $400 million in balance sheet improvements over the next three years (2016-2018). The benefits of "PRIDE Energized" are in addition to Dynegy's previously announced $130 million in acquisition synergies. The overall goal of the PRIDE program continues to be improving operating performance, cost structure and balance sheet efficiency to drive incremental cash flow benefits.

Capital Allocation. The power industry is a capital intensive, cyclical commodity business with significant commodity price volatility. As such, it is imperative to build and maintain a balance sheet with manageable debt levels supported by a flexible and diverse liquidity program. Our ongoing capital allocation priorities, first and foremost, are to maintain an appropriate leverage and liquidity profile and to make the necessary capital investments to maintain the safety and reliability of our fleet and to comply with environmental rules and regulations. We also evaluate other capital allocation options including investing in our existing portfolio, making potential acquisitions, reducing debt and returning capital to shareholders. Capital allocation decisions are generally based on alternatives that provide the highest risk adjusted rates of return.

We continue to focus on maintaining a diverse liquidity program to support our ongoing operations and commercial activities. This includes maintaining adequate cash balances, expanding our first lien collateral program to include additional hedging counterparties and having in place sufficient committed lines of credit to support our ongoing liquidity needs.

Recent Developments

Acquisitions

On February 25, 2016, we announced the acquisition of certain power generation facilities from International Power, S.A., a wholly owned subsidiary of ENGIE, through a joint venture with Energy Capital Partners ("ECP"), for a purchase price of approximately $3.3 billion. The acquisition includes approximately 8,700 MW located in ERCOT, PJM and ISO-NE. Of the 8,700 MW, approximately 8,000 MW are modern, efficient natural gas facilities with the remaining 700 MW being environmentally compliant coal facilities. We expect the transaction to close in the fourth quarter of 2016 after meeting customary conditions, including regulatory approvals from FERC, the Public Utility Commission of Texas, and the expiration of Hart-Scott-Rodino waiting periods.

The joint venture will be approximately 65 percent owned by a subsidiary of Dynegy and approximately 35 percent by affiliates of ECP, and will be a non-recourse subsidiary of Dynegy. In addition to the joint venture, ECP will also purchase approximately $150 million of Dynegy common stock.

Energy Capital Partners Purchase Agreements. On April 1, 2015 (the "EquiPower Closing Date"), pursuant to the terms of the stock purchase agreement dated August 21, 2014, as amended (the "ERC Purchase Agreement"), our wholly-owned subsidiary, Dynegy Resource II, LLC (the "ERC Purchaser") purchased 100 percent of the equity interests in EquiPower Resources Corp. ("ERC") from certain affiliates of Energy Capital Partners (collectively, the "ERC Sellers") thereby acquiring (i) five combined cycle natural gas-fired facilities in Connecticut, Massachusetts and Pennsylvania, (ii) a partial interest in one natural gas-fired peaking facility in Illinois, (iii) two gas and oil-fired peaking facilities in Ohio, and (iv) one coal-fired facility in Illinois (the "ERC Acquisition").

On the EquiPower Closing Date, in a related transaction, pursuant to a stock purchase agreement and plan of merger dated August 21, 2014, as amended (the "Brayton Purchase Agreement" and together with the ERC Purchase Agreement, the "ECP Purchase Agreements"), our wholly-owned subsidiary Dynegy Resource III, LLC (the "Brayton Purchaser" and together with the ERC Purchaser, the "ECP Purchasers") purchased 100 percent of the equity interests in Brayton Point Holdings, LLC ("Brayton") from certain affiliates of Energy Capital Partners (collectively, the "Brayton Sellers" and together with the ERC Sellers, the "ECP Sellers"), thereby acquiring a coal-fired facility in Massachusetts (the "Brayton Acquisition").

The ERC Acquisition and the Brayton Acquisition (collectively, the "EquiPower Acquisition") added approximately 6,300 MW of generation in Connecticut, Illinois, Massachusetts, Ohio and Pennsylvania for an aggregate base purchase price of approximately $3.35 billion in cash plus approximately $105 million in common stock of Dynegy, subject to certain adjustments. In aggregate, the resulting operations from the two coal-fired facilities acquired from the ECP Sellers are reported within our Coal segment, while related operations from the six natural gas-fired and two gas and oil-fired facilities are reported within our Gas segment. Please read Note 3—Acquisitions for further discussion.

Duke Midwest Purchase Agreement. On April 2, 2015 (the "Duke Midwest Closing Date"), pursuant to the terms of the purchase and sale agreement dated August 21, 2014, as amended (the "Duke Midwest Purchase Agreement"), our wholly-owned subsidiary Dynegy Resource I, LLC ("DRI") purchased 100 percent of the membership interests in Duke Energy Commercial Asset Management, LLC and Duke Energy Retail Sales, LLC, from two affiliates of Duke Energy Corporation (collectively, "Duke Energy"), thereby acquiring approximately 6,200 MW of generation including (i) three combined cycle natural gas-fired facilities located in Ohio and Pennsylvania, (ii) two natural gas-fired peaking facilities located in Ohio and Illinois, (iii) one oil-fired peaking facility located in Ohio, (iv) partial interests in five coal-fired facilities located in Ohio, and (v) a retail energy business for a base purchase price of approximately \$2.8 billion in cash (the "Duke Midwest Acquisition"), subject to certain adjustments. We operate two of the five coal-fired facilities, the Miami Fort and Zimmer facilities, with other owners operating the three remaining facilities. The operations from the retail energy business, and the five coal-fired and the one oil-fired facilities, acquired from Duke Energy are reported within our Coal segment, while related operations from the five natural gas-fired facilities are reported within our Gas segment. Please read Note 3—Acquisitions for further discussion.

Share Repurchase Program

On August 3, 2015, our Board of Directors authorized a share repurchase program for up to \$250 million, which was initiated in the third quarter of 2015 and completed in the fourth quarter of 2015. The shares were purchased in the open market at prevailing market prices. Please read Note 17—Capital Stock for further discussion.

Wood River Retirement

On November 5, 2015, Dynegy announced that it expects to retire the final two units at the 465-megawatt Wood River Power Station in Alton, Illinois in mid-2016, subject to the approval of MISO. The decision to retire the Wood River facility was the result of a strategic review performed in the third quarter of 2015, and was primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market.

PJM Capacity Performance

On June 9, 2015, FERC conditionally approved PJM's proposed Capacity Performance ("CP") product, and on July 22, 2015, FERC directed PJM to include CP-eligible demand response and energy efficiency products into the transitional auctions. CP was developed by PJM in response to concerns about plant performance and system reliability. CP features increased availability and flexibility requirements, incentives for performance, significant penalties for non-performance and the ability to bid in a risk premium and recover costs previously disallowed by PJM and the independent market monitor. In August and September of 2015, PJM conducted its capacity auctions for its new CP product. Please read Outlook for further discussion.

MARKET DISCUSSION

Our business operations are focused primarily on the wholesale power generation sector of the energy industry. We manage and report the results of our power generation business within three segments on a consolidated basis: (i) Coal, (ii) IPH and (iii) Gas. Please read Note 23—Segment Information for further information regarding revenues from external customers, operating income (loss) and total assets by segment. We continue to expect that, over the longer-term, power and capacity pricing will improve as natural gas prices increase, marginal generating units retire, and more stringent environmental regulations force the retirement of power generation units that have not invested in environmental upgrades. As a result, we believe our coal-fired baseload fleets are well positioned to benefit from higher power and capacity prices in the Midwest. We also expect these same factors will benefit our combined cycle units throughout the country through increased run-times and/or higher power prices as heat rates expand resulting in improved margins and cash flows. The discussion herein reflects capacities at our net ownership interest.

Coal Segment

Our Coal segment is comprised of 11 coal-fired power generation facilities located in Illinois, Massachusetts, and Ohio with a total generating capacity of 8,420 MW. Baldwin, Havana, Hennepin, and Wood River facilities, located in Illinois, operate in MISO with an aggregate net generating capacity of 3,008 MW. Conesville, Killen, Kincaid, Miami Fort, Stuart and Zimmer facilities, located in Illinois and Ohio, operate in PJM with an aggregate net generating capacity of 3,884 MW. Brayton Point facility, located in Massachusetts operates in ISO-NE and has an aggregate net generating capacity of 1,528 MW. Upon the completion of the planned retirements of our Brayton Point and Wood River facilities, our Coal segment will include 6,427 MW of generation capacity, of which 2,543 MW will operate in MISO and 3,884 MW will operate in PJM.

IPH Segment

Our IPH segment is comprised of five coal-fired power generation facilities located in Illinois with a total generating capacity of 4,178 MW, and primarily operates in MISO. Joppa, which is within the Electric Energy, Inc. (“EEI”) control area, is interconnected to Tennessee Valley Authority and Louisville Gas and Electric Company but primarily sells its capacity and energy to MISO. We currently offer a portion of our IPH segment generating capacity into PJM. As of June 1, 2016, our Coffeen, Duck Creek, E.D. Edwards and Newton facilities will have 937 MW, or 22 percent of IPH's capacity, that is electrically tied into PJM through pseudo-tie arrangements.

Gas Segment

Our Gas segment is comprised of 19 power generation facilities located in California, Illinois, Ohio, Pennsylvania, New York, Massachusetts, Connecticut and Maine, totaling 13,586 MW of electric generating capacity. Our Dicks Creek, Elwood, Fayette, Hanging Rock, Kendall, Lee, Liberty, Ontelaunee, Richland, Stryker and Washington facilities, located in Illinois, Ohio and Pennsylvania, operate in PJM with an aggregate net generating capacity of 7,337 MW. Our Casco Bay, Dighton, Lake Road, Masspower and Milford facilities, located in Maine, Massachusetts, and Connecticut, operate in ISO-NE and have an aggregate net generating capacity of 2,429 MW. Our Moss Landing and Oakland facilities, located in California, operate in CAISO with an aggregate net generating capacity of 2,694 MW. Our Independence facility, located in New York, operates in the Rest of State market and has an aggregate net generating capacity of 1,126 MW.

NERC Regions, RTOs and ISOs

In discussing our business, we often refer to NERC regions. The NERC and its regional reliability entities were formed to ensure the reliability and security of the electricity system. The regional reliability entities set standards for reliable operation and maintenance of power generation facilities and transmission systems. For example, each NERC region establishes a minimum operating reserve requirement to ensure there is sufficient generating capacity to meet expected demand within its region. Each NERC region reports seasonally and annually on the status of generation and transmission in such region.

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in most of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. RTOs and ISOs administer energy and ancillary service markets in the short term, usually day-ahead and real-time markets. Several RTOs and ISOs also ensure long-term planning reserves through monthly, semi-annual, annual and multi-year capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets in which we operate currently impose, and will likely continue to impose, bid and price limits or other similar mechanisms. NERC regions and RTOs/ISOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and RTOs/ISOs, their respective roles and responsibilities do not generally overlap.

In RTO and ISO regions with centrally dispatched market structures, all generators selling into the centralized market receive the same price for energy sold based on the bid price associated with the production of the last MWh that is needed to balance supply with demand within a designated zone or at a given location. Different zones or locations within the same RTO/ISO may produce different prices respective to other zones within the same RTO/ISO due to transmission losses and congestion. For example, a less efficient and/or less economical natural gas-fired unit may be needed in some hours to meet demand. If this unit's production is required to meet demand on the margin, its bid price will set the market clearing price that will be paid for all dispatched generation in the same zone or location (although the price paid at other zones or locations may vary because of transmission losses and congestion), regardless of the price that any other unit may have offered into the market. In RTO and ISO regions with centrally dispatched market structures and location-based marginal price clearing structures (e.g. PJM, NYISO, MISO, CAISO and ISO-NE), generators will receive the location-based marginal price for their output. The location-based marginal price, absent congestion, would be the marginal price of the most expensive unit needed to meet demand. In regions that are outside the footprint of RTOs/ISOs, prices are determined on a bilateral basis between buyers and sellers.

MISO. The MISO market includes all or parts of Iowa, Minnesota, North Dakota, Wisconsin, Michigan, Kentucky, Indiana, Illinois, Missouri, Arkansas, Mississippi, Texas, Louisiana, Montana, South Dakota and Manitoba, Canada. The MISO energy market is designed to ensure that all market participants have open-access to the transmission system on a non-discriminatory basis. MISO, as an independent RTO, maintains functional control over the use of the transmission system to ensure transmission circuits do not exceed their secure operating limits and become overloaded. MISO operates day-ahead and real-time energy markets using an LMP system which calculates a price for every generator and load point within MISO. This market is transparent, allowing generators and load serving entities to see real-time price effects of transmission constraints and the impacts of congestion at each pricing point. An independent market monitor is responsible for evaluating the performance of the markets and identifying conduct by market participants or MISO that may compromise the efficiency or distort the outcome of the markets.

The MISO's tariff provisions provide for a full planning year capacity product (June 1 - May 31) and recognize zonal deliverability capacity requirements. We anticipate that the potential retirement of marginal MISO coal capacity due to poor economics or expected environmental mandates and confirmed future capacity exports from MISO to PJM will affect MISO capacity and energy pricing for future planning years.

We participate in the MISO's annual and monthly FTR auctions to manage the cost of our transmission congestion, as measured by the congestion component of the LMP price differential between two points on the transmission grid across the market area.

In May 2015, three complaints were filed at FERC regarding the Zone 4 results for the 2015-2016 Planning Resource Auction ("PRA") conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General, and Southwestern Electric Cooperative, Inc., have challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds and requested changes to the MISO PRA structure going forward. Complainants have also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the 2015-2016 PRA. The Independent Market Monitor for MISO ("MISO IMM"), which was responsible for monitoring the MISO 2015-2016 PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the proposed remedies. Dynegy complied fully with the terms of the MISO Tariff in connection with the 2015-2016 PRA. In addition, the Illinois Industrial Energy Consumers filed a complaint at FERC against MISO on June 30, 2015 requesting prospective changes to the MISO tariff.

On October 1, 2015, FERC issued an order of non-public, formal investigation, stating that shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public informal investigation into whether market manipulation or other potential violations of FERC orders, rules and regulations occurred before or during the PRA. The Order noted that the investigation is ongoing, and that the order converting the informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. Further, FERC held a Staff-led technical conference on October 20, 2015 to obtain further information concerning potential changes to the MISO PRA structure going forward, including proposals made by complainants. The technical conference did not address the ongoing Office of Enforcement investigation.

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO Tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. Under the order, FERC found that the existing tariff provision which bases Initial Reference Levels for capacity supply offers on the estimated opportunity cost of exporting capacity to a neighboring region (for example, PJM) are no longer just and reasonable. Accordingly, FERC required MISO to set the Initial Reference Level for capacity at $0 per MW-day for the 2016-2017 PRA. Capacity suppliers may also request a facility-specific reference level from the MISO IMM. The order did not address the other arguments of the complainants regarding the 2015-2016 Auction, and stated that those issues remain under consideration and will be addressed in a future order.

PJM. The PJM market includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing a similar LMP system as described in MISO above. PJM operates day-ahead and real-time markets into which generators can bid to provide energy and ancillary services. PJM also administers a forward capacity auction, the RPM, which establishes long-term markets for capacity. We have participated in RPM base residual auctions for years up to and including PJM's Planning Year 2018-2019, which ends May 31, 2019. We also enter into bilateral capacity transactions. Beginning with Planning year 2016-2017, PJM has started to transition to Capacity Performance rules. Full transition of the capacity market to these new rules will occur by Planning Year 2020-2021. These rules are designed to improve system reliability and include penalties for underperforming units and rewards for overperforming units during shortage events. An independent market monitor continually monitors PJM markets to ensure a robust, competitive market and to identify any improper behavior by any entity.

PJM, like MISO, dispatches power plants to meet system energy and reliability needs, and settles physical power deliveries at LMPs. This value is determined by an ISO-administered auction process. The ISO-administered LMP energy markets consist of two separate and characteristically distinct settlement time frames, both of which are financially settled. The first is a day-ahead market and the second is a real-time dispatch and balancing market. Prices paid in these LMP energy markets, however, are affected by, among other things, (i) market mitigation measures, which can result in lower prices associated with certain generating units that are mitigated by shifting to a cost curve because they are deemed to have the potential to exercise locational market power, and (ii) the existing $1,000/MWh energy market price caps that are in place.

NYISO. The NYISO market includes the entire state of New York. The NYISO market dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Energy prices vary among the regional zones in the NYISO and are largely influenced by transmission constraints and fuel supply. NYISO offers a forward capacity market where capacity prices are determined through auctions. Strip auctions occur one to two months prior to the commencement of a six month seasonal planning period. Subsequent auctions provide an opportunity to sell excess capacity for the balance of the seasonal planning period or the prompt month. Due to the short term nature of the NYISO-operated capacity auctions and a relatively liquid OTC market for NYISO capacity products, our Independence facility sells a significant portion of its capacity through bilateral transactions. The balance is cleared through the seasonal and monthly capacity auctions.

ISO-NE. The ISO-NE market includes the six New England states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. ISO-NE also dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Energy prices vary among the participating states in ISO-NE and are largely influenced by transmission constraints and fuel supply. ISO-NE offers a forward capacity market where capacity prices are determined through auctions. ISO-NE implemented changes to its capacity market starting in FCA-8 for Planning Year 2017-2018, which included removal of the price floor and implementation of a minimum offer price rule for new resources to prevent buy-side market power. Additionally, a downward sloping demand curve as well as a “performance incentive” mechanism that will penalize underperforming units and reward overperforming units was implemented for FCA-9.

CAISO. The CAISO market covers approximately 90 percent of the State of California and operates a centrally cleared market for energy and ancillary services. Energy is priced utilizing an LMP system as described above. The capacity market is comprised of Standard and Flexible Resource Adequacy (“RA”) Capacity. Unlike other centrally cleared capacity markets, the CAISO resource adequacy market is a bilaterally traded market which typically transacts in monthly products as opposed to annual capacity products in other regions. On October 1, 2015, FERC approved CAISO’s request to create a voluntary competitive solicitation process that will replace the existing Capacity Procurement Mechanism (“CPM”) process to meet capacity deficiencies in the market. The CAISO plans to implement the competitive solicitation process by hosting monthly and intra-month voluntary auctions beginning on May 1, 2016. The first annual voluntary auction will take place in the fall of 2016 for 2017 RA capacity compliance period.

Reserve Margins

RTOs and ISOs are required to meet NERC planning and resource adequacy standards. The reserve margin, which is the amount of generation resources in excess of peak load, is a measure of resource adequacy and is also used to assess the supply-demand balance of a region. RTOs and ISOs use various mechanisms to help market participants meet their planning reserve margin requirements. Mechanisms range from centralized capacity markets administered by the ISO to markets where entities fulfill their requirements through a combination of long and short-term bilateral contracts between individual counterparties and self-generation.

MISO. MISO has a Planning Reserve Margin of 15.2 percent and has forecasted reserve margins of 16.1 percent for Planning Year 2016-2017. MISO has forecasted reserve margins of 16.6 percent for Planning Year 2017-2018, 16.0 percent for Planning Year 2018-2019, 15.2 percent for Planning Year 2019-2020, and 14.7 percent for Planning Year 2020-2021.

PJM. The Planning Reserve Margin is reviewed by PJM on an annual basis and is 15.6 percent for Planning Years 2016-2017. PJM has forecasted reserve margins based on deliverable capacity of 20.2 percent for Planning Year 2015-2016, 21.1 percent for Planning Year 2016-2017, 19.7 percent for Planning Years 2017-2018 and 19.8 percent for Planning Year 2018-2019.

NYISO. A Planning Reserve Margin of 17 percent was filed with the FERC for the New York Control Area for the period beginning May 1, 2015 and ending April 30, 2016. A Planning Reserve Margin of 17.5 percent for the period beginning May 1, 2016 and ending April 30, 2017 was filed with the FERC in January 2016. The actual amount of installed capacity is approximately 7 percentage points above NYISO’s current Planning Reserve Margin.

ISO-NE. Similar to PJM, ISO-NE will publish on an annual basis the Planning Reserve Margin, which ISO-NE calls the ICR. The ICR is the amount of capacity that must be procured over and above the load forecast for the applicable Planning Year. ISO-NE updates this information annually for each planning year during the Annual Reconfiguration Auctions. For Planning Year 2016-2017, the ICR is 15.6 percent based on data from the third Annual Reconfiguration Auction (ARA3). Forecasted margin for Planning Year 2016-2017 is approximately 25.2 percent based on ARA3 data. For Planning Years 2017-2018, 2018-2019 and 2019-2020, the ICRs are 15.1 percent (ARA2), 14.9 percent (ARA1) and 14.4 percent (FCA10), respectively.

CAISO. The CPUC requires a Planning Reserve Margin of at least 15 percent, and as of the latest summer assessment for the region in May 2015, the forecasted reserve margin was approximately 25.3 percent.

Contracted Capacity and Energy

We commercialize our Gas, Coal and IPH assets through a combination of bilateral wholesale and retail physical and financial power sales, fuel purchases and tolling arrangements. Uncontracted energy is sold in the various ISOs' day ahead and real-time markets. Capacity is commercialized through a combination of centrally cleared auctions and/or bilateral contracts. We use our retail activity to hedge a portion of the output from our MISO and PJM facilities.

MISO. Coal has contracted 913 MW of bilateral capacity transactions, while IPH has contracted 460 MW under wholesale agreements and 700 MW through retail sales for Planning Year 2016-2017. Our IPH segment has also sold a portion of its capacity into the PJM market, including 867 MW for Planning Year 2016-2017, 847 MW for Planning Year 2017-2018, and 835 MW for Planning Year 2018-2019.

PJM. Our Kendall facility has one tolling agreement for 85 MW that expires in 2017, and a 95 MW bilateral capacity transaction in Planning Year 2018-2019. Our Elwood facility has two 150 MW tolling agreements which expire in 2017. Our Ontelaunee facility has a five year 200 MW bilateral capacity transaction beginning in 2018.

NYISO. Due to the short-term, seasonal nature of the NYISO capacity auctions, we monetize the majority of Independence's capacity through bilateral trades. We have sold 1,124 MW of capacity for the Winter 2015-2016 planning period; 822 MW for the Summer 2016 planning period; 653 MW for the Winter 2016-2017 planning period; and 705 MW for the Summer 2017 planning period. Independence also supplies thermal energy to a third party through 2021.

ISO-NE. During the fourth quarter of 2015, Dynegy entered into a three year 75 MW bilateral capacity transaction covering Planning Years 2019-2020, 2020-2021, and 2021-2022. Dynegy also entered into a tolling agreement on its Casco Bay facility for the facility's full output for the calendar year 2016.

CAISO. We contracted RA capacity for Moss Landing Units 1 and 2, averaging 63 MW, 650 MW, 400 MW, and 850 MW for calendar years 2016, 2017, 2018, and 2019, respectively. We have also sold seasonal capacity for Moss Landing Units 1 and 2 opportunistically. Our Moss Landing Units 6 and 7 are contracted under tolling agreements and RA capacity contracts through 2016. Our Oakland facility operated under an RMR contract with the CAISO for 2015 and was given notice of extension for 2016.

Other

Market-Based Rates. Our ability to charge market-based rates for wholesale sales of electricity, as opposed to cost-based rates, is governed by FERC. We have been granted market-based rate authority for wholesale power sales from our exempt wholesale generator facilities, as well as wholesale power sales by our power marketing entities, Dynegy Power Marketing, LLC, Dynegy Marketing and Trade, LLC, Illinois Power Marketing Company ("IPM"), Dynegy Energy Services, LLC, and Dynegy Commercial Asset Management, LLC. Every three years, FERC conducts a review of our market-based rates and potential market power on a regional basis (known as the triennial market power review). In June 2016, we will file a market power update with FERC for our Southwest Region (CAISO) assets.

The Dodd-Frank Act. The U.S. Commodity Futures Trading Commission ("CFTC") has regulatory oversight authority over the trading of electricity and gas commodities, including financial products and derivatives, under the Commodity Exchange Act. On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). The Dodd-Frank Act increased the CFTC's regulatory authority on matters related to OTC derivatives, market clearing, position reporting and capital requirements. Dynegy has systems in place in order to monitor our swap activity and comply with Non-Swap Dealer/Major Swap Participant reporting requirements. We will continue to monitor all relevant developments and rulemakings that could impact our business.

ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations concerning environmental matters, including the discharge of materials into the environment. We are committed to operating within these laws and regulations and to conducting our business in an environmentally responsible manner. The environmental, legal and regulatory landscape continues to change and has become more stringent over time. This may create unprofitable or unfavorable operating conditions or require significant capital and operating expenditures. Further, changing interpretations of existing regulations may subject historical maintenance, repair and replacement activities at our facilities to claims of noncompliance.

The following is a summary of (i) the material federal, state and local environmental laws and regulations applicable to us and (ii) certain pending judicial and administrative proceedings related thereto. Compliance with these environmental laws and regulations and resolution of these various proceedings may result in increased capital expenditures and other environmental compliance costs, impairments, increased operations and maintenance expenses, increased Asset Retirement Obligations ("AROs"), and the imposition of fines and penalties, any of which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, if we are required to incur significant additional costs or expenses to comply with applicable environmental laws or to resolve a related proceeding, the incurrence of such costs or expenses may render continued operation of a plant uneconomical such that we may determine, subject to applicable laws and any applicable financing or other agreements, to reduce the plant’s operations to minimize such costs or expenses or cease to operate the plant completely to avoid such costs or expenses. Unless otherwise expressly noted in the following summary, we are not currently able to reasonably estimate the costs and expenses, or range of the costs and expenses, associated with complying with these environmental laws and regulations or with resolution of these judicial and administrative proceedings. For additional information regarding our pending environmental judicial and administrative proceedings, please read Note 16—Commitments and Contingencies for further discussion.

Our aggregate Coal segment expenditures (both capitalized and those included in operating expense) for compliance with laws and regulations related to the protection of the environment were approximately $72 million in 2015 compared to approximately $30 million in 2014. We estimate that our Coal segment's total expenditures for environmental compliance in 2016 will be approximately $126 million, with approximately $16 million in capital expenditures and $110 million in operating expenses.

Our aggregate IPH segment expenditures (both capitalized and those included in operating expense) for compliance with laws and regulations related to the protection of the environment were approximately $46 million in 2015 compared to approximately $50 million in 2014. We estimate that our IPH segment's total expenditures for environmental compliance in 2016 will be approximately $82 million, with approximately $50 million in capital expenditures and $32 million in operating expenses.

Our aggregate Gas segment expenditures for environmental compliance were approximately $9 million in 2015 compared to approximately $5 million in 2014. We estimate that our Gas segment's total expenditures for environmental compliance in 2016 will be approximately $15 million, with approximately $3 million in capital expenditures and $12 million in operating expenses.

The Clean Air Act

The CAA and comparable state laws and regulations relating to air emissions impose various responsibilities on owners and operators of sources of air emissions, which include requirements to obtain construction and operating permits, pay permit fees, monitor emissions, submit reports and compliance certifications, and keep records. The CAA requires that fossil-fueled electric generating plants meet certain pollutant emission standards and have sufficient emission allowances to cover sulfur dioxide ("SO_2") emissions and in some regions nitrogen oxide ("NO_x") emissions. In order to ensure continued compliance with the CAA and related rules and regulations, we utilize various emission reduction technologies. These technologies include flue gas desulfurization systems, baghouses and activated carbon injection or mercury oxidation systems on select units and electrostatic precipitators, selective catalytic reduction ("SCR") systems, low-NO_x burners and/or overfire air systems on all units. Additionally, our MISO coal-fired facilities mainly use low sulfur coal, which, prior to combustion, goes through a refined coal process to further reduce NO_x and mercury emissions.

Multi-Pollutant Air Emission Initiatives

Cross-State Air Pollution Rule. The "Cross-State Air Pollution Rule" ("CSAPR") to reduce emissions of SO_2 and NO_x from EGUs across the eastern U.S. took effect in 2015. The CSAPR imposes cap-and-trade programs within each affected state that limit emissions of SO_2 and NO_x at levels to help downwind states attain and maintain compliance with the 1997 ozone National Ambient Air Quality Standards ("NAAQS") and the 1997 and 2006 fine particulate matter ("PM2.5") NAAQS.

Under the CSAPR, our generating facilities in Illinois, Ohio, New York and Pennsylvania are subject to cap-and-trade programs for ozone-season emissions of NO_x from May 1 through September 30 and for annual emissions of SO_2 and NO_x. The CSAPR requirements applicable to SO_2 emissions from our affected EGUs will be implemented in two stages with fewer SO_2 emission allowances allocated in the second phase, which will begin in 2017.

In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded to the EPA for reconsideration certain CSAPR emissions budgets for select states. The court rejected all other challenges to the CSAPR. In November 2015, the EPA issued a proposed CSAPR update rule to address the court's remand decision regarding the CSAPR ozone-season NO_x emissions budgets and to reduce those budgets beginning in 2017 to attain and maintain compliance with the 2008 ozone NAAQS. Reduced ozone-season NO_x allowance allocations generally will require affected facilities to reduce NO_x emissions or acquire additional allowances. While the cost of our compliance with the proposed CSAPR update rule is uncertain at this time, the rule is anticipated to increase the compliance costs of our coal-fired EGUs in Illinois and Ohio.

Based on our current projections of emissions for 2016, we anticipate that our Coal segment facilities will have an adequate number of SO_2 and NOx (ozone season and annual) allowances allocated in 2016 under the CSAPR, and that our IPH segment facilities will have an adequate number of SO_2 allowances, but will need to acquire a limited number of NO_x (ozone season and annual) allowances. We anticipate that our Gas segment facilities will need to acquire a limited number of NO_x (ozone season and annual) and SO_2 allowances.

Mercury/HAPs. The EPA's Mercury and Air Toxic Standards ("MATS") rule for EGUs, which was issued in 2011, established numeric emission limits for mercury, non-mercury metals, and acid gases as well as work practice standards for organic HAPs. Compliance with the MATS rule was required by April 16, 2015, unless an extension was granted in accordance with the CAA.

In June 2015, the U.S. Supreme Court found that the EPA failed to properly consider costs when it promulgated the MATS rule. The U.S. Court of Appeals for the District of Columbia Circuit then remanded the MATS rule to the EPA without vacating the rule. In December 2015, the EPA issued a proposed supplemental finding that the consideration of cost does not alter the Agency's conclusion that it is appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112. The EPA anticipates making a final finding regarding costs under the MATS rule by April 2016. We believe the EPA's reconsideration of the MATS rule costs will have little or no bearing on the power markets, given that the majority of EGU retirement and investment decisions related to the MATS rule have already been made or are in process. Furthermore, EGUs are or will be subject to a number of other environmental regulations that also affect retirement and investment decisions, such as the Coal Combustion Residuals ("CCR") rule, the CSAPR, the ELG rule and the Clean Power Plan.

We are in compliance with the MATS rule emission limits and continue to monitor the performance of our units and evaluate approaches to optimize compliance strategies. In accordance with our MISO tariff obligations, we requested a one-year extension of the MATS compliance deadline for Edwards Unit 1, which the Illinois EPA approved in April 2015. We previously had committed to retire Edwards Unit 1 as soon as the MISO allowed, which occurred on January 1, 2016.

The EPA revised the MATS rule in November 2014 to require use of the extensive startup and shutdown monitoring instrumentation. Because installation of such instrumentation by April 2015 was not possible, we filed MATS extension requests regarding the startup and shutdown instrumentation requirements for each of our Illinois and Ohio coal-fired facilities. However, in January 2015, the EPA proposed to correct its November 2014 MATS rule revisions in a manner that, if adopted, would eliminate the need for our startup and shutdown instrumentation extension requests.

Illinois MPS. In 2007, our MISO coal-fired facilities elected to demonstrate compliance with the Illinois Multi-Pollutant Standards ("MPS"), which require compliance with NO_x, SO_2 and mercury emissions limits. We are in compliance with the MPS.

IPH Variance. The MPS SO_2 limits started in 2010 for our IPH coal-fired facilities and would have declined in 2014 and 2015 and required compliance with the final SO_2 limit beginning in 2017. However, the IPCB has granted IPH a variance which provides additional time for economic recovery and related power price improvements necessary to support the installation of flue gas desulfurization ("FGD") systems at the Newton facility such that the IPH coal-fired fleet can meet the MPS system-wide SO_2 limit. The IPCB approved the proposed plan to restrict the SO_2 emissions through 2014 to levels lower than those required by the MPS to offset any environmental impact from the variance. The IPCB's order also included a schedule of milestones for completion of various aspects of the installation of the Newton FGD systems. The first milestone relating to the engineering design was completed in July 2015, while the last milestone relates to major equipment components being placed into final position on or before September 1, 2019. The variance also requires additional environmental protections in the form of enforceable commitments to cap IPH's SO_2 emissions through December 31, 2020, retire Edwards Unit 1 as soon as permitted by the MISO, and, during the variance period, use only low sulfur coal at the Newton, Edwards and Joppa facilities and maintain operation of the existing scrubbers at the Duck Creek and Coffeen facilities to achieve a 98 percent annual average SO_2 removal rate. In December 2015, the EPA approved the variance as part of the Illinois regional haze state implementation plan ("SIP"). In February 2016, Genco issued a notice to the third party contractor constructing the FGD systems directing them to temporarily suspend a portion of the work being performed.

Other Air Emission Initiatives

NAAQS. The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has established NAAQS for six such pollutants, including ozone, SO_2 and PM2.5. Each state is responsible for developing a plan (a SIP) that will attain and maintain the NAAQS. These plans may result in the imposition of emission limits on our facilities.

The EPA's initial area designations for the 2010 one-hour SO_2 NAAQS included designating as nonattainment the area where our IPH segment's Edwards facility is located. In January 2015, Illinois Power Resources Generating, LLC ("IPRG") entered a Memorandum of Agreement ("MOA") with the Illinois EPA that voluntarily committed to early limits on Edwards' allowable one-hour SO_2 emission rate that, in conjunction with reductions to be imposed by the state on other sources, will enable the Illinois EPA to demonstrate attainment with the one-hour SO_2 NAAQS in the Edwards

area. In October 2015, the IPCB approved the Illinois EPA's proposed rule to meet the SO_2 NAAQS, which included the emission limits on Edwards as agreed to in the MOA.
The EPA will complete area designations for the 2010 one-hour SO_2 NAAQS in up to three additional rounds over the period July 2016 to December 31, 2020. The round of area designations due by July 2016 includes areas involving our Newton, Hennepin, Joppa and Wood River facilities and our co-owned Zimmer facility. In February 2016, the EPA provided notice of its intent to designate the areas where each of these facilities is located as unclassifiable/attainment.

The EPA issued a final rule in October 2015 lowering the ozone NAAQS from 75 to 70 parts per billion. The EPA anticipates designating attainment and nonattainment areas for the 2015 ozone NAAQS by October 2017. Various parties have filed lawsuits challenging the 2015 ozone NAAQS.

In May 2015, the EPA issued a final rule that eliminates existing exemptions in the SIPs of many states, including Illinois and Ohio, for emissions during periods of startup, shutdown or malfunction ("SSM"). Affected states are required to submit corrective SIP revisions by November 2016. Various parties have filed lawsuits challenging the EPA's SSM SIP rule.

The nature and scope of potential future requirements concerning the 2010 one-hour SO_2 NAAQS, 2015 ozone NAAQS and SSM SIP rule cannot be predicted with confidence at this time. A future requirement for additional emission reductions at any of our coal-fired generating facilities may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

New Source Review and Clean Air Act Matters

New Source Review. Since 1999, the EPA has been engaged in a nationwide enforcement initiative to determine whether coal-fired power plants failed to comply with the requirements of the New Source Review and New Source Performance Standard provisions under the CAA when the plants implemented modifications. The EPA's initiative focuses on whether projects performed at power plants triggered various permitting requirements, including the need to install pollution control equipment.

In 2012, the EPA issued a Notice of Violation ("NOV") alleging that projects performed in 1997, 2006 and 2007 at the Newton facility violated Prevention of Significant Deterioration ("PSD"), Title V permitting and other requirements. The NOV remains unresolved. We believe our defenses to the allegations described in the NOV are meritorious. A decision by the U.S. Court of Appeals for the Seventh Circuit in 2013 held that similar claims older than five years were barred by the statute of limitations. If not overturned, this decision may provide an additional defense to the allegations in the Newton facility NOV.

Wood River CAA Section 114 Information Request. In 2014, we received an information request from the EPA concerning our Wood River facility's compliance with the Illinois SIP and associated permits. We responded to the EPA's request and believe that there are no issues with Wood River's compliance, but we are unable to predict the EPA's response, if any. We plan to retire our Wood River facility in mid-2016, subject to the approval of MISO.

CAA Notices of Violation. In December 2014, the EPA issued a NOV alleging violation of opacity standards at the Zimmer facility, which we co-own and operate. The EPA previously had issued NOVs to Zimmer in 2008 and 2010 alleging violations of the CAA, the Ohio SIP and the station's air permits involving standards applicable to opacity, SO_2, sulfuric acid mist and heat input. The NOVs remain unresolved. In December 2014, the EPA also issued NOVs alleging violations of opacity standards at the Stuart and Killen facilities, which we co-own but do not operate.

Edwards CAA Citizen Suit. In 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility. The District Court has scheduled the trial date for October 2016. We dispute the allegations and will defend the case vigorously.

The Clean Water Act

The Clean Water Act ("CWA") and analogous state laws regulate water withdrawals and wastewater discharges at our power generation facilities. Our facilities are authorized to discharge pollutants to waters of the United States by National Pollutant Discharge Elimination System ("NPDES") permits, which contain discharge limits and monitoring, recordkeeping and reporting requirements. NPDES permits are limited to five years in duration but can be renewed.

Cooling Water Intake Structures. Cooling water intake structures at our facilities are regulated under CWA Section 316(b). This provision generally requires that the location, design, construction and capacity of cooling water intake structures reflect best technology available ("BTA") for minimizing adverse environmental impacts. Historically, permitting authorities have developed and implemented BTA standards through NPDES permits on a case-by-case basis using best professional judgment.

In 2014, the EPA issued a final rule for cooling water intake structures at existing facilities. The rule establishes seven BTA alternatives for reducing impingement mortality, including modified traveling screens, closed-cycle cooling, a numeric impingement standard, or a site-specific determination. For entrainment, the permitting authority is required to establish a case-by-case standard considering several factors, including social costs and benefits. Compliance with the rule's entrainment and impingement mortality standards is required as soon as practicable, but will vary by site depending on several different factors, including determinations made by the state permitting authority and the timing of renewal of a facility's NPDES permit. Various environmental groups and industry groups filed petitions for judicial review of the EPA's final rule.

At this time, we estimate the cost of our compliance with the cooling water intake structure rule will be approximately $17 million, with the majority of spend in the 2020-2023 timeframe. This estimate excludes Moss Landing, which is discussed in “California Water Intake Policy” below. Our estimate could change materially depending upon a variety of factors, including site-specific determinations made by states in implementing the rule, the results of impingement and entrainment studies required by the rule, the results of site-specific engineering studies, and the outcome of litigation concerning the rule.

California Water Intake Policy. The California State Water Board (the “State Water Board”) adopted its Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the “Policy”) in 2010. The Policy requires existing power plants to reduce water intake flow rate to a level commensurate with that which can be achieved by a closed cycle cooling system or if that is not feasible, to reduce impingement mortality and entrainment to a level comparable to that achieved by such a reduced water intake flow rate using operational or structural controls, or both. Compliance with the Policy, as adopted, would be required at our Gas segment’s Moss Landing facility by December 31, 2017.

In 2014, we entered into a settlement agreement with the State Water Board that would resolve a lawsuit we filed with other California power plant owners challenging the Policy. In accordance with the settlement agreement, following a public rulemaking process, in April 2015, the State Water Board approved an amendment to the Policy extending the compliance deadline for all four units at Moss Landing from December 31, 2017 to December 31, 2020. Under the settlement agreement, we are required to implement operational control measures at Moss Landing for purposes of reducing impingement mortality and entrainment, including the installation of variable speed drive motors on the circulating water pumps for Units 1 and 2 by year end 2016. In addition, we must evaluate and install supplemental control technology at Units 1 and 2 by December 31, 2020. At this time, we preliminarily estimate the cost of our compliance at Moss Landing under the provisions of the settlement agreement will be approximately $10 million in aggregate through 2020. Operation of Moss Landing Units 6 and 7 beyond 2020 would be allowed only if those units comply with the Policy’s impingement mortality and entrainment standards.

Effluent Limitation Guidelines. In September 2015, the EPA issued a final rule revising the ELG for steam electric power generation units. The ELG final rule establishes new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts. For EGUs greater than 50 MW, the final rule establishes a zero discharge standard for bottom ash transport water, fly ash transport water and flue gas mercury control wastewater. The rule also establishes effluent limits for flue gas desulfurization wastewaters. Various industry and environmental groups have filed petitions for judicial review of the ELG final rule.

We have evaluated the ELG final rule and the CCR rule in light of our current management of CCR, including beneficial reuse. At this time, we estimate the cost of our compliance with the ELG rule to be approximately $290 million to $350 million. The majority of ELG compliance expenditures are expected to occur in the 2016-2023 timeframe.

NPDES Permits. We are currently appealing certain requirements in the renewal NPDES permits at several of our facilities, including Baldwin and Joppa.

The operator of the co-owned Stuart facility has appealed various aspects of the Stuart NPDES permit, including provisions regarding thermal discharge limitations, to the Ohio Environmental Review Appeals Commission. Depending on the outcome of the appeal, the effects on Stuart’s operations could be material.

Coal Combustion Residuals

The combustion of coal to generate electric power creates large quantities of ash and byproducts that are managed at power generation facilities in dry form in landfills and in wet form in surface impoundments. Each of our coal-fired plants has at least one CCR surface impoundment. At present, CCR is regulated by the states as solid waste.

EPA CCR Rule. The CCR rule, which took effect in October 2015, establishes requirements for existing and new CCR landfills and surface impoundments as well as inactive CCR surface impoundments. The requirements include location restrictions, structural integrity criteria, groundwater monitoring, operating criteria, liner design criteria, closure and post-closure care, recordkeeping and notification. The rule allows existing CCR surface impoundments to continue to operate for the remainder of their operating life, but generally would require closure if groundwater monitoring demonstrates that the CCR surface impoundment is responsible for exceedances of groundwater quality protection standards or the CCR surface impoundment does not meet location restrictions or structural integrity criteria. The deadlines for beginning and completing closure vary depending on several factors.

The EPA's CCR rule establishes minimum federal criteria that owners or operators of regulated CCR units must meet without the engagement of a state or federal regulatory authority. Affected facilities are required to notify the state of actions taken to comply with requirements of the rule and to maintain a publicly accessible internet site that will document the facility's compliance with the rule's requirements. The rule regulates CCR as a non-hazardous waste under RCRA subtitle D, but defers a final determination on whether regulation of CCR as a hazardous waste is necessary until additional information is available. Several businesses, industry groups and environmental organizations filed petitions for judicial review of the CCR rule.

At this time, we estimate the cost of our compliance will be approximately $210 million to $260 million with the majority of the expenditures in the 2016-2023 timeframe. This estimate is reflected in our AROs. Pursuant to the CCR rule, we filed notices of intent with the Illinois EPA in November 2015 to close eleven inactive surface impoundments located at our Baldwin, Hennepin, Wood River, Coffeen and Duck Creek facilities.

Illinois CCR Rule. In 2013, the Illinois EPA filed a proposed rulemaking with the IPCB that would establish processes governing monitoring, corrective action and closure of CCR surface impoundments at power generating facilities. In 2015, the IPCB stayed the rulemaking proceeding through early March 2016 to allow consideration of the EPA CCR rule, including the impact of legal and legislative actions concerning that rule.

Coal Segment Groundwater. In 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities.

At Baldwin, with approval of the Illinois EPA, we performed a comprehensive evaluation of the Baldwin CCR surface impoundment system beginning in 2013. Based on the results of that evaluation, we recommended to the Illinois EPA in 2014 that the closure process for the inactive east CCR surface impoundment begin and that a geotechnical investigation of the existing soil cap on the inactive old east CCR surface impoundment be undertaken. We also submitted a supplemental groundwater modeling report that indicates no known offsite water supply wells will be impacted under the various Baldwin CCR surface impoundment closure scenarios modeled. We await Illinois EPA action on our proposed action plan and recommendations. Please read “EPA CCR Rule” above for further discussion.

We initiated an investigation at Baldwin in 2011 at the request of the Illinois EPA to determine if the facility’s CCR surface impoundment system impacts offsite groundwater. Results of the offsite groundwater quality investigation, as submitted to the Illinois EPA in 2012, indicate two localized areas where Class I groundwater standards were exceeded. The cause of the exceedances is uncertain.

At our retired Vermilion facility, which is not subject to the CCR rule, we submitted proposed corrective action plans for two CCR surface impoundments (i.e., the old east and the north CCR surface impoundments) to the Illinois EPA in 2012. Our hydrogeologic investigation indicates that these two CCR surface impoundments impact groundwater quality onsite and that such groundwater migrates offsite to the north of the property and to the adjacent Middle Fork of the Vermilion River. The proposed corrective action plans recommend closure in place of both CCR surface impoundments and include an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. In 2014, we submitted a revised corrective action plan for the old east CCR surface impoundment. We await Illinois EPA action on our proposed corrective action plans. In June 2015, we advised the Illinois EPA that the additional analyses requested by the Agency would be performed upon receipt of a riverbank stabilization permit from the U.S. Army Corps of Engineers. Our estimated cost of the recommended closure alternative for both the Vermilion old east and north CCR surface impoundments, including post-closure care, is approximately $10 million.

If remediation measures concerning groundwater are necessary in the future at either Baldwin or Vermilion, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. At this time we cannot reasonably estimate the costs, or range of costs, of remediation, if any, that ultimately may be required.

IPH Segment Groundwater. Groundwater monitoring results indicate that the CCR surface impoundments at each of the IPH segment facilities potentially impact onsite groundwater. In 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities’ CCR surface impoundments. In April 2015, we submitted an assessment monitoring report to the Illinois EPA concerning previously reported groundwater quality standard exceedances at the Newton facility’s active CCR landfill. The report identifies the Newton facility’s inactive unlined landfill as the likely source of the exceedances and recommends various measures to minimize the effects of that source on the groundwater monitoring results of the active landfill.

If remediation measures concerning groundwater are necessary at any of our IPH facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. At this time we cannot reasonably estimate the costs, or range of costs, of remediation, if any, that ultimately may be required.

Dam Safety Assessment Reports. In response to the failure at the Tennessee Valley Authority’s Kingston plant, the EPA initiated a nationwide investigation of the structural integrity of CCR surface impoundments in 2009. The EPA assessments found all of our surface impoundments to be in satisfactory or fair condition, with the exception of the surface impoundments at the Baldwin and Hennepin facilities.

In response to the Hennepin report, we made capital improvements to the Hennepin east CCR surface impoundment berms and notified the EPA of our intent to close the Hennepin west CCR surface impoundment. The preliminary estimated cost for closure of the west CCR surface impoundment, including post-closure monitoring, is approximately $5 million, which is reflected in our ARO. We performed further studies needed to support closure of the west CCR surface impoundment, submitted those studies to the Illinois EPA in 2014 and await Illinois EPA action.

In response to the Baldwin report, we notified the EPA in 2013 of our action plan, which included implementation of recommended operating practices and certain recommended studies. In 2014, we updated the EPA on the status of our Baldwin action plan, including the completion of certain studies and implementation of remedial measures and our ongoing evaluation of potential long-term measures in the context of our concurrent evaluation at Baldwin of groundwater corrective actions. At this time, to resolve the concerns raised in the EPA's assessment report and as a result of the CCR rule, we plan to initiate closure of the Baldwin west fly ash CCR surface impoundment in 2017, which is reflected in our AROs.

