DYNEGY INC.
Form 10-K
February 25, 2015
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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, 2014

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, 2014, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $2,828,298,103 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, 124,438,722 shares outstanding as of February 10, 2015.

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 2015 Annual Meeting of Stockholders, which the registrant intends to file no later than 120 days after December 31, 2014. 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.

CAISO	California Independent System Operator
CPUC	California Public Utility Commission
EGU	Electric Generating Units
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GW	Gigawatt
HAPs	Hazardous Air Pollutants, as defined by the Clean Air Act
IBEW	International Brotherhood of Electrical Workers
ICAP	Installed Capacity
ICC	Illinois Commerce Commission
ICR	Installed Capacity Requirement
IGCC	Integrated Gasification Combined Cycle
IMA	In Market Availability
IUOE	International Union of Operating Engineers
IPCB	Illinois Pollution Control Board
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
TVA	Tennessee Valley Authority
VaR	Value at Risk

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 15 power plants in five states totaling approximately 13,000 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 Illinois Power Holdings, LLC ("IPH") segments are fleets of baseload coal facilities, located in Illinois, which dispatch around the clock throughout the year. 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. Currently our peaking facilities are contracted through either tolling or RMR agreements. 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. Wholesale electricity customers will, for reliability reasons and to meet regulatory requirements, contract for rights to capacity from generating units. Ancillary services are the products of a power generation facility that 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.

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	465	Coal	Baseload	Alton, IL	MISO
Total Coal Segment	3,008				
Coffeen	915	Coal	Baseload	Montgomery County, IL	MISO
Joppa/EEI (2)	802	Coal	Baseload	Joppa, IL	MISO
Newton	1,230	Coal	Baseload	Jasper County, IL	MISO
Duck Creek	425	Coal	Baseload	Canton, IL	MISO
E.D. Edwards	685	Coal	Baseload	Bartonville, IL	MISO
Total IPH Segment (3)	4,057				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterey County, CA	CAISO
Kendall	1,209	Gas	Intermediate	Minooka, IL	PJM
Ontelaunee	560	Gas	Intermediate	Ontelaunee Township, PA	PJM
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Casco Bay	538	Gas	Intermediate	Veazie, ME	ISO-NE
Independence	1,108	Gas	Intermediate	Scriba, NY	NYISO
Total Gas Segment	6,109				
Total Fleet Capacity	13,174				

(1) Unit capabilities are based on winter capacity. We have not included units that have been retired or are out of operation.

(2) We indirectly own an 80 percent interest in this facility.

(3) 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 linking our generation to our customer load which reduces the need to transact additional financial hedging products in the market.

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

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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 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 have dedicated significant resources toward these priorities with approximately $1 billion invested since 2005 in our Coal segment for environmental compliance initiatives to meet contractual obligations and state and federal environmental standards. Additionally in the IPH segment, we continue to invest in flue gas desulfurization systems at the Newton facility. We will continue to invest across all segments to maintain and improve the safety, reliability and efficiency of the fleet. The Pending Acquisitions (as defined 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, 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 our PRIDE program a year ago with a three-year target of $135 million in operating improvements and $165 million in balance sheet efficiencies. In 2014, we exceeded our $60 million EBITDA improvement target and $65 million balance sheet efficiency target and based on performance to date, we plan to accelerate and achieve our original three-year target by the end of 2015, a full year ahead of schedule. After the close of the Pending Acquisitions, new consolidated targets for 2016 will be set.

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. Additional capital allocation options that are evaluated include investments in our existing portfolio, potential acquisitions and returning capital to shareholders. Capital allocation decisions are generally based on alternatives that provide the highest risk adjusted rates of return. In 2014, we allocated a substantial portion of our balance sheet to the Pending Acquisitions.

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. We will continue to evaluate other measures to best manage our balance sheet and liquidity.

Recent Developments

Acquisitions. In August 2014, we entered into agreements with Duke Energy to purchase certain of its facilities located in the Midwest and its retail energy business for a purchase price of $2.8 billion in cash, subject to certain adjustments (the “Duke Midwest Acquisition”), and with the ECP Sellers (as defined herein) to purchase EquiPower Resources Corp. (“ERC”) and Brayton Point Holdings, LLC (“Brayton”) for a purchase price of approximately $3.25 billion in cash in the aggregate and $200 million of our common stock, subject to certain adjustments (collectively, the

“EquiPower Acquisition” and, the EquiPower Acquisition together with the Duke Midwest Acquisition, the “Pending Acquisitions”). The Pending Acquisitions will expand our fleet to 35 power plants in eight states and increase our generation capacity by approximately 12,500 MW to nearly 26,000 MW.

Consummation of the Pending Acquisitions is subject to conditions and governmental approvals, including FERC approval. On February 6, 2015, we responded to a letter from FERC requesting additional information to process the applications filed with FERC on September 11, 2014. Please read Note 3—Merger and Acquisitions for further discussion.

Acquisition Financing. On August 21, 2014, to ensure the financing of the Pending Acquisitions, we obtained commitments for incremental revolving credit facilities (the “Revolvers”) and bridge loan commitments (the “Bridge Loan Facilities”). The Bridge Loan Facilities were terminated on October 27, 2014 as we completed our permanent financings for the acquisitions as discussed below. The Revolvers expand the credit available to us by an aggregate of \$950 million (\$600 million for the Duke Midwest Acquisition and \$350 million for the EquiPower Acquisition) which will be used to support the collateral and liquidity requirements of the acquired businesses. Each Revolver is conditional on the closing of the applicable acquisition. We expect to have at least \$800 million available, net of expected letters of credit outstanding, for future borrowings under our current and incremental revolving credit facilities immediately following the completion of the Pending Acquisitions.

On October 14, 2014, pursuant to registered public offerings, we issued 22.5 million shares of our common stock at \$31.00 per share for gross proceeds of approximately \$698 million, before underwriting discounts and commissions (the “Common Stock Offering”), and 4 million shares of our mandatory convertible preferred stock at \$100 per share, for gross proceeds of approximately \$400 million, before underwriting discounts and commissions (the “Mandatory Convertible Preferred Stock Offering”). Please read Note 16—Capital Stock for further discussion.

On October 27, 2014, we completed the private placement of \$5.1 billion in aggregate principal amount of unsecured senior notes at a weighted average interest rate of 7.18 percent in tranches with maturities ranging from 2019 to 2024 (the “Notes”). The gross proceeds from the issuance of the Notes, less initial purchasers’ discounts and expenses, were placed into escrow pending the consummation of the Pending Acquisitions. Under our escrow agreement related to the Notes, the applicable borrowings for each Pending Acquisition are subject to mandatory redemption, at par, if the acquisitions are not consummated by May 11, 2015, in the case of the EquiPower Acquisition, and August 24, 2015, in the case of the Duke Midwest Acquisition. Please read Note 11—Debt for further discussion.

On November 13, 2014, pursuant to the partial exercise by the underwriters of their option to purchase additional shares of common stock in connection with the previously announced public offering on October 14, 2014, we issued 1.5 million shares of our common stock at \$31.00 per share for gross proceeds of approximately \$46 million, before underwriting discounts and commissions. Please read Note 16—Capital Stock 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 24—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.

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, both bid and price limits. They may also enforce caps and other mechanisms to guard against the exercise of market dominance in these markets. 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.

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 unstructured markets where entities fulfill their requirements through a combination of long and short-term bilateral contracts between individual counterparties and self-generation.

Coal and IPH Segments

Our Coal segment is comprised of four coal-fired power generation facilities located in Illinois with a total generating capacity of 3,008 MW. Our IPH segment is comprised of five coal-fired power generation facilities located in Illinois with a total owned generating capacity of 4,057 MW. All of these facilities, with the exception of Joppa, operate in MISO. Joppa, which is within the Electric Energy, Inc. ("EEI") control area, also sells power and capacity into MISO. We offer a portion of our IPH segment generating capacity into the PJM market.

RTO/ISO Discussion

MISO. The MISO market includes all of Iowa, Minnesota, North Dakota and Wisconsin and portions of 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 a 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.

Contracted Capacity and Energy

We commercialize our Coal and IPH segment assets through a combination of physical participation in the MISO markets (as described above), bilateral physical and financial power sales and fuel and capacity contracts. Capacity revenues consist of revenues billed to a third party at either the market or a negotiated contract price for making installed generation capacity available in order to satisfy system integrity and reliability requirements.

Reserve Margins

The MISO Planning Reserve Margin was 14 percent for Planning Year 2013-2014. The actual Reserve Margin was 22.4 percent. MISO has forecasted reserve margins of 16.6 percent for Planning Year 2015-2016, 11.5 percent for Planning Year

2016-2017, 12.3 percent for Planning Year 2017-2018, 10.6 percent for Planning Year 2018-2019 and 9.0 percent for Planning Year 2019-2020.

Gas Segment

Our Gas segment is comprised of five natural gas-fired power generation facilities located in California, Illinois, Pennsylvania, New York and Maine and one fuel-oil fired power generation facility located in California, totaling 6,109 MW of electric generating capacity.

RTO/ISO Discussion

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. Our Kendall and Ontelaunee facilities, located in Illinois and Pennsylvania, respectively, operate in PJM with an aggregate net generating capacity of 1,769 MW.

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 2017-2018, which ends May 31, 2018. We also enter into bilateral capacity transactions. PJM may offer incremental auctions through Planning Year 2017-2018 to fill incremental capacity needs. 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. PJM has also filed with FERC a proposal for "capacity performance" rules to be phased in beginning Planning Year 2015-2016. These rules are designed to improve system reliability, and include penalties for underperforming units and rewards for overperforming units during shortage events.

NYISO. The NYISO market includes the entire state of New York. Capacity pricing is calculated as a function of NYISO's annual required reserve margin, the estimated net cost of "new entrant" generation, estimated peak demand and the actual amount of capacity bid into the market at or below its demand curve. The demand curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that "new entrant" economics become attractive as the reserve margin approaches required minimum levels. The intent of the demand curve mechanism is to ensure that existing generation facilities have enough revenue to recover their investment when capacity revenues are coupled with energy and ancillary service revenues. Additionally, the demand curve mechanism is intended to attract new investment in generation when and where that new capacity is needed most. To calculate the price and quantity of installed capacity (the available output of power generation in the market), four ICAP demand curves are used: one for Long Island, one for New York City, one for Statewide (commonly referred to as Rest of State), and in May 2014, the fourth demand curve was implemented covering the recently approved Lower Hudson Valley Zone. Our Independence facility operates in the Rest of State market and has an aggregate net generating capacity of 1,108 MW.

NYISO also dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Due to pipeline constraints, natural gas prices tend to be cheaper and less volatile in the northwestern part of the state, where our Independence facility is located.

ISO-NE. The ISO-NE market includes the six New England states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. Our Casco Bay facility, located in Maine, operates in ISO-NE and has an aggregate net generating capacity of 538 MW. 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, much like regional zones in the NYISO 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. Changes include removal of the price floor and implementation of a minimum offer price rule for new resources to prevent buy-side market power. On October 17, 2013, ISO-NE issued a memorandum to market participants noting a potential resource shortfall based on submitted retirement requests. FCA-8 occurred on February 3, 2014 and cleared at a price of $15 per kW-month due to significant capacity requirements in the region. However, due to recent capacity retirements, the "insufficient competition" clause in the ISO-NE tariff was triggered causing existing generation in Rest-of-Pool Capacity Zone, including Casco Bay, to receive an administrative cap price of $7.025 per kW-month. The FCA-9 auction for Planning Year

2018-2019 was held on February 2, 2015. A downward sloping demand curve was implemented for FCA-9. Additionally, in order to ensure reliability, a "performance incentive" mechanism that will penalize underperforming units and reward overperforming units was implemented. Rest-of-Pool cleared at a price of $9.551 per kW-month. The Southeastern Massachusetts and Rhode Island zone ("SEMA-RI") 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 ("Net CONE") price of $11.080 per kW-month and new resources in the zone receiving the auction starting price of $17.728 per kW-month.

CAISO. The CAISO market covers approximately 90 percent of the State of California and operates a centrally cleared market for energy and ancillary services. Our Moss Landing and Oakland facilities operate in CAISO with an aggregate net generating capacity of 2,694 MW. Energy is priced utilizing an LMP system as described above. Currently the CAISO has a mandatory resource adequacy requirement but no centrally-administered capacity market.

Contracted Capacity and Energy

PJM. Our Kendall and Ontelaunee facilities are natural gas-fired, combined-cycle, intermediate dispatch facilities. We commercialize these assets through a combination of bilateral power, fuel and capacity contracts. We commercialize our capacity through either the RPM auction or on a bilateral basis. Our Kendall facility has one tolling agreement for 85 MW that expires in 2017.

NYISO. Our Independence facility, due to the standard capacity market operated by NYISO and liquid OTC market for NYISO capacity products, sells a significant portion of its capacity bilaterally into the market, with the balance cleared through seasonal and monthly capacity auctions. Additionally, we supply steam and up to 44 MW of electric energy to a third party at a fixed price.

ISO-NE. Our Casco Bay facility sells capacity through the forward capacity auctions administered by the ISO-NE. Nine forward capacity auctions have been held to date. All auctions through the seventh auction cleared at the floor price due to oversupply of capacity in the region. In FCA-8, retirements contributed to the auction clearing at the administrative cap for Planning Year 2017-2018. In FCA-9, new capacity rules were implemented including a sloped demand curve for Planning Year 2018-2019. For FCA-9, Casco Bay cleared 488 MW at a price of $9.551 per kW-month.

CAISO. In CAISO, where our assets include intermediate dispatch and peaking facilities, we seek to mitigate spark spread variability through tolling arrangements and physical and financial bilateral power and fuel contracts. All of the capacity of our Moss Landing Units 6 and 7 is contracted under tolling arrangements through 2016. As previously noted, our Oakland facility operates under an RMR contract with the CAISO.

Reserve Margins

PJM. The installed reserve margin requirement is reviewed by PJM on an annual basis and is 15.9 percent for Planning Years 2013-2014 to 2014-2015. PJM has forecasted reserve margins based on deliverable capacity of 17.1 percent for Planning Year 2015-2016, 18 percent for Planning Year 2016-2017, 18.8 percent for Planning Years 2017-2018 and 2018-2019 and 18.2 percent for Planning Year 2019-2020.