Climate Change

For the last several years, there has been a robust public debate about climate change and the potential for regulations requiring lower emissions of greenhouse gas ("GHG"), primarily carbon dioxide ("CO_2") and methane. Power generating facilities are a major source of GHG emissions. In 2015, our Coal, IPH and Gas segment facilities emitted approximately 53 million, 21 million and 24 million tons of Equivalent Carbon Dioxide ("CO_{2e}"), respectively. The amounts of CO_{2e} emitted from our facilities during any time period will depend upon their dispatch rates during the period. We believe that the focus of any federal program attempting to address climate change should include three critical, interrelated elements: (i) the environment, (ii) the economy and (iii) energy security.

Federal Regulation of GHGs. The EPA has issued several rules concerning GHGs as directly relevant to our facilities since the U.S. Supreme Court's 2007 decision in Massachusetts v. EPA, which held that GHGs meet the definition of a pollutant under the CAA and that regulation of GHG emissions is authorized by the CAA. We have implemented processes and procedures to report our GHG emissions. In 2010, the EPA issued PSD and Title V Permitting Guidance for Greenhouse Gases, which focuses on steam turbine and boiler efficiency improvements as a reasonable best available control technology ("BACT") requirement for coal-fired EGUs. The EPA's Tailoring Rule and Timing Rule phased in GHG emissions annual applicability thresholds for the PSD permit program and the Title V operating permit program beginning in 2011. Application of the PSD program to GHG emissions will require implementation of BACT for new and modified major sources of GHG.

In 2014, the U.S. Supreme Court decided Utility Air Regulatory Group v. EPA, holding that the EPA may not impose PSD or Title V permitting requirements on facilities based solely on emissions of GHGs. The Court also invalidated the EPA's Tailoring Rule but concluded that the EPA may impose BACT requirements on GHG emissions if a facility is subject to BACT for other pollutants. The Court also determined that the EPA may establish a de minimis threshold below which BACT would not be required for GHG emissions, but left it open to the EPA to justify the appropriate threshold.

Paris Agreement. In December 2015, over 190 countries, including the U.S., reached an agreement ("Paris Agreement") that establishes a global framework to reduce GHG emissions. The Paris Agreement seeks to keep warming below two degrees Celsius with a goal to limit increases in temperature to 1.5 degrees Celsius. The Paris Agreement directs all countries to prepare and communicate non-binding, nationally determined climate targets every five years starting in 2020.

Clean Power Plan. In August 2015, the EPA issued the Clean Power Plan to reduce carbon emissions from existing EGUs. The EPA also separately issued final rules establishing carbon standards for new, modified and reconstructed EGUs, which include emission standards for new fossil fuel-fired utility boilers based on the performance of a new efficient coal unit implementing partial carbon capture and storage.

The EPA expects that by 2030 when the Clean Power Plan is fully implemented, CO_2 emissions from EGUs will be 32 percent below 2005 levels. States are required to develop plans to achieve interim CO_2 emission rates reductions phased in over the period 2022 to 2029 and the final CO_2 rate for their state by 2030. The state-specific CO_2 emission performance rates reflect the EPA's determination that the best system of emission reduction is comprised of three building blocks: increasing the operational efficiency of existing coal-fired EGUs, shifting electricity generation to natural gas-fired EGUs, and increasing electricity generation from renewable sources. Emission trading programs are permitted. States must submit final plans by September 6, 2016, unless a state makes certain demonstrations justifying a two-year extension for submittal of a final plan by September 2018.

Numerous states, industry associations and labor groups filed lawsuits challenging the EPA's Clean Power Plan. In February 2016, the U.S. Supreme Court stayed the rule pending completion of judicial review. Judicial challenges also have been filed against the EPA's final rules establishing carbon standards for new, modified and reconstructed EGUs. Many states where we operate generation facilities have started efforts aimed at developing plans to implement the Clean Power Plan. We are monitoring and, as appropriate, participating in those state efforts. We also continue to analyze the EPA's final rules to reduce EGU CO_2 emissions, the potential impacts on our power generation facilities, and how the rules intersect with electricity market design.

The nature and scope of CO_2 emission reduction requirements that ultimately may be imposed on our facilities as a result of the EPA's EGU CO_2 reduction rules are uncertain at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

State Regulation of GHGs. Many states where we operate generation facilities have, are considering, or are in some stage of implementing, state-only regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change.

California. Our assets in California are subject to the California Global Warming Solutions Act ("AB 32"), which required the California Air Resources Board ("CARB") to develop a GHG emission control program to reduce emissions of GHGs in the state to 1990 levels by 2020. In April 2015, the Governor of California issued an executive order establishing a new statewide GHG reduction target of 40 percent below 1990 levels by 2030 to ensure California meets its 2050 GHG reduction target of 80 percent below 1990 levels.

Our generating facilities in California emitted approximately 2 million tons of GHGs during 2015. As a result of the tolling agreement for Moss Landing Units 6 and 7 under which GHG allowance costs are passed through to the tolling counterparty, we were required in 2015 to acquire allowances covering the GHG emissions of only Moss Landing Units 1 and 2. The cost of GHG allowances required to operate our units in California during 2015 was approximately $18 million.

We estimate the cost of GHG allowances required to operate our units in California during 2016 will be approximately $12 million; however, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue. Due to the tolling agreement for Moss Landing Units 6 and 7, we expect only to acquire allowances covering the GHG emissions of Moss Landing Units 1 and 2.

RGGI. RGGI, a state-driven GHG emission control program that took effect in 2009 was initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented a cap-and-trade program to reduce CO_2 emissions by at least 10 percent of 2009 emission levels by 2018. Compliance with RGGI can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. While RGGI allowances are sold by year, actual compliance is measured across a three-year control period.

Following a program review, the RGGI states implemented a new 2014 CO_2 emissions cap, which then declines by 2.5 percent each year from 2015 to 2020. We are required to hold allowances equal to at least 50 percent of emissions in each of the first two years of the three-year control period.

Our generating facilities in Connecticut, Maine, Massachusetts and New York emitted approximately 10 million tons of CO_2 during 2015. The cost of RGGI allowances required to operate these facilities during 2015 was approximately $67 million. We estimate the cost of RGGI allowances required to operate our affected facilities during 2016 will be approximately $81 million. While the cost of allowances required to operate our RGGI-affected facilities is expected to increase in future years, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue.

Remedial Laws

We are subject to environmental requirements relating to handling and disposal of toxic and hazardous materials, including provisions of the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and RCRA and similar state laws. CERCLA imposes strict liability for contributions to contaminated sites resulting from the release of "hazardous substances" into the environment. CERCLA or RCRA could impose remedial obligations with respect to a variety of our facilities and operations.

A number of our older facilities contain quantities of asbestos-containing materials, lead-based paint and/or other regulated materials. Existing state and federal rules require the proper management and disposal of these materials. We have developed a plan that includes proper maintenance of existing non-friable asbestos installations and removal and abatement of asbestos-containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself.

COMPETITION

Demand for power may be met by generation capacity based on several competing generation technologies, such as natural gas-fired, coal-fired or nuclear generation, as well as power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. The power generation business is a regional business that is diverse in terms of industry structure. Our Coal, IPH and Gas power generation businesses compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies, including retail power companies, and financial institutions in the regions in which we operate. We believe that our ability to compete effectively in the power generation business will be driven in large part by our ability to achieve and maintain a low cost of production, primarily by managing fuel costs and the reliability of our generating facilities. Our ability to compete effectively will also be impacted by various governmental and regulatory activities designed to reduce GHG emissions and to promote lower emitting generation. For example, regulatory requirements for load-serving entities to acquire a percentage of their energy from renewable-fueled facilities will potentially reduce the demand for energy from coal- and gas-fired facilities, such as those we own and operate. In addition, the recent extension of federal renewable energy tax credit programs is expected to further expand renewable energy development.

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2015, approximately 28 percent and 22 percent of our consolidated revenues were derived from transactions with PJM and MISO, respectively. For the year ended December 31, 2014, approximately 33 percent and 14 percent of our consolidated revenues were derived from transactions with MISO and NYISO, respectively. For the year ended December 31, 2013, approximately 36 percent, 19 percent, 16 percent and 15 percent of our consolidated revenues were derived from transactions with MISO, PJM, NYISO and CAISO, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during the years ended December 31, 2015, 2014 and 2013.

EMPLOYEES

At December 31, 2015, we had approximately 321 employees at our corporate headquarters and approximately 2,270 employees at our facilities, including field-based administrative employees. The field-based employees, who operate our facilities, are divided across our three reportable segments, Coal, IPH and Gas, employing approximately 1,116 employees, 549 employees and 397 employees, respectively. In addition, there are approximately 208 field-based administrative employees who are part of our support and retail functions. Approximately 1,330 employees at our operating facilities are subject to collective bargaining agreements with various unions. In 2015, we reached an agreement on new collective bargaining agreements with the three unions representing our IPH facilities. These agreements cover approximately 400 represented employees located in Illinois and expire between 2018 and 2020. During 2015, the Company did not experience a labor stoppage or a labor dispute at any of its facilities.

Item 1A. Risk Factors

Please note that any risk, uncertainty or other factor that has a material adverse effect on the financial position, results of operations or cash flows of our IPH segment may not result in a material adverse effect on the financial position, results of operations or cash flows of Dynegy on a consolidated basis due to the relative size of the IPH segment as well as the ring-fenced structuring of IPH and its subsidiaries. However, you should review the risk factor regarding the IPH ring-fenced structure and the risk that a creditor of IPH, or a bankruptcy trustee if any entity of the IPH segment were to become a debtor in bankruptcy, may nevertheless be successful in subjecting Dynegy to the claims of IPH and its subsidiaries.

FORWARD-LOOKING STATEMENTS

This Form 10-K includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as “forward-looking statements.” All statements included or incorporated by reference in this annual report, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements represent our reasonable judgment of the future based on various factors and using numerous assumptions and are subject to known and unknown risks, uncertainties and other factors that could cause our actual results and financial position to differ materially from those contemplated by the statements. You can identify these statements by the fact that they do not relate strictly to historical or current facts. They use words such as “anticipate,” “estimate,” “project,” “forecast,” “plan,” “may,” “will,” “should,” “expect” and other words of similar meaning. In particular, these include, but are n limited to, statements relating to the following:

- beliefs and assumptions about weather and general economic conditions;
- beliefs, assumptions and projections regarding the demand for power, generation volumes and commodity pricing, including natural gas prices and the timing of a recovery in natural gas prices, if any;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale and retail power markets, including the anticipation of plant retirements and higher market pricing over the longer term;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- the effects of, or changes to, MISO, PJM, CAISO, NYISO or ISO-NE power and capacity procurement processes;
- expectations regarding, or impacts of, environmental matters, including costs of compliance, availability and adequacy of emission credits and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts and other laws and regulations that we are, or could become, subject to, which could increase our costs, result in an impairment of our assets, cause us to limit or terminate the operation of certain of our facilities, or otherwise have a negative financial effect;
- beliefs about the outcome of legal, administrative, legislative and regulatory matters;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- our focus on safety and our ability to efficiently operate our assets so as to capture revenue generating opportunities and operating margins;
- our ability to mitigate forced outage risk, including managing risk associated with CP in PJM and new performance incentives in ISO-NE;
- our ability to optimize our assets through targeted investment in cost effective technology enhancements;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- efforts to secure retail sales and the ability to grow the retail business;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;
- ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios and other payments;
- expectations regarding performance standards and capital and maintenance expenditures;
- the timing and anticipated benefits to be achieved through our company-wide improvement programs, including our PRIDE initiative;

- anticipated timing, outcomes and impacts of the expected retirements of Brayton Point and Wood River;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the Vermilion facility and any potential future remediation obligations at the South Bay facility; and

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- beliefs regarding redevelopment efforts for the Morro Bay facility.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond our control, including those set forth below.

FACTORS THAT MAY AFFECT FUTURE RESULTS

Risks Related to the Operation of Our Business

Because wholesale and retail power prices are subject to significant volatility and because many of our power generation facilities operate without long-term power sales agreements, our revenues and profitability are subject to wide fluctuations.

The majority of our facilities operate as “merchant” facilities without long-term power sales agreements. As a result, we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other wholesale and retail power markets on a short-term basis and are not guaranteed any rate of return on our capital investments. Consequently, there can be no assurance that we will be able to sell any or all of the electric energy, capacity or ancillary services from those facilities at commercially attractive rates or that our facilities will be able to operate profitably. We depend, in large part, upon prevailing market prices for power, capacity and fuel. Given the volatility of commodity power prices, to the extent we do not secure long-term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to volatility, and our financial condition, results of operations and cash flows could be materially adversely affected. Factors that may materially impact the power markets and our financial results include:

- addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation plants, expansion of existing plants or additional transmission capacity;
- uneconomic generation kept on line by utilities, aided by state-based subsidies;
- environmental regulations and legislation;
- weather conditions, including extreme weather conditions and seasonal fluctuations;
- electric supply disruptions including plant outages;
- basis risk from transmission losses and congestion and changes in power transmission infrastructure;
- development of new technologies for the production of natural gas;
- fuel price volatility;
- economic conditions;
- capacity performance requirements and penalties;
- increased competition or price pressure driven by generation from renewable sources and other subsidized generation;
- regulatory constraints on pricing (current or future), including RTO and ISO rules, policies and actions, or the functioning of the energy trading markets and energy trading generally;
- the existence and effectiveness of demand-side management; and
- conservation efforts and energy efficiency rules and the extent to which they impact electricity demand.

Our commercial strategies for our wholesale and retail businesses may not be executed as planned, may result in lost opportunities or adversely affect financial performance.

We seek to commercialize our assets through sales arrangements of various types. In doing so, we attempt to balance a desire for greater predictability of earnings and cash flows in the short- and medium-terms with our expectation that commodity prices will rise over the longer term, creating upside opportunities for those with unhedged generation volumes. Our ability to successfully execute this strategy is dependent on a number of factors, many of which are outside our control, including market liquidity and design, correlation risk, commodity price cycles, the availability of counterparties willing to transact with us or to transact with us at prices we think are commercially acceptable, the availability of liquidity to post collateral in support of our derivative instruments and the reliability of the systems and models comprising our commercial operations function. The availability of market liquidity and willing counterparties could be negatively impacted by poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties as well as counterparties’ views of our creditworthiness. If we are unable to transact in the short- and medium-terms, our financial condition, results of operations and cash flows will be subject to significant uncertainty and volatility. Alternatively, significant power sales for any such period may precede a run-up in commodity prices, resulting in lost up-side opportunities.

Further, financial performance may be adversely affected if we are unable to effectively manage our power portfolio. A portion of the generation power portfolio is used to provide power to wholesale and retail customers. To the extent portions of the power portfolio are not needed for that purpose, generation output is sold in the wholesale market. To the extent our power portfolio is not sufficient to meet the requirements of our customers, we must purchase power in the wholesale power markets. Our financial results may be negatively affected if we are unable to manage the power portfolio and cost-effectively meet the requirements of our customers.

A decline in market liquidity and our ability to manage our counterparty credit risk could adversely affect us.

Our supplier counterparties may experience deteriorating credit. These conditions could cause counterparties in the natural gas, coal and power markets, particularly in the energy commodity derivative markets that we rely on for our hedging activities, to withdraw from participation in those markets. If multiple parties withdraw from those markets, market liquidity may be threatened, which in turn could adversely impact our business. Additionally, these conditions may cause our counterparties to seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows. In addition, retail sales subject us to credit risk through competitive electricity supply activities to serve commercial and industrial companies and governmental entities. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve that customer, which could have a material adverse effect on our financial condition, results of operations and cash flows.

We are exposed to the risk of fuel and fuel transportation cost increases and interruptions in fuel supplies.

We purchase the fuel requirements for many of our power generation facilities, primarily those that are natural gas-fired, under short-term contracts or on the spot market. As a result, we face the risks of supply interruptions and fuel price volatility, as fuel deliveries may not exactly match those required for energy sales.

Moreover, profitable operation of many of our coal-fired generation facilities is highly dependent on coal prices and coal transportation rates. We mitigate our price exposure to coal and related transportation by entering into long-term contracts. Transportation of coal can also be affected by rail equipment availability, extreme weather or natural disasters, each of which may slow or stop the delivery from the mine to the facility. In addition, certain of our coal suppliers have filed for bankruptcy protection, which could negatively impact our coal supply.

Further, any changes in the costs of coal, fuel oil, natural gas or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. If we are unable to procure fuel for physical delivery at prices we consider favorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Operation of power generation facilities involves significant risks customary to the power industry that could have a material adverse effect on our financial condition, results of operations and cash flows.

The ongoing operation of our facilities involves risks customary to the power industry that include the breakdown or failure of equipment or processes, operational and safety performance below expected levels and the inability to transport our product to customers in an efficient manner due to a lack of transmission capacity. Unplanned outages of generating units, including extensions of scheduled outages due to mechanical failures or other problems, occur from time to time and are an inherent risk of our business. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures, could result in reduced profitability, or with respect to capacity performance, significant penalties. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MW or require us to incur significant costs as a result of running one of our higher cost units or obtaining replacement power from third parties in the open market to satisfy our forward power sales obligations. If we are unsuccessful in operating our facilities efficiently, such inefficiency could have a material adverse effect on our results of operations, financial condition and cash flows.

Our costs of compliance with existing environmental requirements are significant, and costs of compliance with new environmental requirements or factors could materially adversely affect our financial condition, results of operations and cash flows.

Our business is subject to extensive and frequently changing environmental regulation by federal, state and local authorities. Such environmental regulation imposes, among other things, capital and operating expenditures, restrictions, liabilities and obligations in connection with the generation, handling, use, transportation, treatment, storage and disposal of certain substances and wastes, including CCR, and in connection with spills, releases and emissions of various substances (including carbon emissions) into the environment, as well as environmental impacts associated with cooling water intake structures. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or may become applicable to us or our facilities, and litigation or enforcement proceedings could be commenced against us. Proposals being considered by federal and state authorities (including proposals regarding cooling water intake structures and carbon) could, if and when adopted or enacted, require us to make substantial capital and operating expenditures, impair assets, or limit or terminate operation of certain of our facilities. If any of these events occur, our financial condition, results of operations and cash flows could be materially adversely affected.

Many environmental laws require approvals or permits from governmental authorities before construction, modification or operation of a power generation facility may commence. Certain environmental permits must be renewed periodically in order for us to continue operating our facilities. The process of obtaining and renewing necessary permits can be lengthy and complex and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits when we modify and operate our facilities. If there is a delay in obtaining any required environmental regulatory approvals or permits, if we fail to obtain any required approval or permit, or if we are unable to comply with the terms of such approvals or permits, the operation of our facilities may be interrupted or become subject to additional costs and/or legal challenges. Further, changed interpretations of existing regulations may subject historical maintenance, repair and replacement activities at our facilities to claims of noncompliance. With the continuing trend toward stricter environmental standards and more extensive regulatory and permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may significantly increase in the future. As a result, our financial condition, results of operations and cash flows could be materially adversely affected.

Our business is subject to complex government regulation. Changes in these regulations or in their implementation may affect costs of operating our facilities or our ability to operate our facilities, or increase competition, any of which would negatively impact our results of operations.

We are subject to extensive federal, state and local laws and regulations governing the generation and sale of energy commodities in each of the jurisdictions in which we have operations. Compliance with these ever-changing laws and regulations requires expenses (including legal representation) and monitoring, capital and operating expenditures. Potential changes in laws and regulations that could have a material impact on our business include: the introduction, or reintroduction, of rate caps or pricing constraints; inability to pass on costs to customers; state regulatory initiatives, including subsidized generation; increased credit standards, collateral costs or margin requirements, as well as reduced market liquidity, as a result of potential OTC market regulation; or a variation of these. Furthermore, these and other market-based rules and regulations are subject to change at any time, and we cannot predict what changes may occur in the future or how such changes might affect any facet of our business.

The costs and burdens associated with complying with the increased number of regulations may have a material adverse effect on us if we fail to comply with the laws and regulations governing our business or if we fail to maintain or obtain advantageous regulatory authorizations and exemptions. Failure to comply with such requirements could result in the shutdown of any noncompliant facility, the imposition of liens or fines, or civil or criminal liability. Moreover, increased competition within the sector resulting from potential legislative changes, regulatory changes or other factors may create greater risks to the stability of our power generation earnings and cash flows generally.

Regulators, politicians, non-governmental organizations and other private parties have expressed concern about greenhouse gas, or GHG, emissions and the potential risks associated with climate change and are taking actions which could materially adversely affect our financial condition, results of operations and cash flows.

For the last several years, there has been a robust public debate about climate change and the potential for regulations requiring lower emissions of GHG, primarily CO_2 and methane. As discussed in Item 1. Business-Environmental Matters, at the federal and state levels, rules are in effect and policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentives to reduce them. Power generating facilities are a major source of GHG emissions. We cannot confidently predict the final outcome of the current debate on climate change nor can we predict with confidence the ultimate requirements of proposed or anticipated federal and state legislation and regulations intended to address climate change. These activities, and the highly politicized nature of climate change, suggest a trend toward increased regulation of GHG that could result in a material adverse effect on our financial condition, results of operations and cash flows. Existing and anticipated federal and state regulations intended to address climate change may significantly increase the cost of providing electric power, resulting in far-reaching and significant impacts on us and others in the power generation industry over time. It is possible that federal and state actions intended to address climate change could result in costs assigned to GHG emissions that we would not be able to fully recover through market pricing or otherwise. If capital and/or operating costs related to compliance with regulations intended to address climate change become great enough to render the operations of certain plants uneconomical, we could, at our option and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such plants and forego such capital and/or operating costs. Though we consider our largest risk related to climate change to be legislative and regulatory changes, we are subject to physical risks inherent in industrial operations including severe weather events such as hurricanes and tornadoes. To the extent that changes in climate effect changes in weather patterns (such as more severe weather events) or changes in sea level where we have generating facilities, we could be adversely affected.

Availability and cost of emission allowances could materially impact our costs of operations.
We are required to maintain, either through allocation or purchase, sufficient emission allowances to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet our obligations imposed by various applicable environmental laws, and the trend toward more stringent regulations (including regulations regarding GHG emissions) will likely require us to obtain new or additional emission allowances. If our operational needs require more than our allocated quantity of emission allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances, or install costly new emissions controls. As we use the emissions allowances that we have purchased on the open market, costs associated with such purchases will be recognized as an operating expense. If such allowances are available for purchase, but only at significantly higher prices, their purchase could materially increase our costs of operations in the affected markets and materially adversely affect our financial condition, results of operations and cash flows.
Competition in wholesale and retail power markets, together with the age of certain of our generation facilities, may have a material adverse effect on our financial condition, results of operations and cash flows.
Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions in the sale of electric energy, capacity and ancillary services, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generating facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance and/or subsidize renewable generation increases competition from these types of facilities.
We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit, and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources in these areas. In addition, certain of our current facilities are relatively old. Newer plants owned by competitors may be more efficient than some of our plants, which may put these plants at a competitive disadvantage. Over time, some of our plants may become unable to compete because of subsidized generation, including public utility commission supported PPAs, and the construction of new plants. Such new plants could have a number of advantages including: more efficient equipment, newer technology that could result in fewer emissions or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities. Taken as a whole, the potential disadvantages of our aging fleet could result in lower run-times or even early asset retirement.
Other factors may contribute to increased competition in wholesale power markets. New forms of capital and competitors have entered the industry, including financial investors who perceive that asset values are at levels below their true replacement value. As a result, a number of generation facilities in the U.S. are now owned by lenders and investment companies. Furthermore, mergers and asset reallocations in the industry could create powerful new competitors. Under any scenario, we anticipate that we will face competition from numerous companies in the industry.
In addition, our retail marketing efforts compete for customers in a competitive environment, which impacts the margins that we can earn on the volumes we are able to serve. Further, with retail competition, residential customers where we serve load can switch to and from competitive electric generation suppliers for their energy needs. If fewer customers switch to another supplier than anticipated, the load we must serve will be greater and, if market prices have increased, our costs will increase due to the need to go to the market to cover the incremental supply obligation. If more customers switch to another supplier than anticipated, the load we must serve will be lower and, if market prices have decreased, we could lose opportunities in the market. To the extent that competition increases, our financial condition, results of operations and cash flows may be materially adversely affected.
Generally, we do not own or control transmission facilities required to sell wholesale power from our generation facilities. If transmission services are inadequate, our ability to sell and deliver wholesale power may be materially

adversely affected. Furthermore, RTOs and ISOs administer the transmission infrastructure and market, which are subject to changes in structure and operation and impose various pricing limitations. These changes and pricing limitations may affect our ability to deliver power to the market that would, in turn, adversely affect the profitability of our generation facilities.

With the exception of EEI, which owns and controls transmission lines interconnecting the Joppa facility in EEI's control area to MISO, Tennessee Valley Authority ("TVA") and Louisville Gas and Electric Company ("LGE"), we do not own or control the transmission facilities required to deliver the power from our generation facilities to the market. If transmission services from these facilities are unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected, which could result in reduced profitability, or with respect to capacity performance in PJM and performance incentives in ISO-NE, significant penalties. RTOs and ISOs provide transmission services, administer transparent and competitive power markets and maintain system reliability. Many of these RTOs and ISOs operate in the real-time and day-ahead markets in which we sell energy. The RTOs and ISOs that oversee most of the wholesale power markets impose price limitations, offer caps, capacity performance requirements, penalties, and other mechanisms to guard against the potential exercise of market power in these markets. Price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets. Problems or delays that may arise in the formation and operation of maturing RTOs and similar market structures, or changes in geographic scope, rules or market operations of existing RTOs, may also affect our ability to sell, the prices we receive or the cost to transmit power produced by our generating facilities. Market design as well as rules governing the various regional power markets may also change from time to time, which could materially adversely affect our financial condition, results of operations and cash flows.

Our Retail business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to our reputation and/or the results of operations of the Retail business.

The Retail business requires access to sensitive customer data in the ordinary course of business. Examples of sensitive customer data are names, addresses, account information, historical electricity usage, expected patterns of use, payment history, credit bureau data and bank account information. The Retail business may need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center operations, to the Retail business. If a significant breach occurred, our reputation may be adversely affected, customer confidence may be diminished or we may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on our business and/or financial condition, results of operations and cash flows.

Unauthorized hedging and related activities by our employees could result in significant losses.

We intend to continue our commercial strategy, which emphasizes forward power sales opportunities intended to reduce the market price exposure of the Company to power price declines. We have various internal policies and procedures designed to monitor hedging activities and positions. These policies and procedures are designed, in part, to prevent unauthorized purchases or sales of products by our employees. We cannot assure, however, that these steps will detect and prevent inaccurate reporting and all other violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. A significant policy violation that is not detected could result in a substantial financial loss for us.

Our risk management policies cannot fully eliminate the risk associated with our commodity hedging activities.

Our asset-based power position as well as our power marketing, fuel procurement and other commodity hedging activities expose us to risks of commodity price movements. We attempt to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when our policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, we cannot fully predict the impact that our commodity hedging activities and risk management decisions may have on our business and/or financial condition, results of operations and cash flows.

Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

A majority of the employees at our facilities are subject to collective bargaining agreements with various unions. Additionally, unionization activities, including votes for union certification, could occur at the non-union generating facilities in our fleet. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strike or disruption, we could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

The IPH segment’s ring-fencing structure may not work as planned and Dynegy may be subject to the claims of the creditors of IPH and its subsidiaries.

In connection with the 2013 acquisition of New Ameren Energy Resources, LLC (“AER”) and its subsidiaries (the “AER Acquisition”), IPH and its direct and indirect subsidiaries were organized into ring-fenced groups. The entities within the IPH ring-fenced structure maintain corporate separateness from our other current legal entities. This structure was implemented, in part, to minimize the risk that creditors of IPH, or a bankruptcy trustee if any entity of the IPH segment were to become a debtor in a bankruptcy case, would attempt to assert claims against Dynegy for payment of IPH's obligations. The ring-fenced structure should preclude any corporate veil-piercing or other similar claims of IPH's creditors but, if any such claims were successful, it could have a material adverse effect on our financial position, results of operations and cash flows. The ring-fenced structure should also preclude any bankruptcy court from ordering the substantive consolidation of Dynegy's assets and liabilities with the assets and liabilities of any IPH debtor in bankruptcy. However, bankruptcy courts have broad equitable powers and, as a result, outcomes in bankruptcy proceedings are inherently difficult to predict. To the extent a bankruptcy court were to determine that substantive consolidation was appropriate under the facts and circumstances, it could have a material adverse effect on our financial position, results of operations and cash flows.

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

As a power generator, we face heightened risk of terrorism, including cyber terrorism, either by a direct act against one or more of our generating facilities or an act against the transmission and distribution infrastructure that is used to transport our power. We rely on information technology networks and systems, including third party cloud systems, to operate our generating facilities, engage in asset management activities, and process, transmit and store electronic information. Security breaches of this information technology infrastructure, including cyber-attacks and cyber terrorism, could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information related to our employees, vendors and counterparties, including retail counterparties.

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

We may pursue acquisitions or combinations that could be unsuccessful or present unanticipated problems for our business in the future, which would adversely affect our ability to realize the anticipated benefits of those transactions.

We may enter into transactions that include acquiring or combining with other businesses. We may not be able to identify suitable acquisition or combination opportunities or financing to complete any particular acquisition or combination successfully. Furthermore, acquisitions and combinations involve a number of risks and challenges, including:

- the ability to obtain required regulatory and other approvals;
- the need to integrate acquired or combined operations with our operations;
- potential loss of key employees;
- difficulty in evaluating the assets, operating costs, infrastructure requirements, environmental and other liabilities and other factors beyond our control;
- potential lack of operating experience in new geographic/power markets or with different fuel sources;
- an increase in our expenses and working capital requirements;
- management's attention may be temporarily diverted; and
- the possibility that we may be required to issue a substantial amount of additional equity and/or debt securities or assume additional debt in connection with any such transactions.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize synergies or other anticipated benefits from a strategic transaction. Furthermore, the market for transactions is highly competitive, which may adversely affect our ability to find transactions that fit our strategic objectives or increase the price we would be required to pay (which could decrease the benefit of the transaction or hinder our desire or ability to consummate the transaction). Consistent with industry practice, we routinely engage in discussions with industry participants regarding potential transactions, large and small. We intend to continue to engage in strategic discussions and will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at any time and may be significant in size relative to our assets and operations.

Risks Related to Our Financial Structure

Our indebtedness could adversely affect our ability in the future to raise additional capital to fund our operations. It could also expose us to the risk of increased interest rates and limit our ability to react to changes in the economy or our industry as well as impact our cash available for distribution.

As of December 31, 2015, we had approximately $7.4 billion of total indebtedness and approximately $6.9 billion of indebtedness net of cash. Our debt could have negative consequences for our financial condition including:

- increasing our vulnerability to general economic and industry conditions;
- requiring a substantial portion of our cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- limiting our ability to enter into long-term power sales or fuel purchases which require credit support;
- limiting our ability to fund operations or future acquisitions;
- restricting our ability to make certain distributions with respect to our capital stock and the ability of our subsidiaries to make certain distributions to us, in light of restricted payment and other financial covenants in our credit facilities and other financing agreements;
- exposing us to the risk of increased interest rates because certain of our borrowings, including borrowings under our revolving credit facility, are at variable rates of interest;
- limiting our ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and
- limiting our ability to adjust to changing market conditions and placing us at a competitive disadvantage compared to our competitors who may have less debt.

We may not be successful in obtaining additional capital for these or other reasons. Furthermore, we may be unable to refinance or replace our existing indebtedness on favorable terms or at all upon the expiration or termination thereof. Our failure to obtain additional capital or enter into new or replacement financing arrangements when due may constitute a default under such existing indebtedness and may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our existing credit facilities contain, and agreements we enter into in the future may contain, covenants that could restrict our financial flexibility.

Our existing credit facilities contain covenants imposing certain requirements on our business. These requirements may limit our ability to take advantage of potential business opportunities as they arise and may adversely affect the conduct of our current business, including restricting our ability to finance future operations and capital needs and limiting our ability to engage in other business activities. These covenants could place restrictions on our ability and the ability of our operating subsidiaries to, among other things:

- declare or pay dividends, repurchase or redeem stock or make other distributions to stockholders;
- incur additional debt or issue some types of preferred shares;
- create liens;
- make certain restricted investments;
- enter into transactions with affiliates;
- enter into any agreements which limit the ability of certain subsidiaries to make dividends or otherwise transfer cash or assets to us or certain other subsidiaries;
- sell or transfer assets; and
- consolidate or merge.

Agreements we enter into in the future may also have similar or more restrictive covenants. A breach of any covenant in the existing credit facilities or the agreements governing our other indebtedness would result in a default. A default, if not waived, could result in acceleration of the debt outstanding under any such agreement and in a default with respect to, and acceleration of, the debt outstanding under any other debt agreements. The accelerated debt would become due and payable immediately. If that should occur, we may not be able to make all of the required payments or borrow sufficient funds to refinance our debt obligations. Even if new financing were then available, it may not be on terms that are acceptable to us.

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Our sub-investment grade status may adversely impact our commercial operations, increase our liquidity requirements and increase the cost of refinancing opportunities. We may not have adequate liquidity to post required amounts of additional collateral.

Our corporate family credit rating is currently below investment grade and we cannot assure you that our credit ratings will improve, or that they will not decline, in the future. Our credit ratings may affect the evaluation of our creditworthiness by trading counterparties and lenders, which could put us at a disadvantage to competitors with higher or investment grade ratings. We use a portion of our capital resources, in the form of cash, short-term investments, lien capacity and letters of credit, to satisfy these counterparty collateral demands. Our commodity agreements are tied to market pricing and may require us to post additional collateral under certain circumstances. If we are unable to reliably forecast or anticipate collateral calls or if market conditions change such that counterparties are entitled to additional collateral, our liquidity could be strained and may have a material adverse effect on our financial condition, results of operations and cash flows. Factors that could trigger increased demands for collateral include changes in our credit rating or liquidity and changes in commodity prices for power and fuel, among others. Should our ratings continue at their current levels, or should our ratings be further downgraded, we would expect these negative effects to continue and, in the case of a downgrade, become more pronounced.

If our goodwill, amortizable intangible assets, or long-lived assets become impaired, we may be required to record a significant charge to earnings.

We have significant goodwill, amortizable intangible assets and long-lived assets recorded on our balance sheet. In accordance with the Generally Accepted Accounting Principles of the United States of America (“GAAP”), goodwill is required to be tested for impairment at least annually. Additionally, we review goodwill, our amortizable intangible assets and long-lived assets for impairment when events or changes in circumstances indicate the carrying value of the asset may not be recoverable. Factors that may be considered include a decline in future cash flows, and slower growth rates in the energy industry, as well as a sustained decrease in the price of our common stock.

We have performed the test for goodwill impairment and concluded that a goodwill impairment loss has not occurred at this time. Please read Critical Accounting Policies—Goodwill Impairment for further discussion. However, further goodwill impairment testing will be performed in future periods and may result in an impairment loss, which could be material. We performed asset impairment analyses of all facilities in 2015 and determined that no impairment charges were required, other than for our Wood River and Brayton Point facilities. Please read Note 9—Property, Plant and Equipment for further discussion.

Issuances or acquisitions of our common stock, or sales or dispositions of our common stock by stockholders, that result in an ownership change as defined in Internal Revenue Code (“IRC”) §382 could further limit our ability to use our federal net operating losses or alternative minimum tax credits to offset our future taxable income.

If an "ownership change," as defined in Section 382 of the IRC (“IRC §382”) occurs, the amount of net operating losses (“NOLs”) and alternative minimum tax (“AMT”) credits that could be used in any one year following such ownership change could be substantially limited. In general, an "ownership change" would occur when there is a greater than 50 percentage point increase in ownership of a company's stock by stockholders, each of which owns (or is deemed to own under IRC §382) 5 percent or more of such company's stock. Given IRC §382's broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in our stock that is outside our control. Dynegy has already experienced two “ownership changes” under IRC §382 that limit the use of our NOLs and AMT credits that existed at the time and prior to our emergence from bankruptcy. NOLs that have been generated subsequent to our emergence from bankruptcy are not currently subject to the limitations imposed by IRC §382. If, however, there is another “ownership change,” the utilization of all NOLs and AMT credits existing at that time would be subject to additional annual limitations based upon a formula provided under IRC §382 that is based on the fair market value of the Company and prevailing interest rates at the time of the ownership change.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

We have included descriptions of the location and general character of our principal physical operating properties by segment in “Item 1. Business,” which is incorporated herein by reference. Substantially all of the assets of the Coal and Gas segments, including the majority of power generation facilities owned by Dynegy Midwest Generation, LLC

(“DMG”) and Dynegy Power, LLC (“DPC”), two of our wholly-owned subsidiaries, are pledged as collateral to secure the repayment of, and our other obligations under, the Credit Agreement. None of the power generation facilities of the IPH segment are pledged as collateral to secure repayment of any of our debt obligations; however, there are certain restrictions on property sales. Please read Note 13—Debt for further discussion.

Our principal executive office located in Houston, Texas, is held under a lease that expires in 2022. We also lease additional offices in Illinois and Ohio.

Item 3. Legal Proceedings

Please read Note 16—Commitments and Contingencies—Legal Proceedings for a description of our material legal proceedings, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our authorized capital stock consists of 420 million shares of common stock, with a par value of $0.01 per share. Our common stock is listed on the NYSE under the symbol “DYN” and has been trading since October 3, 2012, following our emergence from bankruptcy on October 1, 2012 (the “Plan Effective Date”), which was administered under the Joint Chapter 11 Plan of Reorganization as of the Plan Effective Date (the “Plan”). Based on information provided by our transfer agent, there were 2,542 stockholders of record of our common stock as of February 8, 2016. Also, following the Plan Effective Date we issued 15.6 million five-year warrants to purchase shares of our common stock (the “Warrants”). Each Warrant entitles the holder to a maximum of one share of common stock. The exercise price of each Warrant was set at $40 per warrant. Further, on the Plan Effective Date, approximately 6.1 million shares of our common stock were available for issuance under our 2012 Long Term Incentive Plan.

On October 14, 2014, we issued 22.5 million shares, pursuant to the Common Stock Offering at $31.00 per share. On November 13, 2014, we issued an additional 1.5 million shares, pursuant to the exercise by the underwriters of their 30 day option to purchase up to 3.375 million additional shares of our common stock, at $31.00 per share. On April 1, 2015, pursuant to the ERC Purchase Agreement, 3,460,053 shares of common stock of Dynegy were issued as part of the consideration for the EquiPower Acquisition, valued at approximately $105 million based on the closing price of Dynegy’s common stock on the EquiPower Closing Date. Please read Note 3—Acquisitions for further discussion. On August 3, 2015, our Board of Directors authorized a share repurchase program for up to $250 million, which was initiated in the third quarter of 2015 and completed in the fourth quarter of 2015. As of December 31, 2015, we repurchased 11,326,122 shares at an aggregate cost of $250 million. Please read Note 17—Capital Stock for additional information.

The following table sets forth the per share high and low closing prices for our common stock as reported on the NYSE for the periods presented:

	High	Low
2016:		
First Quarter (through February 8, 2016)	$13.09	$9.88
2015:		
Fourth Quarter	$23.70	$10.02
Third Quarter	$30.07	$19.68
Second Quarter	$34.16	$29.25
First Quarter	$31.43	$26.06
2014:		
Fourth Quarter	$34.76	$27.13
Third Quarter	$34.28	$26.55
Second Quarter	$36.14	$24.80
First Quarter	$24.94	$19.57

We have paid no cash dividends on our common stock and have no current intention of doing so. Any future determinations to pay cash dividends will be at the discretion of our Board of Directors, subject to applicable limitations under Delaware law, and will be dependent upon our results of operations, financial condition, contractual restrictions and other factors deemed relevant by our Board of Directors.

Registration Rights Agreement. Commensurate on the Plan Effective Date, we entered into a registration rights agreement (the “Registration Rights Agreement”) with Franklin Advisers, Inc. At any time prior to the five-year anniversary of the Plan Effective Date, any one or more holders of Registrable Securities, as defined in the Registration Rights Agreement, may request to sell all or any portion of their Registrable Securities in an underwritten offering, subject to certain exceptions provided for in the Registration Rights Agreement. In addition, holders of Registrable Securities may request to sell all or any portion of their Registrable Securities in a non-underwritten offering by providing notice to us no later than two business days (or in certain circumstances five business days) prior to the expected date of such an offering, subject to certain exceptions. Further, when we propose to offer shares in an underwritten offering, whether for our own account or the account of others, holders of Registrable Securities will be entitled to request that their Registrable Securities be included in such offering, subject to specific exceptions. The registration rights granted in the Registration Rights Agreement are subject to customary indemnification and contribution provisions, as well as customary restrictions such as minimums, blackout periods and, if a registration is for an underwritten offering, limitations on the number of shares to be included in the underwritten offering may be imposed by the managing underwriter. Registrable Securities shall cease to constitute Registrable Securities upon the earliest to occur of: (i) the date on which such securities are disposed of pursuant to an effective registration statement under the Securities Act of 1933, as amended (the “Securities Act”); (ii) the date on which such securities are disposed of pursuant to Rule 144 (or any successor provision) promulgated under the Securities Act; (iii) with respect to the Registrable Securities held by any Holder (as defined in the Registration Rights Agreement), any time that such Holder beneficially owns (as defined in Rule 13d-3 under Securities Exchange Act of 1934, as amended (the “Exchange Act”)) Registrable Securities representing less than one percent of the then outstanding common stock and is permitted to sell such Registrable Securities under Rule 144(b)(1); and (iv) the date on which such securities cease to be outstanding.

Stockholder Return Performance Presentation. The following graph compares the cumulative total stockholder return from October 3, 2012, the date our common stock began trading following the Plan Effective Date, through December 31, 2015, for our current existing common stock, the S&P Midcap 400 index and a customized peer group. Because the value of Legacy Dynegy’s old common stock bears no relation to the value of our existing common stock, the graph below reflects only our current existing common stock. The peer group for the fiscal year ended December 31, 2015, which we refer to as the “New Peer Group,” is comprised of Calpine Corp., NRG Energy Inc. and Talen Energy Corporation (“Talen Energy”). The peer group for the fiscal year ended December 31, 2014 and prior periods, which we refer to as the “Old Peer Group,” is comprised of Calpine Corp. and NRG Energy Inc.

The graph tracks the performance of a $100 investment in our current existing common stock, in the peer group and the index (with the reinvestment of all dividends) from October 3, 2012 through December 31, 2015.

	October 3, 2012	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
Dynegy Inc.	$100.00	$99.12	$111.50	$157.25	$69.43
S&P Midcap 400	$100.00	$104.44	$139.42	$153.04	$149.71
Old Peer Group	$100.00	$102.88	$118.36	$122.99	$67.51
New Peer Group (1)	$100.00	$102.88	$118.36	$122.99	$67.51

(1) Talen Energy was added to Dynegy's peer group for the fiscal year ended December 31, 2015. However, as it became publicly traded effective May 18, 2015, it had no market capitalization as of December 31, 2014, and the stock performance of the New Peer Group, as calculated, was equivalent to that of the Old Peer Group.

The stock price performance included in this graph is not necessarily indicative of future stock price performance. The above stock price performance comparison and related discussion is not deemed to be incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act or under the Exchange Act or otherwise, except to the extent that we specifically incorporate this stock price performance comparison and related discussion by reference, and is not otherwise deemed "filed" under the Securities Act or Exchange Act.

Purchases of Equity Securities. The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended December 31, 2015:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 - October 31	2,629,056	$22.82	2,629,056	$—
November 1 - November 30	3,700,767	$17.09	3,700,767	$—
December 1 - December 31	—	$—	—	$—
Total	6,329,823	$19.47	6,329,823	$—

(1) On August 3, 2015, our Board of Directors authorized a share repurchase program for up to $250 million, which was initiated in the third quarter of 2015 and completed in the fourth quarter of 2015. The shares were purchased in the open market at prevailing market prices.

Securities Authorized for Issuance Under Equity Compensation Plans. Please read Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding securities authorized for issuance under our equity compensation plans.

Item 6. Selected Financial Data

The selected financial information presented below as of December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013, was derived from, and is qualified by, reference to our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

As a result of the application of fresh-start accounting as of October 1, 2012, following our reorganization, the financial statements on or prior to October 1, 2012 are not comparable with the financial statements after October 1, 2012. References to “Successor” refer to the Company after October 1, 2012, after giving effect to the application of fresh-start accounting. References to “Predecessor” refer to the Company on or prior to October 1, 2012.

(in millions, except per share data)	Successor Year Ended December 31, 2015 (1)	Year Ended December 31, 2014	Year Ended December 31, 2013 (2)	October 2 Through December 31, 2012	Predecessor January 1 Through October 1, 2012 (3)(4)	Year Ended December 31, 2011 (5)
Statements of Operations Data:						
Revenues	$3,870	$ 2,497	$1,466	$312	$981	$1,333
Depreciation expense	$(587)	$ (247)	$(216)	$(45)	$(110)	$(295)
Impairments	$(99)	$ —	$—	$—	$—	$(5)
General and administrative expense	$(128)	$ (114)	$(97)	$(22)	$(56)	$(102)
Operating income (loss)	$64	$ (19)	$(318)	$(104)	$5	$(189)
Bankruptcy reorganization items, net	$—	$ 3	$(1)	$(3)	$1,037	$(52)
Interest expense and debt extinguishment costs (6)	$(546)	$ (223)	$(108)	$(16)	$(120)	$(369)
Income tax benefit	$474	$ 1	$58	$—	$9	$144
Income (loss) from continuing operations	$47	$ (267)	$(359)	$(113)	$130	$(431)
Income (loss) from discontinued operations, net of taxes (7)	$—	$ —	$3	$6	$(162)	$(509)
Net income (loss)	$47	$ (267)	$(356)	$(107)	$(32)	$(940)
Net income (loss) attributable to Dynegy Inc.	$50	$ (273)	$(356)	$(107)	$(32)	$(940)
Basic earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders (8)	$0.22	$ (2.65)	$(3.59)	$(1.13)	N/A	N/A
Basic earnings per share from discontinued operations attributable to Dynegy Inc. common stockholders (8)	$—	$ —	$0.03	$0.06	N/A	N/A
Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders (8)	$0.22	$ (2.65)	$(3.56)	$(1.07)	N/A	N/A
Cash Flow Data:						
Net cash provided by (used in) operating activities	$94	$ 163	$175	$(44)	$(37)	$(1)
Net cash provided by (used in) investing activities	$(1,194)	$ (5,262)	$474	$265	$278	$(229)
Net cash provided by (used in) financing activities	$(265)	$ 6,126	$(154)	$(328)	$(184)	$375
Capital expenditures, acquisitions and investments	$(6,353)	$ (132)	$136	$(46)	$193	$(21)

(amounts in millions)	Successor December 31, 2015 (1)	2014	2013	2012	Predecessor December 31, 2011
Balance Sheet Data:					
Current assets	$1,945	$2,674	$1,685	$1,043	$3,569
Current liabilities	$812	$681	$721	$347	$3,051
Property, plant and equipment, net	$8,347	$3,255	$3,315	$3,022	$2,821
Total assets	$11,539	$11,232	$5,291	$4,535	$8,311
Current portion of long-term debt	$83	$31	$13	$29	$7
Long-term debt (excluding current portion) (9)	$7,206	$7,075	$1,979	$1,386	$1,069

Total equity	$2,919	$3,023	$2,207	$2,503	$32

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(1) Our 2015 financial statements only reflect the impacts of the EquiPower and Duke Midwest Acquisitions subsequent to April 1, 2015 and April 2, 2015, respectively. Please read Note 3—Acquisitions for further discussion.