NYISO. A reserve margin of 17 percent has been filed with the FERC for the New York Control Area for the period beginning May 1, 2014 and ending April 30, 2015. A reserve margin of 17 percent for the period beginning May 1, 2015 and ending April 30, 2016 has been filed. The actual amount of installed capacity is approximately 2 percentage points above NYISO's current required reserve margin.

ISO-NE. Similar to PJM, ISO-NE will publish on an annual basis the required reserve margin which is called ICR. For Planning Year 2015-2016, the ICR is 24 percent. Actual installed reserve margin is approximately 33.6 percent, which is 13.3 percentage points above the ICR. For Planning Years 2016-2017, 2017-2018 and 2018-2019, the ICRs are 24 percent, 16 percent and 11 percent, respectively.

CAISO. The CPUC requires a resource adequacy margin of 15 to 17 percent. As of the latest summer assessment for the region in May 2014, the reserve margin was approximately 23.8 percent. 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 the state level, there are numerous ongoing market initiatives that impact wholesale generation, principally the development of resource adequacy rules and capacity markets to include the necessary flexibility to integrate the state-mandated 33 percent renewable resources and maintain reliability of the grid. The CPUC has integrated flexible capacity into the 2014 Resource Adequacy procurement requirements and both the CPUC and CAISO recently approved a plan to examine multi-year procurement requirements that will bridge the gap between Resource Adequacy (one-year) and Long Term Power Procurement (ten-year) plans. Both the CAISO and CPUC have recently deferred or delayed parts of these initiatives. The CAISO has delayed the Flexible Ramping Product by several months in order to address issues stakeholders raised during policy development. The CPUC has suspended work on the multi-year Resource Adequacy procurement until further notice. Multi-year Resource Adequacy procurement is likely to be picked back up again in either the current or a future Resource Adequacy proceeding in conjunction with development of the durable flexible capacity program.

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 ("DYPM"), Dynegy Marketing and Trade, LLC ("DMT"), Illinois Power Marketing Company ("IPM") and Dynegy Energy Services, LLC ("DES").

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 December 2014, we filed a market power update with FERC for our Central Region Assets (MISO assets and EEI).

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"), which, among other things, aims to improve transparency in derivative markets. 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. As required, Dynegy is meeting its reporting obligations under Parts 43, 45 and 46 of the CFTC's regulations, which cover real-time public reporting of swap transaction data, reporting of swap transaction data to a registered swap data repository and reporting of historical swaps. We continue to monitor the CFTC's releases for guidance on these rules and any other clearing and reporting requirements that will be required of our business or impact current operations.

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 is subject to change and has become more stringent over time. The process for acquiring or maintaining permits or otherwise complying with applicable rules and regulations 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, 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 15—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 $30 million in 2014 compared to approximately $25 million in 2013. We estimate that our Coal segment's total expenditures for environmental compliance in 2015 will be approximately $35 million, with approximately $10 million in capital expenditures and $25 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 $50 million in 2014. We estimate that our IPH segment's total expenditures for environmental compliance in 2015 will be approximately $55 million, with approximately $25 million in capital expenditures and $30 million in operating expenses.

Our aggregate Gas segment expenditures for environmental compliance were approximately $5 million for both 2014 and 2013. We estimate that our Gas segment's total expenditures for environmental compliance in 2015 will be approximately $5 million in operating expenses.

The Clean Air Act

The Clean Air Act ("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 have sufficient emission allowances to cover actual sulfur dioxide ("SO_2") emissions and in some regions nitrogen oxide ("NO_x") emissions and that they meet certain pollutant emission standards as well.

In order to ensure continued compliance with the CAA and related rules and regulations, we have installed various emission reduction technologies at our Coal and IPH segment facilities. These technologies include flue gas desulfurization systems on select units for the control of SO_2 emissions, electrostatic precipitators on all units and baghouses on select units for the control of particulate matter emissions, activated carbon injection or mercury oxidation systems on all units for the control of mercury emissions, and selective catalytic reduction ("SCR") systems and/or low-NO_x burners and/or overfire air systems on all units to control NO_x emissions. All of our Coal and IPH segment facilities also use low sulfur coal exclusively (except Duck Creek, which blends low and high sulfur coal), which goes through a refined coal process to further reduce NO_x and mercury emissions. All of our Gas segment facilities, except Oakland, use SCR technology to control NO_x emissions.

Multi-Pollutant Air Emission Initiatives

In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have taken effect. In 2005, the EPA finalized the Clean Air Interstate Rule ("CAIR") to reduce emissions of SO_2 and NO_x from coal-fired power generation units across the eastern U.S. The CAIR was challenged by several parties and ultimately remanded to the EPA, but remained in effect in 2014.

Cross-State Air Pollution Rule. In July 2011, the EPA issued its final rule on Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (the "Cross-State Air Pollution Rule," or "CSAPR", formerly known as the Transport Rule) to replace CAIR. The CSAPR imposes cap-and-trade programs within each affected state that cap emissions of SO_2 and NO_x at levels estimated to eliminate that state's contribution to nonattainment with, or interference with maintenance of attainment status by down-wind areas with respect to, the National Ambient Air Quality Standards ("NAAQS") for fine particulate matter (PM2.5) and ozone. Under the CSAPR, our generating facilities in Illinois, New York and Pennsylvania are subject to cap-and-trade programs capping emissions of NO_x from May 1 through September 30 and capping emissions of SO_2 and NO_x on an annual basis. The requirements applicable to SO_2 emissions from EGUs in Illinois, New York and Pennsylvania will be implemented in two stages with existing EGUs in these states allocated fewer SO_2 emission allowances in the second phase.

As a result of various judicial proceedings, including review by the U.S. Supreme Court in 2014, CSAPR Phase I did not take effect until January 1, 2015 for the annual SO_2 and NO_x programs, with the ozone-season NO_x program to begin May 1, 2015. CSAPR Phase 2 will begin in 2017. Judicial challenges to the CSAPR remain pending in the U.S. Court of Appeals for the District of Columbia Circuit.

Based on our current projections of emissions for 2015, we anticipate that our Coal and IPH segment facilities have an adequate number of SO_2 allowances allocated in 2015 under the CSAPR but will need to acquire a limited number of NO_X (ozone season and annual) 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 (filterable particulate may be used as a surrogate), and acid gases (hydrogen chloride may be used as a surrogate, with SO_2 as an optional surrogate for coal-fired units using flue gas desulfurization; oil-fired units also would be subject to a hydrogen fluoride limit), and work practice standards for organic HAPs. Compliance with the MATS rule is required by April 16, 2015, unless an extension is granted in accordance with the CAA. The U.S. Supreme Court is expected to issue a decision by summer 2015 addressing whether the EPA, in adopting the MATS rule, unreasonably refused to consider costs in determining the appropriateness of regulating HAPs emitted by EGUs.

Given the air emission controls already employed, we expect that each of our Coal and IPH segment facilities, except Edwards Unit 1, will be in compliance with the MATS rule emission limits without the need for significant additional capital investment. We continue to monitor the performance of our units and evaluate approaches to optimize compliance strategies. In accordance with our MISO tariff obligations, in December 2014, we requested a one-year extension of the MATS compliance deadline for Edward Unit 1. We have committed to retire Edwards Unit 1 as soon as the MISO allows us to retire the unit.

The EPA revised the MATS rule in November 2014 to require installation and operation of the extensive startup and shutdown monitoring instrumentation. Because installation of such instrumentation by April 2015 would not be possible, we filed MATS extension requests regarding the startup and shutdown instrumentation requirements for each of our Coal and IPH segment 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 Coal and IPH segments elected to demonstrate compliance with the Illinois Multi-Pollutant Standards ("MPS") at their respective coal-fired EGUs in Illinois. The MPS requires compliance with NO_x, SO_2 and mercury emissions limits.

As applicable to our Coal segment facilities, the MPS NO_x limits (ozone season and annual) started in 2012, the MPS SO_2 limits started in 2013 and decline in 2015, and the MPS mercury requirements started in 2009 with the final mercury limit beginning in 2015. Our Coal segment facilities are in compliance with the MPS and already meet the final mercury limit.

IPH Variance. For the IPH facilities, the MPS imposes declining limits that started in 2009 for mercury and in 2010 for NO_x and SO_2. Compliance with the MPS' final SO_2 limit is required beginning in 2017. 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 (i.e. scrubber) systems at the Newton facility such that the IPH coal-fired fleet in Illinois 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 scrubber systems. The first milestone relates to the completion of engineering design by 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 the IPH system's SO_2 emissions by 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 January 2014, an environmental group filed a petition for review of the IPCB's decision and order granting the variance relief in the Illinois Fourth District Appellate Court. In response, we filed a Motion to Dismiss, and on February 24, 2014, the Appellate Court granted our motion and dismissed the appeal. The environmental group then petitioned for leave to appeal the Appellate Court's decision with the Illinois Supreme Court, which we opposed. On September 24, 2014, the Illinois Supreme Court denied the petition for leave to appeal.

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, and is required to review periodically and, as necessary, update such standards. Each state is responsible for developing a plan that will attain and maintain the NAAQS. These plans may result in the imposition of emission limits on our facilities.

In November 2014, the EPA proposed to strengthen the ozone NAAQS, with final action expected to be taken by October 2015. The EPA would make attainment/nonattainment designations for any revised ozone NAAQS by October 2017. Our Coal segment's Wood River facility is located in a multi-state area that is currently designated as nonattainment (marginal) with the 2008 ozone NAAQS. Nine northeast and mid-Atlantic states also have petitioned the EPA to add nine upwind states, including Illinois, to the Ozone Transport Region in order to force those states to reduce emissions of NO_x and volatile organic compounds. The EPA is required to act on the petition by June 2015.

The EPA issued a proposed rule in 2014 that would require States to characterize air quality for purposes of the one-hour SO_2 NAAQS using either ambient air quality measured at monitors or modeling of source emissions. The EPA would use that data in two future rounds of area designations in 2017 and 2020. Areas designated nonattainment must achieve attainment no later than five years after initial designation. None of our Coal segment facilities are located in areas that were initially designated by the EPA as nonattainment with the one-hour SO_2 NAAQS. However, the area where our IPH segment's Edwards facility is located was designated nonattainment. In September 2013, Ameren Energy Resources Generating Company filed a judicial appeal challenging the EPA's one-hour SO_2 nonattainment designation of the Edwards area. The outcome of this litigation is uncertain. In January 2015, Illinois Power Resources Generating, LLC ("IPRG") entered a Memorandum of Agreement with the Illinois EPA that voluntarily committed to early limits on Edwards' allowable 1-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 response to adoption of the 2012 PM2.5 NAAQS, the Illinois EPA had proposed to identify the Metro-East St. Louis area, including the locations of our Wood River and Baldwin facilities, as nonattainment. In December 2014, the EPA designated

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the entire state of Illinois as unclassifiable for the 2012 PM2.5 NAAQS because insufficient quality assured monitoring data existed to assess compliance. The EPA will assess data for unclassifiable areas as they become available and promulgate initial area designations through separate rulemaking action. In general, the earliest attainment deadlines would be approximately no later than six years after designation.

The EPA is expected to take final action in May 2015 on a proposed rule that would eliminate existing exclusions in the state implementation plans ("SIPs") of many states, including Illinois, for emissions during periods of startup, shutdown or malfunction. If adopted, states would be required to modify their SIPs within 18 months.

New Source Review and Clean Air Litigation

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 ("NSPS") 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.

IPH Segment. Commencing in 2005, the IPH facilities received a series of information requests from the EPA pursuant to Section 114(a) of the CAA. The requests sought detailed operating and maintenance history data with respect to the Coffeen, Newton, Edwards, Duck Creek and Joppa facilities. In August 2012, the EPA issued a Notice of Violation 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. We believe IPH's defenses to the allegations described in the Notice of Violation 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 reversed or overturned, this decision may provide an additional defense to the allegations in the Newton facility Notice of Violation. Please read Note 15—Commitments and Contingencies for further discussion.

Wood River CAA Section 114 Information Request. In May 2014, we received an information request from the EPA concerning our Coal segment's 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.

Edwards. In April 2013, environmental groups filed a 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 May 2016. We dispute the allegations and will defend the case vigorously. Please read Note 15—Commitments and Contingencies for further discussion.

The Clean Water Act

Cooling Water Intake Structures. Our water withdrawals and wastewater discharges are permitted under the Clean Water Act ("CWA") and analogous state laws. Cooling water intake structures at our facilities are regulated under Section 316(b) of the CWA. 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. These standards are developed and implemented for power generating facilities through National Pollutant Discharge Elimination System ("NPDES") permits or State Pollutant Discharge Elimination System permits. Historically, standards for minimizing adverse environmental impacts of cooling water intakes have been made by permitting agencies on a case-by-case basis considering the best professional judgment of the permitting agency.

In May 2014, the EPA issued its final rule for cooling water intake structures at existing facilities. The final rule establishes seven alternatives for complying with the BTA requirement 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. The rule does not require closed-cycle cooling and provides that closed-cycle cooling includes impoundments in waters of the United States that were created for the purpose of serving as part of a cooling water system. The rule also includes provisions to address endangered and threatened species. Compliance with the final 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.

Our ultimate compliance approach with the final rule at any particular facility will depend on numerous factors, including implementation by the relevant state permitting authority, the results of technology, biological and other required studies, and the applicable compliance deadline. At this time, based on our initial review of the EPA’s final rule, we estimate the capital cost of our compliance will require an average of approximately $8 million annually over a five-year compliance period beginning in the 2020 timeframe. This estimate assumes that at the Baldwin and Duck Creek facilities only the river intake structures will be subject to the 316(b) rule, that the Havana facility's river intake structure will not be subject to the rule, and that cooling towers are not required at any of our facilities. This estimate also excludes Moss Landing, which is discussed in "California Water Intake Policy" below. Our estimate could change significantly depending upon a variety of factors, including site-specific determinations made by states in implementing the final rule and the results of site-specific engineering studies.

Future NPDES permit proceedings could have a material adverse effect on our financial condition, results of operations and cash flows; however, given the numerous variables and factors involved in calculating the potential costs associated with installing a closed cycle cooling system, any decision to install such a system at any of our facilities would be made on a case-by-case basis considering all relevant factors at such time. If capital expenditures related to cooling water systems are great enough to render the operation of any plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate that facility and forego the capital expenditures.

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 May 2010. The Policy requires that existing power plants: (i) reduce their water intake flow rate to a level commensurate with that which can be achieved by a closed cycle cooling system or (ii) if it is not feasible to reduce the water intake flow rate to this level, 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.