(2) We completed the acquisition of AER effective December 2, 2013; therefore, the results of our IPH segment are only included subsequent to December 1, 2013. Please read Note 3—Acquisitions for further discussion.

(3) We completed the acquisition of DMG effective June 5, 2012; therefore, the results of our Coal segment are only included subsequent to June 5, 2012.

(4) The results of operations for the Predecessor period January 1, 2012 through October 1, 2012 include the effects of the Plan.

(5) We completed the transfer of DMG effective September 1, 2011; therefore, the results of our Coal segment are only included prior to September 1, 2011.

(6) The years ended December 31, 2013 and 2011 include $11 million and $21 million of debt extinguishment costs, respectively.

(7) Discontinued operations include the results of operations from the debtor entities of DNE. Please read Note 21—Discontinued Operations for further discussion of the sale of the DNE facilities.

(8) Although Legacy Dynegy's shares were publicly traded, DH did not have any publicly traded shares prior to the merger; therefore, no earnings (loss) per share is presented for the Predecessor.

(9) The years ended December 31, 2015 and 2014 include $5.1 billion related to our Notes issued on October 27, 2014. Please read Note 13—Debt for further discussion of Acquisitions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the consolidated financial statements and the notes thereto included in this report.

OVERVIEW

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our consolidated financial statements: (i) Coal, (ii) IPH and (iii) Gas.

On April 1, 2015, we completed the acquisition of EquiPower Resources Corp. and Brayton Point Holdings, LLC from Energy Capital Partners for an aggregate base purchase price of approximately $3.35 billion in cash plus $105 million in common stock of Dynegy (the "EquiPower Acquisition"), subject to certain adjustments. On April 2, 2015, we completed the acquisition of Duke Energy's commercial generation assets and retail business in the Midwest for a base purchase price of approximately $2.8 billion in cash (the "Duke Midwest Acquisition"), subject to certain adjustments. With these transactions, we own approximately 26,000 MW of generating capacity in eight states and also provide retail electricity to approximately 931,000 residential customers and approximately 41,000 commercial, industrial and municipal customers in Illinois, Ohio and Pennsylvania.

On August 3, 2015, our Board of Directors authorized a share repurchase program for up to $250 million, initiated in the third quarter of 2015, which was completed in the fourth quarter of 2015. The shares were purchased in the open market at prevailing market prices. As of December 31, 2015, we repurchased 11,326,122 shares at an aggregate cost of $250 million.

On November 5, 2015, Dynegy announced that it expects to retire the final two units at the 465-megawatt Wood River Power Station in Alton, Illinois in mid-2016, subject to the approval of MISO. The decision to retire the Wood River facility was the result of a strategic review performed in the third quarter of 2015, and was primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market.

Business Discussion

We generate earnings and cash flows in the three segments of our power generation business through sales of electric energy, capacity and ancillary services. Primary factors affecting our earnings and cash flows include:

- prices for power, natural gas, coal and fuel oil, which in turn are largely driven by supply and demand. Demand for power can vary due to weather and general economic conditions, among other things. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation;
- the relationship between electricity prices and prices for natural gas and coal, commonly referred to as the "spark spread" and "dark spread," respectively, which impacts the margin we earn on the electricity we generate; and
- our ability to enter into commercial transactions to mitigate short- and medium-term earnings volatility and our ability to manage our liquidity requirements resulting from potential changes in collateral requirements as prices move.

Other factors that have affected, and are expected to continue to affect, earnings and cash flows for the power generation business include:

- transmission constraints, congestion, and other factors that can affect the price differential between the locations where we deliver generated power and the liquid market hub;
- our ability to control capital expenditures, which primarily include maintenance, safety, environmental and reliability projects, and to control operating expenses through disciplined management;
- our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, low-cost operations;
- our ability to optimize our assets through targeted investment in cost effective technology enhancements, such as turbine uprates, or efficiency improvements;
- our ability to operate and market production from our facilities during periods of planned/unplanned electric transmission outages;
- our ability to post the collateral necessary to execute our commercial strategy;
- the cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive. Please read Item 1. Business—Environmental Matters for further discussion;

- market supply conditions resulting from federal and regional renewable power mandates and initiatives or other state-led initiatives;

- our ability to appropriately manage our coal inventory levels, which are dependent upon the continued performance of the mines, railroads and barges for deliveries of coal in a consistent and timely manner, and its impact on our ability to serve the critical winter and summer on-peak loads;
- costs of transportation related to coal deliveries;
- regional renewable energy mandates and initiatives that may alter supply conditions within an ISO and our generating units' positions in the aggregate supply stack;
- changes in MISO, PJM, CAISO and ISO-NE market design or associated rules, including the resulting effect on future capacity revenues from changes in the existing bilateral MISO capacity markets and the existing bilateral CAISO resource adequacy markets;
- our ability to maintain and operate our plants in a manner that ensures we receive full capacity payments under our various tolling agreements;
- our ability to mitigate forced outage risk, including managing risk associated with capacity performance in PJM and new performance incentives in ISO-NE;
- our ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- access to capital markets on reasonable terms, interest rates and other costs of liquidity;
- interest expense; and
- income taxes, which will be impacted by our ability to realize value from our NOLs and AMT credits.

Please read "Item 1A. Risk Factors" for additional factors that could affect our future operating results, financial condition and cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, contractual obligations, capital expenditures (including required environmental expenditures) and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll. Our primary sources of liquidity are cash flows from operations, cash on hand and amounts available under our revolver and letter of credit ("LC") facilities.

IPH and its direct and indirect subsidiaries are organized into ring-fenced groups in order to maintain corporate separateness from Dynegy and our other legal entities. Certain of the entities in the IPH segment, including Genco, have an independent director whose consent is required for certain corporate actions, including material transactions with affiliates. Further, entities within the IPH segment present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Furthermore, they pay liabilities from their own funds, conduct business in their own names and have restrictions on pledging their assets for the benefit of certain other persons. These provisions restrict our ability to move cash out of these entities without meeting certain requirements as set forth in the governing documents.

In connection with the closings of the Acquisitions, we entered into amendments to the Credit Agreement which provide for incremental revolving credit facilities that expand the credit available to us by an aggregate of $950 million which is used to support our collateral and liquidity requirements. The loans issued pursuant to these facilities bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio. As of November 10, 2015, our interest rate margin on our Revolving Facility was decreased from 2.75 percent to 2.25 percent per annum and the commitment fees on the unutilized portion of the facility decreased from 0.5 percent to 0.375 percent.

On March 27, 2015, IPM entered into a letter of credit facility with an issuing bank for up to $25 million. The facility, which is collateralized by receivables, has a two-year tenor and may be extended if agreed to by both parties for one additional year. Interest on the facility is LIBOR plus 500 basis points on issued letters of credit. At December 31, 2015, there was approximately $25 million outstanding under this letter of credit facility. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

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Liquidity. The following table summarizes our liquidity position at December 31, 2015.

	December 31, 2015		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolving Facility and LC capacity (3)	$1,480	$48	$1,528
Less: Outstanding letters of credit	(475)	(45)	(520)
Revolving Facility and LC availability	1,005	3	1,008
Cash and cash equivalents	443	62	505
Total available liquidity (4)	$1,448	$65	$1,513

(1) Includes Cash and cash equivalents of $61 million related to Genco.

(2) As previously discussed, due to the ring-fenced nature of IPH, cash at the IPH and Genco entities may not be moved out of these entities without meeting certain criteria. However, cash at these entities is available to support current operations of these entities.

(3) Dynegy Inc. includes (i) $950 million of aggregate available capacity related to our incremental revolving credit facilities, (ii) $475 million of available capacity related to the five-year senior secured revolving credit facility and (iii) $55 million related to a letter of credit. IPH includes (i) $25 million related to the two-year secured letter of credit facility and (ii) $23 million related to our fully cash collateralized letter of credit and reimbursement agreement. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

(4) On December 2, 2013, Dynegy and Illinois Power Resources, LLC entered into an intercompany revolving promissory note of $25 million. At December 31, 2015, there was $25 million outstanding on the note, which is not reflected in the table above.

The following table presents net cash from operating, investing and financing activities for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Net cash provided by operating activities	$94	$163	$175
Net cash provided by (used in) investing activities	$(1,194)	$(5,262)	$474
Net cash provided by (used in) financing activities	$(265)	$6,126	$(154)

Operating Activities

Historical Operating Cash Flows. Cash provided by operations totaled $94 million for the year ended December 31, 2015. During the period, our power generation business provided cash of $888 million primarily due to the operation of our power generation facilities and our retail operations. Corporate and other activities used cash of $588 million primarily due to interest payments on our various debt agreements of $490 million and payments for acquisition-related costs of $115 million, offset by $17 million related to the Ponderosa Pine Energy, LLC cash receipt. Changes in working capital and other, including general and administrative expenses, used cash of $206 million, net, during the period.

Cash provided by operations totaled $163 million for the year ended December 31, 2014. During the period, our power generation business provided cash of $451 million primarily due to the operation of our power generation facilities and our retail operations. Corporate and other activities used cash of $230 million primarily due to interest payments on our various debt agreements of $193 million and payments for acquisition-related costs of $24 million. In addition, changes in working capital and other, including general and administrative expenses, used cash of approximately $58 million.

Cash provided by operations totaled $175 million for the year ended December 31, 2013. During the period, our power generation business provided cash of $199 million primarily due to the operation of our power generation facilities, partially offset by interest payments to service debt related to the DPC and DMG credit agreements. Corporate and other activities used cash of approximately $80 million primarily due to interest payments related to our Credit Agreement and Senior Notes, payments to advisors, employee-related payments and other general and administrative expenses. In addition, we had $56 million in positive working capital and other changes, which includes $34 million for the return of collateral.

Future Operating Cash Flows. Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the price of power, the prices of natural gas, coal, and fuel oil and their correlation to power prices, collateral requirements, the value of capacity and ancillary services, the run-time of our generating facilities, the effectiveness of our commercial strategy, legal, environmental and regulatory requirements, and our ability to achieve the cost savings

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contemplated in our PRIDE initiative.

Collateral Postings. We use a portion of our capital resources in the form of cash and letters of credit to satisfy counterparty collateral demands. The following table summarizes our collateral postings to third parties by legal entity at December 31, 2015 and 2014:

(amounts in millions)	December 31, 2015	December 31, 2014
Dynegy Inc.:		
Cash (1)	$159	$14
Letters of credit	475	178
Total Dynegy Inc.	634	192
IPH:		
Cash (1) (2)	11	32
Letters of credit (3) (4)	45	10
Total IPH	56	42
Total	$690	$234

(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets on our consolidated balance sheets. As of December 31, 2015 and 2014, $106 million and $9 million of cash posted as collateral were netted against Liabilities from risk management activities on our consolidated balance sheets, respectively.

(2) Includes cash of $1 million and $5 million related to Genco as of December 31, 2015 and 2014, respectively.

(3) Includes letters of credit of approximately $20 million and $10 million outstanding as of December 31, 2015 and 2014 related to the cash-backed LC facility at IPM. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

(4) Includes letters of credit of approximately $25 million related to the two-year secured letter of credit facility entered into by IPM and collateralized by receivables.

Collateral postings increased from December 31, 2014 to December 31, 2015 primarily due to acquisition-related collateral requirements. In addition to cash and letters of credit posted as collateral, we have increased the number of counterparties that participate in our first priority lien program. The additional liens were granted as collateral under certain of our derivative agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to the counterparties under such agreements. The fair value of our derivatives collateralized by first priority liens included liabilities of $167 million and $141 million at December 31, 2015 and 2014, respectively. We expect counterparties' future collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. Our ability to use economic hedging instruments in the future could be limited due to the potential collateral requirements of such instruments.

Investing Activities

Capital Expenditures. Our capital spending by reportable segment was as follows:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Coal	$87	$39	$42
IPH	63	45	1
Gas	112	44	53
Other	13	4	2
Total (1)	$275	$132	$98

(1) Includes capitalized interest of $12 million, $9 million, and $2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Capital spending in our Coal and IPH segments primarily consisted of environmental and maintenance capital projects. Capital spending in our Gas segment primarily consisted of maintenance projects.

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Other Investing Activities. During the year ended December 31, 2015, we paid $6.078 billion in cash, net of cash acquired, in connection with the Acquisitions. In addition, there was a $5.148 billion cash inflow related to the release of restricted cash as a result of closing the Acquisitions. We also received a distribution of $11 million from our unconsolidated investment in Elwood Energy LLC, of which $8 million is considered a return of capital. Please read Note 13—Debt and Note 3—Acquisitions for further discussion.

During the year ended December 31, 2014, there was a $5.148 billion cash outflow related to restricted cash balances due to escrow requirements associated with the Notes issued in 2014, offset by an $18 million cash inflow primarily related to cash proceeds received from the sale of our 50 percent interest in Nevada Cogeneration #2, a partnership that owns Black Mountain. Please read Note 13—Debt and Note 11—Unconsolidated Investments for further discussion.

During the year ended December 31, 2013, there was a $335 million cash inflow related to restricted cash balances due to the release of cash collateral associated with the DPC LC and DMG LC facilities. A portion of these proceeds were used to repay in full and terminate commitments under the DMG and DPC credit agreements as further discussed below. As a result of repaying these credit agreements, all of our restricted cash was released. In addition, in connection with the AER Acquisition, we acquired $234 million in cash. Please read Note 3—Acquisitions for further discussion.

Future Cash Flow from Investing Activities. We expect capital expenditures for 2016 to be approximately $361 million, which is comprised of $72 million, $88 million, $193 million and $8 million in Coal, IPH, Gas, and Other, respectively. The capital budget is subject to revision as opportunities arise or circumstances change.

Financing Activities

Historical Cash Flow from Financing Activities. Cash used in financing activities totaled $265 million for the year ended December 31, 2015 primarily due to (i) $250 million of payments related to our share repurchase program, (ii) $37 million in financing costs related to our debt and equity issuances, (iii) $31 million in repayments associated with our inventory financing agreements and term loan, (iv) $23 million in dividend payments on our Mandatory Convertible Preferred Stock and (v) $17 million in interest rate swap settlement payments, offset by $97 million in proceeds received related to inventory financing agreements. Please read Note 13—Debt and Note 17—Capital Stock for further discussion.

Cash provided by financing activities totaled $6.126 billion during the year ended December 31, 2014 primarily due to (i) $5.1 billion in proceeds from borrowings on the Notes issued in 2014, (ii) $744 million and $400 million in proceeds, net of underwriting discounts and commissions, from the Common Stock Offering and the Mandatory Convertible Preferred Stock Offering, respectively and (iii) $6 million in net proceeds received related to the emissions repurchase agreements, offset by (i) $57 million in financing costs in connection with the Notes issued in 2014, the Credit Agreement, the Senior Notes and a letter of credit with an issuing bank, (ii) $18 million in interest rate swap settlement payments and (iii) $8 million in principal payments of borrowings on the seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan”). Please read Note 13—Debt and Note 17—Capital Stock for further discussion.

Cash used in financing activities totaled $154 million during the year ended December 31, 2013 due to (i) $1.913 billion in repayments of borrowings in full on the DMG and DPC Credit Agreements and the Tranche B-1 Term Loan, including $59 million in prepayment penalties associated with the early termination of the DMG and DPC Credit Agreements, (ii) $4 million in principal payments of borrowings on the Tranche B-2 Term Loan and (iii) $5 million in interest rate swap settlement payments during the fourth quarter 2013, offset by (i) $1.751 billion in proceeds from borrowings on the Credit Agreement and Senior Notes, net of financing costs and (ii) $17 million in proceeds associated with the emissions repurchase agreements. Please read Note 13—Debt for further discussion.

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Summarized Debt and Other Obligations. The following table depicts our third party debt obligations, and the extent to which they are secured as of December 31, 2015 and 2014:

(amounts in millions)	December 31, 2015	December 31, 2014
Dynegy Inc.:		
Secured obligations	$780	$788
Unsecured obligations (1)	5,600	500
Inventory Financing Agreements	136	23
Equipment Financing Agreements	75	—
Unamortized discount	(16)	(3)
Dynegy Finance I, Inc.:		
Secured obligations (1)	—	2,040
Dynegy Finance II, Inc.:		
Secured obligations (1)	—	3,060
Genco:		
Unsecured obligations	825	825
Unamortized discount	(111)	(127)
Total long-term debt	$7,289	$7,106

(1) At December 31, 2014, the Finance I Notes and the Finance II Notes were secured by first-priority liens on amounts in the applicable escrow account which was classified as long-term Restricted cash in our consolidated balance sheet. Upon closing of the Acquisitions, these debt obligations became Dynegy Inc.'s general unsecured obligations. Please read Note 13—Debt for further discussion.

Future Cash Flow from Financing Activities. As a result of our issuance of $400 million of mandatory convertible preferred stock on October 14, 2014, we are obligated to pay dividends of $5.4 million quarterly on a cumulative basis when declared by our Board of Directors or upon conversion. We may pay declared dividends in cash or, subject to certain limitations, in shares of our common stock or by delivery of any combination of cash and shares of our common stock. Our future cash flows from financing activities will include principal payments on our debt instruments as they become due, as well as periodic payments to settle our interest rate swap agreements. Please read Note 17—Capital Stock for further discussion.

Financing Trigger Events. Our debt instruments and certain of our other financial obligations and all the Genco Senior Notes include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events include the violation of covenants (including, in the case of the Credit Agreement under certain circumstances, the senior secured leverage ratio covenant discussed below), defaults on scheduled principal or interest payments, including any indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions, insolvency events, acceleration of other financial obligations and, in the case of the Credit Agreement, change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events. Please read Note 13—Debt for further discussion.

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Financial Covenants

Credit Agreement. On April 23, 2013, we entered into the Credit Agreement. The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a financial covenant specifying required thresholds for our senior secured leverage ratio calculated on a rolling four quarters basis. Under the Credit Agreement, if Dynegy uses 25 percent or more of its Revolving Facility, Dynegy must be in compliance with the following ratios for the respective periods:

Compliance Period	Consolidated Senior Secured Net Debt to Consolidated Adjusted EBITDA (1)
September 30, 2013 through December 31, 2013	5.00: 1.00
March 31, 2014 through December 31, 2014	4.00: 1.00
March 31, 2015 through December 31, 2015	4.75: 1.00
March 31, 2016 through December 31, 2016	3.75: 1.00
March 31, 2017 and Thereafter	3.00: 1.00

(1) For purposes of calculating Net Debt, as defined within the Credit Agreement, we may only apply a maximum of $150 million in cash to our outstanding secured debt.

Our revolver usage at December 31, 2015 was 29 percent of the aggregate revolver commitment due to outstanding letters of credit; therefore, we were required to test the covenant. Based on the calculation outlined in the Credit Agreement, we are in compliance at December 31, 2015.

Genco Senior Notes. Genco's indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make principal or interest payments on subordinated borrowings, to make loans to or investments in affiliates or to incur additional external, third-party indebtedness. The following table summarizes these required ratios:

	Required Ratio
Restricted payment interest coverage ratio (1)	≥1.75
Additional indebtedness interest coverage ratio (2)	≥2.50
Additional indebtedness debt-to-capital ratio (2)	≤60%

(1) As of the date of a restricted payment, as defined, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods.

(2) Ratios must be computed on a pro forma basis considering the additional indebtedness to be incurred and the related interest expense. Other borrowings from third-party external sources are included in the definition of indebtedness and are subject to these incurrence tests.

Based on December 31, 2015 calculations, Genco's interest coverage ratios are less than the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

Please read Note 13—Debt for further discussion.

Dividends. We have paid no cash dividends on our common stock and have no current intention of doing so. Any future determinations to pay cash dividends will be at the discretion of our Board of Directors, subject to applicable limitations under Delaware law, and will be dependent upon our results of operations, financial condition, contractual restrictions and other factors deemed relevant by our Board of Directors.

We pay quarterly dividends on our Mandatory Convertible Preferred Stock on February 1, May 1, August 1, and November 1 of each year, if declared by our Board of Directors. For the year ended December 31, 2015, we paid an aggregate of $23 million in dividends. We paid no dividends during 2014.

On January 5, 2016, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million in the aggregate.

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Credit Ratings

Our current ratings are as follows:

	Moody's	S&P
Dynegy Inc.:		
Corporate Family Rating	B2	B+
Senior Secured	Ba3	BB
Senior Unsecured	B3	B+
Genco:		
Senior Unsecured	B3	CCC+

Disclosure of Contractual Obligations

We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities.

The following table summarizes the contractual obligations of the Company and its consolidated subsidiaries as of December 31, 2015. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Expiration by Period				
(amounts in millions)	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Long-term debt (including current portion)	$7,341	$66	$394	$3,106	$3,775
Interest payments on debt	3,293	523	1,024	792	954
Coal purchase commitments	1,447	638	532	277	—
Coal transportation	904	131	158	160	455
Contractual service agreements	541	154	165	192	30
Gas purchase commitments	254	200	54	—	—
Gas transportation	205	37	60	49	59
Environmental compliance obligations	186	29	95	62	—
Pension funding obligations	232	—	33	47	152
Operating leases	62	16	11	10	25
Other obligations	105	24	44	7	30
Total contractual obligations	$14,570	$1,818	$2,570	$4,702	$5,480

Long-Term Debt (including Current Portion). Long-term debt includes amounts related to the Notes, the Senior Notes, the Credit Agreement, the Genco Senior Notes, and the Inventory Financing Agreements. Amounts do not include unamortized discounts. Please read Note 13—Debt for further discussion.

Interest Payments on Debt. Interest payments on debt represent estimated periodic interest payment obligations associated with the Notes, the Senior Notes, the Credit Agreement, the Genco Senior Notes, and the Inventory Financing Agreements. Amounts include the impact of interest rate swap agreements. Please read Note 13—Debt for further discussion.

Coal Purchase Commitments. At December 31, 2015, our subsidiaries had contracts in place to purchase coal for various generation facilities. The amounts in the table reflect our minimum purchase obligations. To the extent forecasted volumes have not been priced but are subject to a price collar structure, the obligations have been calculated using the minimum purchase price of the collar.

Coal Transportation. At December 31, 2015, we had long-term coal transportation contracts in place. We also had long-term rail car leases in place. The amounts included in Coal transportation reflect our minimum purchase obligations based on the terms of the contracts.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. Under certain of our contractual service agreements in which we receive maintenance and capital

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improvements for our gas-fueled generation fleet, we have obligations to purchase uprate equipment. We currently estimate these agreements will be in effect for a period of 15 or more years. Either party can terminate the agreements based on certain events as specified in the contracts. The table above includes our current estimate of payments under the contracts through 2020 based on anticipated timing of outages and are subject to change as outage dates move. As of December 31, 2015, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $356 million and $431 million in the event all contracts are terminated by us or the counterparty, respectively. Please read Note 16—Commitments and Contingencies—Other Commitments and Contingencies for further discussion.

Gas Purchase Commitments. At December 31, 2015, our subsidiaries had contracts in place to purchase gas for various generation facilities. The amounts in the table reflect our minimum purchase obligations.

Gas Transportation. Gas transportation includes fixed transport capacity obligations associated with fuel procurement for our gas plants.

Environmental Compliance Obligations. The table above includes estimated costs under a third party contract, excluding capitalized interest, for the completion of scheduled milestones related to the installation of the Newton facility scrubber systems, such that the IPH fleet will comply with certain SO_2 emission limits approved in the variance granted by the IPCB in November 2013. Please read Business—Environmental Matters—IPH Variance for further discussion. The first milestone relating to the engineering design was completed in July 2015, while the last milestone relates to major equipment components being placed into final position on or before September 1, 2019. We currently estimate this contract will be in effect for a period of four or more years. We are currently scheduled to complete the Newton scrubber project by the end of 2019 with minimal costs anticipated in 2020. Either party can terminate this contract based on certain events as specified in the contract. In February 2016, Genco issued a notice to the third party contractor constructing the scrubber systems directing them to temporarily suspend a portion of the work being performed.

Pension Funding Obligations. Amounts include our minimum required contributions to our defined benefit pension plans through 2025 as determined by our actuary and are subject to change based on actual results of the plan. We may elect to make voluntary contributions in 2016 which would decrease future funding obligations. Please read Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans for further discussion.

Operating Leases. Operating leases include minimum lease payment obligations associated with office space, office equipment, and land leases. Also included in operating leases are two charter agreements previously utilized in our former global liquids business.

Other Obligations. Other obligations primarily include the following:

- $48 million related to limestone purchase commitments;
- $23 million related to interconnection services; and
- Other miscellaneous items which are individually insignificant.

Commitments and Contingencies

Please read Note 16—Commitments and Contingencies, which is incorporated herein by reference, for further discussion of our material commitments and contingencies.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2015.

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the years ended December 31, 2015, 2014 and 2013. At the end of this section, we have included our business outlook for each segment.

We report the results of our power generation business primarily as three separate segments in our consolidated financial statements: (i) Coal, (ii) IPH and (iii) Gas. Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). All references to hedging within this Form 10-K relate to economic hedging activities as we do not elect hedge accounting.

On December 2, 2013, we completed the AER Acquisition; therefore, the results of our IPH segment are included in our 2013 consolidated results for the period of December 2, 2013 through December 31, 2013. Please read Note 3—Acquisitions—AER Transaction Agreement for further discussion.

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We completed the EquiPower Acquisition and Duke Midwest Acquisition on April 1, 2015 and April 2, 2015, respectively; therefore, the results of our newly acquired plants within our Coal and Gas segments are included in our 2015 consolidated results from the respective acquisition date through December 31, 2015. Please read Note 3—Acquisitions—ECP Purchase Agreements and Duke Midwest Purchase Agreement for further discussion.

Non-GAAP Performance Measures. In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our GAAP results and the accompanying reconciliations to corresponding GAAP financial measures included in the tables below, may provide a more complete understanding of factors and trends affecting our business. These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are by definition an incomplete understanding of Dynegy and must be considered in conjunction with GAAP measures.

We believe that the historical non-GAAP measures disclosed in our filings are only useful as an additional tool to help management and investors make informed decisions about our financial and operating performance. By definition, non-GAAP measures do not give a full understanding of Dynegy; therefore, to be truly valuable, they must be used in conjunction with the comparable GAAP measures. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit) and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of certain assets, (ii) the impacts of mark-to-market changes on derivatives related to our generation portfolio, as well as interest rate swaps and warrants, (iii) the impact of impairment charges and certain other costs such as those associated with acquisitions, and (iv) other material items.

We believe EBITDA and Adjusted EBITDA provide meaningful representations of our operating performance. We consider EBITDA as another way to measure financial performance on an ongoing basis. Adjusted EBITDA is meant to reflect the operating performance of our entire power generation fleet for the period presented; consequently, it excludes the impact of mark-to-market accounting, impairment charges and other items that could be considered "non-operating" or "non-core" in nature. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers and evaluate overall financial performance, we believe they provide useful information for our investors. In addition, many analysts, fund managers and other stakeholders that communicate with us typically request our financial results in an EBITDA and Adjusted EBITDA format.

As prescribed by the SEC, when EBITDA or Adjusted EBITDA is discussed in reference to performance on a consolidated basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is Net income (loss). Management does not analyze interest expense and income taxes on a segment level; therefore, the most directly comparable GAAP financial measure to EBITDA or Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

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Consolidated Summary Financial Information—Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

The following table provides summary financial data regarding our consolidated results of operations for the years ended December 31, 2015 and 2014, respectively:

(amounts in millions)	Year Ended December 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues				
Energy	$3,054	$2,290	$ 764	33 %
Capacity	671	293	378	129 %
Mark-to-market income (loss), net	127	(28)	155	NM
Contract amortization	(83)	(111)	28	25 %
Other (1)	101	53	48	91 %
Total revenues	3,870	2,497	1,373	55 %
Cost of sales, excluding depreciation expense	(2,028)	(1,661)	(367)	(22)%
Gross margin	1,842	836	1,006	120 %
Operating and maintenance expense	(839)	(477)	(362)	(76)%
Depreciation expense	(587)	(247)	(340)	(138)%
Impairments	(99)	—	(99)	NM
Gain (loss) on sale of assets, net	(1)	18	(19)	(106)%
General and administrative expense	(128)	(114)	(14)	(12)%
Acquisition and integration costs	(124)	(35)	(89)	NM
Operating income (loss)	64	(19)	83	NM
Bankruptcy reorganization items, net	—	3	(3)	(100)%
Earnings from unconsolidated investments	1	10	(9)	(90)%
Interest expense	(546)	(223)	(323)	(145)%
Other income and expense, net	54	(39)	93	238 %
Loss from continuing operations before income taxes	(427)	(268)	(159)	(59)%
Income tax benefit	474	1	473	NM
Income (loss) from continuing operations	47	(267)	314	118 %
Income from discontinued operations, net of tax	—	—	—	NM
Net income (loss)	47	(267)	314	118 %
Less: Net income (loss) attributable to noncontrolling interest	(3)	6	(9)	(150)%
Net income (loss) attributable to Dynegy Inc.	$50	$(273)	$ 323	118 %

(1) For the years ended December 31, 2015 and 2014, respectively, Other includes $42 million and $29 million in ancillary services, $17 million and $14 million in tolling revenue and $42 million and $10 million in RMR and other miscellaneous items.

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The following tables provide summary financial data regarding our operating income (loss) by segment for the years ended December 31, 2015 and 2014, respectively:

	Year Ended December 31, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$1,164	$799	$1,907	$—	$3,870
Cost of sales, excluding depreciation expense	(589)	(506)	(933)	—	(2,028)
Gross margin	575	293	974	—	1,842
Operating and maintenance expense	(431)	(215)	(197)	4	(839)
Depreciation expense	(138)	(29)	(416)	(4)	(587)
Impairments	(99)	—	—	—	(99)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(128)	(128)
Acquisition and integration costs	—	—	—	(124)	(124)
Operating income (loss)	$(93)	$49	$360	$(252)	$64

	Year Ended December 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$593	$846	$1,058	$—	$2,497
Cost of sales, excluding depreciation expense	(346)	(596)	(719)	—	(1,661)
Gross margin	247	250	339	—	836
Operating and maintenance expense	(156)	(199)	(123)	1	(477)
Depreciation expense	(51)	(37)	(155)	(4)	(247)
Gain on sale of assets, net	—	—	18	—	18
General and administrative expense	—	—	—	(114)	(114)
Acquisition and integration costs	—	(16)	—	(19)	(35)
Operating income (loss)	$40	$(2)	$79	$(136)	$(19)

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $1.373 billion from $2.497 billion for the year ended December 31, 2014 to $3.870 billion for the year ended December 31, 2015. Our newly acquired plants and higher capacity market pricing contributed to increased revenues, while mild temperatures and increased precipitation levels have lowered demand in our generation areas, resulting in lower volumes and energy prices realized by our legacy plants, compared to 2014. Mark-to-market gains on hedging transactions increased by $155 million primarily as a result of the Acquisitions and lower prices in 2015 primarily as a result of the polar vortex in 2014.

Coal segment revenues increased by $571 million, driven by $630 million in revenues from the newly acquired plants, partially offset by $59 million in lower revenues from our legacy plants. The decrease in revenues from our legacy plants was primarily driven by $94 million in lower energy revenues, net of settled hedges, as a result of lower generation volumes. This decrease was partially offset by $11 million in higher wholesale capacity revenues due to higher MISO capacity market pricing and volumes, $5 million in higher revenues from mark-to-market gains on hedging transactions and $18 million in higher retail revenues.

IPH segment revenues decreased by $47 million, driven by $197 million in lower energy revenues, net of settled hedges, as a result of lower generation volumes and power prices. This decrease was partially offset by $82 million in higher wholesale capacity revenues due to higher MISO and PJM capacity market pricing and volumes, $48 million in higher revenues from mark-to-market gains on hedging transactions, $5 million in higher retail revenues and $15 million in lower amortization on acquired intangibles.

Gas segment revenues increased by $849 million, driven by $993 million in revenues from the newly acquired plants, partially offset by $144 million in lower revenues from our legacy plants. The decrease in revenues from our legacy plants was primarily driven by $229 million in lower energy revenues, net of settled hedges, as a result of lower power prices, partially offset by higher generation volumes due to higher run times at our legacy PJM plants. Also, contributing to this decrease was $97 million in lower revenues due to the expiration of the ConEd contract at Independence. These decreases were partially offset by $44 million in higher market capacity revenues as a result of increased bilateral capacity sales at Independence and higher PJM and ISO-NE capacity market pricing, $102 million in higher revenues from mark-to-market gains on hedging transactions and $37 million in lower amortization on acquired intangibles.

Cost of Sales. Cost of sales increased by $367 million from $1.661 billion for the year ended December 31, 2014 to $2.028 billion for the year ended December 31, 2015.

Coal segment cost of sales increased by $243 million, driven by $287 million in cost of sales from the newly acquired plants, partially offset by $44 million in lower cost of sales from our legacy plants primarily due to $55 million in lower coal and freight costs as a result of lower generation volumes, partially offset by $13 million in higher retail costs.

IPH segment cost of sales decreased by $90 million, driven by $118 million in lower coal and freight costs as a result of lower generation volumes, partially offset by $16 million in higher retail costs and $16 million in lower amortization of acquired intangibles.

Gas segment cost of sales increased by $214 million, driven by $475 million in cost of sales from the newly acquired plants, partially offset by $261 million in lower cost of sales from our legacy plants primarily due to a reduction in natural gas prices which more than offset higher generation volumes primarily due to higher run times at our legacy PJM plants.

Operating and Maintenance Expense. Operating and maintenance expense increased by $362 million from $477 million for the year ended December 31, 2014 to $839 million for the year ended December 31, 2015 primarily due to $326 million in costs from the newly acquired plants and $36 million in higher costs from our legacy plants as a result of more planned outages.

Depreciation Expense. Depreciation expense increased by $340 million from $247 million for the year ended December 31, 2014 to $587 million for the year ended December 31, 2015 primarily due to the newly acquired plants.

Impairments. Impairments of $99 million for the year ended December 31, 2015 are due to our impairments of the Wood River and Brayton Point generation facilities for $74 million and $25 million, respectively. Please read Note 9—Property, Plant and Equipment for further discussion.

Gain (Loss) on Sale of Assets. Gain (loss) on sale of assets decreased by $19 million primarily due to a $17 million gain from the sale of our 50 percent ownership interest in Black Mountain in 2014, not repeated in 2015. Please read Note 11—Unconsolidated Investments for further discussion.

General and Administrative Expense. General and administrative expense increased by $14 million from $114 million for the year ended December 31, 2014 to $128 million for the year ended December 31, 2015. This increase was primarily due to higher overhead associated with the Acquisitions and higher legal fees.

Acquisition and Integration Costs. Acquisition and integration costs increased by $89 million from $35 million for the year ended December 31, 2014 to $124 million for the year ended December 31, 2015. Acquisition and integration costs for the year ended December 31, 2015 consisted of $48 million in Bridge Loan financing fees, $64 million in advisory and consulting fees and $12 million in severance, retention and payroll costs related to the Acquisitions. Acquisition and integration costs for the year ended December 31, 2014 consisted of $19 million in advisory and consulting fees related to the Acquisitions and $16 million related to the acquisition of AER. Please read Note 3—Acquisitions for further discussion.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments decreased by $9 million from $10 million for the year ended December 31, 2014 to $1 million for the year ended December 31, 2015. We received $10 million in cash distributions from Black Mountain during the year ended December 31, 2014 and recorded $1 million in earnings from our 50 percent Elwood investment during the year ended December 31, 2015. Please read Note 11—Unconsolidated Investments for further discussion.

Interest Expense. Interest expense increased by $323 million from $223 million for the year ended December 31, 2014 to $546 million for the year ended December 31, 2015 primarily due to the issuance of debt in October 2014 to finance the Acquisitions. Please read Note 13—Debt for further discussion.

Other Income and Expense, Net. Other income and expense, net increased by $93 million from expense of $39 million for the year ended December 31, 2014 to income of $54 million for the year ended December 31, 2015 primarily due to the change in the fair value of our common stock warrants.

Income Tax Benefit. We reported an income tax benefit of $474 million and $1 million for the years ended December 31, 2015 and 2014, respectively. We released $453 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition, we recorded an additional tax benefit of $21 million for discreet items

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including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance. Please read Note 3—Acquisitions for further discussion of the release of the valuation allowance.

As of December 31, 2015, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction as they arise as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more likely than not that our net deferred tax assets can be realized in the future. Please read Note 14—Income Taxes for further discussion.

Net Income (Loss) Attributable to Noncontrolling Interest. Net income (loss) attributable to noncontrolling interest decreased by $9 million from income of $6 million for the year ended December 31, 2014 to a loss of $3 million for the year ended December 31, 2015 as a result of changes in our minority shareholder's 20 percent interest in EEI.

Adjusted EBITDA — Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2015:

	Year Ended December 31, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$50
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(474)
Other items, net (1)					(54)
Interest expense					546
Earnings from unconsolidated investments					(1)
Operating income (loss)	$(93)	$49	$360	$(252)	$64
Depreciation expense	138	29	416	4	587
Amortization expense	(39)	(6)	39	—	(6)
Earnings from unconsolidated investments	—	—	1	—	1
Other items, net (1)	(1)	—	—	55	54
EBITDA	5	72	816	(193)	700
Acquisition and integration costs	—	—	—	124	124
Loss attributable to noncontrolling interest	—	3	—	—	3
Mark-to-market adjustments	(31)	(10)	(26)	—	(67)
Change in fair value of common stock warrants	—	—	—	(54)	(54)
Impairments	99	—	—	—	99
Loss on sale of assets, net	—	—	1	—	1
Cash distributions from unconsolidated investments	—	—	12	—	12
Baldwin transformer project	7	—	—	—	7
ARO accretion expense	8	12	1	—	21
Other	4	—	(1)	1	4
Adjusted EBITDA	$92	$77	$803	$(122)	$850

(1) Other items, net primarily consists of the change in fair value of our common stock warrants, the write-off of certain power generation assets and the receipt of casualty insurance proceeds.

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2014:

	Year Ended December 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(273)
Income attributable to noncontrolling interest					6
Income tax benefit					(1)
Other items, net (1)					39
Interest expense					223
Earnings from unconsolidated investments					(10)
Bankruptcy reorganization items, net					(3)
Operating income (loss)	$40	$(2)	$79	$(136)	$(19)
Depreciation expense	51	37	155	4	247
Bankruptcy reorganization items, net	—	—	—	3	3
Amortization expense	(6)	(7)	63	—	50
Earnings from unconsolidated investments	—	—	10	—	10
Other items, net (1)	—	—	—	(39)	(39)
EBITDA	85	28	307	(168)	252
Acquisition and integration costs	—	16	—	19	35
Bankruptcy reorganization items, net	—	—	—	(3)	(3)
Income attributable to noncontrolling interest	—	(6)	—	—	(6)
Mark-to-market adjustments	(32)	38	22	—	28
Change in fair value of common stock warrants	—	—	—	40	40
Gain on sale of assets, net	—	—	(18)	—	(18)
ARO accretion expense	6	6	—	—	12
Other	3	1	—	3	7
Adjusted EBITDA	$62	$83	$311	$(109)	$347

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

Adjusted EBITDA increased by $503 million from $347 million for the year ended December 31, 2014 to $850 million for the year ended December 31, 2015. The $503 million increase in Adjusted EBITDA was due to $590 million from the newly acquired plants, partially offset by an $87 million decrease from our legacy plants. The decrease from our legacy plants was driven by lower energy margin at the Coal and IPH segments primarily due to lower generation volumes as a result of mild temperatures and increased precipitation levels, as well as the expiration of the ConEd contract at Independence at the Gas segment. This decrease was partially offset by higher capacity revenues at the Coal, IPH and Gas segments and higher energy margin at the Gas segment primarily as a result of higher spark spreads and run times at our legacy PJM plants. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the years ended December 31, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Year Ended December 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$990	$552	$ 438	79 %
Capacity	156	5	151	NM
Mark-to-market income, net	37	32	5	16 %
Contract amortization	(24)	—	(24)	NM
Other (1)	5	4	1	25 %
Total operating revenues	1,164	593	571	96 %
Operating Costs				
Cost of sales	(652)	(352)	(300)	(85)%
Contract amortization	63	6	57	NM
Total operating costs	(589)	(346)	(243)	(70)%
Gross margin	575	247	328	133 %
Operating and maintenance expense	(431)	(156)	(275)	(176)%
Depreciation expense	(138)	(51)	(87)	(171)%
Impairments	(99)	—	(99)	NM
Operating income (loss)	(93)	40	(133)	NM
Depreciation expense	138	51	87	171 %
Amortization expense	(39)	(6)	(33)	NM
Other items, net	(1)	—	(1)	NM
EBITDA	5	85	(80)	(94)%
Mark-to-market adjustments	(31)	(32)	1	3 %
Impairments	99	—	99	NM
Baldwin transformer project	7	—	7	NM
ARO accretion expense	8	6	2	33 %
Other	4	3	1	33 %
Adjusted EBITDA	$92	$62	$ 30	48 %
Million Megawatt Hours Generated (5)	29.3	19.0	10.3	54 %
IMA for Coal-Fired Facilities (2)(5)	80 %	88 %		
Average Capacity Factor for Coal-Fired Facilities (3)(5)	56 %	73 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$33.50	$48.28	$ (14.78)	(31)%
Commonwealth Edison (NI Hub)	$33.98	$50.60	$ (16.62)	(33)%
Mass Hub	$48.96	$76.97	$ (28.01)	(36)%
AD Hub	$37.52	$54.86	$ (17.34)	(32)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$24.56	$32.52	$ (7.96)	(24)%
Commonwealth Edison (NI Hub)	$22.79	$30.74	$ (7.95)	(26)%

Mass Hub	$34.88	$54.58	$ (19.70)	(36)%
AD Hub	$26.40	$34.81	$ (8.41)	(24)%

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(1) For the years ended December 31, 2015 and 2014, respectively, Other includes zero and $3 million in ancillary services and $5 million and $1 million in other miscellaneous items.

(2) IMA is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. The calculation excludes certain events outside of management control such as weather related issues. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the IMA for our facilities within MISO and PJM (excluding CTs) was 87 percent and 74 percent, respectively.

(3) Reflects actual production as a percentage of available capacity. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the average capacity factors for our facilities within MISO and PJM (excluding CTs) were 61 percent and 51 percent, respectively.

(4) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.

(5) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating loss for the year ended December 31, 2015 was $93 million compared to an operating income of $40 million for the year ended December 31, 2014. Adjusted EBITDA was $92 million for the year ended December 31, 2015 compared to $62 million for the year ended December 31, 2014. The $30 million increase in Adjusted EBITDA was due to $79 million from the newly acquired plants, partially offset by a $49 million decrease from our legacy plants. The decrease from our legacy plants was driven by lower energy margin primarily due to lower generation volumes as a result of mild temperatures and increased precipitation levels, as well as higher operating and maintenance costs driven by planned outages. This decrease was partially offset by higher wholesale capacity revenues due to higher MISO capacity market pricing and volumes, as well as higher retail margins.

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IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the years ended December 31, 2015 and 2014, respectively.

(dollars in millions, except for price information)	Year Ended December 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$681	$886	$ (205)	(23)%
Capacity	124	42	82	195 %
Mark-to-market income (loss), net	10	(38)	48	126 %
Contract amortization	(25)	(40)	15	38 %
Other (1)	9	(4)	13	NM
Total operating revenues	799	846	(47)	(6)%
Operating Costs				
Cost of sales	(537)	(643)	106	16 %
Contract amortization	31	47	(16)	(34)%
Total operating costs	(506)	(596)	90	15 %
Gross margin	293	250	43	17 %
Operating and maintenance expense	(215)	(199)	(16)	(8)%
Depreciation expense	(29)	(37)	8	22 %
Acquisition and integration costs	—	(16)	16	100 %
Operating income (loss)	49	(2)	51	NM
Depreciation expense	29	37	(8)	(22)%
Amortization expense	(6)	(7)	1	14 %
EBITDA	72	28	44	157 %
Acquisition and integration costs	—	16	(16)	(100)%
Loss (income) attributable to noncontrolling interest	3	(6)	9	150 %
Mark-to-market adjustments	(10)	38	(48)	(126)%
ARO accretion expense	12	6	6	100 %
Other	—	1	(1)	(100)%
Adjusted EBITDA	$77	$83	$ (6)	(7)%
Million Megawatt Hours Generated	18.5	23.7	(5.2)	(22)%
IMA for IPH Facilities (2)	89 %	89 %		
Average Capacity Factor for IPH Facilities (3)	52 %	68 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$33.50	$48.28	$ (14.78)	(31)%
Off-Peak: Indiana (Indy Hub)	$24.56	$32.52	$ (7.96)	(24)%

(1) For the years ended December 31, 2015 and 2014, respectively, Other includes $3 million and ($7) million in ancillary services and $6 million and $3 million in other miscellaneous items.

(2) IMA is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

(3) Reflects actual production as a percentage of available capacity.

(4) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.

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Operating income for the year ended December 31, 2015 was $49 million compared to an operating loss of $2 million for the year ended December 31, 2014. Adjusted EBITDA was $77 million for the year ended December 31, 2015 compared to $83 million for the year ended December 31, 2014. The $6 million decrease in Adjusted EBITDA resulted from lower generation volumes and lower power prices driven primarily by mild temperatures and increased precipitation levels, higher operating and maintenance costs driven by planned outages, as well as lower retail gross margin. This was partially offset by higher wholesale capacity revenues due to higher MISO and PJM capacity market pricing and volumes.

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Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the years ended December 31, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Year Ended December 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$1,383	$852	$ 531	62 %
Capacity	391	246	145	59 %
Mark-to-market income (loss), net	80	(22)	102	NM
Contract amortization	(34)	(71)	37	52 %
Other (1)	87	53	34	64 %
Total operating revenues	1,907	1,058	849	80 %
Operating Costs				
Cost of sales	(928)	(727)	(201)	(28)%
Contract amortization	(5)	8	(13)	(163)%
Total operating costs	(933)	(719)	(214)	(30)%
Gross margin	974	339	635	187 %
Operating and maintenance expense	(197)	(123)	(74)	(60)%
Depreciation expense	(416)	(155)	(261)	(168)%
Gain (loss) on sale of assets, net	(1)	18	(19)	(106)%
Operating income	360	79	281	NM
Depreciation expense	416	155	261	168 %
Amortization expense	39	63	(24)	(38)%
Earnings from unconsolidated investments	1	10	(9)	(90)%
EBITDA	816	307	509	166 %
Mark-to-market adjustments	(26)	22	(48)	(218)%
Loss (gain) on sale of assets, net	1	(18)	19	106 %
Cash distributions from unconsolidated investments	12	—	12	NM
ARO accretion expense	1	—	1	NM
Other items, net	(1)	—	(1)	NM
Adjusted EBITDA	$803	$311	$ 492	158 %
Million Megawatt Hours Generated (2)(7)	46.7	17.1	29.6	173 %
IMA for Combined Cycle Facilities (3)(7)	98 %	99 %		
Average Capacity Factor for Combined Cycle Facilities (4)(7)	63 %	45 %		
Average Market On-Peak Spark Spreads ($/MWh) (5)				
Commonwealth Edison (NI Hub)	$14.81	$11.60	$ 3.21	28 %
PJM West	$25.24	$26.82	$ (1.58)	(6)%
North of Path 15 (NP 15)	$14.32	$17.18	$ (2.86)	(17)%
New York - Zone A	$27.60	$34.64	$ (7.04)	(20)%
Mass Hub	$15.23	$20.08	$ (4.85)	(24)%
AD Hub	$28.22	$31.94	$ (3.72)	(12)%
Average Market Off-Peak Spark Spreads ($/MWh) (5)				
Commonwealth Edison (NI Hub)	$3.62	$(8.26)	$ 11.88	144 %
PJM West	$11.84	$4.97	$ 6.87	138 %
North of Path 15 (NP 15)	$7.93	$7.30	$ 0.63	9 %

New York - Zone A	$11.84	$14.09	$ (2.25)	(16)%
Mass Hub	$1.14	$(2.31)	$ 3.45	149%
AD Hub	$16.13	$11.89	$ 4.24	36%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.61	$4.34	$ (1.73)	(40)%

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(1) For the years ended December 31, 2015 and 2014, respectively, Other includes $39 million and $33 million in ancillary services, $17 million and $14 million in tolling revenue and $31 million and $6 million in RMR and other miscellaneous items.
(2) The year ended December 31, 2014 includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility which was sold on June 27, 2014. Please read Note 11—Unconsolidated Investments for further discussion.
(3) IMA is an internal measurement calculation that reflects the percentage of generation available when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.
(4) Reflects actual production as a percentage of available capacity.
(5) Reflects the simple average of the applicable on- and off-peak spark spreads available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas at a daily cash market price and does not reflect spark spreads available to us.
(6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.
(7) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating income for the year ended December 31, 2015 was $360 million compared to $79 million for the year ended December 31, 2014. Adjusted EBITDA totaled $803 million for the year ended December 31, 2015 compared to $311 million for the year ended December 31, 2014. The $492 million increase in Adjusted EBITDA was due to $511 million from the newly acquired plants, partially offset by a $19 million decrease from our legacy plants. The decrease from our legacy plants was driven by the expiration of the ConEd contract at Independence, partially offset by higher energy margin primarily as a result of higher spark spreads and run times at our legacy PJM plants, as well as higher market capacity pricing.