On October 9, 2014, we entered into a settlement agreement with the State Water Board that would resolve a lawsuit we filed in 2010 with other California power plant owners challenging the Policy. Under the settlement agreement, the State Water Board has agreed to propose an amendment to the Policy which would extend the compliance deadline for all four units at Moss Landing from December 31, 2017 to December 31, 2020. The State Water Board issued public notice of the proposed amendment on February 6, 2015 and, in accordance with the settlement agreement, is to take final action on the proposal in early April 2015. 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. The settlement agreement also clarifies the implementation and applicability of various Policy provisions to Moss Landing. 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, which would require the evaluation and installation of control technology, the cost of which would vary depending on the projected operational profile of the units.

Effluent Limitation Guidelines. In 2013, the EPA proposed revisions to the ELG for steam electric power generation units. The proposed rule would establish new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts, including flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and non-chemical metal cleaning. The proposed rule identifies four preferred options for regulation of discharges from existing sources, with the options differing in the number of waste streams covered, the size of the units controlled and the stringency of the controls to be imposed. As proposed, the new ELG requirements would be phased in between 2017 and 2022. The EPA is expected to take final action on the proposal in September 2015 and intends to align the ELG rule with its related Coal Combustion Residuals ("CCR") rule. Depending on the regulatory option the EPA adopts in its final ELG rule, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. Please read "EPA CCR Rule" below for further discussion.

Havana NPDES Permit. In September 2012, the Illinois EPA issued a renewal NPDES permit for our Coal segment's Havana facility. Environmental interest groups filed a petition for review with the IPCB challenging the permit. The petitioners alleged that the permit does not adequately address the discharge of wastewaters associated with newly installed air pollution control equipment (i.e., a spray dryer absorber and activated carbon injection system to reduce SO_2 and mercury air emissions) at Havana. In 2013, the IPCB dismissed petitioners' separate petition seeking to reopen and modify the NPDES permit to include mercury discharge limits. In June 2014, the IPCB granted and denied in part cross motions for summary judgment and remanded the permit to the Illinois EPA to require monthly monitoring for mercury. The environmental interest groups filed a petition for review of the IPCB's decision in the Illinois Fourth District Appellate Court in July 2014. That proceeding is ongoing. We will vigorously defend the permit and the IPCB's decision upholding the permit.

Baldwin NPDES Permit. In December 2014, the Illinois EPA issued a renewal NPDES permit for our Coal segment's Baldwin facility. The permit includes a condition that imposes new discharge limits on non-chemical metal cleaning wastewaters. We filed an appeal and motion for stay of this new permit condition with the IPCB. The IPCB granted our motion for stay.

Other CWA Initiatives. The requirements applicable to water quality are expected to increase in the future. A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters relate primarily to arsenic, mercury and selenium.

In addition, in March 2014, the EPA and the U.S. Army Corps of Engineers released a proposed rule that would define the term "waters of the United States," which is used to determine the jurisdictional reach of the CWA. A final rule is anticipated in 2015.

Coal Combustion Residuals

The combustion of coal to generate electric power creates large quantities of ash that are managed at power generation facilities in dry form in landfills and in liquid or slurry 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.

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

The Baldwin and Hennepin reports rate the CCR surface impoundments at each facility as "poor," meaning that a deficiency was recognized for a required loading condition in accordance with applicable dam safety criteria or that certain documentation was lacking or incomplete or further critical studies are needed to identify any potential dam safety deficiencies. The reports included recommendations for further studies, repairs and changes in operating practices.

In response to the Hennepin report, we notified the EPA in July 2013 of our intent to close the Hennepin west CCR surface impoundment and make certain capital improvements to the east CCR surface impoundment. The preliminary estimated cost for closure of the west CCR surface impoundment, including post-closure monitoring, is approximately $5 million. As a result of these changes, we increased our ARO by approximately $2 million during the second quarter 2013. We performed further studies needed to support closure of the west CCR surface impoundment and submitted them to the Illinois EPA in August 2014. The capital improvements to the Hennepin east CCR surface impoundment berms were completed in 2014 at a cost of approximately $3 million.

In response to the Baldwin report, we notified the EPA in April 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 ongoing evaluation at Baldwin of groundwater corrective actions. In December 2014, we began engineering design work to address repairs of the affected south berm at the Baldwin CCR surface impoundment system. We also performed a deformation analysis of the Baldwin CCR surface impoundment's north berm at the request of the EPA. The nature and scope of repairs that ultimately may be needed at the Baldwin CCR surface impoundment to address the EPA's dam safety assessment is dependent, in part, on the Illinois EPA's response to our groundwater corrective action evaluation recommendations. Please read "Vermilion and Baldwin Groundwater" below for further discussion. At this time, if the Illinois EPA approves our proposed approach to address groundwater at Baldwin and the EPA concurs, we estimate the cost to repair the affected berm at the Baldwin CCR surface impoundment would be approximately $3 million. If such approach is not approved by the Illinois EPA we are unable, at this time, to estimate a reasonably possible cost, or range of costs, of repairs at the Baldwin CCR surface impoundment. Please read Note 15—Commitments and Contingencies for further discussion.

EPA CCR Rule. In December 2014, the EPA issued its final rule addressing CCR. The final 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. The rule, which will become effective six months after publication in the Federal Register, 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. Inactive CCR surface impoundments that are closed within three years would not be subject to any additional requirements under the rule. The final 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, including the ability to obtain extensions in certain circumstances. The final rule does not regulate CCRs that are beneficially used, but establishes a definition of beneficial use to distinguish between beneficial use and disposal.

The EPA’s final CCR rule is self-implementing, establishing 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 EPA intends to align its forthcoming EGU ELG rule (expected in September 2015) with the CCR rule. We are currently evaluating the final CCR rule and the ELG proposal to determine whether current management of CCR, including beneficial reuse, and the use of the CCR surface impoundments should be altered. We are also evaluating the potential costs to comply with these regulations, which could be material. Our preliminary estimate is that the cost of our compliance with these rules would require an average of approximately $25 million annually over a five-year compliance period, in addition to the cost of compliance for closure of surface impoundments, which is addressed in our AROs. This estimate assumes that the final ELG rule is within the EPA's four stated preferred options. This estimate could change significantly depending upon a variety of factors, including detailed site-specific engineering analyses, interpretative issues concerning the CCR rule's requirements, decisions regarding options available under the CCR rule, the outcome of anticipated litigation concerning the rule, possible federal legislation concerning CCR regulation, state adoption of CCR rules, and the requirements of the EPA's final ELG rule.

Illinois. In October 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. We are participating in the rulemaking process. A final rule was expected to be adopted in late 2015. In January 2015, the Illinois EPA requested a 90-day stay of the rulemaking proceeding to consider the implications of the EPA final CCR rule.

Coal Segment. In response to requests by the Illinois EPA, we have implemented hydrogeologic investigations for the CCR surface impoundment system at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility.

Groundwater monitoring results indicate that the CCR surface impoundment system at Baldwin impacts onsite groundwater. Also, at the request of the Illinois EPA, in late 2011 we initiated an investigation at Baldwin to determine if the facility's CCR surface impoundment system impacts offsite groundwater. Results of the offsite groundwater quality investigation at Baldwin, as submitted to the Illinois EPA in April 2012, indicate two localized areas where Class I groundwater standards were exceeded. If offsite groundwater impacts are ultimately attributed to the Baldwin CCR surface impoundment system and remediation measures are necessary in the future, 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 corrective action that ultimately may be required at Baldwin. Please read Note 15—Commitments and Contingencies for further discussion.

In April 2012, we submitted to the Illinois EPA proposed corrective action plans for two of the CCR surface impoundments at the Vermilion facility (i.e., the old east surface impoundment and the north surface impoundment). The proposed corrective action plans reflect the results of a hydrogeologic investigation, which indicate that the facility's old east and north CCR 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 include groundwater monitoring and recommend closure of both CCR impoundments, including installation of a geosynthetic cover. In addition, we submitted an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. In March 2014, we submitted a revised corrective action plan for the old east CCR surface impoundment at Vermilion. 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. The Vermilion facility also has a third CCR surface impoundment, the new east CCR surface impoundment, which is lined and is not known to impact groundwater. Although not part of the proposed corrective action plans, if we decide to close the new east CCR surface impoundment by removing its CCR contents concurrent with the recommended closure alternative for the old east and north CCR surface impoundments, the associated estimated closure cost would add an additional $2 million to the above estimate.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, in 2013 we performed a geotechnical study at Vermilion and began a

12-month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. The geotechnical study at Vermilion confirmed that the cap closure option proposed in our corrective action plans for the north and old east CCR surface impoundments is technically feasible. In September 2014, the Illinois EPA requested additional analyses concerning the closure plans for the Vermilion old east and north CCR surface impoundments. Those analyses, if performed, would not be completed until late 2015. In June 2014, we submitted the results of our evaluation of the Baldwin CCR surface impoundment system to the Illinois EPA. Based on the results of that evaluation, we recommended to the Illinois EPA that the closure process for the Baldwin out-of-service east CCR surface impoundment begin and that a geotechnical investigation of the existing soil cap on the out-of-service Baldwin old east CCR surface impoundment be undertaken. In October 2014, we submitted a supplemental groundwater modeling report to the Illinois EPA that indicates no known offsite water supply wells will be impacted under the various Baldwin CCR surface impoundment closure scenarios modeled. At this time we cannot reasonably estimate the costs of resolving these groundwater issues, but resolution of these matters may cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows.

IPH Segment. Hydrogeologic investigations of the CCR surface impoundments have been performed at the IPH segment facilities. 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 with respect to groundwater conditions at the Newton and Coffeen facilities CCR surface impoundment systems. In February 2013, the Illinois EPA provided written notice that it may pursue legal action with respect to each of these matters through referral to the Illinois Office of the Attorney General. In addition, the Illinois EPA has issued a permit modification for the Newton facility's active CCR surface impoundment that requires us to perform assessment monitoring concerning previously reported groundwater quality standard exceedances and to submit the findings of that assessment, including proposed courses of action, in April 2015. The Illinois EPA also has required assessment monitoring at the Duck Creek facility's active CCR surface impoundment, with the findings of that assessment, including proposed remedial action, if any, due in September 2015.

In April 2013, Ameren Energy Resources Company filed a proposed site-specific rulemaking with the IPCB which, if approved, would provide for the systematic and eventual closure of its surface impoundments that impact groundwater in exceedance of applicable groundwater standards. The proposed site-specific rulemaking, which now covers IPH CCR surface impoundments, has been stayed to allow the Illinois EPA proposed rulemaking on power generating facility CCR surface impoundments to proceed. Please read Note 15—Commitments and Contingencies for further discussion.

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 2014, our Coal, IPH and Gas segment facilities emitted approximately 21 million, 27 million and 8 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.

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. To the extent that climate change results in changes in sea level, we would expect such effects to be gradual and amenable to structural mitigation during the useful life of the facilities. We could experience both risks and opportunities as a result of related physical impacts. For example, more extreme weather patterns such as a warmer summer or a cooler winter could increase demand for our products. However, we also could experience more difficult operating conditions in that type of environment. We maintain various types of insurance in amounts we consider appropriate for risks associated with weather events.

Federal Regulation of Greenhouse Gases. 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. In January 2010, the EPA rule requiring annual reporting of GHG emissions from all sectors of the economy went into effect. We have implemented processes and procedures to report our GHG emissions. In November 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 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 January 2011. Application of the PSD program to GHG emissions will require implementation of best available control technology ("BACT") for new and modified major sources of GHG. The EPA's GHG rulemakings have had mixed results on judicial review. In 2012, in Coalition For Responsible Regulation, Inc. v. EPA, the U.S. Court of Appeals for the District of Columbia Circuit upheld the EPA's 2009 finding that motor vehicle GHG emissions cause or contribute to air pollution that endangers the public health and welfare. The court held that the EPA's endangerment finding was not arbitrary and capricious notwithstanding scientific uncertainty and also dismissed challenges to the EPA's Tailoring Rule and Timing Rule, deciding that the petitioners lacked standing to challenge those rules. In 2013, the court dismissed challenges to the EPA rules concerning incorporation of GHG requirements into PSD permit programs of state implementation plans, again finding that petitioners lacked standing. However, in June 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. In doing so, the Court also invalidated the EPA's Tailoring Rule, which had modified the CAA's emissions permitting thresholds for PSD and Title V to account for GHGs, concluded that the EPA may impose BACT requirements on GHG emissions if a facility is otherwise subject to BACT for emissions of 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.

In June 2013, President Obama announced his Administration's plan to address climate change. In accordance with the plan, in September 2013, the EPA re-proposed GHG NSPS for new EGUs (that were originally proposed in 2012), with separate emission standards (i.e. pounds of CO_2 per MWh gross output) for natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and IGCC units. The proposed emission standards for fossil fuel-fired utility boilers and IGCC units are based on the performance of a new efficient coal unit implementing partial carbon capture and storage.

The Administration's climate change plan also directed the EPA to develop carbon emission standards for existing EGUs. In June 2014, the EPA issued a proposed rule (the "Clean Power Plan") to reduce CO_2 emissions from existing EGUs. The proposed Clean Power Plan would not directly establish emission rates for fossil-fuel EGUs, but instead would require states to meet state-specific CO_2 emissions rate targets (expressed as weighted-average pounds of CO_2 per net MWh), beginning with an interim rate in summer 2020 and a final rate to be achieved by 2030. Overall, the EPA expects the proposal would reduce CO_2 emissions from the power generation sector by 30 percent nationwide from 2005 levels.

Under the proposed Clean Power Plan, each state would be required to reduce CO_2 emissions rates from fossil-fuel EGUs to varying degrees. The emission rate targets are based on each state's unique mix of historical fossil-fuel EGU CO_2 emissions and projected emissions, reflecting individual state regulatory programs such as renewable energy mandates and energy efficiency standards. The EPA intends for states to take the lead in determining how to reduce CO_2 emissions. The proposed state-specific emissions targets are based on four approaches to CO_2 reduction, namely, heat rate improvements at existing solid-fuel EGUs, greater use of natural gas in place of the most carbon intensive affected EGUs, greater use of low- or zero-carbon generation units, and demand side energy efficiency measures that reduce the amount of generation. States would choose how to meet their specific emissions targets and could do so by either meeting the specified target emissions rate or establishing an equivalent mass-based cap-and-trade program. States also would have the flexibility to comply using their own programs or by joining a multi-state approach to compliance. States generally would be required to submit implementation plans detailing their CO_2 reduction plans by summer 2016.