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Consolidated Summary Financial Information—Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

The following table provides summary financial data regarding our consolidated results of operations for the years ended December 31, 2014 and 2013, respectively:

(amounts in millions)	Year Ended December 31, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues				
Energy	$2,290	$1,253	$ 1,037	83 %
Capacity	293	242	51	21 %
Mark-to-market income (loss), net	(28)	(37)	9	24 %
Contract amortization	(111)	(138)	27	20 %
Other (1)	53	146	(93)	(64)%
Total revenues	2,497	1,466	1,031	70 %
Cost of sales, excluding depreciation expense	(1,661)	(1,145)	(516)	(45)%
Gross margin	836	321	515	160 %
Operating and maintenance expense	(477)	(308)	(169)	(55)%
Depreciation expense	(247)	(216)	(31)	(14)%
Gain on sale of assets, net	18	2	16	NM
General and administrative expense	(114)	(97)	(17)	(18)%
Acquisition and integration costs	(35)	(20)	(15)	(75)%
Operating loss	(19)	(318)	299	94 %
Bankruptcy reorganization items, net	3	(1)	4	NM
Earnings from unconsolidated investments	10	2	8	NM
Interest expense	(223)	(97)	(126)	(130)%
Loss on extinguishment of debt	—	(11)	11	100 %
Other income and expense, net	(39)	8	(47)	NM
Loss from continuing operations before income taxes	(268)	(417)	149	36 %
Income tax benefit	1	58	(57)	(98)%
Loss from continuing operations	(267)	(359)	92	26 %
Income from discontinued operations, net of tax	—	3	(3)	(100)%
Net loss	(267)	(356)	89	25 %
Less: Net income attributable to noncontrolling interest	6	—	6	NM
Net loss attributable to Dynegy Inc.	$(273)	$(356)	$ 83	23 %

(1) For the years ended December 31, 2014 and 2013, respectively, Other includes $29 million and $33 million in ancillary services, $14 million and $96 million in tolling revenue and $10 million and $17 million in RMR and other miscellaneous items.

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The following tables provide summary financial data regarding our operating income (loss) by segment for the years ended December 31, 2014 and 2013, respectively:

	Year Ended December 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$593	$846	$1,058	$—	$2,497
Cost of sales, excluding depreciation expense	(346)	(596)	(719)	—	(1,661)
Gross margin	247	250	339	—	836
Operating and maintenance expense	(156)	(199)	(123)	1	(477)
Depreciation expense	(51)	(37)	(155)	(4)	(247)
Gain on sale of assets, net	—	—	18	—	18
General and administrative expense	—	—	—	(114)	(114)
Acquisition and integration costs (1)	—	(16)	—	(19)	(35)
Operating income (loss)	$40	$(2)	$79	$(136)	$(19)

(1) Relates to costs associated with the AER Acquisition and the Acquisitions. Please read Note 3—Acquisitions for further discussion.

	Year Ended December 31, 2013				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$467	$67	$932	$—	$1,466
Cost of sales, excluding depreciation expense	(459)	(46)	(640)	—	(1,145)
Gross margin	8	21	292	—	321
Operating and maintenance expense	(167)	(15)	(125)	(1)	(308)
Depreciation expense	(50)	(3)	(160)	(3)	(216)
Gain on sale of assets, net	2	—	—	—	2
General and administrative expense	—	—	—	(97)	(97)
Acquisition and integration costs (1)	—	(20)	—	—	(20)
Operating income (loss)	$(207)	$(17)	$7	$(101)	$(318)

(1) Relates to costs associated with the AER Acquisition. Please read Note 3—Acquisitions for further discussion.

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $1.031 billion from $1.466 billion for the year ended December 31, 2013 to $2.497 billion for the year ended December 31, 2014. IPH segment revenues increased $779 million on 25.1 million MWh of power generation for the year ended December 31, 2014 compared to 2.4 million MWh for the year ended December 31, 2013 primarily due to the AER Acquisition. Coal segment revenues increased by $126 million driven largely by higher realized energy prices in 2014 and higher revenues associated with derivative instruments. Gas segment revenues increased by $126 million driven largely by higher spark spreads and generation volumes primarily at Independence, Ontelaunee and Casco Bay in 2014, partially offset by a decrease in revenue associated with the Moss Landing toll and the expiration of an Independence capacity contract.

Cost of Sales. Cost of sales increased by $516 million from $1.145 billion for the year ended December 31, 2013 to $1.661 billion for the year ended December 31, 2014. IPH segment cost of sales increased by $550 million primarily due to the AER Acquisition. Gas segment cost of sales increased by $79 million primarily driven by higher natural gas pricing and volumes in 2014. Coal segment cost of sales decreased by $113 million primarily due to lower amortization costs associated with rail transportation contracts recorded in connection with the application of fresh-start accounting and lower coal fuel costs primarily due to lower generation volumes, partially offset by higher coal transportation costs due to a contracted price increase.

Operating and Maintenance Expense. Operating and maintenance expense increased by $169 million from $308 million for the year ended December 31, 2013 to $477 million for the year ended December 31, 2014. The increase was due to an increase in IPH segment costs of $184 million primarily due to the AER Acquisition. The increase was partially offset by $11 million in

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lower Coal segment costs primarily due to $4 million in lower maintenance costs as the result of fewer planned outages during 2014 and $4 million in strike contingency costs during the year ended December 31, 2013, not repeated in 2014.

Depreciation Expense. Depreciation expense increased by $31 million from $216 million for the year ended December 31, 2013 to $247 million for the year ended December 31, 2014. The increase was primarily related to a $34 million increase in the IPH segment as a result of the AER Acquisition.

Gain on Sale of Assets. Gain on sale of assets increased by $16 million from $2 million for the year ended December 31, 2013 to $18 million for the year ended December 31, 2014. The increase was primarily due to the sale of our 50 percent interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain. Please read Note 11—Unconsolidated Investments for further discussion.

General and Administrative Expense. General and administrative expense increased by $17 million from $97 million for the year ended December 31, 2013 to $114 million for the year ended December 31, 2014. The increase was due to $13 million in higher general corporate support primarily related to the AER Acquisition as well as a $4 million release of legal reserves in 2013 related to settled legal matters with no such activity in 2014.

Acquisition and Integration Costs. Acquisition and integration costs increased by $15 million from $20 million for the year ended December 31, 2013 to $35 million for the year ended December 31, 2014. The increase was primarily due to costs of $19 million associated with the Acquisitions, partially offset by $4 million in lower costs related to the integration of the AER Acquisition.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments increased by $8 million from $2 million for the year ended December 31, 2013 to $10 million for the year ended December 31, 2014. The increase was primarily due to cash distributions received from Black Mountain. Please read Note 11—Unconsolidated Investments for further discussion.

Interest Expense. Interest expense increased by $126 million from $97 million for the year ended December 31, 2013 to $223 million for the year ended December 31, 2014. The increase was primarily due to $66 million in interest related to the Notes issued in 2014, $54 million in interest related to the Genco Senior Notes as a result of the AER Acquisition and $9 million in mark-to-market losses on interest rate swaps, partially offset by a $7 million increase in capitalized interest. Please read Note 13—Debt for further discussion.

Loss on Extinguishment of Debt. During the year ended December 31, 2013, loss on extinguishment of debt totaled $11 million. The loss was incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately $59 million, (ii) $2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) $6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) $56 million in non-cash gains for the accelerated amortization of the remaining premium related to the DPC and DMG credit agreements.

Other Income and Expense, Net. Other income and expense, net decreased by $47 million from income of $8 million for the year ended December 31, 2013 to expense of $39 million for the year ended December 31, 2014. The decrease was primarily due to a $40 million change in the fair value of our common stock warrants and the receipt of $8 million in insurance proceeds during the year ended December 31, 2013 with no such activity in the year ended December 31, 2014.

Income Tax Benefit. We reported an income tax benefit of $1 million and $58 million for the years ended December 31, 2014 and 2013, respectively. The effective tax rates for the years ended December 31, 2014 and 2013 were zero percent and 14 percent, respectively.

For the year ended December 31, 2014, the difference between the effective rate of zero percent and the statutory rate of 35 percent resulted primarily due to a change in our valuation allowance. As of December 31, 2014, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing existing taxable temporary differences.

For the year ended December 31, 2013, the difference between the effective rate of 14 percent and the statutory rate of 35 percent resulted primarily due to a change in our valuation allowance. During 2013, we recognized a tax benefit of

$32 million in continuing operations for pre-tax income from components other than continuing operations that resulted in a reduction of the valuation allowance. In addition, a tax benefit of $35 million was also recognized in continuing operations that resulted from the tax impact of the AER Acquisition which also reduced our valuation allowance. The benefit of these valuation allowance adjustments was partially offset by $9 million of tax expense associated with current federal and state taxes. Please read Note 14—Income Taxes for further discussion.

Income from Discontinued Operations. During the year ended December 31, 2013, income from discontinued operations was $3 million. Income from discontinued operations primarily consisted of a $7 million DNE pension curtailment gain due to the

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termination of a majority of the Danskammer employees and closing the Roseton sale, partially offset by a $2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility and $2 million in tax expense. There was no similar activity during the year ended December 31, 2014. Please read Note 21—Discontinued Operations for further discussion.

Net Income Attributable to Noncontrolling Interest. For the year ended December 31, 2014, net income attributable to noncontrolling interest was $6 million related to the minority shareholder's 20 percent interest in EEI.

Adjusted EBITDA — Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2014:

	Year Ended December 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(273)
Income attributable to noncontrolling interest					6
Income tax benefit					(1)
Other items, net (1)					39
Interest expense					223
Earnings from unconsolidated investments					(10)
Bankruptcy reorganization items, net					(3)
Operating income (loss)	$40	$(2)	$79	$(136)	$(19)
Depreciation expense	51	37	155	4	247
Bankruptcy reorganization items, net	—	—	—	3	3
Amortization expense	(6)	(7)	63	—	50
Earnings from unconsolidated investments	—	—	10	—	10
Other items, net (1)	—	—	—	(39)	(39)
EBITDA	85	28	307	(168)	252
Acquisition and integration costs	—	16	—	19	35
Bankruptcy reorganization items, net	—	—	—	(3)	(3)
Income attributable to noncontrolling interest	—	(6)	—	—	(6)
Mark-to-market adjustments	(32)	38	22	—	28
Change in fair value of common stock warrants	—	—	—	40	40
Gain on sale of assets, net	—	—	(18)	—	(18)
ARO accretion expense	6	6	—	—	12
Other	3	1	—	3	7
Adjusted EBITDA	$62	$83	$311	$(109)	$347

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(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2013:

	Year Ended December 31, 2013				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(356)
Income from discontinued operations, net of tax					(3)
Income tax benefit					(58)
Other items, net (1)					(8)
Loss on extinguishment of debt					11
Interest expense					97
Earnings from unconsolidated investments					(2)
Bankruptcy reorganization items, net					1
Operating income (loss)	$(207)	$(17)	$7	$(101)	$(318)
Depreciation expense	50	3	160	3	216
Bankruptcy reorganization items, net	—	—	—	(1)	(1)
Amortization expense	126	(2)	127	—	251
Earnings from unconsolidated investments	—	—	2	—	2
Other items, net (1)	—	—	2	6	8
EBITDA	(31)	(16)	298	(93)	158
Acquisition and integration costs	—	20	—	—	20
Bankruptcy reorganization items, net	—	—	—	1	1
Mark-to-market adjustments	25	8	4	—	37
Change in fair value of common stock warrants	—	—	—	1	1
Other	2	—	—	8	10
Adjusted EBITDA	$(4)	$12	$302	$(83)	$227

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

Adjusted EBITDA increased by $120 million from $227 million for the year ended December 31, 2013 to $347 million for the year ended December 31, 2014. The increase was primarily due to the addition of our IPH segment on December 2, 2013, improved realized power prices in our Coal segment and increased spark spreads and generation volumes in our Gas segment. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the years ended December 31, 2014 and 2013, respectively.

(dollars in millions, except for price information)	Year Ended December 31, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$552	$488	$ 64	13 %
Capacity	5	4	1	25 %
Mark-to-market income (loss), net	32	(25)	57	228 %
Other (1)	4	—	4	NM
Total operating revenues	593	467	126	27 %
Operating Costs				
Cost of sales	(352)	(333)	(19)	(6)%
Contract amortization	6	(126)	132	105 %
Total operating costs	(346)	(459)	113	25 %
Gross margin	247	8	239	NM
Operating and maintenance expense	(156)	(167)	11	7 %
Depreciation expense	(51)	(50)	(1)	(2)%
Gain on sale of assets, net	—	2	(2)	(100)%
Operating income (loss)	40	(207)	247	119 %
Depreciation expense	51	50	1	2 %
Amortization expense	(6)	126	(132)	(105)%
EBITDA	85	(31)	116	NM
Mark-to-market adjustments	(32)	25	(57)	(228)%
ARO accretion expense	6	—	6	NM
Other	3	2	1	50 %
Adjusted EBITDA	$62	$(4)	$ 66	NM
Million Megawatt Hours Generated	19.0	20.4	(1.4)	(7)%
IMA for Coal-Fired Facilities (2)	88 %	89 %		
Average Capacity Factor for Coal-Fired Facilities (3)	73 %	78 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$48.28	$38.01	$ 10.27	27 %
Off-Peak: Indiana (Indy Hub)	$32.52	$27.49	$ 5.03	18 %

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(1) For the years ended December 31, 2014 and 2013, respectively, Other includes $3 million and $4 million in ancillary services and $1 million and ($4) million in other miscellaneous items.

(2) IMA is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. The calculation excludes certain events outside of management control such as weather related issues.

(3) Reflects actual production as a percentage of available capacity.

(4) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.

Operating income for the year ended December 31, 2014 was $40 million compared to an operating loss of $207 million for the year ended December 31, 2013. Adjusted EBITDA was $62 million for the year ended December 31, 2014 compared to a loss of $4 million for the year ended December 31, 2013. The $66 million increase in Adjusted EBITDA resulted primarily from

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higher realized energy prices and lower operating and maintenance expense in 2014 due to fewer planned outages and strike contingency costs in 2013, which more than offset lower generation volumes and higher delivered coal costs due to a contracted price increase.

IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the years ended December 31, 2014 and 2013, respectively. As a result of the AER Acquisition, 2013 results only include activity for the period December 2, 2013 through December 31, 2013.

(dollars in millions, except for price information)	Year Ended December 31, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$886	$70	$ 816	*
Capacity	42	1	41	*
Mark-to-market loss, net	(38)	(8)	(30)	*
Contract amortization	(40)	(3)	(37)	*
Other (1)	(4)	7	(11)	*
Total operating revenues	846	67	779	*
Operating Costs				
Cost of sales	(643)	(51)	(592)	*
Contract amortization	47	5	42	*
Total operating costs	(596)	(46)	(550)	*
Gross margin	250	21	229	*
Operating and maintenance expense	(199)	(15)	(184)	*
Depreciation expense	(37)	(3)	(34)	*
Acquisition and integration costs	(16)	(20)	4	*
Operating loss	(2)	(17)	15	*
Depreciation expense	37	3	34	*
Amortization expense	(7)	(2)	(5)	*
EBITDA	28	(16)	44	*
Acquisition and integration costs	16	20	(4)	*
Income attributable to noncontrolling interest	(6)	—	(6)	*
Mark-to-market adjustments	38	8	30	*
ARO accretion expense	6	—	6	
Other	1	—	1	*
Adjusted EBITDA	$83	$12	$ 71	*
Million Megawatt Hours Generated (2)	23.7	2.4	*	*
IMA for IPH Facilities (3)	89%	90%		
Average Capacity Factor for IPH Facilities (4)	68%	75%		
Average Quoted Market Power Prices ($/MWh) (5):				
On-Peak: Indiana (Indy Hub)	$48.28	$40.32	*	*
Off-Peak: Indiana (Indy Hub)	$32.52	$30.82	*	*

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* Not meaningful due to only one month of activity for the year ended December 31, 2013 compared to a full year of activity for the year ended December 31, 2014.

(1) For the years ended December 31, 2014 and 2013, respectively, Other includes ($7) million and ($1) million in ancillary services and $3 million and $8 million in other miscellaneous items.

(2)

Reflects production volumes in million MWh generated during the period IPH was included in our consolidated results.

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(3) IMA is an internal measurement calculation that reflects the percentage of generation available when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues. Reflects the percentage of generation available during the period IPH was included in our consolidated results.

(4) Reflects actual production as a percentage of available capacity during the period IPH was included in our consolidated results.

(5) Reflects the average of day-ahead quoted prices for the period IPH was included in our consolidated results and does not necessarily reflect prices we realized.

Operating loss for the year ended December 31, 2014 was $2 million compared to $17 million for the year ended December 31, 2013. Adjusted EBITDA was $83 million for the year ended December 31, 2014 compared to $12 million for the year ended December 31, 2013. The $71 million increase was primarily due to the inclusion of a full year of results for the year ended December 31, 2014 compared to one month of results for the year ended December 31, 2013. During the year ended December 31, 2014, the capacity factor was 68 percent primarily due to unplanned outages at our Coffeen and Newton facilities. IPH also benefited from retail sales of 14.6 million MWh into both MISO and PJM.

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Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the years ended December 31, 2014 and 2013, respectively:

(dollars in millions, except for price information)	Year Ended December 31, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$852	$695	$ 157	23 %
Capacity	246	237	9	4 %
Mark-to-market loss, net	(22)	(4)	(18)	NM
Contract amortization	(71)	(135)	64	47 %
Other (1)	53	139	(86)	(62)%
Total operating revenues	1,058	932	126	14 %
Operating Costs				
Cost of sales	(727)	(648)	(79)	(12)%
Contract amortization	8	8	—	— %
Total operating costs	(719)	(640)	(79)	(12)%
Gross margin	339	292	47	16 %
Operating and maintenance expense	(123)	(125)	2	2 %
Depreciation expense	(155)	(160)	5	3 %
Gain on sale of assets, net	18	—	18	NM
Operating income	79	7	72	NM
Depreciation expense	155	160	(5)	(3)%
Amortization expense	63	127	(64)	(50)%
Earnings from unconsolidated investments	10	2	8	NM
Other items, net	—	2	(2)	(100)%
EBITDA	307	298	9	3 %
Mark-to-market adjustments	22	4	18	NM
Gain on sale of assets, net	(18)	—	(18)	NM
Adjusted EBITDA	$311	$302	$ 9	3 %
Million Megawatt Hours Generated (2)	17.1	16.2	0.9	6 %
IMA for Combined Cycle Facilities (3)	99 %	97 %		
Average Capacity Factor for Combined Cycle Facilities (4)	45 %	43 %		
Average Market On-Peak Spark Spreads ($/MWh) (5)				
Commonwealth Edison (NI Hub)	$11.60	$11.38	$ 0.22	2 %
PJM West	$26.82	$17.65	$ 9.17	52 %
North of Path 15 (NP 15)	$17.18	$16.21	$ 0.97	6 %
New York - Zone A	$34.64	$20.12	$ 14.52	72 %
Mass Hub	$20.08	$16.35	$ 3.73	23 %
Average Market Off-Peak Spark Spreads ($/MWh) (5)				
Commonwealth Edison (NI Hub)	$(8.26)	$(0.13)	$ (8.13)	NM
PJM West	$4.97	$4.99	$ (0.02)	— %
North of Path 15 (NP 15)	$7.30	$8.46	$ (1.16)	(14)%
New York - Zone A	$14.09	$7.49	$ 6.60	88 %
Mass Hub	$(2.31)	$(0.16)	$ (2.15)	NM
Average natural gas price—Henry Hub ($/MMBtu) (6)	$4.34	$3.72	$ 0.62	17 %

(1) For the years ended December 31, 2014 and 2013, respectively, Other includes $33 million and $30 million in ancillary services, $14 million and $96 million in tolling revenue and $6 million and $13 million in RMR and other miscellaneous items.

(2) The year ended December 31, 2013 includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility. The year ended December 31, 2014 includes our ownership percentage in

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the MWh generated through June 27, 2014 when we completed the sale of our 50 percent partnership interest in Black Mountain. Please read Note 11—Unconsolidated Investments for further discussion.

(3) IMA is an internal measurement calculation that reflects the percentage of generation available when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

(4) Reflects actual production as a percentage of available capacity.

(5) Reflects the simple average of the applicable on- and off-peak spark spreads available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas at a daily cash market price and does not reflect spark spreads available to us.

(6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Operating income for the year ended December 31, 2014 was $79 million compared to $7 million for the year ended December 31, 2013. Adjusted EBITDA totaled $311 million during the year ended December 31, 2014 compared to $302 million during the same period in 2013. The $9 million increase in Adjusted EBITDA primarily resulted from higher energy margin due to increased generation and higher spark spreads primarily at Independence and Ontelaunee and higher capacity revenue at Kendall. These increases were partially offset by a decrease in revenues related to the Moss Landing toll and the expiration of the Independence capacity contract in October 2014.

Outlook

We expect that our future financial results will continue to be impacted by market structure and prices for electric energy, capacity and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, the volatility of fuel and electricity prices, transportation and transmission logistics, weather conditions and the availability of our plants. Further, there is a trend toward greater environmental regulation of all aspects of our business. As this trend continues, it is possible that we will experience additional costs related to water, air and coal ash regulations. Our coal fleet, primarily, may experience added costs associated with GHG and the handling and disposal of coal ash.

All references to hedging within this Form 10-K relate to economic hedging activities as we do not elect hedge accounting.

Coal. The Coal segment is comprised of 11 operating generation facilities located within MISO (3,008 MW), PJM (3,884 MW) and the ISO-NE (1,528 MW) regions, with a total generating capacity of 8,420 MW. Our Brayton Point facility is expected to be retired in June 2017.

On November 5, 2015, Dynegy announced that it expects to retire the final two units at the 465 MW Wood River Power Station in Alton, Illinois in mid-2016, subject to the approval of MISO. The decision to retire the Wood River facility was the result of a strategic review performed in the third quarter of 2015, and was primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market. Upon the completion of the planned retirements of our Brayton Point and Wood River facilities, our Coal segment will include 6,427 MW of generation capacity, of which 2,543 MW will operate in MISO and 3,884 MW will operate in PJM.

As of February 8, 2016, our expected remaining generation volumes, excluding Brayton Point and Wood River, are 61 percent hedged volumetrically for 2016 and approximately 26 percent hedged volumetrically for 2017. We plan to continue our hedging program over a one- to three-year period using various instruments, including retail sales. Dynegy’s portfolio beyond 2016 is primarily open to benefit from possible future power market pricing improvements. We use our retail business, Dynegy Energy Services, to hedge a portion of the output from our facilities.

As of February 8, 2016, excluding Brayton Point, Wood River and non-operated jointly-owned generating units, our expected coal requirements for 2016 are 76 percent contracted and 73 percent priced. Our forecasted coal requirements for 2017, excluding Brayton Point, Wood River and non-operated jointly-owned generating units, are 29 percent contracted and 24 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2016 and 99 percent contracted for 2017. Our coal transportation requirements are approximately 67 percent contracted for 2018 to 2020. We recently entered into a new long-term coal transportation agreement for our Kincaid facility. The contract, which begins in 2017, reflects a reduction from the 2016 rate.

We cleared no volume in the MISO Planning Year 2014-2015 capacity auction and cleared 398 MW in the MISO Planning Year 2015-2016 capacity auction at $150 per MW-day.

On September 29, 2015, the Illinois Power Agency ("IPA") issued a Request For Proposals, approved by the Illinois Commerce Commission, that included a request for capacity in Illinois for MISO Zone 4 for the 2016-2017 Planning Year. The IPA procured 1,033 MW in Zone 4 at an average price of $138.12 per MW-day. Dynegy was one of four selected suppliers.

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In New England, our Brayton Point facility cleared 1,484 MW in the Planning Year 2014-2015 capacity auction, 1,363 MW in the Planning Year 2015-2016 capacity auction and 1,303 MW in the Planning Year 2016-2017 capacity auction. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.

In PJM, we cleared 3,341 MW in the Planning Year 2014-2015 capacity auction and 3,331 MW in the Planning Year 2015-2016 capacity auction. PJM introduced its new CP product beginning with Planning Year 2016-2017. In PJM, we cleared 3,566 MW in the Planning Year 2016-2017 (1,702 MW legacy capacity and 1,864 MW CP), 3,377 MW in the Planning Year 2017-2018 (2,027 MW legacy capacity and 1,350 MW CP). Base capacity resources ("Base") are those capacity resources, beginning in Planning Year 2018-2019, that are not capable of sustained, predictable operation throughout the entire delivery year, but are capable of providing energy and reserves during hot weather operations. They are subject to non-performance charges assessed during emergency conditions, from June through September. In PJM, we cleared 3,347 MW in the Planning Year 2018-2019 capacity auction (1,734 MW Base and 1,613 MW CP).

IPH. The IPH segment is comprised of five plants, totaling 4,178 MW, and primarily operates in MISO. Joppa, which is within the EEI control area, is interconnected to Tennessee Valley Authority and Louisville Gas and Electric Company but primarily sells its capacity and energy to MISO. On September 24, 2015, MISO notified us that Edwards Unit 1 is no longer needed as a System Support Resource unit. We retired Edwards Unit 1 effective January 1, 2016. We currently offer a portion of our IPH segment generating capacity into PJM. As of June 1, 2016, our Coffeen, Duck Creek, E.D. Edwards and Newton facilities will have 937 MW, or 22 percent of IPH's capacity, that is electrically tied into PJM through pseudo-tie arrangements.

As of February 8, 2016, IPH's expected remaining generation volumes are approximately 51 percent hedged volumetrically for 2016 and approximately 26 percent hedged volumetrically for 2017. IPH will continue to use our retail business, Homefield Energy, to hedge a portion of the output from our IPH facilities. The retail hedges are well correlated to our facilities due to the close proximity of the hedge and through participation in FTR markets. Homefield Energy's ability to keep and possibly grow its existing market share will impact IPH's hedge levels in the future.

As of February 8, 2016, our expected coal requirements for IPH for 2016 are 96 percent contracted and 74 percent priced. Our forecasted coal requirements for 2017 are 46 percent contracted and 26 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2016 and 2017. Our coal transportation requirements are approximately 58 percent contracted for 2018 to 2020.

In addition, we recently entered into new long-term coal transportation agreements for our Duck Creek and Joppa facilities. The rate for Duck Creek is a reduction from the 2014 rate and began in April of 2015. The new Joppa transportation contract will begin in 2018 and is also a reduction from the 2017 rate.

IPH realized capacity sales in the MISO Planning Year 2014-2015 capacity auction, clearing 1,995 MW to offset retail load obligations. IPH cleared 1,864 MW in the MISO Planning Year 2015-2016 capacity auction, including 1,709 MW to offset retail load obligations. IPH only sold 155 MW that received the $150 per MW-day clearing price.

In PJM, we cleared no volume in the Planning Year 2014-2015 capacity auction, 301 MW in the Planning Year 2015-2016 capacity auction, 867 MW in Planning Year 2016-2017 (138 MW legacy capacity and 729 MW CP), 847 MW in Planning Year 2017-2018 (376 MW legacy capacity and 471 MW CP), and 835 MW in the Planning Year 2018-2019 capacity auction (all CP). In addition, we have also secured one segment of the transmission path required to offer an additional 240 MW of capacity and energy into PJM.

Gas. The Gas segment is comprised of 19 power generation facilities within PJM (7,337 MW), CAISO (2,694 MW), ISO-NE (2,429 MW) and NYISO (1,126 MW) regions, totaling 13,586 MW of electric generating capacity.

In PJM, we are installing a total of 272 MW of uprates, which will be accomplished primarily through upgrades to the hot gas path components of our combined cycle gas turbines. The uprates started in Fall 2015 at the Hanging Rock facility and are expected to be completed in the Spring of 2017 at Liberty Electric.

In New England, at our Lake Road and Milford facilities, we cleared 70 MW of new uprates in FCA-10, locking the capacity rate of $7.03 per kW-month for seven years beginning with Planning Year 2019-2020 and extending through Planning year 2025-2026.

In New York, we will be installing 45 MW of additional uprates at our Independence facility in 2016.
Excluding volumes subject to tolling agreements, as of February 8, 2016, our Gas portfolio is 53 percent hedged volumetrically through 2016 and approximately 14 percent hedged volumetrically for 2017. As a result of the offsetting risks of our Gas and Coal segments, we are able to reduce the costs associated with hedging with third parties by executing a portion of our natural gas hedges with an affiliate. We continue to manage our remaining commodity price exposure to changing fuel and power prices in accordance with our risk management policy.

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In PJM, we cleared 5,922 MW in the Planning Year 2014-2015 capacity auction, 5,996 MW in the Planning Year 2015-2016 capacity auction, 6,244 MW in Planning Year 2016-2017 (2,296 MW legacy capacity and 3,948 MW CP), 6,458 MW in Planning Year 2017-2018 (1,771 MW legacy capacity and 4,687 MW CP), and 5,708 MW in the Planning Year 2018-2019 capacity auction (all CP).

In New England, we cleared 1,890 MW in the Planning Year 2014-2015 capacity auction, 1,956 MW in the Planning Year 2015-2016 capacity auction, 1,893 MW in the Planning Year 2016-2017 capacity auction, 2,147 MW in the Planning Year 2017-2018 capacity auction, 2,148 MW in the Planning Year 2018-2019 capacity auction and 2,226 MW in the Planning Year 2019-2020 capacity auction. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.

In New York, almost 76 percent of our Independence facility's winter capacity had been sold bilaterally prior to the most recent auction covering the Winter 2015-2016 planning period. As of February 8, 2016, 1,124 MW of capacity was sold for the Winter 2015-2016 planning period; 822 MW were sold for the Summer 2016 planning period; 653 MW were sold for the Winter 2016-2017 planning period; and 705 MW were sold for the Summer 2017 planning period.

In October 2015, we contracted RA capacity with Southern California Edison for Moss Landing Units 1 and 2 for 575 MW, 400 MW and 850 MW, for calendar years 2017, 2018 and 2019, respectively.

In its 2015 Gas Transmission and Storage rate case, which will set gas transportation rates for 2015-2017, Pacific Gas & Electric Company's ("PG&E") proposed revenue requirements and allocation proposals which, if adopted, would result in a significant increase in the rates for electric generators served by the local transmission system, including Moss Landing Units 1 and 2. Historically, after PG&E's gas transportation rate structure was changed to unbundle the Backbone Transmission System ("BB") rates, PG&E gas transmission and storage rate case settlements have included a bill credit for Moss Landing Units 1 and 2 that effectively reduces the differential between rates for BB and local transmission system service, allowing the plant to compete against other power generators. However, according to PG&E's own estimates, the rate differential between BB and local transmission system rates PG&E proposes in its 2015 proceeding would result in Moss Landing Units 1 and 2 likely experiencing a decline in dispatch hours. Dynegy is actively participating in the hearing process before the CPUC and is advocating positions that would maintain the ability of Moss Landing Units 1 and 2 to compete in the California electricity market. Post-hearing briefing concluded in May 2015, and Oral Argument was held on October 28, 2015. A decision is expected in early 2016.

Capacity Markets

MISO. We currently have approximately 7,186 MW of power generation in MISO. With the expected retirement of Wood River and the PJM pseudo-tie arrangements that begin June 1, 2016, we will have approximately 5,784 MW in MISO. The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each Planning Year:

	2014-2015	2015-2016
Price per MW-day	$16.75	$150.00

As previously noted, we cleared no volume in the MISO Planning Year 2014-2015 capacity auction, and our Coal and IPH segments cleared 398 MW and 155 MW, respectively, in the MISO Planning Year 2015-2016 capacity auction at $150 per MW-day, incremental to our retail load obligations.

Asset retirements and confirmed future capacity exports from MISO to PJM are expected to continue reducing reserve margins in MISO. MISO has a Planning Reserve Margin of 15.2 percent and has forecasted reserve margins of 16.1 percent for Planning Year 2016-2017, 16.6 percent for Planning Year 2017-2018, 16.0 percent for Planning Year 2018-2019, 15.2 percent for Planning Year 2019-2020 and 14.7 percent for Planning Year 2020-2021.

In May 2015, three complaints were filed at FERC regarding the Zone 4 results for the 2015-2016 PRA conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General, and Southwestern Electric Cooperative, Inc., have challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds and requested changes to the MISO PRA structure going forward. Complainants have also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the 2015-2016 PRA. The MISO IMM, which was responsible for monitoring the

MISO 2015-2016 PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the proposed remedies. Dynegy complied fully with the terms of the MISO Tariff in connection with the 2015-2016 PRA. In addition, the Illinois Industrial Energy Consumers filed a complaint at FERC against MISO on June 30, 2015 requesting prospective changes to the MISO tariff.

On October 1, 2015, FERC issued an order of non-public, formal investigation, stating that shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public informal investigation into whether market manipulation or other potential violations of FERC orders, rules and regulations occurred before or during the PRA. The Order noted that the

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investigation is ongoing, and that the order converting the informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. Further, FERC held a Staff-led technical conference on October 20, 2015 to obtain further information concerning potential changes to the MISO PRA structure going forward, including proposals made by complainants. The technical conference did not address the ongoing Office of Enforcement investigation.

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO Tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. Under the order, FERC found that the existing tariff provision, which bases Initial Reference Levels for capacity supply offers on the estimated opportunity cost of exporting capacity to a neighboring region (for example, PJM), are no longer just and reasonable. Accordingly, FERC required MISO to set the Initial Reference Level for capacity at $0 per MW-day for the 2016-17 PRA. Capacity suppliers may also request a facility-specific reference level from the MISO IMM. The order did not address the other arguments of the complainants regarding the 2015-2016 Auction, and stated that those issues remain under consideration and will be addressed in a future order.

ISO-NE. We have approximately 3,957 MW of power generation in ISO-NE. The most recent forward capacity auction results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each Planning Year:

	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Price per kW-month	$3.21	$3.43	$3.15	$7.03	$9.55	$7.03

The forecasted 2015 ISO-NE reserve margin is 22.8 percent versus a target reserve margin of 13.9 percent. On February 2, 2015, ISO-NE conducted the capacity auction for Planning Year 2018-2019 (FCA-9). Effective for this auction, a downward sloping demand curve replaced the vertical demand curve and the system-wide administrative pricing rules. Performance incentive rules also went into effect for Planning Year 2018-2019, having the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level. Rest-of-Pool, which includes most of our facilities, cleared at a price of $9.55 per kW-month. The Southeastern Massachusetts and Rhode Island zone, where our recently acquired Dighton facility is located, had insufficient supply to satisfy its capacity requirements. As a result, the zone separated from Rest-of-Pool, with existing resources in the zone receiving the Net Cost of New Entry price of $11.08 per kW-month and new resources in the zone receiving the auction starting price of $17.73 per kW-month. Performance incentive rules went into effect for Planning Year 2018-2019, having the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level. On February 8, 2016, ISO-NE conducted the capacity auction for Planning Year 2019-2020 (FCA-10). In this auction, Rest-of-Pool cleared at $7.03 per kW-month.

PJM. We currently have approximately 11,221 MW of power generation in PJM. With the expected PJM pseudo-tie arrangements from the IPH fleet beginning June 1, 2016, we will have approximately 12,158 MW of power generation in PJM. Our plants within PJM are mixed between Eastern Mid-Atlantic Area Council ("EMAAC") (Liberty), Mid-Atlantic Area Council ("MAAC") (Ontelaunee), Commonwealth Edison ("COMED") (Elwood, Kendall, Lee and Kincaid), American Transmission Service, Inc. ("ATSI") (Richland/Stryker) and RTO (balance of plants). PJM has begun the transition of the PJM capacity market to CP product. On August 26-27, 2015, PJM held a transitional auction to convert up to 60 percent of PJM's capacity needs for Planning Year 2016-2017 from legacy capacity to CP. On September 3-4, 2015, PJM held a transitional auction to convert 70 percent of PJM's capacity needs for Planning Year 2017-2018 from legacy capacity to CP. On August 10-14, 2015, PJM held the BRA to procure CP for 80 percent and Base for 20 percent of PJM's capacity needs for the Planning Year 2018-2019. PJM will procure 100 percent CP for all resources beginning with Planning Year 2020-2021. The most recent RPM auction results for PJM's RTO and MAAC zones, in which our assets are located, are as follows for each Planning Year:

	2014-2015	2015-2016	2016-2017		2017-2018		2018-2019	
				CP		CP	Base	CP

	Legacy Capacity	Legacy Capacity	Legacy Capacity		Legacy Capacity			
RTO zone, price per MW-day	$ 125.99	$ 136.00	$ 59.37	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77
MAAC zone, price per MW-day	$ 136.50	$ 167.46	$ 119.13	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77
EMAAC zone, price per MW-day	$ 136.50	$ 167.46	$ 119.13	$ 134.00	$ 120.00	$ 151.50	$ 210.63	$ 225.42
COMED zone, price per MW-day	$ 125.99	$ 136.00	$ 59.37	$ 134.00	$ 120.00	$ 151.50	$ 200.21	$ 215.00
ATSI zone, price per MW-day	$ 125.99	$ 357.00	$ 114.23	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77

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NYISO. We have approximately 1,126 MW of power generation in NYISO. The most recent seasonal auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Summer 2014	Winter 2014-2015	Summer 2015	Winter 2015-2016
Price per kW-month	$5.15	$2.90	$3.50	$1.25

CAISO. We have approximately 2,694 MW of power generation in CAISO. The CAISO capacity market is a bilateral market in which Load Serving Entities are required to procure sufficient resources to meet their peak load plus a 15 percent reserve margin. We transact with investor owned utilities, municipalities, community choice aggregators, retail providers, and other marketers through Request for Offers ("RFO") solicitations, broker markets, and directly with bilateral transactions for both the Standard and Flexible RA capacity. Beginning on May 1, 2016, CAISO is expected to implement the voluntary capacity auction for annual, monthly and intra-month procurement to cover for deficiencies in the market. This competitive solicitation process will replace the existing CPM, and will provide another venue to sell RA capacity. Although the CPUC created the new flexible RA capacity market to address the risk of retirement of flexible gas-fired generation and implemented a voluntary auction, demand for RA capacity is low due to ample supply of generation. In addition, net energy demand has been stagnant mainly due to energy efficiency programs and distributed generation of residual and commercial rooftop solar.

Other Market Developments

On January 25, 2016, the U.S. Supreme Court overturned the decision of the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") and affirmed FERC's jurisdiction over compensation to Demand Response providers in wholesale competitive markets and the compensation method as proscribed in FERC Order No. 745. The decision effectively maintains the status-quo with respect to Demand Response participation in the wholesale markets, because the ISOs/RTOs refrained from making changes to market design while the case was pending.

SEASONALITY

Our revenues and operating income are subject to fluctuations during the year, primarily due to the impact seasonal factors have on sales volumes and the prices of power and natural gas. Power marketing operations and generating facilities have higher volatility and demand in the summer cooling months and winter heating season.

CRITICAL ACCOUNTING POLICIES

Our Accounting Department is responsible for the development and application of accounting policy and control procedures. This department conducts these activities independent of any active management of our risk exposures, is independent of our business segments and reports to the Chief Financial Officer ("CFO").

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments. It is possible that materially different amounts could be recorded if these estimates and judgments change or if actual results differ from these estimates and judgments. We have identified the following critical accounting policies that require a significant amount of estimation and judgment and are considered important to the portrayal of our financial position and results of operations:

- Revenue Recognition and Derivative Instruments;
- Fair Value Measurements;
- Accounting for Income Taxes;
- Business Combinations;
- Impairment of Long-Lived Assets; and
- Goodwill Impairment.

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Revenue Recognition and Derivative Instruments

We earn revenue from our facilities in three primary ways: (i) the sale of energy, including fuel, through both physical and financial transactions; (ii) sale of capacity; and (iii) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load and provide emergency reserves for major changes to the balance of generation and load. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. Please read "Derivative Instruments—Generation" below for further discussion of the accounting for these types of transactions.

Derivative Instruments—Generation. We enter into commodity contracts that meet the definition of a derivative. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include forward contracts, which commit us to sell commodities in the future; futures contracts, which are generally broker-cleared standard commitments to purchase or sell a commodity; option contracts, which convey the right to buy or sell a commodity; and swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined quantity. There are two different ways to account for these types of contracts, as Dynegy does not elect hedge accounting for any of its derivative instruments: (i) as an accrual contract, if the criteria for the "normal purchase, normal sale" exception are met, documented, and elected; or (ii) as a mark-to-market contract with changes in fair value recognized in current period earnings. All derivative commodity contracts that do not qualify for, or for which we do not elect, the "normal purchase, normal sale" exception are recorded at fair value in risk management assets and liabilities on the consolidated balance sheets with the associated changes in fair value recorded currently to revenues. Comparability of our financial statements to our peers for similar contracts may not be possible due to differences in electing the normal purchase, normal sale exception.

Entities may choose whether or not to offset related assets and liabilities and report the net amounts on their consolidated balance sheets if the right of offset exists. We elect to offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we elect to offset the fair value of amounts recognized for the cash collateral paid or received against the fair value of amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, our consolidated balance sheets present derivative assets and liabilities, as well as the related cash collateral paid or received, on a net basis.

Derivative Instruments—Financing Activities. We are exposed to changes in interest rate risk through our variable rate debt. In order to manage our interest rate risk, we enter into interest rate swap agreements that meet the definition of a derivative. All derivative instruments are recorded at their fair value on the consolidated balance sheets with the changes in fair value recorded currently to interest expense. Our interest-based derivative instruments are not designated as hedges of our variable debt.

Fair Value Measurements

Fair Value Measurements. Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. In estimating fair value, we use discounted cash flow ("DCF") projections, recent comparable market transactions, if available, or quoted prices. We consider assumptions that third parties would make in estimating fair value, including, but not limited to, the highest and best use of the asset. There is a significant amount of judgment involved in cash-flow estimates, including assumptions regarding market convergence, discount rates, commodity prices, useful lives and growth factors. The assumptions used by another party could differ significantly from our assumptions.

Our estimate of fair value reflects the impact of credit risk. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs are classified as readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the classification of the inputs used to calculate the fair value of a transaction. The inputs used to measure fair value have been placed in a hierarchy based on priority. The hierarchy gives the highest priority to unadjusted, readily observable quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

Fair Value Measurements—Risk Management Activities. The determination of the fair value for each derivative contract incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings when assessing the credit standing of our counterparties, and when applicable, adjusted based on management's estimates of assumptions market participants would use in determining fair value.

Assets and liabilities from risk management activities may include exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivatives, as discussed above, are generally classified as Level 1; however, some exchange-traded derivatives are valued using broker or dealer quotations or market transactions in either the listed or OTC markets. In such cases, these exchange-traded derivatives are classified within Level 2. OTC derivative instruments include swaps, forwards and options. In certain instances, these instruments may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Other OTC derivatives trade in less active markets with a lower availability of pricing information. In addition, complex or structured transactions, such as heat-rate call options, can introduce the need for internally-developed model inputs that might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

Changes to our assumptions for the fair value of our derivative instruments (primarily forward price curves, pricing risk, and credit risk) could result in a material change to the fair value of our risk management assets and liabilities recorded to our consolidated balance sheets and corresponding changes in fair value recorded to our consolidated statements of operations. Please read Note 5—Fair Value Measurements for further discussion of our assumptions.

Accounting for Income Taxes

We file a consolidated U.S. federal income tax return. We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing tax and accounting treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Because we operate and sell power in many different states, our effective annual state income tax rate may vary from period to period due to changes in our sales profile by state, as well as jurisdictional and legislative changes by state. As a result, changes in our estimated effective annual state income tax rate can have a significant impact on our measurement of temporary differences. We project the rates at which state tax temporary differences will reverse based upon estimates of revenues and operations in the respective jurisdictions in which we conduct business.

The guidance related to accounting for income taxes requires that a valuation allowance be established when it is more likely than not that all or a portion of a deferred tax asset will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income of the appropriate character during the periods in which those temporary differences are deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including our past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available to realize the tax benefits from net deferred tax assets not otherwise realized by reversing existing taxable temporary differences. Therefore, we continue to recognize a valuation allowance against our net deferred tax assets as of December 31, 2015. Any change in the valuation allowance would impact our income tax benefit (expense) and net income (loss) in the period in which the change occurs.

Accounting for uncertainty in income taxes requires that we determine whether it is more likely than not that a tax position we have taken will be sustained upon examination. If we determine that it is more likely than not that the position will be sustained, we recognize the largest amount of the benefit that is greater than 50 percent likely of being realized upon settlement. There is a significant amount of judgment involved in assessing the likelihood that a tax position will be sustained upon examination and in determining the amount of the benefit that will ultimately be realized.

We recognize accrued interest expense and penalties related to unrecognized tax benefits as income tax expense. Please read Note 14—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and changes in our valuation allowance.

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Business Combinations

Accounting Standards Codification ("ASC") 815, Business Combinations requires that the purchase price for a business combination be assigned and allocated to the identifiable assets acquired and liabilities assumed based upon their fair value. Generally, the amount recorded in the financial statements for an acquisition's assets and liabilities is equal to the purchase price (the fair value of the consideration paid); however, a purchase price that exceeds the fair value of the net assets acquired will result in the recognition of goodwill. Conversely, a purchase price that is below the fair value of the net assets acquired will result in the recognition of a bargain purchase in the income statement.

In addition to the potential for the recognition of goodwill or a bargain purchase, differing fair values will impact the allocation of the purchase price to the individual assets and liabilities and can impact the gross amount and classification of assets and liabilities recorded on our consolidated balance sheets, which can impact the timing and amount of depreciation and amortization expense recorded in any given period. We utilize our best effort to make our determinations and review all information available, including estimated future cash flows and prices of similar assets when making our best estimate. We also may hire independent appraisers or valuation specialists to help us make this determination as we deem appropriate under the circumstances.

There is a significant amount of judgment in determining the fair value of the Acquisitions and in allocating value to individual assets and liabilities. Had different assumptions been used, the fair value of the assets acquired and liabilities assumed could have been significantly higher or lower with a corresponding increase or reduction in recognized goodwill, or could have required recognition of a bargain purchase. Refer to Note 3—Acquisitions for further discussion of the Acquisitions.

Impairment of Long-Lived Assets

ASC 360, Property, Plant and Equipment ("PP&E") requires for an entity to assess whether the recorded values of PP&E and finite-lived intangible assets have become impaired when certain indicators of impairment exist. Examples of these indicators include, but are not limited to:

- A significant decrease in the market price of a long-lived asset (asset group);
- A significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used, or in its physical condition;
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset (asset group), including an adverse action or assessment by a regulator;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset (asset group);
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group); and
- A current expectation that it is more likely than not a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

If we determine that an asset or asset group may have become impaired, then we will perform step one of the impairment analysis, which requires us to determine if the asset's value is recoverable using forecasted undiscounted cash flows. If it is determined that the asset's value is not recoverable, then we will perform step two of the impairment analysis and fair value the asset using a DCF model and record an impairment charge to reduce the value of the asset to its fair value. The assumptions and estimates used by management to assess whether the asset may have become impaired, whether the asset's value is recoverable, and to determine the fair value of the estimate are significant and may vary materially from the assumptions used by our peers. Some examples of the assumptions and estimates used include:

- Determination of decreases in the market price of an asset being a short-term or long-term, fundamental change;
- The highest and best use of the asset;
- Forecasted environmental and regulatory changes;
- Management's fundamental view of the long-term pricing environment for energy and capacity;
- Management's forecast of gross margin, capital expenditures, and operations and maintenance costs;
- Remaining useful life of our assets;

- Salvage value;
- Discount rates; and
- Inflation rates.

Changes in any of management's assumptions and estimates could result in significantly different results than what we have reported herein.

We performed asset impairment analyses of all facilities in 2015 and determined that no impairment charges were required, other than for our Wood River and Brayton Point facilities. Please read Note 9—Property, Plant and Equipment for further discussion.

Goodwill Impairment

We record goodwill when the purchase price for an acquisition classified as a business combination exceeds the estimated net fair value of the identifiable tangible and intangible assets acquired. The amount of goodwill which can be recognized as part of an acquisition can change materially based upon the assumptions used when determining the net fair value of those assets. We allocate goodwill to reporting units based on the relative fair value of the purchased operating assets assigned to those reporting units.

ASC 350, Intangibles-Goodwill and Other requires an entity to assess whether goodwill has become impaired at least annually, or when certain indicators of impairment exist on an interim basis. We have elected October 1 for our annual assessment. Examples of the indicators of impairment include, but are not limited to:

- A deterioration of general economic conditions, limitation on accessing capital, or other developments in equity and credit markets;
- Increases in costs which have a negative effect on earnings and cash flows;
- Overall financial performance such as negative or declining cash flows or a decline in actual or planned revenue or earnings;
- Other relevant entity-specific events such as changes in management, key personnel, strategy, or customers, contemplation of bankruptcy, or litigation;
- A more likely than not expectation of selling or disposing all, or a portion, of a reporting unit; and,
- Recognition of a goodwill impairment loss in the financial statements of a subsidiary that is a component of a reporting unit.

Determining whether a goodwill impairment trigger exists involves significant judgment by management, which may result in a different answer if our peers were to consider the same facts and circumstances. In the event management determines a triggering event has occurred or it is the period for the annual assessment, ASC 350 allows an entity to elect to qualitatively assess whether it is more likely than not that an impairment has occurred (step zero). If we determine that it is more likely than not that goodwill has become impaired, we utilize a two-step process to conclude if goodwill has become impaired and to calculate the impairment charge. Step one involves fair valuing the reporting units to which goodwill has been assigned and comparing that fair value to the book value of the reporting units, inclusive of goodwill. In the event the fair value of the reporting unit is less than its book value, inclusive of goodwill, step two must be performed, which compares the implied fair value of goodwill to its book value.

The assumptions and estimates used by management to determine the fair value of our reporting units and goodwill for step one and step two, respectively, are significant and may vary materially from the assumptions and estimates used by our peers. Some examples of the assumptions and estimates used include:

- The highest and best use of the reporting units assets;
- Forecasted environmental and regulatory changes;
- Management's fundamental view of the long-term pricing environment for energy and capacity;
- Remaining useful life of our assets;
- Salvage value;
- Discount rates; and
- Inflation rates.

At October 1, 2015, Dynegy performed its annual goodwill assessment and determined that no impairment was required. As of December 31, 2015, we concluded that, due to the decrease in our stock price, it was more likely than not that the fair value of goodwill attributed to the reporting units in the Gas segment was less than its carrying amount. As a result, we performed a quantitative impairment analysis using a DCF model for each of the reporting units to which we assigned goodwill and determined that the fair value of the reporting units exceeded their respective carrying amounts, inclusive of goodwill. Changes in management's assumptions and estimates regarding the fair value of these reporting units could result in a materially different result.

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RECENT ACCOUNTING PRONOUNCEMENTS

Please read Note 2—Summary of Significant Accounting Policies for further discussion of accounting principles adopted and accounting principles not yet adopted.

RISK MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk management data contained within our consolidated balance sheets on a net basis:

(amounts in millions)	As of and for the Year Ended December 31, 2015
Fair value of portfolio at December 31, 2014	$(83)
Risk management losses recognized through the statement of operations in the period, net	84
Contracts realized or otherwise settled during the period	46
Acquisitions	(235)
Change in collateral/margin netting	98
Fair value of portfolio at December 31, 2015	$(90)

The net risk management liability of $90 million is the aggregate of the following line items on our consolidated balance sheets: Current Assets—Assets from risk management activities, Other Assets—Assets from risk management activities, Current Liabilities—Liabilities from risk management activities and Other Liabilities—Liabilities from risk management activities.

Risk Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of December 31, 2015, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2016	2017	2018	2019	2020	Thereafter
Market quotations (1) (2)	$(148)	$(83)	$(54)	$(6)	$(4)	$(1)	$—
Prices based on models (2)	(48)	(31)	(9)	(10)	1	1	—
Total (3)	$(196)	$(114)	$(63)	$(16)	$(3)	$—	$—

(1) Prices obtained from actively traded, liquid markets for commodities.

(2) The market quotations category represents our transactions classified as Level 1 and Level 2. The prices based on models category represents transactions classified as Level 3. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

(3) Excludes $106 million of broker margin that has been netted against Risk management liabilities on our consolidated balance sheet. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to commodity price variability related to our power generation business. In order to manage these commodity price risks, we routinely utilize various fixed-price forward purchase and sales contracts, futures and option contracts traded on the NYMEX or the Intercontinental Exchange and swaps and options traded in the OTC financial markets to:

- manage and hedge our fixed-price purchase and sales commitments;
- reduce our exposure to the volatility of cash market prices; and
- hedge our fuel requirements for our generating facilities.

The potential for changes in the market value of our commodity and interest rate portfolios is referred to as "market risk." A description of each market risk category is set forth below:

- commodity price risks result from exposures to changes in spot prices, forward prices and volatilities in commodities, such as electricity, natural gas, coal, fuel oil, emissions and other similar products; and
- interest rate risks primarily result from exposures to changes in the level, slope and curvature of the yield curve and the volatility of interest rates.

In the past, we have attempted to manage these market risks through diversification, controlling position sizes and executing hedging strategies. The ability to manage an exposure may, however, be limited by adverse changes in market liquidity, our credit capacity or other factors.

VaR. The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a Monte Carlo simulation-based methodology. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. VaR does not account for liquidity risk or the potential that adverse market conditions may prevent liquidation of existing market positions in a timely fashion. While management believes that these assumptions and approximations are reasonable, there is no uniform industry methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

We use historical data to estimate our VaR and, to better reflect current asset and liability volatilities, this historical data is weighted to give greater importance to more recent observations. Given our reliance on historical data, VaR is effective in estimating risk exposures in markets in which there are no sudden fundamental changes or abnormal shifts in market conditions. An inherent limitation of VaR is that past changes in market risk factors, even when weighted toward more recent observations, may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology's other limitations.

VaR represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon within a specified confidence level. For the VaR numbers reported below, a one-day time horizon and a 95 percent confidence level were used. This means that there is a one in 20 chance that the daily portfolio value will drop in value by an amount larger than the reported VaR. Thus, an adverse change in portfolio value greater than the expected change in portfolio value on a single trading day would be anticipated to occur, on average, about once a month. Gains or losses on a single day can exceed reported VaR by significant amounts. Gains or losses can also accumulate over a longer time horizon such as a number of consecutive trading days.

In addition, we have provided our VaR using a one-day time horizon with a 99 percent confidence level. The purpose of this disclosure is to provide an indication of earnings volatility using a higher confidence level. Under this presentation, there is a one in 100 statistical chance that the daily portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR. We have also disclosed a two-year comparison of daily VaR in order to provide context for the one-day amounts.

The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk-management portfolio primarily associated with the Coal and Gas segments. The VaR calculation does not include market risks associated with the accrual portion of the risk-management portfolio that is designated as "normal purchase, normal sale," nor does it include expected future production from our generating assets.

The increase in the December 31, 2015 one day VaR compared to December 31, 2014 was primarily due to increased forward positions and increased price volatility.

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Daily and Average VaR for Risk-Management Portfolios

(amounts in millions)	December 31, 2015	December 31, 2014
One day VaR—95 percent confidence level	$20	$10
One day VaR—99 percent confidence level	$29	$14
Average VaR—95 percent confidence level for the rolling twelve months ended	$8	$8

Credit Risk. Credit risk represents the loss that we would incur if a counterparty fails to perform pursuant to the terms of its contractual obligations. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to reduce credit risk further with certain counterparties by obtaining third-party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure of wholesale counterparties on a daily basis and outstanding receivable size and aging information of retail customers on a weekly basis.

The following table represents our credit exposure at December 31, 2015 associated with the wholesale mark-to-market portion of our risk-management portfolio, on a net basis. We have no exposure related to non-investment grade quality counterparties.

Credit Exposure Summary

(amounts in millions)	Investment Grade Quality
Type of Business:	
Financial institutions	$31
Utility and power generators	14
Total	$45

Interest Rate Risk

We are exposed to fluctuating interest rates related to variable rate financial obligations, which consist of amounts outstanding under our Credit Agreement. We currently use interest rate swaps to mitigate this interest rate exposure. Our interest rate hedging instruments are recorded at their fair value. As a result of our outstanding interest rate derivatives, we do not have any significant exposure to changes in LIBOR.

The absolute notional amounts associated with our interest rate contracts were as follows at December 31, 2015 and December 31, 2014, respectively:

	December 31, 2015	December 31, 2014
Interest rate swaps (in millions of U.S. dollars)	$777	$785
Fixed interest rate paid (percent)	3.19 %	3.19 %

Item 8. Financial Statements and Supplementary Data

The report of our independent registered public accounting firm and our Consolidated Financial Statements and Financial Statement Schedules are filed pursuant to this Item 8 and are included later in this report. See Index to Consolidated Financial Statements and Financial Statement Schedules on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of management, including our Chief Executive Officer ("CEO") and our CFO, of the effectiveness of the design and

operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2015.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of our company are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including the CEO and CFO, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, we used the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this assessment and on those criteria, we concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal controls over financial reporting that materially affected or are reasonably likely to materially affect our internal controls over financial reporting during the quarter ended December 31, 2015.

Item 9B. Other Information

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers. We intend to include the information with respect to our executive officers required by this Item 10 in our definitive proxy statement for our 2016 annual meeting of stockholders under the heading "Executive Officers," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, information with respect to Executive Officers will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Code of Ethics. We have adopted a Code of Ethics within the meaning of Item 406(b) of Regulation S-K. This Code of Ethics applies to our CEO, CFO, Chief Accounting Officer and other persons performing similar functions designated by the CFO, and is filed as an exhibit to this Form 10-K.

Other Information. We intend to include the other information required by this Item 10 in our definitive proxy statement for our 2016 annual meeting of stockholders under the headings "Proposal 1—Election of Directors" and "Compliance with Section 16(a) of the Exchange Act," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, information with respect to Other Information will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 11. Executive Compensation

We intend to include information with respect to executive compensation in our definitive proxy statement for our 2016 annual meeting of stockholders under the heading "Executive Compensation," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, information with respect to executive compensation will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

We intend to include information regarding ownership of our outstanding securities in our definitive proxy statement for our 2016 annual meeting of stockholders under the heading "Security Ownership of Certain Beneficial Owners and Management" and "Securities Authorized for Issuance Under Equity Compensation Plan," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, information with respect to beneficial ownership will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 13. Certain Relationships and Related Transactions, and Director Independence

We intend to include the information regarding related party transactions and director independence in our definitive proxy statement for our 2016 annual meeting of stockholders under the headings "Transactions with Related Persons, Promoters and Certain Control Persons," and "Corporate Governance," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, information with respect to certain relationships will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 14. Principal Accountant Fees and Services

We intend to include information regarding principal accountant fees and services in our definitive proxy statement for our 2016 annual meeting of stockholders under the heading "Independent Registered Public Auditors—Principal Accountant Fees and Services," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2015. However, if such proxy statement is not filed within such 120-day period, information with respect to the principal accountant fees and services will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents, which we have filed with the SEC pursuant to the Securities Exchange Act of 1934, as amended, are by this reference incorporated in and made a part of this report:

1. Financial Statements—Our consolidated financial statements are incorporated under Item 8. of this report.
2. Financial Statement Schedules—Financial Statement Schedules are incorporated under Item 8. of this report.
3. Exhibits—The following instruments and documents are included as exhibits to this report.

Exhibit Number	Description
1.1	Underwriting Agreement relating to the Common Stock, dated October 7, 2014, between Dynegy Inc. and Morgan Stanley & Co. LLC, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, RBC Capital Markets, LLC and UBS Securities LLC, as representatives of the underwriters (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 14, 2014, File No. 001-33443).
1.2	Underwriting Agreement relating to the Mandatory Convertible Preferred Stock, dated October 7, 2014, between Dynegy Inc. and Morgan Stanley & Co. LLC, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, RBC Capital Markets, LLC and UBS Securities LLC, as representatives of the underwriters (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 14, 2014 File No. 001-33443).
2.1	Confirmation Order for Dynegy Inc. and Dynegy Holdings, LLC, as entered by the Bankruptcy Court on September 10, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on September 13, 2012, File No. 001-33443).
*2.2	Purchase and Sale Agreement by and among Duke Energy SAM, LLC and Duke Energy Commercial Enterprises, Inc., as sellers, and Dynegy Resources I, LLC, as buyer, dated as of August 21, 2014 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on August 26, 2014 File No. 001-33443).
*2.3	Letter Agreement to Purchase and Sale Agreement by and among Duke Energy SAM, LLC and Duke Energy Commercial Enterprises, Inc., as sellers, and Dynegy Resources I, LLC, as buyer, dated as of October 24, 2014 (incorporated by reference to Exhibit 2.2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2014 of Dynegy Inc. File No. 001-33443).
*2.4	Stock Purchase Agreement by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein, dated as of August 21, 2014 (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K of Dynegy Inc. filed on August 26, 2014 File No. 001-33443).
2.5	Letter Agreement to Purchase and Sale Agreement by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein, dated November 12, 2014 (incorporated by reference to Exhibit 2.5 to the Annual Report on Form 10-K for the Year Ended December 31, 2014 of Dynegy Inc. File No. 001-33443).
*2.6	Letter Agreement to Purchase and Sale Agreement by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein,

	EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein, dated March 30, 2015 (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2015 of Dynegy Inc. File No. 001-33443).
2.7	Amendment to Stock Purchase Agreement, dated as of March 30, 2015, by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein(incorporated by reference to Exhibit 2.1 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 1, 2015).

*2.8	Stock Purchase Agreement and Agreement and Plan of Merger by and among Energy Capital Partners GP II, LP, Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-D, LP, Energy Capital Partners II-C (Cayman), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, Brayton Point Holdings, LLC, Dynegy Resource III, LLC, Dynegy Resource III-A, LLC, and Dynegy Inc., for the limited purposes set forth therein, dated as of August 21, 2014 (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K of Dynegy Inc. filed on August 26, 2014 File No. 001-33443).
2.9	Letter Agreement to Purchase and Sale Agreement by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein, and Stock Purchase Agreement and Agreement and Plan of Merger by and among Energy Capital Partners GP II, LP, Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-D, LP, Energy Capital Partners II-C (Cayman), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, Brayton Point Holdings, LLC, Dynegy Resource III, LLC, Dynegy Resource III-A, LLC, and Dynegy Inc., for the limited purposes set forth therein dated November 25, 2014 (incorporated by reference to Exhibit 2.7 to the Annual Report on Form 10-K for the Year Ended December 31, 2014 of Dynegy Inc. File No. 001-33443).
2.10	Revised Attachment A to the Letter Agreement to Purchase and Sale Agreement by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein, and Stock Purchase Agreement and Agreement and Plan of Merger by and among Energy Capital Partners GP II, LP, Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-D, LP, Energy Capital Partners II-C (Cayman), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, Brayton Point Holdings, LLC, Dynegy Resource III, LLC, Dynegy Resource III-A, LLC, and Dynegy Inc., for the limited purposes set forth therein dated February 4, 2015 (incorporated by reference to Exhibit 2.8 to the Annual Report on Form 10-K for the Year Ended December 31, 2014 of Dynegy Inc. File No. 001-33443).
*2.11	Transaction Agreement by and between Ameren Corporation and Illinois Power Holdings, LLC, dated as of March 14, 2013 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 15, 2013 File No. 001-33443).
*2.12	Letter Agreement, dated December 2, 2013, between Ameren Corporation and Illinois Power Holdings, LLC, amending the Transaction Agreement, dated as of March 14, 2013 (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K of Dynegy Inc. filed on December 4, 2013 File No. 001-33443).
2.13	Confirmation Order for Dynegy Northeast Generation, Inc., Hudson Power, L.L.C., Dynegy Danskammer, L.L.C., and Dynegy Roseton, L.L.C., as entered by the Bankruptcy Court on March 15, 2013 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 19, 2013 File No. 001-33443).
3.1	Dynegy Inc. Third Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
3.2	Dynegy Inc. Sixth Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on August 26, 2014 File No. 001-33443).

3.3	Certificate of Designations of the 5.375% Series A Mandatory Convertible Preferred Stock of Dynegy Inc., filed with the Secretary of State of the State of Delaware and effective October 14, 2014 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 14, 2014 File No. 001-33443).
4.1	Registration Rights Agreement, dated October 1, 2012, by and among the Company and the investors party thereto (Common Stock) (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
4.2	Indenture, dated May 20, 2013, among Dynegy Inc., the Guarantors and Wilmington Trust, National Association as Trustee (5.875% Senior Notes due 2023) (2023 Notes Indenture) (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
4.3	First Supplemental Indenture to the 2023 Notes Indenture, dated as of December 5, 2014, among Dynegy Inc., the Guarantors and Wilmington Trust, National Association as Trustee (incorporated by reference to Exhibit 4.3 to the Annual Report on Form 10-K for the Year Ended December 31, 2013 of Dynegy Inc. File No. 001-33443).

4.4	Second Supplemental Indenture to the 2023 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee (incorporated by reference to Exhibit 4.20 to the Current Report on Form 8-K of Dynegy Inc. filed April 7, 2015 File No. 001-33443).
4.5	Third Supplemental Indenture to the 2023 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee, pursuant to which the Subsidiary Guarantors are added to the 2023 Notes Indenture (incorporated by reference to Exhibit 4.28 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015).
4.6	Fourth Supplemental Indenture to the 2023 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 of Dynegy Inc. File No. 001-33443).
4.7	Fifth Supplemental Indenture to the 2023 Notes Indenture, dated September 21, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2015 of Dynegy Inc. File No. 001-33443).
4.8	Indenture dated as of November 1, 2000, from Illinois Power Generating Company to The Bank of New York Mellon Trust Company, N.A., as successor trustee (Genco Indenture) (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-4 of Illinois Power Generating Company Filed March 6, 2001, File No. 333-56594).
4.9	Third Supplemental Indenture dated as of June 1, 2002, to Genco Indenture, relating to the 7.95% Senior Notes, Series E due 2032 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 of Illinois Power Generating Company, File No. 333-56594).
4.10	Fourth Supplemental Indenture dated as of January 15, 2003, to Genco Indenture, relating to the 7.95% Senior Notes, Series F due 2032 (incorporated by reference to Exhibit 4.5 to the Annual Report on Form 10-K for the year ended December 31, 2002 of Illinois Power Generating Company, File No. 333-56594).
4.11	Fifth Supplemental Indenture dated as of April 1, 2008, to Genco Indenture, relating to the 7.00% Senior Notes, Series G due 2018 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Illinois Power Generating Company filed on April 9, 2008, File No. 333-56594).
4.12	Sixth Supplemental Indenture, dated as of July 7, 2008, to Genco Indenture, relating to the 7.00% Senior Notes, Series H due 2018 (incorporated by reference to Exhibit 4.55 to the Registration Statement on Form S-3 of Illinois Power Generating Company, Filed November 17, 2008, File No. 333-56594).
4.13	Seventh Supplemental Indenture, dated as of November 1, 2009, to Genco Indenture, relating to the 6.30% Senior Notes, Series I due 2020 (incorporated by reference to Exhibit 4.8 to the Current Report on Form 8-K of Illinois Power Generating Company filed on November 17, 2009, File No. 333-56594).
4.14	Registration Rights Agreement, dated June 6, 2002 among Illinois Power Generating Company and the Initial Purchasers relating to the Illinois Power Generating Company 7.95% Senior Notes, Series E due 2032 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 of Illinois Power Generating Company, File No. 333-56594).
4.15	Registration Rights Agreement, dated April 9, 2008 among Illinois Power Generating Company and the Initial Purchasers relating to the Illinois Power Generating Company 7.00% Senior Notes, Series G due 2018 (incorporated by reference to Exhibit 4.8 to the Registration Statement on Form S-4 of Illinois Power Generating Company Filed May 19, 2008, File No. 333-56594).

4.16	2019 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and Wilmington Trust, National Association, as trustee (2019 Notes Indenture) (incorporated by reference to Exhibit 4.7 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.17	First Supplemental Indenture to the 2019 Notes Indenture, dated April 1, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.8 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.18	Second Supplemental Indenture to the 2019 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.9 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.19	Third Supplemental Indenture to the 2019 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding the Duke Acquired Entities as guarantors (incorporated by reference to Exhibit 4.13 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015).

4.20	Fourth Supplemental Indenture to the 2019 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors, (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 of Dynegy Inc. File No. 001-33443).
4.21	Fifth Supplemental Indenture to the 2019 Notes Indenture, dated September 21, 2015, among Dynegy Inc., the Subsidiary Guarantors, (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2015 of Dynegy Inc. File No. 001-33443).
4.22	2022 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and Wilmington Trust, National Association, as trustee (2022 Notes Indenture) (incorporated by reference to Exhibit 4.8 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.23	First Supplemental Indenture to the 2022 Notes Indenture, dated April 1, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.11 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.24	Second Supplemental Indenture to the 2022 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.12 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.25	Third Supplemental Indenture to the 2022 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding the Duke Acquired Entities as guarantors (incorporated by reference to Exhibit 4.17 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015).
4.26	Fourth Supplemental Indenture to the 2022 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 of Dynegy Inc. File No. 001-33443).
4.27	Fifth Supplemental Indenture to the 2022 Notes Indenture, dated September 21, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2015 of Dynegy Inc. File No. 001-33443).
4.28	2024 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and Wilmington Trust, National Association, as trustee (2024 Notes Indenture) (incorporated by reference to Exhibit 4.9 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.29	First Supplemental Indenture to the 2024 Notes Indenture, dated April 1, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.14 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.30	Second Supplemental Indenture to the 2024 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.15 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.31	Third Supplemental Indenture to the 2024 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding the Duke Acquired Entities as guarantors (incorporated by reference to Exhibit 4.21 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015).

4.32	Fourth Supplemental Indenture to the 2024 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 of Dynegy Inc. File No. 001-33443).
4.33	Fifth Supplemental Indenture to the 2024 Notes Indenture, dated September 21, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor (incorporated by reference to Exhibit 4.3 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2015 of Dynegy Inc. File No. 001-33443).

4.34	Registration Rights Agreement, dated October 27, 2014, among Dynegy Finance I, Inc., Dynegy Finance II, Inc. and Morgan Stanley & Co. LLC, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, RBC Capital Markets, LLC and UBS Securities LLC as representatives of the initial purchasers identified therein (incorporated by reference to Exhibit 4.10 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.35	Joinder to the Registration Rights Agreement, dated April 1, 2015, among Dynegy Inc. and the subsidiary guarantors identified therein (incorporated by reference to Exhibit 4.17 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).
4.36	Joinder to the Registration Rights Agreement, dated April 2, 2015, among Dynegy Inc. and the subsidiary guarantors identified therein (incorporated by reference to Exhibit 4.24 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015).
10.1	Dynegy Inc. Severance Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2015 File No. 001-33443).††
10.2	Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††
10.3	First Amendment to the Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††
10.4	Second Amendment to Dynegy Inc. Restoration 401(k) Savings Plan, effective January 1, 2012 (incorporated by reference to Exhibit 10.23 to the Annual Report on Form 10-K of Dynegy Inc. for the year ended December 31, 2011, File No. 1-33443).††
10.5	Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††
10.6	First Amendment to the Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††
10.7	Second Amendment to the Dynegy Inc. Restoration Pension Plan, executed on July 2, 2010 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. and Dynegy Holdings Inc. filed on August 6, 2010, File No. 000-29311).††
10.8	Third Amendment to Dynegy Inc. Restoration Pension Plan, effective January 1, 2012 (incorporated by reference to Exhibit 10.27 to the Annual Report on Form 10-K of Dynegy Inc. for the year ended December 31, 2011, File No. 1-33443).††
10.9	Dynegy Inc. 2009 Phantom Stock Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443).††
10.10	First Amendment to the Dynegy Inc. 2009 Phantom Stock Plan, dated as of July 8, 2011(incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.11	Dynegy Inc. Deferred Compensation Plan for Certain Directors, as amended and restated, effective January 1, 2008 (incorporated by reference to Exhibit 10.55 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).††
10.12	Trust under Dynegy Inc. Deferred Compensation Plan for Certain Directors, effective January 1, 2009 (incorporated by reference to Exhibit 10.56 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).††
10.13	Dynegy Inc. Incentive Compensation Plan, as amended and restated effective May 21, 2010 (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2010, File No. 001-33443)††
10.14	

	2012 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).††
10.15	Amended and Restated Employment Agreement by and between Dynegy Operating Company and Robert C. Flexon (incorporated by reference to Exhibit 10.1 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on May 6, 2015). ††
10.16	Form of Dynegy Inc. Executive Participation Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2015 File No. 001-33443).††
10.17	Form of Non-Qualified Stock Option Award Agreement (2012 Awards) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443). ††

10.18	Form of Non-Qualified Stock Option Award Agreement (2013 Awards) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.19	Form of Non-Qualified Stock Option Award Agreement (2014 Awards) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2014 of Dynegy Inc. File No. 001-33443).††
10.20	Form of Non-Qualified Stock Option Award Agreement (2015 Awards) (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2015 of Dynegy Inc. File No. 001-33443).††
10.21	Amendment to Non-Qualified Stock Option Award Agreement - Flexon (2015 Employment Agreement Award) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2015 of Dynegy Inc. File No. 001-33443).††
10.22	Form of Stock Unit Award Agreement - Officers (2012 Awards) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443). ††
10.23	Form of Stock Unit Award Agreement - Officers (2013 Awards) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.24	Form of Stock Unit Award Agreement - Officers (2014 Awards) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2014 of Dynegy Inc. File No. 001-33443). ††
10.25	Form of Stock Unit Award Agreement - Officers (2015 Awards) (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2015 of Dynegy Inc. File No. 001-33443). ††
10.26	Form of Stock Unit Award Agreement - Flexon (2015 Employment Agreement Award) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 of Dynegy Inc. File No. 001-33443). ††
10.27	Form of Stock Unit Award Agreement - Directors (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443). ††
10.28	Form of Performance Award Agreement (2013 Awards) (for Managing Directors and Above) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.29	Form of Performance Award Agreement (2014 Awards) (for Managing Directors and Above)(incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2014 of Dynegy Inc. File No. 001-33443). ††
10.30	Form of Performance Award Agreement (2015 Awards) (for Managing Directors and Above)(incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2015 of Dynegy Inc. File No. 001-33443). ††
10.31	Form of Phantom Stock Unit Award Agreement - MD & Above Version (2012 LTIP Awards) (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2012 of Dynegy Inc., File No. 1- 33443). ††
10.32	Form of Phantom Stock Unit Award Agreement - MD & Above Version (2012 Replacement Shares) (incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2012 of Dynegy Inc., File No. 1- 33443). ††
10.33	Credit Agreement, dated as of April 23, 2013, among Dynegy Inc., as borrower and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.34	Guarantee and Collateral Agreement, dated as of April 23, 2013 among Dynegy Inc., the subsidiaries of the borrower from time to time party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee (incorporated by reference to Exhibit 10.2 to the Current

	Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.35	Collateral Trust and Intercreditor Agreement, dated as of April 23, 2013 among Dynegy, the Subsidiary Guarantors (as defined therein), Credit Suisse AG, Cayman Islands Branch and each person party thereto from time to time (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.36	First Amendment to Credit Agreement, dated as of April 1, 2015, among Dynegy Inc., as borrower, and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.4 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015).

10.37	Second Amendment to Credit Agreement, dated as of April 2, 2015, among Dynegy Inc., as borrower, and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.5 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015).
10.38	Letter of Credit Reimbursement Agreement, dated as of September 18, 2014 among Dynegy Inc., Macquarie Bank Limited, and Macquarie Energy LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 22, 2014 File No. 001-33443).
10.39	Purchase Agreement, dated May 15, 2013, among Dynegy Inc., the Guarantors, Morgan Stanley and Credit Suisse (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
10.40	Purchase Agreement, dated October 10, 2014, among Dynegy Inc., Dynegy Finance I, Inc., Dynegy Finance II, Inc., the guarantors identified therein and Morgan Stanley & Co. LLC, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, RBC Capital Markets, LLC and UBS Securities LLC, as representatives of the initial purchasers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 14, 2014 File No. 001-33443).
10.41	Revolving Promissory Note by and between Dynegy Inc., as Lender, and Illinois Power Resources, LLC (formerly New Ameren Energy Resources, LLC), as Borrower (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 4, 2013 File No. 001-33443).
10.42	Guaranty, dated August 21, 2014, by Dynegy Inc., for the benefit of Duke Energy SAM, LLC and Duke Energy Commercial Enterprises, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on August 26, 2014 File No. 001-33443).
****10.43	Warrant Agreement, dated October 1, 2012, by and among Dynegy Inc., Computershare Inc. and Computershare Trust Company, N.A., as warrant agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
10.44	Letter of Credit and Reimbursement Agreement, dated as of January 29, 2014 between Illinois Power Marketing Company and Union Bank, N.A. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. and Illinois Power Generating Company filed on February 4, 2014, File No. 001-33443).
10.45	Waiver and Amendment No. 1 to Letter of Credit and Reimbursement Agreement by and between Illinois Power Marketing Company and Union Bank, N.A. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2014 of Dynegy Inc., File No. 001-33443).
10.46	Amendment No. 2 to Letter of Credit and Reimbursement Agreement by and between Illinois Power Marketing Company and Union Bank, N.A. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2015 of Dynegy Inc., File No. 001-33443).
14.1	Dynegy Inc. Code of Ethics for Senior Financial Professionals, as amended on July 23, 2013(incorporated by reference to Exhibit 14.1 to the Annual Report on Form 10-K for the Year Ended December 31, 2013 of Dynegy Inc. File No. 001-33443).
***21.1	Significant subsidiaries of the Registrant
***23.1	Consent of Ernst & Young LLP
***31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
***31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	

	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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* Pursuant to Item 6.01(b)(2) of Regulation S-K exhibits and schedules are omitted. Dynegy agrees to furnish to the Commission supplementally a copy of any omitted schedule or exhibit upon request of the Commission.

** XBRL information is furnished and not filed for purposes of Section 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.

*** Filed herewith.

**** Pursuant to a request for confidential treatment, portions of this Exhibit have been redacted and filed separately with the SEC as required by Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

† Pursuant to Securities and Exchange Commission Release No. 33-8238, this certification will be treated as "accompanying" this report and not "filed" as part of such report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or the Exchange Act, or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

†† Management contract or compensation plan.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, the thereunto duly authorized.

		DYNEGY INC.	
			/s/ ROBERT C. FLEXON
Date:	February 25, 2016	By:	Robert C. Flexon
			President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

/s/ ROBERT C. FLEXON Robert C. Flexon	President and Chief Executive Officer & Director (Principal Executive Officer)	February 25, 2016
/s/ CLINT C. FREELAND Clint C. Freeland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2016
/s/ J. CLINTON WALDEN J. Clinton Walden	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2016
/s/ PAT WOOD III Pat Wood III	Chairman of the Board	February 25, 2016
/s/ HILARY E. ACKERMANN Hilary E. Ackermann	Director	February 25, 2016
/s/ PAUL M. BARBAS Paul M. Barbas	Director	February 25, 2016
/s/ RICHARD LEE KUERSTEINER Richard Lee Kuersteiner	Director	February 25, 2016
/s/ JEFFREY S. STEIN Jeffrey S. Stein	Director	February 25, 2016
/s/ JOHN R. SULT John R. Sult	Director	February 25, 2016

DYNEGY INC.
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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.:

We have audited Dynegy Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Dynegy Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Dynegy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2015 consolidated financial statements of Dynegy Inc. and our report dated February 25, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.:
We have audited the accompanying consolidated balance sheets of Dynegy Inc. (the Company) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.
We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.
In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dynegy Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dynegy Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 25, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 25, 2016

Item 1—FINANCIAL STATEMENTS

DYNEGY INC.
CONSOLIDATED BALANCE SHEETS
(in millions, except share data)

	December 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$505	$1,870
Restricted cash	39	113
Accounts receivable, net of allowance for doubtful accounts of $1 and $2, respectively	402	270
Inventory	597	208
Assets from risk management activities	100	78
Intangible assets	102	27
Prepayments and other current assets	200	108
Total Current Assets	1,945	2,674
Property, Plant and Equipment	9,235	3,685
Accumulated depreciation	(888)	(430)
Property, Plant and Equipment, Net	8,347	3,255
Other Assets		
Investment in unconsolidated affiliate	190	—
Restricted cash	—	5,100
Assets from risk management activities	18	2
Goodwill	797	—
Intangible assets	62	38
Deferred income taxes	—	20
Other long-term assets	180	143
Total Assets	$11,539	$11,232

See the notes to consolidated financial statements.

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DYNEGY INC.
CONSOLIDATED BALANCE SHEETS
(in millions, except share data)

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 292	$ 216
Accrued interest	74	80
Deferred income taxes	—	20
Intangible liabilities	85	45
Accrued liabilities and other current liabilities	175	157
Liabilities from risk management activities	103	132
Debt, current portion	83	31
Total Current Liabilities	812	681
Debt, long-term portion	7,206	7,075
Other Liabilities		
Liabilities from risk management activities	105	31
Asset retirement obligations	230	205
Deferred income taxes	29	—
Intangible liabilities	55	36
Other long-term liabilities	183	181
Total Liabilities	8,620	8,209
Commitments and Contingencies (Note 16)		
Stockholders' Equity		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized:		
Series A 5.375% mandatory convertible preferred stock, $0.01 par value; 4,000,000 shares issued and outstanding, respectively	400	400
Common stock, $0.01 par value, 420,000,000 shares authorized; 128,228,477 shares issued and 116,902,355 shares outstanding at December 31, 2015; 124,436,941 shares issued and outstanding at December 31, 2014	1	1
Additional paid-in capital	3,187	3,338
Accumulated other comprehensive income, net of tax	19	20
Accumulated deficit	(686)	(736)
Total Dynegy Stockholders' Equity	2,921	3,023
Noncontrolling interest	(2)	—
Total Equity	2,919	3,023
Total Liabilities and Equity	$ 11,539	$ 11,232

See the notes to consolidated financial statements.

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DYNEGY INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share data)

	Year Ended December 31,		
	2015	2014	2013
Revenues	$3,870	$2,497	$1,466
Cost of sales, excluding depreciation expense	(2,028)	(1,661)	(1,145)
Gross margin	1,842	836	321
Operating and maintenance expense	(839)	(477)	(308)
Depreciation expense	(587)	(247)	(216)
Impairments	(99)	—	—
Gain (loss) on sale of assets, net	(1)	18	2
General and administrative expense	(128)	(114)	(97)
Acquisition and integration costs	(124)	(35)	(20)
Operating income (loss)	64	(19)	(318)
Bankruptcy reorganization items, net	—	3	(1)
Earnings from unconsolidated investments	1	10	2
Interest expense	(546)	(223)	(97)
Loss on extinguishment of debt	—	—	(11)
Other income and expense, net	54	(39)	8
Loss from continuing operations before income taxes	(427)	(268)	(417)
Income tax benefit (Note 14)	474	1	58
Income (loss) from continuing operations	47	(267)	(359)
Income from discontinued operations, net of tax (Note 21)	—	—	3
Net income (loss)	47	(267)	(356)
Less: Net income (loss) attributable to noncontrolling interest	(3)	6	—
Net income (loss) attributable to Dynegy Inc.	50	(273)	(356)
Less: Dividends on preferred stock	22	5	—
Net income (loss) attributable to Dynegy Inc. common stockholders	$28	$(278)	$(356)
Earnings (Loss) Per Share (Note 15):			
Basic and diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders:			
Income (loss) from continuing operations	$0.22	$(2.65)	$(3.59)
Income from discontinued operations	—	—	0.03
Basic and diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders	$0.22	$(2.65)	$(3.56)
Basic shares outstanding	125	105	100
Diluted shares outstanding	126	105	100

See the notes to consolidated financial statements.

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DYNEGY INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in millions)

	Year Ended December 31,		
	2015	2014	2013
Net income (loss)	$47	$(267)	$(356)
Other comprehensive income (loss) before reclassifications:			
Actuarial gain (loss) and plan amendments (net of tax expense of zero, zero, and $31, respectively)	4	(36)	57
Amounts reclassified from accumulated other comprehensive income:			
Reclassification of curtailment gain included in net loss (net of tax of zero, zero, and zero, respectively)	—	—	(7)
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero, zero, and zero, respectively)	(4)	(5)	(2)
Other comprehensive income (loss), net of tax	—	(41)	48
Comprehensive income (loss)	47	(308)	(308)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(2)	3	1
Total comprehensive income (loss) attributable to Dynegy Inc.	$49	$(311)	$(309)

See the notes to consolidated financial statements.

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DYNEGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$47	$(267)	$(356)
Adjustments to reconcile net loss to net cash flows from operating activities:			
Depreciation expense	587	247	216
Loss on extinguishment of debt	—	—	11
Non-cash interest expense	38	21	2
Amortization of intangibles	(11)	45	251
Impairment	99	—	—
Risk management activities	(130)	26	38
(Gain) loss on sale of assets, net	1	(18)	(2)
Earnings from unconsolidated investments	(1)	—	—
Deferred income taxes	(477)	(1)	(56)
Change in value of common stock warrants	(54)	40	1
Other	51	35	14
Changes in working capital:			
Accounts receivable, net	(64)	161	(75)
Inventory	(119)	(20)	24
Prepayments and other current assets	84	22	48
Accounts payable and accrued liabilities	90	(131)	71
Distributions from unconsolidated investments	3	—	—
Changes in restricted cash	(28)	—	—
Changes in non-current assets	(27)	(4)	(12)
Changes in non-current liabilities	5	7	—
Net cash provided by operating activities	94	163	175
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(275)	(132)	(98)
Proceeds from asset sales, net	—	18	3
(Increase) decrease in restricted cash	5,148	(5,148)	335
Acquisitions, net of cash acquired/divestitures	(6,078)	—	234
Distributions from unconsolidated affiliates	8	—	—
Other investing	3	—	—
Net cash provided by (used in) investing activities	(1,194)	(5,262)	474
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	97	5,112	1,768
Proceeds from issuance of preferred stock	—	400	—
Proceeds from issuance of common stock	—	744	—
Repayments of borrowings, including debt extinguishment costs	(31)	(14)	(1,917)
Financing costs from debt issuance	(31)	(57)	—
Financing costs from equity issuance	(6)	(38)	—
Dividends paid	(23)	—	—
Interest rate swap settlement payments	(17)	(18)	(5)

Repurchase of common stock	(250)	—	—
Other financing	(4)	(3)	—
Net cash provided by (used in) financing activities	(265)	6,126	(154)
Net increase (decrease) in cash and cash equivalents	(1,365)	1,027	495
Cash and cash equivalents, beginning of period	1,870	843	348
Cash and cash equivalents, end of period	$505	$1,870	$843

See the notes to consolidated financial statements.

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DYNEGY INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(in millions)

	Preferred Stock	Common Stock	Additional Paid-In Capital	AOCI	Accumulated Deficit	Total Controlling Interests	Noncontrolling Interest	Total
December 31, 2012	$—	$1	$2,598	$11	$(107)	$2,503	$—	$2,503
Net loss	—	—	—	—	(356)	(356)	—	(356)
Other comprehensive income, net of tax	—	—	—	47	—	47	1	48
Share-based compensation expense, net of tax	—	—	14	—	—	14	—	14
Options exercised	—	—	2	—	—	2	—	2
AER Acquisition	—	—	—	—	—	—	(4)	(4)
December 31, 2013	—	1	2,614	58	(463)	2,210	(3)	2,207
Net income (loss)	—	—	—	—	(273)	(273)	6	(267)
Other comprehensive loss, net of tax	—	—	—	(38)	—	(38)	(3)	(41)
Share-based compensation expense, net of tax	—	—	17	—	—	17	—	17
Options exercised	—	—	1	—	—	1	—	1
Issuance of new equity interests (Note 17)	400	—	706	—	—	1,106	—	1,106
December 31, 2014	400	1	3,338	20	(736)	3,023	—	3,023
Net income (loss)	—	—	—	—	50	50	(3)	47
Equity issuance for acquisition, net (Note 17)	—	—	99	—	—	99	—	99
Other comprehensive income (loss), net of tax	—	—	—	(1)	—	(1)	1	—
Share-based compensation expense, net of tax	—	—	22	—	—	22	—	22
Options exercised	—	—	1	—	—	1	—	1
Dividends paid	—	—	(23)	—	—	(23)	—	(23)
Repurchases of common stock (Note 17)	—	—	(250)	—	—	(250)	—	(250)
December 31, 2015	$400	$1	$3,187	$19	$(686)	$2,921	$(2)	$2,919

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Operations

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. Unless the context indicates otherwise, throughout this report, the terms "Dynegy," "the Company," "we," "us," "our" and "ours" are used refer to Dynegy Inc. and its direct and indirect subsidiaries. We report the results of our power generation business as three segments in our consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). All significant intercompany transactions have been eliminated. Please read Note 23—Segment Information for further discussion.

IPH and its direct and indirect subsidiaries are organized into ring-fenced groups in order to maintain corporate separateness from Dynegy and its other subsidiaries. Certain of the entities in the IPH segment, including Illinois Power Generating Company ("Genco"), have an independent director whose consent is required for certain corporate actions, including material transactions with affiliates. Further, entities within the IPH segment present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Furthermore, they pay liabilities from their own funds, conduct business in their own names and have restrictions on pledging their assets for the benefit of certain other persons. These provisions restrict our ability to move cash out of these entities without meeting certain requirements as set forth in the governing documents.

Note 2—Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries. Intercompany accounts and transactions have been eliminated. Certain prior period amounts in our consolidated balance sheets have been reclassified to conform to current year presentation. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America ("U.S.").

Unconsolidated Investments. We use the equity method of accounting for investments in affiliates over which we exercise significant influence. We use the cost method of accounting where we do not exercise significant influence. Our share of net income (loss) from these affiliates is reflected in the consolidated statements of operations as Earnings from unconsolidated investments. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in Earnings from unconsolidated investments in the consolidated statements of operations.

Undivided Interest Accounting. We account for our undivided interests in certain of our coal-fired power generation facilities whereby our proportionate share of each facility's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements.

Noncontrolling Interest. Noncontrolling interest is comprised of the 20 percent of Electric Energy, Inc. ("EEI") which we do not own. This noncontrolling interest is classified as a component of equity separate from our equity in the consolidated balance sheets.

Use of Estimates. The preparation of consolidated financial statements in conformity with Generally Accepted Accounting Principles ("GAAP") requires management to make informed estimates and judgments that affect our reported financial position and results of operations based on currently available information. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things: (i) developing fair value assumptions, including estimates of future cash flows and discount rates, (ii) analyzing tangible and intangible assets for possible impairment, (iii) estimating the useful lives of our assets and Asset Retirement Obligations ("AROs"), (iv) assessing future tax exposure and the realization of deferred tax assets, (v) determining amounts to accrue for contingencies, guarantees and, indemnifications and (vi) estimating various factors used to value our pension assets and liabilities. Actual results could differ materially from our estimates. In the opinion of management, all adjustments considered necessary for a fair presentation have been included in our consolidated financial statements.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid short-term investments with original maturities of three months or less.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Cash. Restricted cash represents cash that is not readily available for general purpose cash needs. Restricted cash is classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse. As of December 31, 2015, we had $39 million of restricted cash classified as current assets related to cash deposits associated with certain letters of credit. We included this change in restricted cash as an operating activity in our consolidated statements of cash flows. As of December 31, 2014, we had $5.1 billion of restricted cash classified as long-term assets and $113 million of prepaid interest classified as current assets related to the issuance of the Notes, as defined herein. Upon the close of the Acquisitions, as defined herein, the proceeds from the issuance of the Notes were released from escrow. Please read Note 13—Debt for further information. We included the changes in restricted cash related to the payment to the escrow agents for the Acquisitions and the prepayment of interest on the Notes as investing activities in our consolidated statements of cash flows. Payments to the escrow agents for interest accrued on the Notes are reflected as operating activities in our consolidated statements of cash flows.

Accounts Receivable and Allowance for Doubtful Accounts. We record accounts receivable at the net realizable value ("NRV") when the product or service is delivered to the customer. We establish provisions for losses on accounts receivable if it becomes probable that we will not collect all or part of outstanding balances. We review collectability and establish or adjust our allowance as necessary using the specific identification method.

Inventory. Our commodity and materials and supplies inventories are carried at the lower of weighted average cost or NRV.

Property, Plant and Equipment. Property, plant and equipment ("PP&E"), which consists principally of power generating facilities, including capitalized interest, is generally recorded at historical cost. Expenditures for major installations, replacements, and improvements or betterments are capitalized and depreciated over the expected life cycle. Expenditures for maintenance, repairs and minor renewals to maintain the operating condition of our assets are expensed. Depreciation is recognized using the straight-line method over the estimated economic service lives of the assets, ranging from two to 40 years.

The estimated economic service lives of our asset groups are as follows:

Asset Group	Range of Years
Power generation	2 to 36
Buildings and improvements	2 to 40
Office and other equipment	3 to 20

Gains and losses on sales of individual assets or asset groups are reflected in Gain (loss) on sale of assets, net in the consolidated statements of operations. We evaluate our PP&E for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. If an impairment is indicated, the carrying value is first compared to the undiscounted cash flows for the asset's or asset group's remaining useful life to determine if the carrying value is recoverable. In the event the carrying value is not recoverable, an impairment is recognized for the amount of carrying value in excess of the asset's or asset group's fair value. As a result of our impairment analyses performed in 2015, we determined that our Brayton Point and Wood River facilities were impaired resulting in an aggregate impairment charge of $99 million for the year ended December 31, 2015. Please read Note 9—Property, Plant and Equipment for further information.