Together with the proposed Clean Power Plan, the EPA also issued proposed CO_2 emission standards for modified and reconstructed power plants. For modified utility boilers and IGCC units, the EPA proposed two alternative standards. Under the first alternative, modified sources would be required to meet a limit determined by the unit's best historical annual CO_2 emission rate since 2002, plus an additional two percent reduction. However, the limit would be no lower than 1,900 lbs CO_2/MWh for sources with heat input greater than 2,000 MMBtu/hr or 2,100 lbs CO_2/MWh for sources with heat input less than or equal to 2,000 MMBtu/hr. Under the second alternative, the applicable emissions limit would depend on when the modification occurs. If the source is modified before it becomes subject to a Clean Power Plan, the first alternative identified above would apply. If the source is modified after it becomes subject to a Clean Power Plan, the source must meet a unit-specific limit determined by the implementing authority based on the results of an energy efficiency improvement audit. The proposed CO_2 emission standard for reconstructed utility boilers and IGCC units is 1,900 lbs CO_2/MWh for sources with heat input greater than 2,000 MMBtu/hr or 2,100 lbs CO_2/MWh for sources with a lower heat input. The proposed standard for modified or reconstructed natural gas fired stationary combustion turbines is identical to the proposed NSPS for such units (e.g., 1,000 lbs CO_2/MWh-gross).

The EPA anticipates issuing final rules for the Clean Power Plan and new and modified/reconstructed power plants in mid-summer 2015. The EPA also has announced plans to propose a federal plan in summer 2015, with a final federal plan to be adopted in summer 2016, for meeting the Clean Power Plan goals that would apply in the event that a state does not submit an implementation plan or a submitted plan is rejected by the EPA. Legal challenges to the proposed Clean Power Plan are currently pending in the U.S. Court of Appeals for the District of Columbia Circuit. The court is anticipated to rule on those challenges in 2015.

We continue to analyze the EPA's proposed rules to reduce EGU CO_2 emissions, the potential impacts on our power generation facilities, and how the proposals intersect with electricity market design. The nature and scope of CO_2 emission reduction requirements that ultimately may be imposed on our facilities as result of the EPA's EGU CO_2 reduction rulemakings 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 Greenhouse Gases. 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.

Illinois. Illinois has participated in regional partnership initiatives, such as the Midcontinent States Environmental and Energy Regulators group, to explore implementation options regarding the EPA's proposed Clean Power Plan. Illinois also is a signatory to the Midwest Greenhouse Gas Accord ("MGGA"), an agreement entered in 2007 by six states and one Canadian province to develop a market-based, multi-sector cap-and-trade program to achieve GHG reduction targets. Illinois had set a goal of reducing GHG emissions to 1990 levels by the year 2020, and to 60 percent below 1990 levels by 2050. The MGGA advisory group released a model rule in 2010, but implementation by the MGGA participants has not moved forward.

California. Our assets in California are subject to the California Global Warming Solutions Act ("AB 32"), which requires the California Air Resources Board ("CARB") to develop a GHG emission control program that will reduce emissions of GHG in the state to their 1990 levels by 2020. The CARB's final GHG cap-and-trade regulation took effect on January 1, 2012, but cap-and-trade compliance obligations did not begin until January 1, 2013 due to litigation. The emissions cap set by the CARB declines by approximately two percent per year through 2014 and by approximately three percent annually from 2015 to 2020. The first compliance period covered 2013-2014. The current compliance period covers 2015-2017. Beginning January 1, 2014, California and Québec linked their cap-and-trade programs.

The first joint CARB and Québec allowance auction was held in November 2014 with 2014 auction allowances selling at a clearing price of $12.10 per metric tonne and 2017 auction allowances selling at a clearing price of $11.86 per metric tonne. The CARB expects allowance prices to be in the $15 to $30 range by 2020.

Our generating facilities in California emitted approximately 2 million tons of GHGs during 2014. As a result of tolling agreements for certain of our California units under which GHG allowance costs are passed through to the tolling counterparty, we were required in 2014 to acquire allowances covering the GHG emissions of only Moss Landing Units 1 and 2 and Morro Bay. The cost of CARB allowances required to operate our affected facilities during 2014 was approximately $21 million.

We have participated in the CARB's quarterly allowance auctions and will procure additional allowances as needed in future auctions and secondary markets. The next quarterly auction is scheduled for February 2015. We estimate the cost of GHG allowances required to operate our units in California during 2015 will be approximately $17 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 under which GHG allowance costs are passed through to the tolling counterparty and the retirement of the Morro Bay facility, we expect only to acquire allowances covering the GHG emissions of Moss Landing Units 1 and 2.

California also participates in the Western Climate Initiative ("WCI"), which started in 2007 as a collaborative effort among seven states and four Canadian provinces to identify and implement emission trading policies to address climate change. California currently is the sole remaining state participant in the WCI.

In 2014, the CARB amended its GHG cap-and-trade program rule to address certain issues and provide additional clarity in implementation and adopted its first update to the AB 32 Scoping Plan, which includes a recommendation to develop a comprehensive GHG reduction program for the state's electric and energy utilities by 2016. The CARB's cap-and-trade allowance auction program also remains subject to ongoing litigation. While the Sacramento Superior Court previously had decided that the auctions do not constitute a tax but are more akin to a regulatory fee, that decision has been appealed. We continue to monitor developments regarding the California cap-and-trade program and evaluate any potential impacts on our operations.

RGGI. On January 1, 2009, our assets in New York and Maine became subject to a state-driven GHG emission control program known as RGGI. RGGI was developed and initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented rules regulating GHG emissions using a cap-and-trade program to reduce CO_2 emissions by at least 10 percent of 2009 emission levels by the year 2018. Compliance with RGGI can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. While allowances are sold by year, actual compliance is measured across a three-year control period. RGGI's second control period began January 1, 2012 and ended on December 31, 2014. Nine states participated in RGGI's second control period. The current control period covers 2015-2017.

RGGI released an updated model rule in 2013 that reduced the program's 2014 CO_2 emissions cap from 165 million tons to 91 million tons. The cap then declines by 2.5 percent each year from 2015 to 2020. Under the new cap, RGGI expects the allowance price to rise to approximately $10.00 per ton in 2020. RGGI set the allowance auction minimum reserve price at $2.00 per ton for 2014 and will increase it by 2.5 percent per year. The updated model rule also requires covered sources to hold allowances equal to at least 50 percent of their emissions in each of the first two years of the three-year control period. New York and Maine have adopted regulations to implement the requirements of the updated model rule. RGGI intends to review the program by 2016 to consider potential additional reductions to the cap after 2020.

In December 2014, RGGI held its twenty-sixth auction, in which approximately 18 million allocation year 2014 allowances were sold at a clearing price of $5.21 per allowance. RGGI's next quarterly auction is scheduled for March 2015. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

Our generating facilities in New York and Maine emitted approximately 3 million tons of CO_2 during 2014. The cost of allowances required to operate these facilities during 2014 was approximately $12 million. We estimate the cost of RGGI allowances required to operate our affected facilities during 2015 will be approximately $20 million. While the cost of allowances required to operate our New York and Maine 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.

Climate Change Litigation. There is a risk of litigation from those seeking injunctive relief from power generators or to impose liability on sources of GHG emissions, including power generators, for claims of adverse effects due to climate change.