Goodwill. Goodwill represents, at the time of an acquisition, the excess of purchase price over fair value of net assets acquired. The carrying amount of our goodwill will be periodically reviewed, at least annually, for impairment and whenever events or changes in circumstances indicate that the carrying value may not be recoverable. In accordance with Accounting Standards Codification ("ASC") 350, Intangibles-Goodwill and Other, we can opt to perform a qualitative assessment to test goodwill for impairment or we can directly perform a two-step impairment test. Based on our qualitative assessment, if we determine that the fair value of a reporting unit is more likely than not (i.e., a likelihood of more than 50 percent) to be less than its carrying amount, the two-step impairment test will be performed.

In the absence of sufficient qualitative factors, goodwill impairment is determined using a two-step process:

- Step one—Identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value exceeds book value, the goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, proceed to step two.
- Step two—Compare the implied fair value of the reporting unit's goodwill to the book value of the reporting unit's goodwill. If the book value of goodwill exceeds the implied fair value, an impairment charge is recognized for the excess.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2015, we concluded that, due to the decrease in our stock price, it was more likely than not that the fair value of goodwill attributed to the reporting units in the Gas segment was less than its carrying amount. As a result, we performed a quantitative impairment analysis using a Discounted Cash Flow ("DCF") model for each of the reporting units to which we assigned goodwill and determined that the fair value of the reporting units exceeded their respective carrying amounts, inclusive of goodwill. Therefore, as of December 31, 2015, no impairment loss related to goodwill was required.

Intangible Assets and Liabilities. We initially record and measure intangible assets and liabilities ("Intangibles") based on the fair value of those rights transferred in the transaction in which the asset was acquired. All recognized Intangibles consist of contractual rights and obligations with finite lives. The Intangibles are based on quoted market prices, if available, or measurement techniques based on the best information available such as a present value of future cash flows. We amortize our definite-lived Intangibles based on the useful life of the respective contract or contracts.

Asset Retirement Obligations. We record the present value of our legal obligations to retire tangible, long-lived assets on our consolidated balance sheets as liabilities when the liability is incurred. Our AROs relate to activities such as Coal Combustion Residuals ("CCR") surface impoundments and landfill closure, dismantlement of power generation facilities, future removal of asbestos-containing material from certain power generation facilities, closure and post-closure costs, environmental testing, remediation, monitoring and land obligations. Accretion expense is included in Operating and maintenance expense on our consolidated statements of operations. A summary of changes in our AROs is as follows:

	Year Ended December 31,	
(amounts in millions)	2015	2014
Balance at beginning of year	$224	$181
Accretion expense	21	12
Liabilities incurred	4	—
Liabilities settled	(4)	(2)
Revision of previous estimate (1)	(57)	33
Acquisitions (2)	92	—
Balance at end of year	$280	$224

(1) During 2015, we revised our ARO downward by $57 million based on management's review and assessment of CCR compliance timing and site-specific analysis. During 2014, we revised our ARO upward by $33 million based on observed trends in Illinois, primarily related to CCR surface impoundment closures and landfills in accordance with the standards used in the industry.

(2) As a result of the Acquisitions in April 2015, the associated AROs were assumed.

Contingencies, Commitments, Guarantees and Indemnifications. We are involved in numerous lawsuits, claims, proceedings and tax-related audits in the normal course of our operations. We record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on our consolidated balance sheets. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Liabilities for environmental contingencies are recorded when an environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability.

We disclose and account for various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances; however, management also considers the probability of such circumstances occurring when estimating the fair value.

Preferred Stock. Our preferred shares are mandatorily convertible, are not redeemable and are classified as stockholders' equity. We present the gross proceeds from their issuance as a single line item within stockholders' equity on the consolidated balance sheets. Dividends on the preferred shares are cumulative and are presented as a reduction of net income (or increase of net loss) to derive net income (loss) attributable to common shareholders on the consolidated statements of operations. Dividends are recognized in stockholders' equity in the period in which they are declared, and are presented as a financing activity on the consolidated statements of cash flows when paid.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Treasury Stock. Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock, which is presented on our consolidated balance sheets as a reduction of Additional paid-in capital.

Revenue Recognition. We earn revenue from our facilities in three primary ways: (i) the sale of energy through both physical and financial transactions to optimize the financial performance of our generating facilities; (ii) the sale of capacity; and (iii) the sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. Please read "Derivative Instruments—Generation" for further discussion of the accounting for these types of transactions.

Derivative Instruments—Generation. We enter into commodity contracts that meet the definition of a derivative. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include forward contracts, which commit us to buy or sell commodities in the future; futures contracts, which are generally broker-cleared standard commitments to purchase or sell a commodity; option contracts, which convey the right to buy or sell a commodity; and swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined quantity. All derivative commodity contracts that do not qualify for the "normal purchase, normal sale" exception are recorded at fair value in Risk management assets and liabilities on the consolidated balance sheets. We elect not to apply hedge accounting to our derivative commodity contracts; therefore, changes in fair value are recorded currently in earnings. As a result, these mark-to-market gains and losses are not reflected in the consolidated statements of operations in the same period as the underlying activity for which the derivative instruments serve as economic hedges. Derivative instruments and related cash collateral or margin that are executed with the same counterparty under a master netting agreement are reflected on a net basis in the consolidated balance sheets.

Cash inflows and cash outflows associated with the settlement of risk management activities are recognized in net cash provided by (used in) operating activities on the consolidated statements of cash flows.

Derivative Instruments—Financing Activities. We are exposed to changes in interest rates through our variable rate debt. In order to manage our interest rate risk, we enter into interest rate swap and cap agreements. We elect not to apply hedge accounting to our interest rate derivative contracts; therefore, changes in fair value are recorded currently in earnings through interest expense. Cash settlements related to our current interest rate contracts are classified as either inflows or outflows from financing activities on the consolidated cash flow statements due to an other-than-insignificant financing element at inception of these contracts. Please read Note 13—Debt for more information.

Fair Value Measurements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Our estimate of fair value reflects the impact of credit risk. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs are classified as readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the classification of the inputs used to calculate the fair value of a transaction. The inputs used to measure fair value have been placed in a hierarchy based on priority.

The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.

- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using industry-standard models or other valuation methodologies in which substantially all assumptions are observable in the marketplace throughout the full term of the instrument, and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter forwards, options and swaps.
- Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3

instruments include those that may be more structured or otherwise tailored to our needs. At each balance sheet date, we perform an analysis of all instruments and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

The determination of fair value incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings evidence when assessing the credit standing of our counterparties and, when applicable, adjusted based on management's estimates of assumptions market participants would use in determining fair value.

Income Taxes. We file a consolidated U.S. federal income tax return. IPH and its subsidiaries (ring-fenced entities) operate under a tax sharing agreement with Dynegy.

We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant differences as of each reporting date.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing tax and accounting treatment of certain items, such as depreciation for tax and accounting purposes. These differences can result in deferred tax assets and liabilities which are included within our consolidated balance sheets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Because we operate and sell power in many different states, our effective annual state income tax rate may vary from period to period because of changes in our sales profile by state, as well as jurisdictional and legislative changes by state. As a result, changes in our estimated effective annual state income tax rate can have a significant impact on our measurement of temporary differences. We project the rates at which state tax temporary differences will reverse based upon estimates of revenues and operations in the respective jurisdictions in which we conduct business.

The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. In making this determination, we consider all available positive and negative evidence affecting specific deferred tax assets, including our past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Accounting for uncertainty in income taxes requires that we determine whether it is more likely than not that a tax position we have taken will be sustained upon examination. If we determine that it is more likely than not that the position will be sustained, we recognize the largest amount of the benefit that is greater than 50 percent likely of being realized upon settlement. We recognize accrued interest expense and penalties related to unrecognized tax benefits as income tax expense.

Please read Note 14—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and changes in our valuation allowance.

Earnings (Loss) Per Share. Basic earnings (loss) per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings (loss) per share includes the effect of issuing shares of common stock, assuming stock options and warrants are exercised and restricted stock units and performance stock units are fully vested under the treasury stock method. Diluted earnings (loss) per share also includes the effect of the assumed conversion of our convertible preferred stock into common stock under the if-converted method.

Business Combinations Accounting. The Company accounts for its business combinations in accordance with ASC 805, Business Combinations ("ASC 805"), which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also requires an acquirer to measure any goodwill acquired and determine what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, ASC 805 requires transaction costs to be expensed as incurred.

Accounting Standards Adopted

Income Taxes. In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-17-Income Taxes (Topic 740). The amendment in this ASU eliminates the current requirement for organizations to present deferred tax liabilities and assets as current and noncurrent in a classified balance sheet. Instead, organizations will be required to classify all deferred tax assets and liabilities as noncurrent. The guidance in this ASU is effective for public entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. The ASU may be applied prospectively to all deferred tax assets and liabilities or retrospectively to all periods presented. We adopted ASU 2015-17 as of December 31, 2015 and applied the guidance prospectively with no change to prior period amounts disclosed in our consolidated balance sheets and related notes to the consolidated financial statements. Please read Note 14—Income Taxes for further discussion.

Business Combinations. In September 2015, the FASB issued ASU 2015-16-Business Combinations (Topic 805). The amendments in this ASU require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in this ASU require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in this ASU require an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The guidance in this ASU is effective prospectively for interim and annual periods beginning after December 15, 2016, with early adoption permitted for financial statements that have not been issued. We adopted ASU 2015-16 as of September 30, 2015. Please read Note 3—Acquisitions for a summary of the impact on our consolidated financial statements.

Derivatives. In August 2015, the FASB issued ASU 2015-13-Derivatives and Hedging (Topic 815). The amendments in this ASU specify that the use of LMP by an ISO does not constitute net settlement of a contract for the purchase or sale of electricity on a forward basis and, therefore, does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. If the physical delivery criterion is met, along with all of the other criteria of the normal purchases and normal sales scope exception, an entity may elect to designate that contract as a normal purchase or normal sale. The amendments in this ASU are effective upon issuance and should be applied prospectively. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Inventory. In July 2015, the FASB issued ASU 2015-11-Inventory (Topic 330). The amendments in this ASU require that inventory is measured at the lower of cost or NRV, with the latter defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. This ASU eliminates the need to determine market or replacement cost and evaluate whether it is above the ceiling at NRV or below the floor (NRV less a normal profit margin). The guidance in this ASU is effective prospectively for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We adopted ASU 2015-11 as of July 1, 2015. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Retirement Benefits. In April 2015, the FASB issued ASU 2015-04-Compensation-Retirement Benefits (Topic 715). For an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan or post retirement plan assets and obligations, the amendments in this ASU provide a practical expedient that permits the entity to remeasure the plan assets and obligations using the month-end that is closest to the date of the significant event. The month-end remeasurement of defined benefit plan assets and obligations that is closest to the date of the significant event should be adjusted for any effects of the significant event that may or may not be captured in the month-end measurement. An entity is required to disclose the accounting policy election and the date used to measure defined benefit plan assets and obligations in accordance with the amendments in this ASU. The amendments in this ASU are effective for public business entities for financial statements issued for fiscal years beginning after December

15, 2015, and interim periods within those fiscal years, with early adoption allowed. The amendments in this ASU should be applied prospectively. We adopted the guidance in this ASU on July 1, 2015. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Reporting Discontinued Operations and Asset Disposals. In April 2014, the FASB issued ASU 2014-08-Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosure of Disposals of Components of an Entity. The amendments in this ASU change the requirements for reporting discontinued operations in Subtopic 205-20. An entity is required to report within discontinued operations on the statement of operations the results of a component or group of components of an entity if the disposal represents a strategic shift that has, or will have, a major effect on an entity's operations and financial results. Additionally, the associated assets and liabilities are required to be presented separately from other assets and liabilities on the balance sheet for all comparative periods. The ASU includes updated guidance regarding what meets the definition of a component of an entity. The new financial statement presentation provisions relating to this ASU are prospective and effective for interim and annual periods beginning after December 15, 2014, with early adoption permitted. We adopted the guidance in this ASU on January 1, 2015. The adoption of this ASU did not have a material impact on our consolidated financial statements or disclosures.

Accounting Standards Not Yet Adopted

Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03-Interest-Imputation of Interest (Subtopic 835-30). The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update.

In August 2015, the FASB issued ASU 2015-15-Interest-Imputation of Interest (Subtopic 835-30). The amendments in this ASU further clarify the guidance provided in ASU 2015-03 to include the presentation of debt issuance costs in relation to line-of-credit arrangements. The amendments state these costs may be presented as an asset and subsequently amortized ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement.

The guidance in these ASUs is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The adoption of these ASUs should be applied on a retrospective basis, affecting all balance sheet periods presented. We do not anticipate the adoption of these ASUs will have a material impact on our consolidated balance sheets.

Consolidation. In February 2015, the FASB issued ASU 2015-02-Consolidation (Topic 810). The amendments in this ASU respond to concerns about the current accounting for consolidation of certain legal entities, in particular: (i) consolidation of limited partnerships and similar legal entities, (ii) evaluating fees paid to a decision maker or a service provider as a variable interest, (iii) the effect of fee arrangements on the primary beneficiary determination, (iv) the effect of related parties on the primary beneficiary determination and (v) consolidation of certain investment funds. The guidance in this ASU is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted in an interim period. We do not anticipate the adoption of this ASU will have a material impact on our consolidated financial statements.

Extraordinary and Unusual Items. In January 2015, the FASB issued ASU 2015-01-Income Statement-Extraordinary and Unusual Items (Subtopic 225-20). The amendments in this ASU eliminate from GAAP the concept of extraordinary items and will no longer require separate classification of these items within the statement of operations. Presentation and disclosure guidance for items that are unusual in nature or occur infrequently will be retained and will be expanded to include items that are both unusual in nature and infrequently occurring. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Reporting entities may elect to apply the amendments prospectively only, or retrospectively for all prior periods presented in the financial statements. Early adoption is permitted provided that the guidance is applied from the beginning of the fiscal year of adoption. We do not anticipate the adoption of this ASU will have a material impact on our consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the FASB and International Accounting Standards Board ("IASB") jointly issued ASU 2014-09-Revenue from Contracts with Customers (Topic 606). This ASU was further updated through the issuance of ASU 2015-14 in August 2015. The amendments in this ASU develop a common revenue standard for GAAP and International Financial Reporting Standards ("IFRS") by removing inconsistencies and weaknesses in revenue requirements, providing a more robust framework for addressing revenue issues, improving comparability of revenue recognition practices, providing more useful information to users of financial statements and simplifying the preparation of financial statements. The guidance in this ASU is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted for interim and annual periods beginning after December 15, 2016. We are currently assessing this ASU; however, we do not anticipate the adoption of this ASU will have a material impact on our consolidated financial statements.

Note 3—Acquisitions

Energy Capital Partners ("ECP") Purchase Agreements. On April 1, 2015 (the "EquiPower Closing Date"), pursuant to the terms of the stock purchase agreement dated August 21, 2014, as amended (the "ERC Purchase Agreement"), our wholly-owned subsidiary, Dynegy Resource II, LLC (the "ERC Purchaser") purchased 100 percent of the equity interests in EquiPower Resources Corp. ("ERC") from certain affiliates of ECP (collectively, the "ERC Sellers") thereby acquiring: (i) five combined cycle natural-gas fired facilities in Connecticut, Massachusetts and Pennsylvania, (ii) a partial interest in one natural gas-fired peaking facility in Illinois, (iii) two gas and oil fired peaking facilities in Ohio and (iv) one coal-fired facility in Illinois (the "ERC Acquisition").

On the EquiPower Closing Date, in a related transaction, pursuant to a stock purchase agreement and plan of merger dated August 21, 2014, as amended (the "Brayton Purchase Agreement" and together with the ERC Purchase Agreement, the "ECP

Purchase Agreements") our wholly-owned subsidiary, Dynegy Resource III, LLC (the "Brayton Purchaser" and, together with the ERC Purchaser, the "ECP Purchasers") purchased 100 percent of the equity interests in Brayton Point Holdings, LLC ("Brayton") from certain affiliates of ECP (collectively, the "Brayton Sellers" and together with the ERC Sellers, the "ECP Sellers"), thereby acquiring a coal-fired facility in Massachusetts (the "Brayton Acquisition").

The ERC Acquisition and the Brayton Acquisition (collectively, the "EquiPower Acquisition") added approximately 6,300 MW of generation in Connecticut, Illinois, Massachusetts, Ohio and Pennsylvania for an aggregate base purchase price of approximately $3.35 billion in cash plus approximately $105 million in common stock of Dynegy, subject to certain adjustments. In aggregate, the resulting operations from the two coal-fired facilities acquired from the ECP Sellers are reported within our Coal segment, while related operations from the six natural gas-fired and two gas and oil-fired facilities are reported within our Gas segment.

Under the ECP Purchase Agreements, the ECP Purchasers and ECP Sellers have agreed to indemnify the other applicable parties for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions and limitations. Neither the ECP Purchasers nor the ECP Sellers, in the aggregate, are entitled to indemnification in excess of $276 million, and $104 million of the purchase price which will be held in escrow for one year after closing to support the post-closing adjustment and indemnification obligations of the ECP Sellers.

Duke Midwest Purchase Agreement. On April 2, 2015 (the "Duke Midwest Closing Date"), pursuant to the terms of the purchase and sale agreement dated August 21, 2014, as amended (the "Duke Midwest Purchase Agreement"), our wholly owned subsidiary Dynegy Resource I, LLC ("DRI") purchased 100 percent of the membership interests in Duke Energy Commercial Asset Management, LLC and Duke Energy Retail Sales, LLC, from two affiliates of Duke Energy Corporation (collectively, "Duke Energy"), thereby acquiring approximately 6,200 MW of generation including: (i) three combined cycle natural gas-fired facilities located in Ohio and Pennsylvania, (ii) two natural gas-fired peaking facilities located in Ohio and Illinois, (iii) one oil-fired peaking facility located in Ohio, (iv) partial interests in five coal-fired facilities located in Ohio and (v) one retail energy business for a base purchase price of $2.8 billion in cash (the "Duke Midwest Acquisition"), subject to certain adjustments. We operate two of the five coal-fired facilities, the Miami Fort and Zimmer facilities, with other owners operating the three remaining facilities. The operations from the retail energy business, the five coal-fired and the one oil-fired facilities acquired from Duke Energy are reported within our Coal segment, while related operations from the five natural gas-fired facilities are reported within our Gas segment.

Under the Duke Midwest Purchase Agreement, DRI and Duke Energy have agreed to indemnify the other applicable parties for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions and limitations. Dynegy has guaranteed, up to a maximum liability of $2.8 billion, the Obligations of DRI under the Duke Midwest Purchase Agreement and related Transition Services Agreement ("TSA"). DRI shall, in the aggregate, not be entitled to indemnification in excess of $280 million for most matters and $2.8 billion for certain fundamental representations, tax matters and fraud.

Business Combinations Accounting. The EquiPower Acquisition and the Duke Midwest Acquisition (collectively, the "Acquisitions") have been accounted for in accordance with ASC 805, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition dates, April 1, 2015 and April 2, 2015, respectively. The valuation of these assets and liabilities is classified as Level 3 within the fair value hierarchy levels. The initial accounting for the Acquisitions is not complete because certain information and analysis that may impact our initial valuation is still being obtained or reviewed. Dynegy expects to finalize these amounts during the second quarter of 2016. The significant assets and liabilities for which provisional amounts are recognized at the respective acquisition dates are PP&E, goodwill, deferred income taxes and taxes other than deferred income taxes. We continue to evaluate settlements which could relate to pre-acquisition activity from the ISOs. Additionally, some taxes have not yet been finalized with the associated taxing jurisdictions, resulting in a potential change to their fair value at acquisition. These changes may also impact the fair value of the acquired PP&E, goodwill or deferred tax liability. As such, the provisional amounts recognized are subject to revision until our valuations are completed, not to exceed one year, and any material adjustments identified that existed as of the acquisition date will be recognized in the current period.

To fair value working capital, we used available market information. ARO's were recorded in accordance with ASC 410, Asset Retirement and Environmental Obligations. To fair value the acquired PP&E, we used a DCF analysis based upon a debt-free, free cash flow model. The DCF model was created for each power generation facility based on its remaining useful life, and included gross margin forecasts for each facility using forward commodity market prices obtained from third party quotations for the years 2015 through 2016. For the years 2017 through 2024, we used gross margin forecasts based upon commodity and capacity price curves developed internally using forward NYMEX natural gas prices and supply and demand factors. For periods beyond 2024, we assumed a 2.5 percent growth rate. We also used management's forecasts of operations and maintenance expense, general and administrative expense and capital expenditures for the years 2015 through 2019 and assumed a 2.5 percent growth rate, based upon management's view of future conditions, thereafter. The resulting cash flows were then discounted using plant specific discount rates of approximately 8 percent to 10 percent for gas-fired generation facilities and approximately 9 percent to

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13 percent for coal-fired generation facilities, based upon the asset's age, efficiency, region and years until retirement. Contracts with terms that are not at current market prices were also valued using a DCF analysis. The cash flows generated by the contracts were compared with their cash flows based on current market prices with the resulting difference recorded as either an intangible asset or liability. The 3,460,053 shares of common stock of Dynegy issued as part of the consideration for the EquiPower Acquisition were valued at approximately $105 million based on the closing price of Dynegy's common stock on the EquiPower Closing Date.
The following table summarizes the consideration paid and the provisional fair value amounts recognized for the assets acquired and liabilities assumed related to the EquiPower Acquisition and Duke Midwest Acquisition, as of the respective acquisition dates, April 1, 2015 and April 2, 2015:

(amounts in millions)	EquiPower Acquisition	Duke Midwest Acquisition	Total
Cash	$3,350	$2,800	$6,150
Equity instruments (3,460,053 common shares of Dynegy)	105	—	105
Net working capital adjustment	206	(9)	197
Fair value of total consideration transferred	$3,661	$2,791	$6,452
Cash	$267	$—	$267
Accounts receivable	49	127	176
Inventory	167	105	272
Assets from risk management activities (including current portion of $4 million and $30 million, respectively)	4	33	37
Prepayments and other current assets	32	69	101
Property, plant and equipment	2,773	2,734	5,507
Investment in unconsolidated affiliate	200	—	200
Intangible assets (including current portion of $67 million and $36 million, respectively)	111	84	195
Other long-term assets	28	35	63
Total assets acquired	3,631	3,187	6,818
Accounts payable	27	97	124
Accrued liabilities and other current liabilities	22	10	32
Debt, current portion	39	—	39
Liabilities from risk management activities (including current portion of $41 million and zero, respectively)	57	107	164
Asset retirement obligations	43	49	92
Intangible liabilities (including current portion of $24 million and $58 million, respectively)	73	93	166
Deferred income taxes, net	506	—	506
Other long-term liabilities	—	40	40
Total liabilities assumed	767	396	1,163
Identifiable net assets acquired	2,864	2,791	5,655
Goodwill	797	—	797
Net assets acquired	$3,661	$2,791	$6,452

As a result of recording the stepped up fair market basis for GAAP purposes, but receiving primarily carryover basis for tax purposes in the EquiPower Acquisition, we initially recorded a net deferred tax liability of $537 million within our provisional valuation of the EquiPower Acquisition as of the acquisition date. As we had previously recorded a valuation allowance against our historical deferred tax assets, we released approximately $480 million of our valuation allowance as a result of these increased deferred tax liabilities during the second quarter of 2015. During the second half of 2015, we reduced the initially-recognized deferred tax liability by $31 million due to newly available information regarding the fair values of assets and liabilities acquired in the EquiPower Acquisition. This reduction to the deferred tax liability resulted primarily in a corresponding reduction to goodwill, as discussed below, and a $27 million reversal of the previously released valuation allowance discussed above. As of December 31, 2015, we have recorded a net deferred tax liability of $506 million and released approximately $453 million of our valuation allowance related to the EquiPower Acquisition.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Goodwill resulting from the EquiPower Acquisition reflects the excess of our purchase price over the fair value of the net assets acquired. We recorded initial goodwill of $837 million as of the acquisition date, and subsequently reduced the amount during the second half of 2015 by $40 million due to the newly available information discussed above. As of December 31, 2015, we have recognized goodwill of $797 million related to the EquiPower Acquisition, all of which is allocated to our Gas reporting segment. None of the goodwill recognized is deductible for income tax purposes, and as such, no deferred taxes related to goodwill have been recorded. No goodwill was recognized as a result of the Duke Midwest Acquisition.

We incurred acquisition costs of $86 million and $19 million for the years ended December 31, 2015 and 2014, respectively, related to the Acquisitions, which are included in Acquisition and integration costs on our consolidated statements of operations. Acquisition costs for the year ended December 31, 2015 include $48 million of commitment fees associated with a temporary bridge facility, which were payable only upon the closing of the Acquisitions. No amounts were borrowed under the bridge facility, and the bridge facility was cancelled, as our permanent financing for the Acquisitions was executed. Revenues of $1.623 billion and operating income of $154 million attributable to the Acquisitions for the year ended December 31, 2015 are included in our consolidated statement of operations.

Pro Forma Results. The unaudited pro forma financial results for the years ended December 31, 2015 and 2014 assume the EquiPower Acquisition and the Duke Midwest Acquisition occurred on January 1, 2014. The unaudited pro forma financial results may not be indicative of the results that would have occurred had the acquisitions been completed on January 1, 2014, nor are they indicative of future results of operations.

	Year Ended December 31,	
(amounts in millions)	2015	2014
Revenues	$4,860	$5,574
Net income (loss)	$308	$(613)
Net income (loss) attributable to noncontrolling interest	$(3)	$6
Net income (loss) attributable to Dynegy Inc.	$311	$(619)

AER Transaction Agreement. On December 2, 2013, pursuant to the terms of the definitive agreement dated as of March 14, 2013 and as amended on December 2, 2013 (the "AER Transaction Agreement") by and between IPH, an indirect wholly-owned subsidiary of Dynegy, and Ameren Corporation ("Ameren"), IPH completed its acquisition from Ameren of 100 percent of the equity interests of New Ameren Energy Resources, LLC ("AER") and its subsidiaries (the "AER Acquisition"). The acquisition added 4,062 MW of generation in Illinois and also included the Homefield Energy retail business. There was no cash consideration or stock issued as part of the purchase price. We acquired AER and its subsidiaries through IPH, which will maintain corporate separateness from our legal entities outside of IPH.

We incurred acquisition costs of $16 million and $20 million related to the AER Acquisition, which are included in Acquisition and integration costs on our consolidated statements of operations for the years ended December 31, 2014 and 2013, respectively. Revenues of $846 million and $67 million and operating losses of $2 million and $17 million attributable to IPH are included in our consolidated statements of operations for the years ended December 31, 2014 and 2013, respectively. Please read Note 23—Segment Information for further discussion.

Note 4—Risk Management Activities, Derivatives and Financial Instruments

The nature of our business necessarily involves commodity market and financial risks. Specifically, we are exposed to commodity price variability related to our power generation business. Our commercial team manages these commodity price risks with financially and physically settled contracts consistent with our commodity risk management policy. Our treasury team manages our interest rate risk.

Our commodity risk management policy gives us the flexibility to sell energy and capacity and purchase fuel through a combination of spot market sales and near-term contractual arrangements (generally over a rolling one- to three-year time frame). Our commodity risk management goal is to protect cash flow in the near-term while keeping the ability to capture value longer-term.

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our consolidated statements of operations. We have other contractual arrangements such as capacity forward sales arrangements, tolling arrangements, fixed price coal purchases and retail power sales which do not receive recurring fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as “normal purchase, normal sale,” in accordance with ASC 815, Derivatives and Hedging. As a result, the gains and losses with respect to these arrangements are not reflected in the consolidated statements of operations until the delivery occurs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Quantitative Disclosures Related to Financial Instruments and Derivatives
As of December 31, 2015, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type (dollars and quantities in millions)	Quantity Purchases (Sales)	Unit of Measure	Fair Value (1) Asset (Liability)
Commodity contracts:			
Electricity derivatives (2)	(45)	MWh	$(1)
Electricity basis derivatives (3)	(29)	MWh	$24
Natural gas derivatives (2)	305	MMBtu	$(143)
Natural gas basis derivatives	69	MMBtu	$(7)
Diesel fuel	3	Gallon	$(4)
Coal derivatives (4)	—	Metric Ton	$(23)
Interest rate swaps	777	U.S. Dollar	$(42)
Common stock warrants (5)	16	Warrant	$(7)

(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting of $106 million.
(2) Mainly comprised of swaps, options and physical forwards.
(3) Comprised of FTRs and swaps.
(4) Our net position rounds to less than 1 million tons.
(5) Each warrant is convertible into one share of Dynegy common stock.

Derivatives on the Balance Sheet. The following table presents the fair value and balance sheet classification of derivatives in our consolidated balance sheets as of December 31, 2015 and 2014. As of December 31, 2015 and 2014, there were no gross amounts available to be offset that were not offset in our consolidated balance sheets.

		December 31, 2015			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$403	$(285)	$	$118
Total derivative assets		$403	$(285)	$—	$118
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(557)	$285	$106	$(166)
Interest rate contracts	Liabilities from risk management activities	(42)	—	—	(42)
Common stock warrants	Other long-term liabilities	(7)	—	—	(7)
Total derivative liabilities		$(606)	$285	$106	$(215)
Total derivatives		$(203)	$	$106	$(97)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

		December 31, 2014			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$115	$(35)	$	$80
Total derivative assets		$115	$(35)	$—	$80
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(163)	$35	$9	$(119)
Interest rate contracts	Liabilities from risk management activities	(44)	—	—	(44)
Common stock warrants	Other long-term liabilities	(61)	—	—	(61)
Total derivative liabilities		$(268)	$35	$9	$(224)
Total derivatives		$(153)	$	$9	$(144)

Certain of our derivative instruments have credit limits that require us to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as our established credit limit with the respective counterparty. If our credit rating were to change, the counterparties could require us to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in our credit rating as well as the requirements of the individual counterparty. The aggregate fair value of all commodity derivative instruments with credit-risk-related contingent features that are in a liability position that are not fully collateralized (excluding transactions with our clearing brokers that are fully collateralized) as of December 31, 2015 is $49 million for which we have posted $21 million in collateral. Our remaining derivative instruments do not have credit-related collateral contingencies as they are included within our first-lien collateral program.

The following table summarizes our cash collateral posted as of December 31, 2015 and 2014, within Prepayments and other current assets on our consolidated balance sheets, and the amount applied against short-term risk management activities:

Location on balance sheet	December 31, 2015	December 31, 2014
(amounts in millions)		
Gross collateral posted with counterparties	$162	$49
Less: Collateral netted against risk management liabilities	106	9
Net collateral within Prepayments and other current assets	$56	$40

Impact of Derivatives on the Consolidated Statements of Operations

The following discussion and table present the location and amount of gains and losses on derivative instruments in our consolidated statements of operations.

Financial Instruments Not Designated as Hedges. We elect not to designate derivatives related to our power generation business and interest rate instruments as cash flow or fair value hedges. Thus, we account for changes in the fair value of these derivatives within our consolidated statements of operations.

Our consolidated statements of operations for the years ended December 31, 2015, 2014 and 2013 include the impact of derivative financial instruments as presented below.

Derivatives Not Designated as Hedges (amounts in millions)	Location of Gain (Loss) Recognized in Income on Derivatives	Year Ended December 31, 2015	2014	2013
Commodity contracts	Revenues	$194	$(183)	$(101)
Interest rate contracts	Interest expense	$(15)	$(15)	$(7)
Common stock warrants	Other income (expense), net	$54	$(40)	$(1)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5—Fair Value Measurements

We apply the market approach for recurring fair value measurements, employing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We have consistently used the same valuation techniques for all periods presented. Please read Note 2—Summary of Significant Accounting Policies—Fair Value Measurements for further discussion.

The finance organization monitors commodity risk through the Commodity Risk Control Group ("CRCG"). The Executive Management Team ("EMT") monitors interest rate risk. The EMT has delegated the responsibility for managing interest rate risk to the Chief Financial Officer ("CFO"). The CRCG is independent of our commercial operations and has direct access to the Audit Committee. The Finance and Risk Management Committee, comprised of members of management and chaired by the CFO, meets periodically and is responsible for reviewing our overall day-to-day energy commodity risk exposure, as measured against the limits established in our Commodity Risk Policy.

Each quarter, as part of its internal control processes, representatives from the CRCG review the methodology and assumptions behind the pricing of the forward curves. As part of this review, liquidity periods are established based on third party market information, the basis relationship between direct and derived curves is evaluated, and changes are made to the forward power model assumptions.

The CRCG reviews changes in value on a daily basis through the use of various reports. The pricing for power, natural gas and fuel oil curves is automatically entered into our commercial system nightly based on data received from our market data provider. The CRCG reviews the data provided by the market data provider by utilizing third party broker quotes for comparison purposes. In addition, our traders are required to review various reports to ensure accuracy on a daily basis.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2015 and 2014 and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid.

	Fair Value as of December 31, 2015			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$308	$40	$348
Natural gas derivatives	—	40	2	42
Coal derivatives	—	10	3	13
Total assets from commodity risk management activities	$—	$358	$45	$403
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(267)	$(58)	$(325)
Natural gas derivatives	—	(158)	(34)	(192)
Diesel fuel derivatives	—	(4)	—	(4)
Coal derivatives	—	(35)	(1)	(36)
Total liabilities from commodity risk management activities	—	(464)	(93)	(557)
Liabilities from interest rate contracts	—	(42)	—	(42)
Liabilities from outstanding common stock warrants	(7)	—	—	(7)
Total liabilities	$(7)	$(506)	$(93)	$(606)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Fair Value as of December 31, 2014			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$88	$22	$110
Natural gas derivatives	—	3	—	3
Emissions derivatives	—	2	—	2
Total assets from commodity risk management activities	$—	$93	$22	$115
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(27)	$(26)	$(53)
Natural gas derivatives	—	(100)	—	(100)
Diesel fuel derivatives	—	(6)	—	(6)
Crude oil derivatives	—	(3)	—	(3)
Coal derivatives	—	(1)	—	(1)
Total liabilities from commodity risk management activities	—	(137)	(26)	(163)
Liabilities from interest rate contracts	—	(44)	—	(44)
Liabilities from outstanding common stock warrants	(61)	—	—	(61)
Total liabilities	$(61)	$(181)	$(26)	$(268)

Level 3 Valuation Methods. The electricity derivatives classified within Level 3 include financial swaps executed in illiquid trading locations or on long dated contracts, capacity contracts, heat rate derivatives and FTRs. The curves used to generate the fair value of the financial swaps are based on basis adjustments applied to forward curves for liquid trading points, while the curves for the capacity deals are based upon auction results in the marketplace, which are infrequently executed. The forward market price of FTRs is derived using historical congestion patterns within the marketplace and heat rate derivative valuations are derived using a Black-Scholes spread model, which uses forward natural gas and power prices, market implied volatilities and modeled correlation values. The natural gas derivatives classified within Level 3 include financial swaps, basis swaps and physical purchases executed in illiquid trading locations or on long dated contracts. The coal derivatives classified within Level 3 include financial swaps executed in illiquid trading locations.

Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measurement of our commodity instruments categorized within Level 3 of the fair value hierarchy include estimates of forward congestion, power price spreads, natural gas and coal pricing and the difference between our plant locational prices to liquid hub prices. Power price spreads, natural gas and coal pricing and the difference between our plant locational prices to liquid hub prices are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price of the spread on a buy or sell position in isolation would result in a higher/lower fair value measurement. The significant unobservable inputs used in the valuation of Dynegy's contracts classified as Level 3 as of December 31, 2015 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Inputs	Significant Unobservable Inputs Range
(dollars in millions)						

Electricity derivatives:								
Forward contracts—power (1)	(4	)	Million MWh	$(11	)	Basis spread + liquid location	Basis spread	$5.00 - $7.00
FTRs	24		Million MWh	$(7	)	Historical congestion	Forward price	$0 - $1.00
Natural gas derivatives (1)	96		Million MMBtu	$(32	)	Illiquid location fixed price	Forward price	$1.40 - $1.70
Coal derivatives (1)	—		Thousand Tons	$2		Illiquid location fixed price	Forward price	$4.35 - $5.35

(1) Represents forward financial and physical transactions at illiquid pricing locations.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables set forth a reconciliation of changes in the fair value of financial instruments classified as Level 3 in the fair value hierarchy:

(amounts in millions)	Year Ended December 31, 2015 Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at December 31, 2014	$(4)	$—	$—	$—	$(4)
Total gains included in earnings	39	3	—	—	42
Settlements (1)	1	28	9	(2)	36
Acquisitions	(54)	(63)	(9)	4	(122)
Balance at December 31, 2015	$(18)	$(32)	$—	$2	$(48)
Unrealized gains relating to instruments held as of December 31, 2015	$39	$3	$—	$—	$42

(amounts in millions)	Year Ended December 31, 2014 Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at December 31, 2013	$11	$—	$(1)	$—	$10
Total gains (losses) included in earnings	(9)	—	1	—	(8)
Settlements (1)	(6)	—	—	—	(6)
Balance at December 31, 2014	$(4)	$—	$—	$—	$(4)
Unrealized gains (losses) relating to instruments held as of December 31, 2014	$(9)	$—	$1	$—	$(8)

(amounts in millions)	Year Ended December 31, 2013 Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at December 31, 2012	$5	$—	$2	$—	$7
Total gains (losses) included in earnings	(4)	—	1	—	(3)
Settlements (1)	(6)	—	(3)	—	(9)
AER Acquisition	16	—	(1)	—	15
Balance at December 31, 2013	$11	$—	$(1)	$—	$10
Unrealized gains (losses) relating to instruments held as of December 31, 2013	$(4)	$—	$1	$—	$(3)

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(1) For purposes of these tables, we define settlements as the beginning of period fair value of contracts that settled during the period.

Gains and losses recognized for Level 3 recurring items are included in Revenues in our consolidated statements of operations for commodity derivatives. We believe an analysis of commodity instruments classified as Level 3 should be undertaken with the understanding that these items generally serve as economic hedges of our power generation portfolio. We did not have any transfers between Level 1, Level 2 and Level 3 for the years ended December 31, 2015 and 2014.

Nonfinancial Assets and Liabilities. Nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

During December 31, 2015 and 2014, we measured at fair value on a nonrecurring basis certain nonfinancial assets and liabilities. Our measurement of the provisional purchase price allocation is discussed in Note 3—Acquisitions, and the measurements of the Wood River Power Station and Brayton Point generation facilities are discussed in Note

9—Property, Plant and Equipment.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value of Financial Instruments. The following table discloses the fair value of financial instruments recognized on our consolidated balance sheets. Unless otherwise noted, the fair value of debt as reflected in the table has been calculated based on the average of certain available broker quotes as of December 31, 2015 and 2014.

(amounts in millions)	December 31, 2015 Carrying Amount	December 31, 2015 Fair Value	December 31, 2014 Carrying Amount	December 31, 2014 Fair Value
Dynegy Inc.:				
6.75% Senior Notes, due 2019 (2)(6)	$(2,100)	$(1,985)	$(2,100)	$(2,132)
Tranche B-2 Term Loan, due 2020 (1)(2)	$(778)	$(754)	$(785)	$(775)
7.375% Senior Notes, due 2022 (2)(6)	$(1,750)	$(1,531)	$(1,750)	$(1,777)
5.875% Senior Notes, due 2023 (2)	$(500)	$(404)	$(500)	$(475)
7.625% Senior Notes, due 2024 (2)(6)	$(1,250)	$(1,078)	$(1,250)	$(1,272)
Inventory financing agreements (2)	$(136)	$(136)	$(23)	$(23)
Equipment financing agreements (7)	$(61)	$(61)	$—	$—
Interest rate derivatives (2)	$(42)	$(42)	$(44)	$(44)
Commodity-based derivative contracts (3)	$(154)	$(154)	$(48)	$(48)
Common stock warrants (4)	$(7)	$(7)	$(61)	$(61)
Genco:				
7.00% Senior Notes Series H, due 2018 (2)(5)	$(276)	$(204)	$(268)	$(264)
6.30% Senior Notes Series I, due 2020 (2)(5)	$(213)	$(148)	$(206)	$(208)
7.95% Senior Notes Series F, due 2032 (2)(5)	$(225)	$(162)	$(224)	$(241)

(1) Carrying amount includes an unamortized discount of $2 million and $3 million as of December 31, 2015 and 2014, respectively. Please read Note 13—Debt for further discussion.
(2) The fair values of these financial instruments are classified as Level 2 within the fair value hierarchy levels.
(3) Carrying amount of commodity-based derivative contracts excludes $106 million and $9 million of cash posted as collateral, as of December 31, 2015 and 2014, respectively.
(4) The fair value of the common stock warrants is classified as Level 1 within the fair value hierarchy levels.
(5) Combined carrying amounts as of December 31, 2015 and 2014 include unamortized discounts of $111 million and $127 million, respectively. Please read Note 13—Debt for further discussion.
(6) At December 31, 2014, these debt agreements were held by Dynegy Finance I, Inc. and Dynegy Finance II, Inc. Upon the closing of the Acquisitions, the Dynegy Finance I and Dynegy Finance II notes were exchanged for an equal aggregate principal amount of notes with the same terms issued by Dynegy (the “Notes”).
(7) Carrying amounts for the equipment financing agreements include unamortized discounts of $14 million as of December 31, 2015. In addition, the fair value is classified as Level 3 within the fair value hierarchy levels.

Concentration of Credit Risk. We sell our energy products and services to customers in the electric and natural gas distribution industries, financial institutions, residential customers and to entities engaged in commercial and industrial businesses. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

At December 31, 2015 and 2014, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $45 million and $12 million, respectively. We seek to reduce our credit exposure by executing agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

We enter into master netting agreements in an attempt to both mitigate credit exposure and reduce collateral requirements. In general, the agreements include our risk management subsidiaries and allow the aggregation of credit exposure, margin and set-off. As a result, we decrease a potential credit loss arising from a counterparty default.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We include cash collateral deposited with brokers and cash paid to non-broker counterparties which has not been offset against risk management liabilities in Prepayments and other current assets on our consolidated balance sheets. As of December 31, 2015 and 2014, we had $56 million and $40 million recorded to Prepayments and other current assets, respectively. We include cash collateral received from non-broker counterparties in Accrued liabilities and other current liabilities on our consolidated balance sheets. As of December 31, 2015, we were not holding any collateral received from counterparties.

Note 6—Accumulated Other Comprehensive Income

Changes in accumulated other comprehensive income ("AOCI"), net of tax, by component are as follows:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Beginning of period	$20	$58	$11
Other comprehensive income (loss) before reclassifications:			
Actuarial gain (loss) and plan amendments (net of tax of zero, zero and $31, respectively)	3	(33)	56
Amounts reclassified from accumulated other comprehensive income:			
Reclassification of curtailment gain included in net loss (net of tax of zero, zero, and zero, respectively) (1)	—	—	(7)
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero, zero and zero, respectively) (2)	(4)	(5)	(2)
Net current period other comprehensive income (loss), net of tax	(1)	(38)	47
End of period (3)	$19	$20	$58

(1) Amount related to the DNE pension curtailment gain and was recorded in Income (loss) from discontinued operations, net of tax on our consolidated statements of operations. Please read Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans for further discussion.

(2) Amounts are associated with our defined benefit pension and other post-employment benefit plans and are included in the computation of net periodic pension cost. Please read Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans for further discussion.

(3) Includes a tax impact of $31 million due to remeasurements of certain of our pension and other post-employment benefit plans in 2013 that will only reverse if and when the Dynegy plans terminate.

Note 7—Cash Flow Information

The supplemental disclosures of cash flow and non-cash investing and financing information are as follows:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Interest paid (net of amount capitalized)	$491	$120	$92
Taxes paid (net of refunds)	$2	$—	$(1)
Other non-cash investing and financing activity:			
Non-cash capital expenditures (1)	$10	$23	$(3)
Non-cash capital expenditures pursuant to an equipment financing agreement	$61	$—	$—
Acquisition consideration (2)	$105	$—	$7

(1) These expenditures are primarily for changes in our accruals of capital expenditures for all years presented.
(2) Represents the consideration given by us for acquisitions. Please read Note 3—Acquisitions for further discussion.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8—Inventory

A summary of our inventories is as follows:

(amounts in millions)	December 31, 2015	December 31, 2014
Materials and supplies	$175	$83
Coal (1)	350	119
Fuel oil (1)	17	3
Emissions allowances (2)	51	2
Other	4	1
Total	$597	$208

(1) At December 31, 2015, approximately $44 million and $16 million of the coal and fuel oil inventory, respectively, are part of an inventory financing agreement. At December 31, 2014, there were no amounts that were part of an inventory financing agreement. Please read Note 13—Debt—Brayton Point Inventory Financing for further discussion.

(2) At December 31, 2015, a portion of this inventory was held as collateral by one of our counterparties as part of an inventory financing agreement. At December 31, 2014, there were no amounts that were part of an inventory financing agreement. Please read Note 13—Debt—Emissions Repurchase Agreements for further discussion.

Note 9—Property, Plant and Equipment

A summary of our property, plant and equipment is as follows:

(amounts in millions)	December 31, 2015	December 31, 2014
Power generation	$8,178	$3,174
Buildings and improvements	956	457
Office and other equipment	101	54
Property, plant and equipment	9,235	3,685
Accumulated depreciation	(888)	(430)
Property, plant and equipment, net	$8,347	$3,255

The following table summarizes total interest costs incurred and interest capitalized related to costs of construction projects in process:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Total interest costs incurred	$487	$187	$86
Capitalized interest	$12	$9	$2

On November 5, 2015, Dynegy announced that it expects to retire the final two units at its Wood River Power Station (“Wood River”) in mid-2016, subject to the approval of MISO. The decision to retire Wood River was the result of a strategic review performed in the third quarter of 2015, and was primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market. As a result of these factors, we performed an impairment analysis, which indicated that Wood River had a negative fair value. Therefore, we recorded an impairment charge of $74 million in Impairments in our consolidated statements of operations for the year ended December 31, 2015 to write off the entire carrying value. The fair value of Wood River was determined using a DCF model, utilizing a 12 percent discount rate, and assuming normal operations for the remainder of its estimated useful life. For the model, gross margin was based on publicly available forward market quotes, operations and maintenance expenses were based on current forecasts, and capital expenditures assumed the minimum of cash expenditures required to continue running the plant until its anticipated retirement. The valuation is classified as Level 3 within the fair value hierarchy levels.

In the fourth quarter of 2015, Dynegy’s Brayton Point generation facility’s operating area experienced significantly warmer weather than normal, resulting in lowered demand and power prices for the period. Dynegy has previously disclosed plans to retire the facility in June 2017, thus the temperate weather had a significant impact on the facility’s remaining cash flows, resulting in an impairment trigger. We performed step one of the impairment analysis using undiscounted cash flows for the facility’s remaining operational years, and determined the book value of the asset would not be recovered. We performed step

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

two of the impairment analysis using a DCF model, utilizing a 9 percent discount rate, and assuming normal operations for the remainder of its estimated useful life. For the model, gross margin was based on publicly available forward market quotes, operations and maintenance expenses were based on current forecasts, and capital expenditures assumed the minimum of cash expenditures required to continue running the plant until its anticipated retirement. The model resulted in a fair value of the facility of $86 million; therefore, we recorded an impairment charge of $25 million in Impairments in our consolidated statements of operations for the year ended December 31, 2015 to reduce the carrying value of the Brayton Point facility. The valuation is classified as Level 3 within the fair value hierarchy levels.

Note 10—Joint Ownership of Generating Facilities

We hold ownership interests in certain jointly owned generating facilities. We are entitled to the proportional share of the generating capacity and the output of each unit equal to our ownership interests. We pay our share of capital expenditures, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs. Our share of revenues and operating costs of the jointly owned generating facilities are included within the corresponding financial statement line items in our consolidated statements of operations.

The following table presents the ownership interests of the jointly owned facilities included in our consolidated balance sheets. Each facility is co-owned with one or more other generation companies.

	December 31, 2015				
(dollars in millions)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress	Total
Miami Fort	64.0 %	$207	$(16)	$3	$194
Stuart (1)	39.0 %	$32	$(4)	$20	$48
Conesville (1)	40.0 %	$61	$(2)	$4	$63
Zimmer	46.5 %	$99	$(10)	$11	$100
Killen (1)	33.0 %	$17	$(1)	$2	$18

(1) Facilities not operated by Dynegy.

Note 11—Unconsolidated Investments

Equity Method Investments

Elwood. In connection with the EquiPower Acquisition, we acquired a 50 percent interest in Elwood Energy LLC, a limited liability company ("Elwood Energy") and Elwood Expansion LLC, a limited liability company ("Elwood Expansion" and, together with Elwood Energy, "Elwood"). Elwood Energy owns a 1,576 MW natural gas-fired facility located in Elwood, Illinois. As of December 31, 2015, our investment was $190 million. Upon the acquisition of our Elwood investment, we recognized basis differences in the net assets of approximately $89 million related to working capital, property plant and equipment, debt and intangibles. These basis differences are being amortized over their respective useful lives. Our risk of loss related to our equity method investment is limited to our investment balance. Holders of the debt of our unconsolidated investment do not have recourse to us and our other subsidiaries; therefore, the debt of our unconsolidated investment is not reflected in our consolidated balance sheets.

We recorded $1 million in equity earnings related to our investment in Elwood, which is reflected in Earnings from unconsolidated investments in our consolidated statement of operations for the year ended December 31, 2015. For the year ended December 31, 2015, we received a distribution of $11 million, of which $8 million was considered a return of investment. As of December 31, 2015 we have approximately $3 million in accounts receivable due from Elwood, which is included in Accounts receivable in our consolidated balance sheets.

Black Mountain. On June 27, 2014, we completed the sale of our 50 percent partnership interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain, an 85 MW (43 net MW) natural gas-fired combined cycle gas turbine facility in Nevada. We received $17 million in cash proceeds upon the close of the transaction, which is reflected in Gain on sale of assets, net in our consolidated statements of operations for the year ended December 31, 2014. In connection with the sale, our guarantee was terminated. Additionally, we received $10 million in cash distributions from Black Mountain, which is recorded as Earnings (losses) from unconsolidated investments in our consolidated statements of operations for the year ended December 31, 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12—Intangible Assets and Liabilities

The following table summarizes the components of our intangible assets and liabilities as of December 31, 2015 and 2014:

(amounts in millions)	December 31, 2015 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	December 31, 2014 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Intangible Assets:						
Electricity contracts	$260	$(126)	$134	$111	$(46)	$65
Gas transport contracts	46	(16)	30	—	—	—
Total intangible assets	$306	$(142)	$164	$111	$(46)	$65
Intangible Liabilities:						
Electricity contracts	$(30)	$19	$(11)	$(20)	$14	$(6)
Coal contracts	(134)	82	(52)	(41)	22	(19)
Coal transport contracts	(104)	64	(40)	(81)	32	(49)
Gas transport contracts	(64)	27	(37)	(24)	17	(7)
Total intangible liabilities	$(332)	$192	$(140)	$(166)	$85	$(81)
Intangible assets and liabilities, net	$(26)	$50	$24	$(55)	$39	$(16)

The following table presents our amortization expense (revenue) of intangible assets and liabilities for the past three years during the years ended December 31, 2015, 2014 and 2013:

(amounts in millions)	Year Ended December 31, 2015	2014	2013
Electricity contracts, net (1)	$75	$96	$136
Coal contracts, net (2)	(60)	(14)	129
Coal transport contracts (2)	(32)	(29)	(7)
Gas transport contracts (2)	6	(8)	(7)
Total	$(11)	$45	$251

(1) The amortization of these contracts is recognized in Revenues or Cost of sales in our consolidated statements of operations.
(2) The amortization of these contracts is recognized in Cost of sales in our consolidated statements of operations.

Amortization expense (revenue), net for the next five years as of December 31, 2015 is as follows: 2016—$18 million, 2017—$19 million, 2018—$4 million, 2019—zero and 2020—$(2) million.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the components of our contract based intangible assets and liabilities recorded in connection with the Acquisitions in April 2015:

(amounts in millions/months)	EquiPower Acquisition Gross Carrying Amount	EquiPower Acquisition Weighted-Average Amortization Period	Duke Midwest Acquisition Gross Carrying Amount	Duke Midwest Acquisition Weighted-Average Amortization Period
Intangible Assets:				
Electricity contracts	$68	31	$80	38
Coal contracts	—	—	—	9
Gas transport contracts	43	28	4	19
Total intangible assets	$111	30	$84	37
Intangible Liabilities:				
Electricity contracts	$—	—	$(10)	23
Coal contracts	(10)	21	(83)	27
Coal transport contracts	(23)	22	—	—
Gas contracts	—	1	—	—
Gas transport contracts	(40)	128	—	—
Total intangible liabilities	$(73)	81	$(93)	27
Total intangible assets and liabilities, net	$38		$(9)	

Note 13—Debt

A summary of our long-term debt is as follows:

(amounts in millions)	December 31, 2015	December 31, 2014
Dynegy Inc.:		
6.75% Senior Notes, due 2019 (1)	$2,100	$2,100
Tranche B-2 Term Loan, due 2020	780	788
7.375% Senior Notes, due 2022 (1)	1,750	1,750
5.875% Senior Notes, due 2023	500	500
7.625% Senior Notes, due 2024 (1)	1,250	1,250
Revolving Facility	—	—
Inventory Financing Agreements	136	23
Equipment Financing Agreements	75	—
Genco:		
7.00% Senior Notes Series H, due 2018	300	300
6.30% Senior Notes Series I, due 2020	250	250
7.95% Senior Notes Series F, due 2032	275	275
	7,416	7,236
Unamortized discounts on debt, net	(127)	(130)
	7,289	7,106
Less: Current maturities, including unamortized discounts, net	83	31
Total Long-term debt	$7,206	$7,075

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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(1) At December 31, 2014, these debt agreements were held by Dynegy Finance I, Inc. and Dynegy Finance II, Inc. Upon the closing of the Acquisitions, the Dynegy Finance I and Dynegy Finance II notes were exchanged for an equal aggregate principal amount of notes with the same terms issued by Dynegy (the "Notes").

Aggregate maturities of the principal amounts of all long-term indebtedness, excluding unamortized discounts, as of December 31, 2015 are as follows: 2016—$83 million, 2017—$55 million, 2018—$359 million, 2019—$2.116 billion, 2020—$1.012 billion and thereafter—$3.791 billion.

Debt Issuance

On October 27, 2014, Dynegy Finance II, Inc. (the "EquiPower Escrow Issuer"), a wholly-owned subsidiary of Dynegy, issued $3.06 billion in aggregate principal amount of senior notes, the proceeds of which were placed into escrow until the closing of the EquiPower Acquisition. On the EquiPower Closing Date, the proceeds from the issuance were released from escrow and used to pay a portion of the EquiPower Acquisition consideration and to pay fees and expenses. On the EquiPower Closing Date, Dynegy, as successor in interest to the EquiPower Escrow Issuer, executed supplemental indentures evidencing its accession to the 6.75 percent senior notes due 2019 (the "2019 Finance II Notes"), the 7.375 percent senior notes due 2022 (the "2022 Finance II Notes"), and the 7.625 percent senior notes due 2024 (the "2024 Finance II Notes" and, together with the 2019 Finance II Notes and the 2022 Finance II Notes, the "Finance II Notes").

Further, on October 27, 2014, Dynegy Finance I, Inc. (the "Duke Escrow Issuer"), a wholly-owned subsidiary of Dynegy, issued $2.04 billion in aggregate principal amount of senior notes, the proceeds of which were placed into escrow until the closing of the Duke Midwest Acquisition. On the Duke Midwest Closing Date, the proceeds from the issuance were released from escrow and used to pay a portion of the Duke Midwest Acquisition consideration and to pay fees and expenses. On the Duke Midwest Closing Date, Dynegy, as successor in interest to the Duke Escrow Issuer, executed supplemental indentures evidencing its accession to the 6.75 percent senior notes due 2019 (the "2019 Finance I Notes"), the 7.375 percent senior notes due 2022 (the "2022 Finance I Notes"), and the 7.625 percent senior notes due 2024 (the "2024 Finance I Notes" and, together with the 2019 Finance I Notes and the 2022 Finance I Notes, the "Finance I Notes"). Concurrently with Dynegy's accession to the Finance I Notes, as successor in interest to the Duke Escrow Issuer, each series of Finance I Notes was automatically exchanged for an equal aggregate principal amount of Finance II Notes with the same terms, as applicable, issued by Dynegy. The additional Finance II Notes issued pursuant to such automatic exchanges were treated as a single class for all purposes and are fully fungible with the Finance II Notes with the same terms previously issued under the Finance II indentures.

On the EquiPower Closing Date, generally, each of Dynegy's current wholly-owned domestic subsidiaries that is a borrower or guarantor under Dynegy's existing credit facilities (the "Dynegy Guarantors"), and the entities acquired in the EquiPower Acquisition (the "EquiPower Guarantors") executed supplemental indentures evidencing their accession to the Finance II Notes as guarantors. Similarly, on the Duke Midwest Closing Date, each of Dynegy's current wholly-owned domestic subsidiaries that is a borrower or guarantor under Dynegy's existing credit facilities and the entities acquired in the Duke Midwest Acquisition (the "Duke Guarantors" and, together with the Dynegy Guarantors and the EquiPower Guarantors, the "Guarantors") executed supplemental indentures evidencing their accession to the Finance I Notes and the Finance II Notes as guarantors.

On the EquiPower Closing Date, the Dynegy Guarantors and the EquiPower Guarantors executed a joinder to the registration rights agreement, dated October 27, 2014, among the EquiPower Escrow Issuer, the Duke Escrow Issuer, and Morgan Stanley & Co. LLC, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, RBC Capital Markets, LLC and UBS Securities LLC as representatives of the initial purchasers identified therein (the "Registration Rights Agreement"). Additionally, on the Duke Midwest Closing Date, the Duke Guarantors executed a joinder to the Registration Rights Agreement.

As required by the Registration Rights Agreement, on July 17, 2015, Dynegy commenced registered exchange offers for the Notes, which closed on August 17, 2015. The terms of the exchange notes are identical in all material respects to the terms of the Notes, except that the exchange notes have been registered under the Securities Act. We received no proceeds from these exchange offers.

Credit Agreement

As of December 31, 2015, we had a $2.225 billion credit agreement that consisted of (i) an $800 million seven-year senior secured term loan B facility (the "Tranche B-2 Term Loan") and (ii) a $1.425 billion five-year senior secured revolving credit facility (the "Revolving Facility," and collectively with the Tranche B-2 Term Loan, the "Credit Agreement"). Dynegy and its Subsidiary Guarantors (as defined in the Credit Agreement) also entered into an indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of unsecured senior notes (the "Senior Notes") at par. Following the closings of the Acquisitions in April 2015, the acquired entities were added as additional subsidiary guarantors.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2015, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit of approximately $420 million, which reduce the amount available under the Revolving Facility. The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a Senior Secured Leverage Ratio (as defined in the Credit Agreement) calculated on a rolling four quarters basis. Based on the calculation outlined in the Credit Agreement, we are in compliance as of December 31, 2015.

Credit Agreement Amendments. On the EquiPower Closing Date, Dynegy entered into a First Amendment to the Credit Agreement (the “First Amendment”) among Dynegy, certain subsidiaries of Dynegy, the lenders party thereto, Credit Suisse AG, Cayman Islands Branch (“Credit Suisse”), as administrative agent, and the other parties thereto. The First Amendment provides for a new $350 million five-year senior secured incremental tranche of revolving commitments (the “Incremental Tranche A Revolving Loan Commitments”), which have terms substantially the same as the terms of the outstanding tranche of revolving loans under the Credit Agreement and will mature on April 1, 2020. Amounts available under the Incremental Tranche A Revolving Loan Commitments are available on a revolving basis, and such amounts that are repaid or prepaid may be re-borrowed. The loans issued pursuant to the Incremental Tranche A Revolving Loan Commitments bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio (as such terms are defined in the Credit Agreement).

Further on the Duke Midwest Closing Date, Dynegy entered into a Second Amendment to the Credit Agreement (the “Second Amendment”) among the Company, certain subsidiaries of Dynegy, the lenders party thereto, Credit Suisse, as administrative agent, and the other parties thereto. The Second Amendment provides for a new $600 million five-year senior secured incremental tranche of revolving commitments (the “Incremental Tranche B Revolving Loan Commitments”), which have terms substantially the same as the terms of the outstanding tranche of revolving loans under the Credit Agreement and will mature on April 2, 2020. Amounts available under the Incremental Tranche B Revolving Loan Commitments are available on a revolving basis, and such amounts that are repaid or prepaid may be re-borrowed. The loans issued pursuant to the Incremental Tranche B Revolving Loan Commitments bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio (as such terms are defined in the Credit Agreement).

Subsequent to the First Amendment and Second Amendment, we have three tranches of revolvers: (i) $475 million tranche which will mature on April 23, 2018, (ii) $350 million tranche which will mature April 1, 2020 and (iii) $600 million tranche which will mature on April 2, 2020.

Genco Senior Notes

On December 2, 2013, in connection with the AER Acquisition, Genco’s approximately $825 million in aggregate principal amount of unsecured senior notes (the “Genco Senior Notes”) remained outstanding as an obligation of Genco, a subsidiary of IPH.

Genco’s indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make principal or interest payments on subordinated borrowings, to make loans to or investments in affiliates, or to incur additional external, third-party indebtedness.

The following table summarizes these required ratios:

	Required Ratio
Restricted payment interest coverage ratio (1)	≥1.75
Additional indebtedness interest coverage ratio (2)	≥2.50
Additional indebtedness debt-to-capital ratio (2)	≤60%

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(1) As of the date of the restricted payment, as defined, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods.

(2)

Ratios must be computed on a pro forma basis considering the additional indebtedness to be incurred and the related interest expense. Other borrowings from third-party external sources are included in the definition of indebtedness and are subject to these incurrence tests.

Genco’s debt incurrence-related ratio restrictions under the indenture may be disregarded if both Moody’s and S&P reaffirm the ratings in place at the time of the debt incurrence after considering the additional indebtedness.

Based on December 31, 2015 calculations, Genco’s interest coverage ratios are less than the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Letter of Credit Facilities

On January 29, 2014, IPM entered into a fully cash collateralized Letter of Credit and Reimbursement Agreement with Union Bank, as amended on May 16, 2014 ("LC Agreement"), pursuant to which the issuing bank agreed to issue from time to time, one or more standby letters of credit in an aggregate stated amount not to exceed $25 million at any one time to support performance obligations and other general corporate activities of IPM, provided that IPM deposits in an account controlled by the issuing bank an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereon. As of December 31, 2015, IPM had $23 million deposited with Union Bank and $20 million in letters of credit outstanding.

On September 18, 2014, Dynegy entered into a Letter of Credit Reimbursement Agreement with an issuing bank, and its affiliate Macquarie Energy, LLC (the "Lender"), for a letter of credit in an amount not to exceed $55 million. The facility expires in May 2016. At December 31, 2015, there was $55 million outstanding under this letter of credit.

On March 27, 2015, IPM entered into a letter of credit facility with the Lender for up to $25 million. The facility, which is collateralized by receivables, has a two-year tenor and may be extended if agreed to by both parties for one additional year. Interest on the facility is LIBOR plus 500 basis points on issued letters of credit. At December 31, 2015, there was $25 million outstanding under this letter of credit facility.

Inventory Financing Agreements

Brayton Point Inventory Financing. In connection with the EquiPower Acquisition, we assumed an inventory financing agreement (the "Inventory Financing Agreement") for coal and fuel oil inventories at our Brayton Point facility, consisting of a debt obligation for existing and subsequent inventories, as well as a $15 million line of credit. Balances in excess of the $15 million line of credit are cash collateralized. The Inventory Financing Agreement terminates, and any remaining obligation becomes due and payable, on May 31, 2017. As of December 31, 2015, there was $58 million outstanding under this agreement.

As the materials are purchased and delivered to our facilities, our debt obligation and line of credit increase based on the then market rate of the materials, transportation cost, and other expenses. The debt obligation increases for 85 percent of the total price of the coal and 90 percent for the total price of fuel oil. The line of credit increases for the remaining 15 percent and 10 percent for coal and oil, respectively. Upon consuming the materials, we repay the debt obligation and line of credit at the then market price, as defined within the Inventory Financing Agreement, for the amount of the materials consumed on a weekly basis.

As of December 31, 2015, both the debt obligation related to coal and the base level of fuel oil, as well as the line of credit, bear interest at an annual interest rate of the 3-month LIBOR plus 5.6 percent. An availability fee is calculated on a per annum rate of 0.75 percent.

Emissions Repurchase Agreements. On August 14, 2015, we entered into a repurchase transaction with a third party in which we sold approximately $58 million of RGGI inventory and received cash. We are obligated to repurchase a portion of the inventory in February 2017 and the remaining inventory in February 2018 at a specified price with an annualized carry cost of approximately 3.56 percent. On August 20, 2015, we entered into an additional repurchase transaction with a third party in which we sold $20 million of RGGI inventory and received cash. We are obligated to repurchase the additional RGGI inventory in February 2017 at a specified price with an annualized carry cost of approximately 3.31 percent. As of December 31, 2015, there was $78 million, in aggregate, outstanding under these agreements.

In 2013, we entered into two repurchase transactions in which we sold $6 million in California Carbon Allowances ("CCA") credits and $11 million of RGGI inventory and received cash. In the first quarter 2014, we entered into an additional repurchase agreement with a third party in which we sold $12 million of RGGI inventory and received cash. In October 2014, we repurchased all $6 million of the previously sold CCA credits in February 2015, we repurchased all $23 million of the previously sold RGGI inventory.

Equipment Financing Agreements

Under certain of our contractual service agreements in which we receive maintenance and capital improvements for our gas-fueled generation fleet, we have obtained parts and equipment intended to increase the output, efficiency and availability of our generation units. We have financed these parts and equipment under agreements with maturities ranging from 2017 to 2025. The portion of future payments attributable to principal will be classified as cash outflows from financing activities and the portion of future payments attributable to interest will be classified as cash outflows from operating activities in our consolidated statements of cash flows. As of December 31, 2015, there was $75 million outstanding under these agreements. The related assets were recorded at the net present value of the payments of $61 million. The $14 million discount is currently amortized as interest expense over the life of the payments.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swaps

Subsequent to executing the Credit Agreement and issuing the Senior Notes, we amended our interest rate swaps to more closely match the terms of our Tranche B-2 Term Loan. The swaps have an aggregate notional value of approximately $777 million at an average fixed rate of 3.19 percent with a floor of one percent and expire during the second quarter of 2020. In lieu of paying the breakage fees related to terminating the old swaps and issuing the new swaps, the costs were incorporated into the terms of the new swaps. As a result, any cash flows related to the settlement of the new swaps are reflected as a financing activity in our consolidated statements of cash flows.

Note 14—Income Taxes

Income Tax Benefit. We are subject to U.S. federal and state income taxes on our operations.

Our losses from continuing operations before income taxes were $427 million, $268 million and $417 million for the years ended December 31, 2015, 2014 and 2013, respectively, which was solely from domestic sources.

Our components of income tax (expense) benefit related to income (loss) from continuing operations were as follows:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Current tax expense	$(3)	$—	$(9)
Deferred tax benefit	477	1	67
Income tax benefit	$474	$1	$58

Our income tax benefit related to losses from continuing operations before income taxes for each of the years ended December 31, 2015, 2014 and 2013 were equivalent to effective rates of 111 percent, zero percent and 14 percent, respectively. Differences between taxes computed at the U.S. federal statutory rate and our reported income tax benefit were as follows:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Expected tax benefit at U.S. statutory rate (35%)	$149	$94	$146
State taxes	68	—	3
Permanent differences (1)	16	(15)	2
Valuation allowance (2)(3)(4)	271	(331)	(22)
Uncertain tax position	—	244	(67)
Unconsolidated subsidiary adjustment	—	5	—
Adjustment to AMT credits	(26)	—	—
Other	(4)	4	(4)
Income tax benefit	$474	$1	$58

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(1) Permanent items for 2015 and 2014 included an $18 million benefit and $14 million expense, respectively, for the change in the fair value of warrants during the year that were not deductible for income taxes.

(2) The AER Acquisition in 2013 caused a change in the attributes and impacted our estimate of the realizability of our deferred tax assets. As a result, we recorded a $36 million reduction to our valuation allowance in connection with the AER Acquisition. In addition, the EquiPower Acquisition on April 1, 2015 caused a change in the attributes and impacted our estimate of the realizability of our deferred tax assets. As a result, we recorded a $453 million reduction to our valuation allowance.

(3) Pre-tax income from components other than continuing operations provided a source of income that allowed for the reduction of the valuation allowance from continuing operations the year ended December 31, 2013.

(4) On April 14, 2014, we received final notice from the Internal Revenue Service (“IRS”) that their audit of our 2012 tax year has been completed. In accordance with accounting guidance in ASC 740, Income Taxes (“ASC 740”), we recognized $270 million of net tax benefits for tax positions included in the 2012 tax return that had not previously met the “more likely than not” recognition threshold. These benefits were recognized in the second quarter of 2014 as a discrete item with a corresponding adjustment to the valuation allowance.

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred Tax Liabilities and Assets. Our significant components of deferred tax assets and liabilities were as follows:

	Year Ended December 31,	
(amounts in millions)	2015	2014
Current:		
Deferred tax assets:		
Reserves (legal, environmental and other)	$—	$5
Intangible contracts and other	—	44
Derivative contracts	—	28
Other	—	9
Subtotal	—	86
Less: valuation allowance	—	(72)
Total current deferred tax assets	—	14
Deferred tax liabilities:		
Derivative contracts	—	(23)
Other	—	(11)
Total current deferred tax liabilities	—	(34)
Net current deferred tax liabilities	—	(20)
Non-current:		
Deferred tax assets:		
NOL carryforwards	1,533	1,305
AMT and state tax credit carryforwards	275	280
Reserves (legal, environmental and other)	17	6
Pension and other post-employment benefits	16	20
Asset retirement obligations	89	81
Deferred financing costs and intangible/other contracts	64	40
Derivative contracts	69	14
Other	27	14
Subtotal	2,090	1,760
Less: valuation allowance	(1,276)	(1,463)
Total non-current deferred tax assets	814	297
Deferred tax liabilities:		
Depreciation and other property differences	(738)	(209)
Deferred financing costs and power contracts	—	—
Investment in unconsolidated partnership	(27)	—
Derivative contracts	(4)	(14)
Other	(74)	(54)
Total non-current deferred tax liabilities	(843)	(277)
Net non-current deferred tax assets (liabilities)	(29)	20
Net deferred tax liability	$(29)	$—

NOL Carryforwards. As of December 31, 2015, we had approximately $3.9 billion of federal tax net operating loss carryforwards (“NOLs”) and $3.1 billion of state NOLs that can be used to offset future taxable income. The federal NOLs expire beginning in 2024 through 2035. Similarly, the state NOLs will expire at various dates (based on the company’s review of the application of apportionment factors and other state tax limitations). Under federal income tax law, our NOLs can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Internal Revenue Code (“IRC”) Section 382. If an ownership change were to occur as a result of future transactions in our stock, our ability to utilize the NOLs may be significantly limited.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Alternative Minimum Tax Credit Carryforwards. While our Alternative Minimum Tax ("AMT") credits do not expire, the change in control that occurred on May 9, 2012 materially impacted our ability to utilize the AMT credits. The Company filed an amended 2009 tax return on April 8, 2015, as permitted by the IRS, which allows the Company to utilize more AMT NOLs. This relief resulted in a reduction of AMT credits of $26 million.

Change in Valuation Allowance. Realization of our deferred tax assets is dependent upon, among other things, our ability to generate taxable income of the appropriate character in the future. At December 31, 2015, we have a valuation allowance against our net deferred assets including federal and state NOLs and AMT credit carryforwards. Additionally, at December 31, 2015, our temporary differences were in a net deferred tax asset position. We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available, to realize the tax benefits of our net deferred tax asset associated with temporary differences. Accordingly, we have recorded a full valuation allowance against the net asset temporary differences related to federal income tax and the net asset temporary differences related to most state income tax as appropriate.

The changes in the valuation allowance were as follows:

(amounts in millions)	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Additions/ (Deductions)	Balance at End of Period
Year Ended December 31, 2015					
Changes in valuation allowance—continuing operations	$1,535	(259)	—	—	$1,276
Year Ended December 31, 2014					
Changes in valuation allowance—continuing operations	$1,149	370	16	—	$1,535
Year Ended December 31, 2013					
Changes in valuation allowance—continuing operations	$1,121	28	—	—	$1,149

Unrecognized Tax Benefits. We are complete with federal income tax audits by the IRS through 2013 as a result of our participation in the IRS' Compliance Assurance Process. However, any NOLs we claim in future years to reduce taxable income could be subject to additional IRS examination regardless of when the NOLs occurred. We are generally not subject to examinations for state and local taxes for tax years 2010 or earlier with few exceptions.

On April 14, 2014, we received final notice from the IRS that their audit of our 2012 tax year was completed. In accordance with accounting guidance in ASC 740, we recognized $270 million of net tax benefits for tax positions included in the 2012 tax return that had not previously met the "more likely than not" recognition threshold. These benefits were recognized in 2014 as a discrete item with a corresponding adjustment to the valuation allowance.

A reconciliation of our beginning and ending amounts of unrecognized tax benefits follows:

	Year Ended December 31,		
amounts in millions	2015	2014	2013
Unrecognized tax benefits, beginning of period	$4	$274	$1
Increase based on tax positions related to the prior period	—	—	273
Decrease due to settlements and payments	(1)	(270)	—
Unrecognized tax benefits, end of period	$3	$4	$274

As of December 31, 2015, approximately $3 million of unrecognized tax benefits would impact our effective tax rate if recognized.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15—Earnings (Loss) Per Share

The reconciliation of basic earnings (loss) per share to diluted earnings (loss) per share from continuing operations attributable to our common stockholders during the years ended December 31, 2015, 2014 and 2013 is shown in the following table.

	Year Ended December 31,		
(in millions, except per share amounts)	2015	2014	2013
Income (loss) from continuing operations	$47	$(267)	$(359)
Less: Net income (loss) attributable to noncontrolling interest	(3)	6	—
Income (loss) from continuing operations attributable to Dynegy Inc.	50	(273)	(359)
Less: Dividends on preferred stock	22	5	—
Income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for basic and diluted earnings (loss) per share	$28	$(278)	$(359)
Basic weighted-average shares	125	105	100
Effect of dilutive securities (1)	1	—	—
Diluted weighted-average shares	126	105	100
Basic and diluted earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders (1)	$0.22	$(2.65)	$(3.59)

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(1) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the years ended December 31, 2014 and 2013.

For the years ended December 31, 2015, 2014 and 2013, the following potentially dilutive securities were not included in the computation of diluted per share amounts because the effect would be anti-dilutive:

	Year Ended December 31,		
(in millions of shares)	2015	2014	2013
Stock options	0.5	1.4	1.0
Restricted stock units	—	1.0	0.7
Performance stock units	—	0.3	0.1
Warrants	15.6	15.6	15.6
Series A 5.375% mandatory convertible preferred stock	12.9	4.0	—
Total	29.0	22.3	17.4

Note 16—Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. We record accruals for estimated losses from contingencies when available information indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition, we disclose matters for which management believes a material loss is reasonably possible. In all instances, management has assessed the matters below based on current information and made judgments concerning their potential outcome, giving consideration to the nature of the claim, the amount, if any, and nature of damages sought and the probability of success. Management regularly reviews all new information with respect to such contingencies and adjusts its assessments and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties including unfavorable rulings or developments, it is possible that the ultimate resolution of our legal proceedings could involve amounts that are different from our currently recorded accruals and that such differences could be material.

In addition to the matters discussed below, we are party to other routine proceedings arising in the ordinary course of business. Any accruals or estimated losses related to these matters are not material. In management's judgment, the ultimate resolution of these matters will not have a material effect on our financial condition, results of operations or cash flows.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gas Index Pricing Litigation. We, through our subsidiaries, and other energy companies are named as defendants in several lawsuits claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications from 2000-2002. The cases allege that the defendants engaged in an antitrust conspiracy to inflate natural gas prices in three states (Kansas, Missouri, and Wisconsin) during the relevant time period. The cases are consolidated in a multi-district litigation proceeding pending in the United States District Court for Nevada. At this time we cannot reasonably estimate a potential loss.

Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company ("IGC") received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC ("PPE"). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award. On May 23, 2014, the Texas Supreme Court vacated the arbitration award based upon the evident partiality of one of the arbitrators. On November 20, 2014, PPE initiated a new arbitration against IGC and its co-respondents, but the Dallas District Court enjoined the arbitration from proceeding against IGC while any dispute over IGC's $17 million payment remains pending. On December 16, 2014, the Dallas District Court entered a judgment requiring the return of the $17 million to IGC and an additional $2.5 million payment to IGC for interest. PPE paid the $17 million principal to IGC (not the $2.5 million in interest), but simultaneously appealed the judgment, which remains pending in the Dallas Court of Appeals.

Other Contingencies

MISO 2015-2016 Planning Resource Auction. In May 2015, three complaints were filed at FERC regarding the Zone 4 results for the 2015-2016 Planning Resource Auction ("PRA") conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General, and Southwestern Electric Cooperative, Inc., have challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds and requested changes to the MISO PRA structure going forward. Complainants have also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the 2015-2016 PRA. The Independent Market Monitor for MISO ("MISO IMM"), which was responsible for monitoring the MISO 2015-2016 PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the proposed remedies. Dynegy complied fully with the terms of the MISO Tariff in connection with the 2015-2016 PRA, disputes the allegations and will defend its actions vigorously. Dynegy filed its Answer to these complaints. In addition, the Illinois Industrial Energy Consumers filed a complaint at FERC against MISO on June 30, 2015 requesting prospective changes to the MISO tariff. Dynegy also responded to this complaint.

On October 1, 2015, FERC issued an order of non-public, formal investigation, stating that shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public informal investigation into whether market manipulation or other potential violations of FERC orders, rules and regulations occurred before or during the PRA (the "Order"). The Order noted that the investigation is ongoing, and that the order converting the informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule or regulation. Further, FERC held a Staff-led technical conference on October 20, 2015 to obtain further information concerning potential changes to the MISO PRA structure going forward, including proposals made by complainants. The technical conference did not address the ongoing Office of Enforcement investigation.

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO Tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. Under the order, FERC found that the existing tariff provision which bases Initial Reference Levels for capacity supply offers on the estimated opportunity cost of exporting capacity to a neighboring region (for example, PJM) are no longer just and reasonable. Accordingly, FERC required MISO to set the Initial Reference Level for capacity at $0 per MW-day for the 2016-2017 PRA. Capacity suppliers may also request a facility-specific reference level from the MISO IMM. The order did not address the arguments of the complainants regarding the 2015-2016 Auction, and stated that those issues remain under consideration and will be addressed in a future order.

New Source Review and Clean Air Act Matters.

New Source Review. Since 1999, the EPA has been engaged in a nationwide enforcement initiative to determine whether coal-fired power plants failed to comply with the requirements of the New Source Review and New Source Performance Standard provisions under the CAA when the plants implemented modifications. The EPA's initiative focuses on whether projects performed at power plants triggered various permitting requirements, including the need to install pollution control equipment.

In August 2012, the EPA issued a Notice of Violation ("NOV") alleging that projects performed in 1997, 2006 and 2007 at the Newton facility violated Prevention of Significant Deterioration, Title V permitting and other requirements. The NOV remains unresolved. We believe our defenses to the allegations described in the NOV are meritorious. A decision by the U.S.

Court of Appeals for the Seventh Circuit in 2013 held that similar claims older than five years were barred by the statute of limitations. If not overturned, this decision may provide an additional defense to the allegations in the Newton facility NOV.

Wood River CAA Section 114 Information Request. In 2014, we received an information request from the EPA concerning our Wood River facility's compliance with the Illinois State Implementation Plan ("SIP") and associated permits. We responded to the EPA's request and believe that there are no issues with Wood River's compliance, but we are unable to predict the EPA's response, if any. We plan to retire our Wood River facility in mid-2016, subject to the approval of MISO.

CAA Notices of Violation. In December 2014, the EPA issued a NOV alleging violation of opacity standards at the Zimmer facility, which we co-own and operate. The EPA previously had issued NOVs to Zimmer in 2008 and 2010 alleging violations of the CAA, the Ohio SIP and the station's air permits involving standards applicable to opacity, sulfur dioxide, sulfuric acid mist and heat input. The NOVs remain unresolved. In December 2014, the EPA also issued NOVs alleging violations of opacity standards at the Stuart and Killen facilities, which we co-own but do not operate.

Edwards CAA Citizen Suit. In April 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility. The District Court has scheduled the trial date for October 2016. We dispute the allegations and will defend the case vigorously.

Ultimate resolution of any of these CAA matters could have a material adverse impact on our future financial condition, results of operations and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve these matters.

Stuart NPDES Permit Appeal. In January 2013, the Ohio EPA reissued the National Pollutant Discharge Elimination System ("NPDES") permit for the co-owned Stuart facility. The operator of Stuart, The Dayton Power and Light Company, appealed various aspects of the permit, including provisions regarding thermal discharge limitations, to the Ohio Environmental Review Appeals Commission. Depending on the outcome of the appeal, the effects on Stuart's operations could be material. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve this matter.

Coal Segment Groundwater. In 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities.

At Baldwin, with approval of the Illinois EPA, we performed a comprehensive evaluation of the Baldwin CCR surface impoundment system beginning in 2013. Based on the results of that evaluation, we recommended to the Illinois EPA in 2014 that the closure process for the inactive east CCR surface impoundment begin and that a geotechnical investigation of the existing soil cap on the inactive old east CCR surface impoundment be undertaken. We also submitted a supplemental groundwater modeling report that indicates no known offsite water supply wells will be impacted under the various Baldwin CCR surface impoundment closure scenarios modeled. We await Illinois EPA action on our proposed action plan and recommendations.

We initiated an investigation at Baldwin in 2011 at the request of the Illinois EPA to determine if the facility's CCR surface impoundment system impacts offsite groundwater. Results of the offsite groundwater quality investigation, as submitted to the Illinois EPA in 2012, indicate two localized areas where Class I groundwater standards were exceeded. The cause of the exceedances is uncertain.

At our retired Vermilion facility, which is not subject to the CCR rule, we submitted proposed corrective action plans for two CCR surface impoundments (i.e., the old east and the north CCR surface impoundments) to the Illinois EPA in 2012. Our hydrogeologic investigation indicates that these two CCR surface impoundments impact groundwater quality onsite and that such groundwater migrates offsite to the north of the property and to the adjacent Middle Fork of the Vermilion River. The proposed corrective action plans recommend closure in place of both CCR surface impoundments and include an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. In 2014, we submitted a revised corrective action plan for the old east CCR surface impoundment. We await Illinois EPA action on our proposed corrective action plans. In June 2015, we advised the Illinois EPA that the additional analyses requested by the Agency would be performed upon receipt of a riverbank stabilization permit from the U.S. Army Corps of Engineers. Our estimated cost of the recommended closure alternative for both the Vermilion old east and north CCR surface impoundments, including post-closure care, is approximately $10 million.

If remediation measures concerning groundwater are necessary in the future at either Baldwin or Vermilion, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. At this time we cannot reasonably estimate the costs, or range of costs, of remediation, if any, that ultimately may be required.

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IPH Segment Groundwater. Groundwater monitoring results indicate that the CCR surface impoundments at each of the IPH segment facilities potentially impact onsite groundwater. In 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. In April 2015, we submitted an assessment monitoring report to the Illinois EPA concerning previously reported groundwater quality standard exceedances at the Newton facility's active CCR landfill. The report identifies the Newton facility's inactive unlined landfill as the likely source of the exceedances and recommends various measures to minimize the effects of that source on the groundwater monitoring results of the active landfill.

If remediation measures concerning groundwater are necessary at any of our IPH facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. At this time we cannot reasonably estimate the costs, or range of costs, of remediation, if any, that ultimately may be required.

Dam Safety Assessment Reports. In response to the failure at the Tennessee Valley Authority's Kingston plant, the EPA initiated a nationwide investigation of the structural integrity of CCR surface impoundments in 2009. The EPA assessments found all of our surface impoundments to be in satisfactory or fair condition, with the exception of the surface impoundments at the Baldwin and Hennepin facilities.

In response to the Hennepin report, we made capital improvements to the Hennepin east CCR surface impoundment berms and notified the EPA of our intent to close the Hennepin west CCR surface impoundment. The preliminary estimated cost for closure of the west CCR surface impoundment, including post-closure monitoring, is approximately $5 million, which is reflected in our ARO. We performed further studies needed to support closure of the west CCR surface impoundment, submitted those studies to the Illinois EPA in 2014 and await Illinois EPA action.

In response to the Baldwin report, we notified the EPA in 2013 of our action plan, which included implementation of recommended operating practices and certain recommended studies. In 2014, we updated the EPA on the status of our Baldwin action plan, including the completion of certain studies and implementation of remedial measures and our ongoing evaluation of potential long-term measures in the context of our concurrent evaluation at Baldwin of groundwater corrective actions. At this time, to resolve the concerns raised in the EPA's assessment report and as a result of the CCR rule, we plan to initiate closure of the Baldwin west fly ash CCR surface impoundment in 2017, which is reflected in our AROs.

Other Commitments

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, design and construction, plant sites, power generation assets and liquefied petroleum gas vessel charters. The following describes the more significant commitments outstanding at December 31, 2015.

Coal Purchase Commitments. At December 31, 2015, we had contracts in place to purchase coal for our generation facilities with aggregate minimum commitments of $1.447 billion. To the extent forecasted volumes have not been priced but are subject to a price collar structure, the obligations have been calculated using the minimum purchase price of the collar.

Coal Transportation. At December 31, 2015, we had coal transportation contracts and rail car leases in place for our generation facilities with aggregate minimum commitments of $904 million.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. Under certain of our contractual service agreements in which we receive maintenance and capital improvements for our gas-fueled generation fleet, we have obligations to purchase uprate equipment of $102 million through 2025. Recently we have undertaken several measures to restructure our existing maintenance agreements as well as negotiate new long-term maintenance service agreements with proven turbine service providers. The term of these agreements will be determined by the maintenance cycles of the respective facility. We currently estimate these agreements will be in effect for a period of 15 or more years. Either party can terminate the agreements based on certain events as specified in the contracts. As of December 31, 2015, our minimum obligation with respect

to these agreements is limited to the termination payments, which are approximately $356 million and $431 million in the event all contracts are terminated by us or the counterparty, respectively.
Environmental Compliance Obligations. We estimate costs, excluding capitalized interest, of approximately $186 million for the completion of scheduled milestones related to the installation of the Newton facility scrubber systems, such that the IPH fleet will comply with certain SO_2 emission limits approved in the variance granted by the IPCB in November 2013. Please read Business - Environmental Matters - IPH Variance for further details. The first milestone relating to the engineering design was completed in July 2015, while the last milestone relates to major equipment components being placed into final position on or before September 1, 2019. We currently estimate this contract will be in effect for a period of four or more years. We are

currently scheduled to complete the Newton scrubber project by the end of 2019 with minimal costs anticipated in 2020. Either party can terminate this contract based on certain events as specified in the contract. In February 2016, Genco issued a notice to the third party contractor constructing the scrubber systems directing them to temporarily suspend a portion of the work being performed.

Gas Purchase Commitments. At December 31, 2015, we had contracts in place to purchase gas for our generation facilities with aggregate minimum commitments of $254 million.

Gas Transportation. At December 31, 2015, we had firm capacity payment obligations related to transportation of natural gas. Such arrangements are routinely used in the physical movement and storage of energy. The total of such obligations was $205 million.

Operating leases.

Office Space, Equipment and Other Property. Minimum lease payment obligations, by year, associated with office space, equipment, land and other leases are $5 million per year for the years 2016-2020.

During the years ended December 31, 2015, 2014 and 2013, we recognized rental expense of approximately $5 million, $5 million and $6 million, respectively.

Charter Agreements. The aggregate minimum base commitments of our charter party agreements are approximately $11 million for the year ended December 31, 2016. We are party to two charter agreements related to very large gas carriers ("VLGCs") previously utilized in our former global liquids business. The primary term of one charter expired at the end of September 2013 but has been extended annually, through September 2016, at the option of the counterparty. The primary term of the second charter was through September 2014 but has been extended through September 2016 at the option of the counterparty. The first charter will terminate at the end of September 2016, and the second charter has an optional one-year extension remaining. Both of these VLGCs have been sub-chartered to a wholly-owned subsidiary of Transammonia Inc. on terms that are identical to the terms of the original charter agreements. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreement and has not exercised the remaining optional extension.

Other Obligations. We have other obligations of $48 million for contracts in place to purchase limestone, $23 million for interconnection services and $28 million for other miscellaneous items which are individually insignificant.

Indemnifications and Guarantees

In the ordinary course of business, we routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, asset sales agreements and procurement and construction contracts. Some agreements contain indemnities that cover the other party's negligence or limit the other party's liability with respect to third party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be remote.

LS Power Indemnities. In connection with the 2009 transaction with LS Power, we agreed to indemnify LS Power against claims regarding any breaches in our representations and warranties and certain other potential liabilities. Even though Dynegy was discharged from any claims pursuant to the order confirming our Joint Chapter 11 Plan of Reorganization, effective October 1, 2012, (the "Plan"), Dynegy Power Generation Inc., Dynegy Power, LLC ("DPC"), Dynegy Midwest Generation, LLC ("DMG") and Dynegy Power Marketing, LLC remain jointly and severally liable for any indemnification claims. Although certain of the indemnification obligations are indefinite, some are no longer in effect under the relevant transaction agreements or have exceeded the applicable statute of limitations. In addition, some of these indemnification obligations are subject to individual thresholds and/or maximum aggregate limits depending on the terms of the transaction agreement. We have accrued no amounts with respect to the indemnifications as of December 31, 2015 because none were probable of occurring, nor could they be reasonably estimated.

EquiPower Acquisition. In connection with the ECP Purchase Agreements, the ECP Purchasers agreed to indemnify the ECP Sellers against claims regarding breaches in the covenants and representations and warranties of the ECP Purchasers and certain other potential liabilities. The indemnification obligations of the ECP Purchasers survive for one year for most covenants and representations and warranties of the ECP Purchasers, two years for fundamental representations and indefinitely for certain other matters. The ECP Sellers shall, in the aggregate, not be entitled to indemnification in excess of $276 million. We have

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accrued no amounts with respect to this indemnification as of December 31, 2015. Please read Note 3—Acquisitions for further discussion.

Duke Midwest Acquisition. In connection with the Duke Midwest Purchase Agreement, DRI agreed to indemnify Duke Energy against claims regarding breaches in the covenants and representations and warranties of DRI and certain other potential liabilities. The indemnification obligations of DRI survive for one year for most covenants and representations and warranties of DRI, three years for fundamental representations, 30 days after the applicable statute of limitations for certain tax matters, and indefinitely for certain other matters. We have accrued no amounts with respect to this indemnification as of December 31, 2015. Dynegy has guaranteed, up to a maximum liability of $2.8 billion, the obligations of DRI under the Duke Midwest Purchase Agreement and related TSA. Please read Note 3—Acquisitions for further discussion.

Note 17—Capital Stock

Preferred Stock

We have authorized preferred stock consisting of 20 million shares, $0.01 par value. Our preferred stock may be issued from time to time in one or more series, the shares of each series to have such designations and powers, preferences, rights, qualifications, limitations and restrictions thereof as specified by our Board of Directors. As of December 31, 2015, there were 4 million shares of our Series A Mandatory Convertible Preferred Stock (as described below) issued and outstanding.

Series A Mandatory Convertible Preferred Stock. On October 14, 2014, we issued 4 million shares, $0.01 par value, pursuant to a registered public offering, of our 5.375% Series A Mandatory Convertible Preferred Stock (“Mandatory Convertible Preferred Stock”) at $100 per share, for gross proceeds of approximately $400 million, before underwriting discounts and commissions of $13 million (“Mandatory Convertible Preferred Stock Offering”). These issuance costs are included in Additional paid-in capital on our consolidated balance sheets. The underwriters in the Mandatory Convertible Preferred Stock Offering had an option for 30 days to purchase an additional 0.6 million shares of our Mandatory Convertible Preferred Stock at $100 per share; however, the option was not exercised.

The Mandatory Convertible Preferred Stock has a liquidation preference of $100 per share, or an aggregate preference of $400 million. Dividends accrue at 5.375 percent per annum on the liquidation preference and will be payable on a cumulative basis when and if declared by our Board of Directors. We may pay declared dividends in cash or, subject to certain limitations, in shares of our common stock or by delivery of any combination of cash and shares of our common stock on February 1, May 1, August 1 and November 1 of each year, commencing on February 1, 2015, and to, and including, November 1, 2017. On January 15, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.64 per share, or approximately $7 million in the aggregate. The dividend is for the initial dividend period beginning on October 14, 2014 and ending on January 31, 2015. Such dividends were paid on February 2, 2015 to stockholders of record as of January 15, 2015. On March 3, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million. An equivalent dividend was also declared on July 1, 2015, October 2, 2015 and January 5, 2016. Such dividends were paid on May 1, 2015, August 3, 2015, November 2, 2015 and February 1, 2016, respectively. As long as we are not in default on our credit agreements, we are not restricted from paying dividends on the Mandatory Convertible Preferred Stock. During the year ended December 31, 2015, we paid an aggregate of $23 million in dividends. We paid no dividends during 2014.

At any time prior to November 1, 2017, other than during a Fundamental Change Conversion Period (as defined in the Certificate of Designations for the Mandatory Convertible Preferred Stock (the “Certificate of Designations”)), holders of the Mandatory Convertible Preferred Stock have the right to elect to convert their shares in whole or in part at the Minimum Conversion Rate of 2.5806 shares of our common stock per share of Mandatory Convertible Preferred Stock. This Minimum Conversion Rate is subject to certain anti-dilution adjustments. The Certificate of Designations provides that during a Fundamental Change Conversion Period, the shares may be converted by the holder at the Fundamental Change Conversion Rate, as defined therein.

Each share of Mandatory Convertible Preferred Stock will, unless previously converted, automatically convert on November 1, 2017, into between 2.5806 and 3.2258 shares of our common stock, subject to anti-dilution and other adjustments. The Mandatory Convertible Preferred Stock is not redeemable by us. The holders of the Mandatory Convertible Preferred Stock generally have no voting rights except in the case of dividend arrearages. Holders are not entitled to participate in any dividends which may be declared and paid on our common stock.

Common Stock

Upon our emergence from bankruptcy on October 1, 2012 (the “Plan Effective Date”), we authorized 420 million shares of common stock, $0.01 par value per share, of which approximately 100 million shares were issued in the aggregate and no shares were held in treasury. On October 14, 2014, we issued 22.5 million shares, pursuant to a registered public offering, of our common stock at $31.00 per share (“Common Stock Offering”). On November 13, 2014, we issued an additional 1.5 million shares, pursuant to the exercise by the underwriters of their 30 day option to purchase up to 3.375 million additional shares of our common stock, at $31.00 per share. The aggregate gross proceeds received by Dynegy from the Common Stock Offering were approximately $744 million, before underwriting discounts and commissions of $38 million, which are recorded on a net basis and included in Additional paid-in capital on our consolidated balance sheets. During the year ended December 31, 2015, no quarterly cash dividends related to our common stock were paid by us.

On April 1, 2015, pursuant to the ERC Purchase Agreement, 3,460,053 shares of common stock of Dynegy valued at approximately $105 million were issued as part of the consideration for the EquiPower Acquisition, before related financing costs of approximately $6 million, which is recorded on a net basis and included in Additional paid-in capital on our consolidated balance sheets. The value of the common stock issued was based on the closing price of Dynegy's common stock on the EquiPower Closing Date. Please read Note 3—Acquisitions for further discussion.

On August 3, 2015, our Board of Directors authorized a share repurchase program for up to $250 million, which was initiated in the third quarter of 2015 and completed in the fourth quarter of 2015. The shares were purchased in the open market or in privately negotiated transactions at prevailing market prices. As of December 31, 2015, we repurchased 11,326,122 shares at an aggregate cost of $250 million.

As of the Plan Effective Date, we issued to Legacy Dynegy stockholders warrants to purchase up to 15.6 million shares of common stock for an exercise price of $40 per share (the "Warrants"). The Warrants have a five-year term expiring on October 2, 2017. The exercise price of the Warrants and the number of shares issuable upon exercise of the Warrants are subject to adjustment upon certain events including: stock subdivisions, combinations, splits, stock dividends, capital reorganizations or capital reclassifications of common stock. Further, in connection with Subject Transactions (as defined in the Warrant Agreement), warrant holders are entitled to certain distributions. If the value of the Warrants is underwater upon the determination date of a Subject Transaction, such distributions are equivalent to $0.01 per warrant, or approximately $150 thousand for all Warrants outstanding. As a result of this potential distribution, the Warrants are classified as a liability in our consolidated financial statements and are adjusted to their estimated fair value at the end of each reporting period with the change in fair value recognized in Other income (expense) on our consolidated statement of operations. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Stock Award Plans

We have one stock award plan, the Dynegy 2012 Long Term Incentive Plan (the "2012 LTIP"), which provides for the issuance of authorized shares of our common stock. Restricted Stock Units ("RSUs"), Performance Stock Units ("PSUs") and option grants were issued under the 2012 LTIP following the Plan Effective Date. Each option granted is exercisable at a strike price, which ranges from $18.70 per share to $32.56 per share for options currently outstanding as of December 31, 2015. The 2012 LTIP is a broad-based plan and provides for the issuance of approximately 6.1 million authorized shares through October 2022. The maximum number of shares of common stock that may be subject to options, restricted stock awards, stock unit awards, stock appreciation rights, phantom stock awards and performance awards, denominated in shares of common stock granted to any one individual during any calendar year may not exceed approximately 1.2 million shares or the equivalent of approximately 1.2 million shares of common stock (subject to adjustment in accordance with the provisions of the 2012 LTIP). The maximum amount of compensation that may be paid under all performance awards denominated in cash (including the fair market value of any shares of common stock paid in satisfaction of such performance awards) granted to any one individual during any calendar year may not exceed a fair market value of $10 million. Any options granted under the 2012 LTIP will expire no later than 10 years from the date of the grant.

All options granted under the 2012 LTIP cease vesting for employees who are terminated with cause. For severance-eligible terminations, as defined under the severance pay plan, disability, retirement or death, immediate or continued vesting and/or an extended period in which to exercise vested options may apply, dependent upon the terms of the grant agreement applying to a specific grant that was awarded. Shares of common stock are issued upon exercise of stock options from previously unissued shares.

All RSUs granted under the 2012 LTIP contain a service condition and cease vesting for employees or directors who are terminated with cause. For severance-eligible employee terminations, as defined under the severance pay plan, director terminations without cause, employee or director disability, retirement or death, immediate vesting of some or all of the RSUs may apply, dependent upon the terms of the grant agreement applying to a specific grant that was awarded. Shares of common stock are issued upon vesting of RSUs from previously unissued shares.

All PSUs granted under the 2012 LTIP contain a performance condition and cease vesting for employees who do not remain continuously employed during the performance period under the grant agreements. For severance-eligible terminations, as defined under the severance pay plan, disability, retirement or death, immediate vesting of some or all of the PSUs may apply, dependent upon the terms of the grant agreement applying to a specific grant that was awarded. Upon a corporate change, employees receive an immediate vesting of PSUs regardless of whether the employee is terminated.

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We use the fair value based method of accounting for stock-based employee compensation. Compensation expense related to options, RSUs and PSUs granted totaled $28 million, $19 million and $15 million for the years ended December 31, 2015, 2014 and 2013, respectively. We recognize compensation expense ratably over the vesting period of the respective awards. Tax benefits for compensation expense related to options, RSUs and PSUs granted totaled $10 million, $7 million and $5 million for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015, $25 million of total unrecognized compensation expense related to options, RSUs and PSUs granted is expected to be recognized over a weighted-average period of 2.5 years. The total fair value of options, RSUs and PSUs vested was $18 million, $14 million and $5 million for the years ended December 31, 2015, 2014 and 2013, respectively. We did not capitalize or use cash to settle any share-based compensation in the years ended December 31, 2015, 2014 and 2013.

Cash received from option exercises for the years ended December 31, 2015, 2014 and 2013 was $0.5 million, $1 million and $2 million, respectively, and the tax benefit realized for the additional tax deduction from share-based payment awards totaled less than $1 million for the years ended December 31, 2015, 2014 and 2013.

The following summarizes our stock option activity:

	Year Ended December 31, 2015				
	Options (in thousands)		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (amounts in millions)
Outstanding at beginning of period	1,372		$21.15		
Granted	485		$27.43		
Exercised	(25	)	$20.93		
Outstanding at end of period	1,832		$22.81	8.54	$—
Vested and unvested expected to vest	1,832		$22.81	8.54	$—
Exercisable at end of period	945		$20.38	7.27	$—

During the years ended December 31, 2015, 2014 and 2013, we did not grant any options at an exercise price less than the market price on the date of grant. The weighted average exercise price of options granted during the years ended December 31, 2014 and 2013 was $23.03 and $22.84, respectively. The intrinsic value of options exercised during the years ended December 31, 2015, 2014 and 2013 was less than $1 million.

For stock options, we determine the fair value of each stock option at the grant date using a Black-Scholes model, with the following weighted-average assumptions used for grants:

	Year Ended December 31,					
	2015		2014		2013	
Dividend Yield	$—		$—		$—	
Expected volatility (1)	27.70	%	23.96	%	32.79	%
Risk-free interest rate (2)	1.64	%	1.61	%	1.05	%
Expected option life (3)	5.5 years		5.5 years		5.5 years	

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(1) For the years ended December 31, 2015 and 2014, the expected volatility was calculated based on the historical volatilities of our stock since October 3, 2012. For the year ended December 31, 2013, the expected volatility was calculated based on five-year historical volatilities of the stock of comparable companies whose shares are traded using daily stock price returns equivalent to the expected term of the options.

(2) The risk-free interest rate was calculated based upon observed interest rates appropriate for the term of our employee stock options.

(3) Currently, we calculate the expected option life using the simplified methodology suggested by authoritative guidance issued by the SEC.

The weighted average grant-date fair value of options granted during the years ended December 31, 2015, 2014 and 2013 was $7.93, $5.91 and $7.35, respectively.

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The following summarizes our RSU activity:

	Year Ended December 31, 2015	
	RSUs (in thousands)	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	1,046	$22.94
Granted	878	$28.93
Vested and released	(468)	$22.53
Forfeited	(43)	$25.83
Outstanding at end of period	1,413	$26.71

For RSUs, we consider the fair value to be the closing price of the stock on the grant date. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2014 and 2013 was $23.36 and $23.15, respectively. We recognize the fair value of our share-based payments over the vesting periods of the awards, which is typically a three-year service period.

The following summarizes our PSU activity:

	Year Ended December 31, 2015	
	PSUs (in thousands)	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	304	$23.13
Granted	278	$27.54
Vested and released	—	$—
Forfeited	(6)	$27.07
Outstanding at end of period	576	$25.22

The weighted average grant date fair value of PSUs granted during the years ended December 31, 2014 and 2013 was $23.03 and $23.10.

The fair value of PSUs is determined using total shareholder return ("TSR"), measured over a three-year period relative to a selected group of energy industry peer companies, using a Monte Carlo model. The key characteristics of the PSUs are as follows:

- Three-year performance period;
- Payout opportunity of 0-200 percent of target, intended to be settled in shares;
- Cumulative TSR percentile ranking calculated at end of performance period and applied to the payout scale to determine the number of earned/vested PSUs; and
- If absolute TSR is negative, PSU award payouts will be capped at 100 percent of the target number of PSUs granted, regardless of relative TSR positioning.

Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans

We sponsor and administer defined benefit plans and defined contribution plans for the benefit of our employees and also provide other post-employment benefits to retirees who meet age and service requirements. During the years ended December 31, 2015, 2014 and 2013, our contributions related to these plans were approximately $50 million, $37 million and $28 million, respectively. The following summarizes these plans:

Short-Term Incentive Plan. Dynegy maintains a discretionary incentive compensation plan to provide our employees with rewards for the achievement of corporate goals and individual, professional accomplishments. Specific awards are determined by Dynegy's Compensation and Human Resources Committee of the Board of Directors and are based on predetermined goals and objectives established at the start of each performance year.

Phantom Stock Plan. Dynegy has issued phantom stock units under its 2009 Phantom Stock Plan. Units awarded under this plan are long term incentive awards that grant the participant the right to receive a cash payment based on the fair market value of Dynegy's stock on the vesting date of the award. As these awards must be settled in cash, we account for them as liabilities, with changes in the fair value of the liability recognized as expense in our consolidated statements of operations. Expense recognized in connection with these awards during the years ended December 31, 2015, 2014 and 2013 was $1 million, $4 million and $5 million, respectively.

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Dynegy Inc. 401(k) Savings Plans. For the years ended December 31, 2015, 2014 and 2013, our employees participated in several 401(k) savings plans, all of which meet the requirements of IRC Section 401(k) and are defined contribution plans subject to the provisions of the Employee Retirement Income Security Act. The following summarizes the plans:

- Dynegy 401(k) Plan. This plan and the related trust fund are established and maintained for the exclusive benefit of participating employees in the U.S. Generally, all employees of designated Dynegy subsidiaries are eligible to participate in this plan. Except for certain represented employees, employee pre-tax and Roth contributions to the plan are matched by the Company at 100 percent, up to a maximum of five percent of base pay (subject to IRS limitations) and vesting in company contributions is based on years of service with 50 percent vesting per full year of service. Effective December 2, 2013, IPH employees participate in this plan and effective January 1, 2014, EEI employees participate in this plan. This plan also allows for a discretionary contribution to eligible employee accounts for each plan year, subject to the sole discretion of the Compensation and Human Resources Committee of the Board of Directors. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2015.
- EquiPower 401(k) Plans. As part of the EquiPower transaction, we acquired various 401(k) plans set forth below. Through December 31, 2015, these plans provided benefits to the former EquiPower and Brayton Point represented and non-represented employees. Effective January 1, 2016, all of these plans, except for the Brayton Point Energy LLC 401k Plan for Bargaining Employees, were merged into the Dynegy 401(k) Plan and employees who participate in these plans became eligible to participate in the Dynegy 401(k) Plan.

- Kincaid Energy Services Company, LLC 401(k) Plan
- Kincaid Energy Services Company, LLC 401(k) Plan for Bargaining Employees
- Brayton Point Energy LLC 401k Plan
- Brayton Point Energy LLC 401k Plan for Bargaining Employees
- Elwood Services Company LLC 401k Plan
- EquiPower Resources Corp. 401k Plan
- Kincaid Energy Services Company LLC 401k Plan
- Kincaid Energy Services Company LLC 401k Plan for Bargaining Employees

During the years ended December 31, 2015, 2014 and 2013, we recognized aggregate costs related to these employee compensation plans of $10 million, $7 million and $4 million, respectively.

Pension and Other Post-Employment Benefits

We have various defined benefit pension plans and post-employment benefit plans. Generally, all employees participate in the pension plans (subject to plan eligibility requirements), but only some of our employees participate in the other post-employment medical and life insurance benefit plans. The pension plans are in the form of cash balance plans and more traditional career average or final average pay formula plans. Separately, our EEI employees and retirees participate in EEI’s single-employer pension and other post-employment plans. We consolidate EEI, and therefore, EEI’s plans are reflected in our pension and post-employment balances and disclosures. Dynegy and EEI both use a measurement date of December 31 for their pension and post-employment benefit plans.

In 2013, we recognized a curtailment loss of $1 million related to EEI’s other post-employment plan for EEI salaried employees, resulting from a plan amendment and terminations associated with the AER Acquisition and a curtailment gain of $7 million in connection with the termination of a majority of the Danskammer, L.L.C. (“Danskammer”) employees and the sale of our Dynegy Roseton, L.L.C. (“Roseton”) facility. In addition, we also reached an agreement with the union representing employees of the facility. As a result of these amendments to certain pension and other post-employment benefit plans, we remeasured our benefit obligations and the funded status of the affected plans in 2013.

Upon the close of the Duke Midwest Acquisition on April 2, 2015, we assumed certain benefit plan obligations and the associated plan assets were transferred to us. These benefit plan obligations and related plan assets were merged into our pension and other post-employment benefit plans. The Duke employees began participating in our plans upon acquisition, which as a result triggered a remeasurement of our plans during the second quarter of 2015. No pension obligations associated with the EquiPower employees were assumed upon the EquiPower Acquisition on April 1, 2015. Effective January 1, 2016, EquiPower employees were eligible to participate in our plan, except for employees that were in the Brayton Point Energy LLC 401k Plan for Bargaining Employees as it was not merged into our plan. In August 2015, we finalized certain new collective bargaining agreements that resulted in amendments to certain pension and other post-employment benefit plans. As a result of these amendments, we remeasured our benefit obligations and the funded status of the affected plans during the third quarter of 2015.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Obligations and Funded Status. The following tables contain information about the obligations, plan assets and funded status of plans in which we, or one of our subsidiaries, formerly sponsored or participated in on a combined basis. These amounts include the obligations, plan assets and funded status of EEI's pension and post-employment plans.

	Pension Benefits		Other Benefits	
	Year Ended December 31,			
(amounts in millions)	2015	2014	2015	2014
Benefit obligation, beginning of the year	$408	$390	$95	$81
Service cost	14	12	1	1
Interest cost	18	17	4	4
Actuarial (gain) loss	(20)	40	(12)	15
Benefits paid	(26)	(37)	(5)	(6)
Plan change	—	—	(10)	—
Settlements	—	(14)	(1)	—
Duke Midwest Acquisition	89	—	2	—
Benefit obligation, end of the year	$483	$408	$74	$95
Fair value of plan assets, beginning of the year	$364	$373	$68	$67
Actual return on plan assets	(13)	39	2	5
Employer contributions	4	3	—	—
Benefits paid	(26)	(37)	(3)	(4)
Settlements	—	(14)	—	—
Duke Midwest Acquisition	81	—	—	—
Fair value of plan assets, end of the year	$410	$364	$67	$68
Funded status	$(73)	$(44)	$(7)	$(27)

Our accumulated benefit obligation related to pension plans was $481 million and $408 million as of December 31, 2015 and 2014, respectively. Our accumulated benefit obligation related to other post-employment plans was $74 million and $95 million as of December 31, 2015 and 2014, respectively.

Amounts recognized in the consolidated balance sheets consist of:

	Pension Benefits		Other Benefits	
	Year Ended December 31,			
(amounts in millions)	2015	2014	2015	2014
Non-current assets	$5	$1	$23	$15
Current liabilities	—	—	(2)	(2)
Non-current liabilities	(78)	(45)	(28)	(40)
Net amount recognized	$(73)	$(44)	$(7)	$(27)

Pre-tax amounts recognized in AOCI consist of:

	Pension Benefits		Other Benefits	
	Year Ended December 31,			
(amounts in millions)	2015	2014	2015	2014
Prior service credit	$(11)	$(12)	$(34)	$(27)
Actuarial loss (gain)	(6)	(21)	2	12
Net gain recognized	$(17)	$(33)	$(32)	$(15)

The net actuarial loss (gain) and prior service credit that were amortized from AOCI into net periodic benefit cost during the years ended December 31, 2015, 2014 and 2013 for the defined benefit pension plans were $1 million, $2 million and $1 million, respectively. The net prior service credit that was amortized from AOCI into net periodic benefit cost during the years ended December 31, 2015, 2014 and 2013 for other post-employment benefit plans was $3 million, $3 million and $1 million, respectively.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The expected amounts that will be amortized from AOCI and recognized as components of net periodic benefit cost (gain) in 2016 are as follows:

(amounts in millions)	Pension Benefits	Other Benefits
Prior service credit	$(1)	$(4)
Actuarial (gain) loss	—	—
Net gain recognized	$(1)	$(4)

The amortization of prior service cost is determined using a straight line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plans.

Components of Net Periodic Benefit Cost (Gain). The components of net periodic benefit cost (gain) were as follows:

	Pension Benefits Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Service cost benefits earned during period	$14	$12	$9
Interest cost on projected benefit obligation	18	17	14
Expected return on plan assets	(23)	(21)	(19)
Amortization of:			
Prior service credit	(1)	(1)	(1)
Actuarial gain	—	(1)	—
Net periodic benefit cost	8	6	3
Curtailment gain (1)	—	—	(7)
Total benefit cost (gain)	$8	$6	$(4)

(1) The curtailment gain was related to the DNE pension plan and resulted from the Roseton sale and the termination of a majority of the Danskammer employees.

	Other Benefits Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Service cost benefits earned during period	$1	$1	$1
Interest cost on projected benefit obligation	4	4	2
Expected return on plan assets	(4)	(4)	—
Amortization of:			
Prior service credit	(3)	(3)	(1)
Net periodic benefit cost (gain)	(2)	(2)	2
Curtailment loss (1)	—	—	1
Total benefit cost (gain)	$(2)	$(2)	$3

(1) The curtailment loss for the year ended December 31, 2013 was related to EEI's other post-employment plan for EEI salaried employees, resulting from a plan amendment and terminations associated with the AER Acquisition.

Assumptions. The following weighted average assumptions were used to determine benefit obligations:

	Pension Benefits Year Ended December 31,		Other Benefits	
	2015	2014	2015	2014
Discount rate (1)	4.35%	4.00%	4.35%	4.00%
Rate of compensation increase (2)	3.50%	3.50%	3.50%	3.50%

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) We utilized a yield curve approach to determine the discount. Projected benefit payments for the plans were matched against the discount rates in the yield curve.

(2) The rate of compensation increase used for other post-employment benefits is specifically related to the EEI post-employment plans.

The following weighted average assumptions were used to determine net periodic benefit cost (gain):

	Pension Benefits			Other Benefits		
	Year Ended December 31,					
	2015	2014	2013	2015	2014	2013
Discount rate	4.35 %	4.00 %	4.82 %	4.35 %	4.00 %	4.78 %
Dynegy - Expected return on plan assets	5.70 %	6.00 %	7.00 %	N/A	N/A	N/A
EEI - Expected return on plan assets (1)	6.00 %	6.25 %	6.25 %	5.50 %	6.00 %	6.00 %
Rate of compensation increase (2)	3.50 %	3.50 %	3.50 %	3.50 %	3.50 %	3.50 %

(1) The average expected return on EEI's other post-employment plan assets was 5.50 percent for the year ended December 31, 2015 and 6 percent for the years ended December 31, 2014 and 2013. The expected return on EEI's other post-employment plan assets was 6.20 percent for EEI union employees and 4.80 percent for EEI salaried employees for the year ended December 31, 2015. For the years ended December 31, 2014 and 2013, the expected return on EEI's other post-employment plan assets was 6.50 percent for EEI union employees and 5.50 percent for EEI salaried employees.

(2) The rate of compensation increase used for other post-employment benefits for the years ended December 31, 2015, 2014 and 2013 is specifically related to the EEI post-employment plans.

Our expected long-term rate of return on Dynegy's pension plan assets and EEI's pension plan assets is 5.60 percent and 5.90 percent, respectively, for the year ended December 31, 2016. Our expected long-term rate of return on EEI's other post-employment plan assets is 6.30 percent for EEI union employees and 5.75 percent for EEI salaried employees for the year ended December 31, 2016. This figure begins with a blend of asset class-level returns developed under a theoretical global capital asset pricing model methodology conducted by an outside consultant. In development of this figure, the historical relationships between equities and fixed income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long term. Current market factors such as inflation and interest rates are also incorporated in the assumptions. This figure gives consideration towards the plan's use of active management and favorable past experience. It is also net of plan expenses.

The following summarizes our assumed health care cost trend rates:

	Year Ended December 31,		
	2015	2014	2013
Health care cost trend rate assumed for next year	7.00 %	7.25 %	7.75 %
Ultimate trend rate	4.50 %	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2023	2023	2023

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The impact of a one percent increase/decrease in assumed health care cost trend rates is as follows:

(amounts in millions)	Increase	Decrease
Aggregate impact on service cost and interest cost	$1	$—
Impact on accumulated post-employment benefit obligation	$9	$(7)

Plan Assets. We employ a total return investment approach whereby a mix of equity and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks as well as growth, value, and small and large capitalizations. The Dynegy plans recently adopted a glide-path approach to de-risk the portfolio as funding levels increased. The target allocations for equity and fixed income investments have changed throughout 2015 and the asset mix as of December 31, 2015 was approximately 46 percent to equity investments and approximately 54 percent to fixed

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

income investments. The target asset mix for EEI's plan assets as of December 31, 2015 was approximately 60 percent to equity investments and approximately 40 percent to fixed income investments. EEI's plan assets are routinely monitored and rebalanced as circumstances warrant.

Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investment. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, periodic asset/liability studies and annual liability measurements.

The following tables set forth by level within the fair value hierarchy assets that were accounted for at fair value related to our pension and other post-employment plans. These assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of December 31, 2015			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$1	$1	$—	$2
Equity securities:				
U.S. companies (1)	32	125	—	157
Non-U.S. companies (2)	—	10	—	10
International (3)	8	54	—	62
Fixed income securities (4)	83	152	—	235
Trust asset receivable (5)	—	11	—	11
Total	$124	$353	$—	$477

	Fair Value as of December 31, 2014			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$—	$2	$—	$2
Equity securities:				
U.S. companies (1)	7	142	—	149
Non-U.S. companies (2)	—	11	—	11
International (3)	2	53	—	55
Fixed income securities (4)	81	134	—	215
Total	$90	$342	$—	$432

(1) This category comprises a domestic common collective trust not actively managed that tracks the Dow Jones total U.S. stock market.
(2) This category comprises a common collective trust not actively managed that tracks the MSCI All Country World Ex-U.S. Index.
(3) This category comprises actively managed common collective trusts that hold U.S. and foreign equities. These trusts track the MSCI World Index.
(4) This category includes a mutual fund and a trust that invest primarily in investment grade corporate bonds.
(5) Relates to the pension and other post-employment plans transferred to Dynegy as a result of the Acquisitions.

Contributions and Payments. We were required to make contributions of $4 million and $3 million to our pension plans and no contributions to our other post-employment benefit plans during the years ended December 31, 2015 and 2014, respectively. We are required to make contributions of $2 million to our other post-employment benefit plans and no contributions to our pension plans during 2016.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our expected benefit payments for future services for our pension and other post-employment benefits are as follows:

(amounts in millions)	Pension Benefits	Other Benefits
2016	$36	$4
2017	$36	$4
2018	$36	$4
2019	$35	$4
2020	$36	$4
2021 - 2025	$183	$22

Note 19—Quarterly Financial Information

The following is a summary of our unaudited quarterly financial information:

	Quarter Ended			
(amounts in millions, except per share data)	March 31	June 30	September 30	December 31
2015 (1)				
Revenues	$632	$990	$1,232	$1,016
Operating income (loss) (2)	$(40)	$10	$107	$(13)
Net income (loss)	$(181)	$386	$(24)	$(134)
Net income (loss) attributable to Dynegy Inc. common stockholders	$(185)	$382	$(29)	$(140)
Net income (loss) per share attributable to Dynegy Inc. common stockholders—Basic	$(1.49)	$2.98	$(0.23)	$(1.18)
Net income (loss) per share attributable to Dynegy Inc. common stockholders—Diluted	$(1.49)	$2.73	$(0.23)	$(1.18)
2014				
Revenues	$762	$521	$615	$599
Operating income (loss)	$1	$(54)	$22	$12
Net loss	$(37)	$(122)	$(5)	$(103)
Net loss attributable to Dynegy Inc. common stockholders	$(41)	$(123)	$(5)	$(109)
Net loss per share attributable to Dynegy Inc. common stockholders—Basic and diluted	$(0.41)	$(1.23)	$(0.05)	$(0.91)

(1) The unaudited quarterly information for the quarters ended June 30, 2015, September 30, 2015 and December 31, 2015 reflect the impact of the Acquisitions. Please read Note 3—Acquisitions for further discussion.

(2) The results for the quarters ended September 30, 2015 and December 31, 2015, include impairment charges of $74 million and $25 million, respectively. See Note 9—Property, Plant and Equipment for more information.

Note 20—Condensed Consolidating Financial Information

On May 20, 2013, Dynegy issued the Senior Notes as further described in Note 13—Debt. On October 27, 2014, the Escrow Issuers, wholly-owned subsidiaries of Dynegy, issued the Notes as further described in Note 13—Debt. The 100 percent owned Subsidiary Guarantors, jointly, severally and unconditionally, guaranteed the payment obligations under the Senior Notes and the Notes. Not all of Dynegy's subsidiaries guarantee the Senior Notes and the Notes including Dynegy's indirect, wholly-owned subsidiary, IPH, which acquired AER and its subsidiaries on December 2, 2013.

The following condensed consolidating financial statements present the financial information of (i) Dynegy (Parent), which is the parent and issuer of the Senior Notes, on a stand-alone, unconsolidated basis, (ii) Escrow Issuers, which are the finance company issuers of the Notes, (iii) the guarantor subsidiaries of Dynegy, (iv) the non-guarantor subsidiaries of Dynegy and (v) the eliminations necessary to arrive at the information for Dynegy on a consolidated basis.

These statements should be read in conjunction with the consolidated financial statements and notes thereto of Dynegy. The condensed consolidating financial statements have been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For purposes of the condensed consolidating financial statements, a portion of our intercompany receivable, which we do not consider to be likely of settlement, has been classified as equity as of December 31, 2015 and December 31, 2014.

Condensed Consolidating Balance Sheet for the Year Ended December 31, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$327	$94	$ 84	$—	$505
Restricted cash	—	—	39	—	39
Accounts receivable, net	499	1,503	130	(1,730)	402
Inventory	—	331	266	—	597
Other current assets	26	335	55	(14)	402
Total Current Assets	852	2,263	574	(1,744)	1,945
Property, Plant and Equipment, Net	—	7,813	534	—	8,347
Other Assets					
Investment in affiliates	13,017	190	—	(13,017)	190
Other long-term assets	77	133	50	—	260
Goodwill	—	797	—	—	797
Intercompany note receivable	17	—	—	(17)	—
Total Assets	$13,963	$11,196	$ 1,158	$(14,778)	$11,539
Current Liabilities					
Accounts payable	$1,388	$238	$ 396	$(1,730)	$292
Other current liabilities	95	277	162	(14)	520
Total Current Liabilities	1,483	515	558	(1,744)	812
Long-term debt	6,370	122	714	—	7,206
Intercompany note payable	3,042	—	17	(3,059)	—
Other long-term liabilities	147	317	138	—	602
Total Liabilities	11,042	954	1,427	(4,803)	8,620
Stockholders’ Equity					
Dynegy Stockholders’ Equity	2,921	13,284	(267)	(13,017)	2,921
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders’ Equity	2,921	10,242	(267)	(9,975)	2,921
Noncontrolling interest	—	—	(2)	—	(2)
Total Equity	2,921	10,242	(269)	(9,975)	2,919
Total Liabilities and Equity	$13,963	$11,196	$ 1,158	$(14,778)	$11,539

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Balance Sheet for the Year Ended December 31, 2014
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets						
Cash and cash equivalents	$1,642	$—	$54	$ 174	$—	$1,870
Restricted cash	—	113	—	—	—	113
Accounts receivable, net	14	—	672	176	(592)	270
Inventory	—	—	88	120	—	208
Other current assets	9	6	125	73	—	213
Total Current Assets	1,665	119	939	543	(592)	2,674
Property, Plant and Equipment, Net	—	—	2,812	443	—	3,255
Other Assets						
Investment in affiliates	6,133	—	—	—	(6,133)	—
Restricted cash	—	5,100	—	—	—	5,100
Other long-term assets	46	47	53	57	—	203
Intercompany interest receivable	17	—	—	—	(17)	—
Total Assets	$7,861	$5,266	$3,804	$ 1,043	$(6,742)	$11,232
Current Liabilities						
Accounts payable	$310	$166	$112	$ 220	$(592)	$216
Other current liabilities	51	67	250	97	—	465
Total Current Liabilities	361	233	362	317	(592)	681
Long-term debt	1,277	5,100	—	698	—	7,075
Intercompany note payable	3,042	—	—	17	(3,059)	—
Other long-term liabilities	158	—	105	190	—	453
Total Liabilities	4,838	5,333	467	1,222	(3,651)	8,209
Stockholders' Equity						
Dynegy Stockholders' Equity	3,023	(67)	6,379	(179)	(6,133)	3,023
Intercompany note receivable	—	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	3,023	(67)	3,337	(179)	(3,091)	3,023
Noncontrolling interest	—	—	—	—	—	—
Total Equity	3,023	(67)	3,337	(179)	(3,091)	3,023
Total Liabilities and Equity	$7,861	$5,266	$3,804	$ 1,043	$(6,742)	$11,232

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Operations for the Year Ended December 31, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$2,979	$ 895	$(4)	$3,870
Cost of sales, excluding depreciation expense	—	(1,485)	(547)	4	(2,028)
Gross margin	—	1,494	348	—	1,842
Operating and maintenance expense	—	(570)	(269)	—	(839)
Depreciation expense	—	(500)	(87)	—	(587)
Impairments	—	(74)	(25)	—	(99)
Gain on sale of assets, net	—	(1)	—	—	(1)
General and administrative expense	(6)	(91)	(31)	—	(128)
Acquisition and integration costs	—	(124)	—	—	(124)
Operating income (loss)	(6)	134	(64)	—	64
Earnings from unconsolidated investments	—	1	—	—	1
Equity in earnings from investments in affiliates	476	—	—	(476)	—
Interest expense	(475)	(1)	(70)	—	(546)
Other income and expense, net	55	(1)	—	—	54
Income (loss) before income taxes	50	133	(134)	(476)	(427)
Income tax benefit (Note 14)	—	471	3	—	474
Net income (loss)	50	604	(131)	(476)	47
Less: Net loss attributable to noncontrolling interest	—	—	(3)	—	(3)
Net income (loss) attributable to Dynegy Inc.	$50	$604	$ (128)	$(476)	$50

Condensed Consolidating Statements of Operations for the Year Ended December 31, 2014
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$—	$1,651	$ 846	$—	$2,497
Cost of sales, excluding depreciation expense	—	—	(1,065)	(596)	—	(1,661)
Gross margin	—	—	586	250	—	836
Operating and maintenance expense	—	—	(279)	(198)	—	(477)
Depreciation expense	—	—	(210)	(37)	—	(247)
Gain on sale of assets, net	—	—	18	—	—	18
General and administrative expense	(9)	—	(60)	(45)	—	(114)
Acquisition and integration costs	—	—	—	(35)	—	(35)
Operating income (loss)	(9)	—	55	(65)	—	(19)
Bankruptcy reorganization items, net	3	—	—	—	—	3
	—	—	10	—	—	10

Earnings from unconsolidated investments						
Equity in losses from investments in affiliates	(131)	—	—	—	131	—
Interest expense	(89)	(67)	—	(68)	1	(223)
Other income and expense, net	(39)	—	1	—	(1)	(39)
Income (loss) before income taxes	(265)	(67)	66	(133)	131	(268)
Income tax benefit (expense) (Note 14)	(8)	—	—	9	—	1
Net income (loss)	(273)	(67)	66	(124)	131	(267)
Less: Net income attributable to noncontrolling interest	—	—	—	6	—	6
Net income (loss) attributable to Dynegy Inc.	$(273)	$(67)	$66	$ (130)	$131	$(273)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Operations for the Year Ended December 31, 2013
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$1,398	$ 68	$—	$1,466
Cost of sales, excluding depreciation expense	—	(1,099)	(46)	—	(1,145)
Gross margin	—	299	22	—	321
Operating and maintenance expense	—	(293)	(15)	—	(308)
Depreciation expense	—	(213)	(3)	—	(216)
Gain on sale of assets, net	—	2	—	—	2
General and administrative expense	(5)	(90)	(2)	—	(97)
Acquisition and integration costs	—	—	(20)	—	(20)
Operating loss	(5)	(295)	(18)	—	(318)
Bankruptcy reorganization items, net	—	—	—	—	—
Earnings from unconsolidated investments	—	2	—	—	2
Equity in losses from investments in affiliates	(315)	—	—	315	—
Interest expense	(56)	(36)	(5)	—	(97)
Loss on extinguishment of debt	(8)	(3)	—	—	(11)
Other income and expense, net	4	3	—	—	7
Loss from continuing operations before income taxes	(380)	(329)	(23)	315	(417)
Income tax benefit (expense) (Note 14)	21	58	(21)	—	58
Loss from continuing operations	(359)	(271)	(44)	315	(359)
Income (loss) from discontinued operations, net of tax (Note 21)	3	(2)	—	2	3
Net loss	(356)	(273)	(44)	317	(356)
Less: Net income (loss) attributable to noncontrolling interest	—	—	—	—	—
Net (loss) attributable to Dynegy Inc.	$(356)	$(273)	$ (44)	$317	$(356)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Year Ended December 31, 2015

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$50	$604	$ (131)	$(476)	$47
Other comprehensive income (loss) before reclassifications:					
Actuarial gain (loss) and plan amendments, net of tax of zero	(8)	2	10	—	4
Amounts reclassified from accumulated other comprehensive income (loss):					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(3)	—	(1)	—	(4)
Other comprehensive income from investment in affiliates	11	—	—	(11)	—
Other comprehensive income, net of tax	—	2	9	(11)	—
Comprehensive income (loss)	50	606	(122)	(487)	47

Less: Comprehensive income (loss) attributable to noncontrolling interest	1	—	(2)	(1)	(2)
Total comprehensive income (loss) attributable to Dynegy Inc.	$49	$606	$ (120)	$(486)	$49

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Comprehensive Loss for the Year Ended December 31, 2014

(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(273)	$(67)	$66	$ (124)	$131	$(267)
Other comprehensive income before reclassifications:						
Actuarial loss and plan amendments, net of zero tax expense	(20)	—	—	(16)	—	(36)
Amounts reclassified from accumulated other comprehensive income (loss):						
Amortization of unrecognized prior service credit and actuarial gain, net of zero tax expense	(5)	—	—	—	—	(5)
Other comprehensive loss from investment in affiliates	(16)	—	—	—	16	—
Other comprehensive loss, net of tax	(41)	—	—	(16)	16	(41)
Comprehensive income (loss)	(314)	(67)	66	(140)	147	(308)
Less: comprehensive income attributable to noncontrolling interest	3	—	—	3	(3)	3
Total comprehensive income (loss) attributable to Dynegy Inc.	$(317)	$(67)	$66	$ (143)	$150	$(311)

Condensed Consolidating Statements of Comprehensive Loss for the Year Ended December 31, 2013

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(356)	$(273)	$ (44)	$317	$(356)
Other comprehensive income before reclassifications:					
Actuarial gain and plan amendments, net of $31 tax expense	53	—	4	—	57
Amounts reclassified from accumulated other comprehensive income (loss):					
Reclassification of curtailment gain included in net loss, net of tax	(7)	—	—	—	(7)
Amortization of unrecognized prior service credit and actuarial gain, net of zero tax expense	(2)	—	—	—	(2)
Other comprehensive income from investment in affiliates	4	—	—	(4)	—
Other comprehensive income, net of tax	48	—	4	(4)	48

Comprehensive loss	(308)	(273)	(40)	313	(308)
Less: comprehensive income attributable to noncontrolling interest	1	—	1	(1)	1
Total comprehensive loss attributable to Dynegy Inc.	$(309)	$(273)	$ (41)	$314	$(309)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(352)	$574	$ (128)	$—	$94
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	(13)	(199)	(63)	—	(275)
Decrease in restricted cash	5,148	—	—	—	5,148
Acquisitions	(6,207)	29	100	—	(6,078)
Net intercompany transfers	448	—	—	(448)	—
Distributions from unconsolidated affiliates	—	8	—	—	8
Other investing	—	3	—	—	3
Net cash provided by (used in) investing activities	(624)	(159)	37	(448)	(1,194)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of financing costs	—	78	19	—	97
Repayments of borrowings	(8)	(23)	—	—	(31)
Financing costs from debt issuances	(31)	—	—	—	(31)
Financing costs from equity issuances	(6)	—	—	—	(6)
Dividends paid	(23)	—	—	—	(23)
Net intercompany transfers	—	(430)	(18)	448	—
Interest rate swap settlement payments	(17)	—	—	—	(17)
Repurchase of common stock	(250)	—	—	—	(250)
Other financing	(4)	—	—	—	(4)
Net cash provided by (used in) financing activities	(339)	(375)	1	448	(265)
Net increase (decrease) in cash and cash equivalents	(1,315)	40	(90)	—	(1,365)
Cash and cash equivalents, beginning of period	1,642	54	174	—	1,870
Cash and cash equivalents, end of period	$327	$94	$ 84	$—	$505

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2014
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:						
Net cash provided by (used in) operating activities	$(70)	$(62)	$353	$ (58)	$—	$163
CASH FLOWS FROM INVESTING ACTIVITIES:						
Capital expenditures	—	—	(87)	(45)	—	(132)
Proceeds from sales of assets, net	—	—	18	—	—	18
Increase in restricted cash	—	(5,148)	—	—	—	(5,148)
Net intercompany transfers	162	—	—	—	(162)	—
Net cash provided by (used in) investing activities	162	(5,148)	(69)	(45)	(162)	(5,262)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from issuance of preferred stock	400	—	—	—	—	400
Proceeds from issuance of common stock	744	—	—	—	—	744
Proceeds from long-term borrowings	—	5,100	12	—	—	5,112
Repayments of borrowings	(8)	—	(6)	—	—	(14)
Financing costs from debt issuances	(1)	(56)	—	—	—	(57)
Financing costs from equity issuances	(38)	—	—	—	—	(38)
Interest rate swap settlement payments	(18)	—	—	—	—	(18)
Net intercompany transfers	—	166	(390)	62	162	—
Other financing	(3)	—	—	—	—	(3)
Net cash provided by (used in) financing activities	1,076	5,210	(384)	62	162	6,126
Net increase (decrease) in cash and cash equivalents	1,168	—	(100)	(41)	—	1,027
Cash and cash equivalents, beginning of period	474	—	154	215	—	843
Cash and cash equivalents, end of period	$1,642	$—	$54	$ 174	$—	$1,870

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2013
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					

Net cash provided by (used in) operating activities	$(61)	$254	$ (18)	$—	$175
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(97)	(1)	—	(98)
Decrease in restricted cash	29	306	—	—	335
Acquisitions	—	—	234	—	234
Net intercompany transfers	(1,044)	—	—	1,044	—
Other investing	—	3	—	—	3
Net cash provided by (used in) investing activities	(1,015)	212	233	1,044	474
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of financing costs	1,753	15	—	—	1,768
Repayments of borrowings, including debt extinguishment costs	(504)	(1,413)	—	—	(1,917)
Net intercompany transfers	—	1,044	—	(1,044)	—
Interest rate swap settlement payments	(5)	—	—	—	(5)
Net cash provided by (used in) financing activities	1,244	(354)	—	(1,044)	(154)
Net increase in cash and cash equivalents	168	112	215	—	495
Cash and cash equivalents, beginning of period	306	42	—	—	348
Cash and cash equivalents, end of period	$474	$154	$ 215	$—	$843

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21—Discontinued Operations

On April 30, 2013, we completed the sale of Roseton. On November 1, 2013, the Danskammer assets were sold. Any activity related to our Roseton and Danskammer operations is included in Income from discontinued operations, net of tax in our consolidated statement of operations for the year ended December 31, 2013. On November 4, 2013, the DNE Joint Plan of Liquidation became effective and Hudson Power, L.L.C., Danskammer and Roseton were deemed to have been merged into DNE or dissolved. On December 30, 2014, DNE was dissolved. The proceeds from the Facilities Sale Transactions of $1 million were distributed pursuant to the Joint Plan of Liquidation, including any modification thereto.

Note 22—Restructuring Charges

During the year ended December 31, 2013, approximately 102 positions were eliminated, primarily related to the AER Acquisition. We paid approximately $3 million in severance benefits to affected employees during the year ended December 31, 2013, which is included in Acquisition and integration costs on our consolidated statement of operations.

During the year ended December 31, 2014, approximately 106 positions were eliminated, primarily related to the AER Acquisition. We paid approximately $12 million in severance benefits to affected employees during the year ended December 31, 2014, which is included in Acquisition and integration costs on our consolidated statement of operations.

During the year ended December 31, 2015, approximately 49 positions were eliminated, primarily related to the EquiPower Acquisition in April 2015. We paid approximately $14 million in severance benefits to affected employees during the year ended December 31, 2015. We were reimbursed $3 million by ECP to cover a portion of these severance benefits during the year ended December 31, 2015. These severance costs, net of the reimbursement, is included in Acquisition and integration costs on our consolidated statement of operations.

The following table summarizes activity related to liabilities associated with costs related to severance and retention benefits:

	Year Ended December 31,		
(amounts in millions)	2015	2014	2013
Beginning of period	$—	$12	$2
Expense (1)	16	3	14
Payments	(15)	(15)	(4)
End of period	$1	$—	$12

(1) Expense during the years ended December 31, 2015, 2014 and 2013 includes $1 million, $1 million and $3 million in retention benefits, respectively.

Note 23—Segment Information

We report the results of our operations in three segments: (i) Coal, (ii) IPH and (iii) Gas. The Coal segment includes certain of our coal-fired power generation facilities and our Dynegy Energy Services retail business. The IPH segment includes Genco, and Illinois Power Resources Generating, LLC (“IPRG”), which also own, directly and indirectly, certain of our coal-fired power generation facilities. IPH also includes our Homefield Energy retail business in Illinois. IPH and its direct and indirect subsidiaries and Genco and its direct and indirect subsidiaries are each organized into ring-fenced groups in order to maintain corporate separateness. The Gas segment includes substantially all of our natural gas-fired power generation facilities. Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense).

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2015, 2014 and 2013 is presented below:

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Segment Data as of and for the Year Ended December 31, 2015
(amounts in millions)

	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$1,298	$804	$1,768	$—	$3,870
Intercompany revenues	(134)	(5)	139	—	—
Total revenues	$1,164	$799	$1,907	$—	$3,870
Depreciation expense	$(138)	$(29)	$(416)	$(4)	$(587)
Impairments	(99)	—	—	—	(99)
Gain on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(128)	(128)
Operating income (loss)	$(93)	$49	$360	$(252)	$64
Earnings from unconsolidated investments	—	—	1	—	1
Interest expense	—	—	—	(546)	(546)
Other items, net	(1)	—	—	55	54
Loss before income taxes					(427)
Income tax benefit	—	—	—	474	474
Net loss					47
Less: Net income attributable to noncontrolling interest					(3)
Net loss attributable to Dynegy Inc.					$50
Total assets—domestic	$2,324	$897	$7,811	$507	$11,539
Investment in unconsolidated affiliate	$—	$—	$190	$—	$190
Capital expenditures	$(87)	$(63)	$(112)	$(13)	$(275)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Segment Data as of and for the Year Ended December 31, 2014
(amounts in millions)

	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$587	$850	$1,060	$—	$2,497
Intercompany revenues	6	(4)	(2)	—	—
Total revenues	$593	$846	$1,058	$—	$2,497
Depreciation expense	$(51)	$(37)	$(155)	$(4)	$(247)
Gain on sale of assets	—	—	18	—	18
General and administrative expense	—	—	—	(114)	(114)
Operating income (loss)	$40	$(2)	$79	$(136)	$(19)
Bankruptcy reorganization items, net	—	—	—	3	3
Earnings from unconsolidated investments	—	—	10	—	10
Interest expense	—	—	—	(223)	(223)
Other items, net	—	—	—	(39)	(39)
Loss from continuing operations before income taxes					(268)
Income tax benefit	—	—	—	1	1
Loss from continuing operations					(267)
Net loss					(267)
Less: Net income (loss) attributable to noncontrolling interest					6
Net loss attributable to Dynegy Inc.					$(273)
Total assets—domestic	$1,168	$1,039	$2,027	$6,998	$11,232
Capital expenditures	$(39)	$(45)	$(44)	$(4)	$(132)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Segment Data as of and for the Year Ended December 31, 2013
(amounts in millions)

	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$469	$67	$930	$—	$1,466
Intercompany revenues	(2)	—	2	—	—
Total revenues	$467	$67	$932	$—	$1,466
Depreciation expense	$(50)	$(3)	$(160)	$(3)	$(216)
Gain on sale of assets	2	—	—	—	2
General and administrative expense	—	—	—	(97)	(97)
Operating income (loss)	$(207)	$(17)	$7	$(101)	$(318)
Bankruptcy reorganization items, net	—	—	—	(1)	(1)
Earnings from unconsolidated investments	—	—	2	—	2
Interest expense	—	—	—	(97)	(97)
Loss on extinguishment of debt	(5)	—	2	(8)	(11)
Other items, net	—	—	2	6	8
Loss from continuing operations before income taxes					(417)
Income tax benefit	—	—	—	58	58
Loss from continuing operations					(359)
Income from discontinued operations, net of tax	—	—	—	3	3
Net loss					(356)
Less: Net income (loss) attributable to noncontrolling interest					—
Net loss attributable to Dynegy Inc.					$(356)
Total assets—domestic	$1,153	$1,190	$2,303	$645	$5,291
Capital expenditures	$(42)	$(1)	$(53)	$(2)	$(98)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Significant Customers

Our total revenues for customers which individually accounted for more than 10% of our consolidated revenues, and the segments impacted, for the years ended December 31, 2015, 2014 and 2013 are presented below:

Customers	Revenues	Segment(s)
(amounts in millions)		
2015		
PJM	$1,088	Coal, IPH, Gas
MISO	842	Coal, IPH
2014		
MISO	$836	Coal, IPH
NYISO	342	Gas
2013		
MISO	$526	Coal, IPH
PJM	275	Gas
NYISO	231	Gas
CAISO	221	Gas

Note 24—Subsequent Event

On February 25, 2016, we announced the acquisition of certain power generation facilities from International Power, S.A., a wholly owned subsidiary of ENGIE, through a joint venture with ECP, for a purchase price of approximately $3.3 billion. The acquisition includes approximately 8,700 MW located in ERCOT, PJM and ISO-NE. Of the 8,700 MW, approximately 8,000 MW are modern, efficient natural gas facilities with the remaining 700 MW being environmentally compliant coal facilities.

The joint venture will be approximately 65 percent owned by a subsidiary of Dynegy and approximately 35 percent by affiliates of ECP, and will be a non-recourse subsidiary of Dynegy. In addition to the joint venture, ECP will also purchase approximately $150 million of Dynegy common stock.