In June 2011, the U.S. Supreme Court issued its decision in AEP v. Connecticut, which reviewed the U.S. Court of Appeals for the Second Circuit's decision that the U.S. District Court was an appropriate forum for resolving claims by eight states and New York City against six electric power generators related to climate change. The Supreme Court was equally divided by a vote of 4-4 on the question of whether the plaintiffs had standing to bring the suit and, therefore, affirmed the court's exercise of jurisdiction. On the merits the Court ruled by a vote of 8-0 that the CAA and EPA action authorized by the CAA displace any federal common law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants. The Court did not reach the issue of whether the CAA preempts similar claims under state nuisance law.

The U.S. Court of Appeals for the Ninth Circuit has addressed climate change issues in two recent cases. In September 2012, in Native Village of Kivalina v. ExxonMobil Corp. (following the filing of the DH Chapter 11 Cases, the Kivalina plaintiffs voluntarily dismissed DH with prejudice), the Ninth Circuit ruled that the CAA and EPA actions authorized by the Act have displaced federal common law public nuisance claims concerning domestic GHGs. The court, relying heavily on the Supreme Court's 2011 ruling in AEP v. Connecticut, decided that the displacement of federal common law public nuisance claims regarding GHGs applies equally to actions seeking damages or injunctive relief. The Ninth Circuit declined to address whether the plaintiffs had standing or whether plaintiffs' claims were political questions not subject to judicial review. The court subsequently denied the Kivalina plaintiffs' petition for rehearing. In May 2013, the Supreme Court denied the plaintiffs' petition for review.

In 2013, the Ninth Circuit addressed standing in the GHG context, ruling that it did not have jurisdiction to hear a challenge to the State of Washington's failure to regulate GHGs. In Washington Environmental Council v. Bellon, plaintiffs challenged the state's failure to set Reasonably Available Control Technology limits for GHG emissions from the state's five oil refineries. The Ninth Circuit vacated the district court's decision in favor of the plaintiffs, holding that the plaintiffs lacked standing. The court found that the causal link between the plaintiffs' alleged climate change injuries and the refineries' emissions was too attenuated and that the plaintiffs did not show that their injuries would be redressed by an order requiring the state to impose GHG limits on the refineries. The Ninth Circuit distinguished the Supreme Court's decision in Massachusetts v. EPA because the private organization plaintiffs, unlike state plaintiffs, were not entitled to relaxed standing requirements and because the GHG emissions levels at issue did not meaningfully contribute to global GHG emissions. In February 2014, the Ninth Circuit declined to rehear the case en banc.

In June 2014, the U.S. Court of Appeals for the District of Columbia Circuit affirmed a district court decision dismissing a climate change lawsuit based on the public trust doctrine. In Alec L. v. EPA, plaintiffs had asserted that various federal agencies were trustees of the atmosphere, a public trust resource, and had violated their fiduciary duties to protect the atmosphere by failing to reduce GHG emissions. The court found that the public trust doctrine did not arise under the U.S. Constitution or federal laws, as would be needed to establish federal question jurisdiction.

Carbon Initiatives. We participate in several programs that partially offset or mitigate our GHG emissions. In the lower Mississippi River Valley, we have partnered with the U.S. Fish & Wildlife Service to restore more than 45,000 acres of hardwood forests by planting more than eight million bottomland hardwood seedlings. In 2012, a portion of the Lower Mississippi River Valley reforestation project was registered under the Verified Carbon Standard, the first U.S. forest carbon offset project to receive this certification. In Illinois, we funded prairie, bottomland hardwood and savannah restoration projects in partnership with the Illinois Conservation Foundation. We also have programs to reuse CCR produced at our coal-fired generation units through agreements with cement manufacturers that incorporate the material into cement products, helping to reduce CO_2 emissions from the cement manufacturing process.

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. Those with potential liabilities include the current or previous owner and operator of a facility and companies that disposed, or arranged for disposal, of hazardous substances found at a contaminated facility. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery for costs of cleaning up hazardous substances that have been released and for damages to natural resources from responsible parties. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations with respect to a variety of our facilities and operations.

In August 2014, environmental groups filed a lawsuit seeking to force the EPA to issue regulations under CERCLA requiring several industry categories, including the electric power generation industry, to maintain evidence of financial responsibility for managing hazardous substances. The lawsuit follows the EPA’s 2009 advance notice of proposed rulemaking in which the agency identified plans to develop, as necessary, financial responsibility requirements for electric power generation facilities and three other industry categories.

As a result of their age, a number of our 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 management 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 providing reliable service to our customers. Our ability to compete effectively will also be impacted by various governmental and regulatory activities designed to reduce GHG emissions. 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.

SIGNIFICANT CUSTOMERS

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. For the 2012 Successor Period (as defined below), approximately 34 percent, 13 percent, 15 percent, 16 percent and 14 percent of our consolidated revenues were derived from transactions with MISO, NYISO, PJM, CAISO and Natural Gas Exchange Inc., respectively. For the 2012 Predecessor Period (as defined below), approximately 30 percent, 16 percent, 15 percent and 10 percent of our consolidated revenues were derived from transactions with MISO, NYISO, PJM and DB Energy Trading, LLC, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during the years ended December 31, 2014 and 2013, the 2012 Successor Period or the 2012 Predecessor Period.

EMPLOYEES

At December 31, 2014, we had approximately 276 employees at our corporate headquarters and approximately 1,403 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 495, 551 and 197 employees, respectively. In addition, there are approximately 160 field-based administrative employees who are part of our support and retail functions. Approximately 885 employees at our operating facilities are subject to collective bargaining agreements with various unions. We are currently a party to ten different collective bargaining agreements, one of which was renegotiated in 2014. Our collective bargaining agreements with IBEW Local 51 and Local 702 and IUOE Local 148, which in aggregate represent approximately 413 physical and clerical employees at our Duck Creek, Edwards, Coffeen, Newton and Joppa facilities, expire on June 30, 2015. We anticipate that we will successfully negotiate new agreements in the coming months.

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 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 to which we are, or could become, subject;
- 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 as we become subject to proposed capacity performance 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;
- expectations regarding the synergies, financing, completion, timing, terms and anticipated benefits of the Pending Acquisitions;

- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the South Bay and Vermilion facilities;
- the strategic evaluation of our California assets; and

- 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;
- 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;
- increased competition or price pressure driven by generation from renewable sources;
- 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 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.

Further, any changes in the costs of Powder River Basin 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.

The concentration of our existing business in Illinois and the MISO market increases the effects of any adverse conditions in Illinois and MISO and any disruption of production at our Gas segment could have a material adverse effect on our financial condition, results of operations and cash flows.

A substantial portion of our business is located in Illinois and MISO where more than 50 percent of our current plant capacity is located. Further, natural disasters in Illinois and changes in economic conditions in MISO, including changing demographics, congestion, or oversupply of or reduced demand for power, could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, a substantial portion of our Gas segment gross margin is derived from three of our facilities, Kendall, Ontelaunee and Independence. Any disruption of production at these facilities could have a material adverse effect on our financial condition, results of operations and cash flows.

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. Further, the majority of our facilities are old and require periodic upgrading and improvement. 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, 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 substances and waste, 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 or consider retiring 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; 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.

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 could increase 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 the construction of new plants, and 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, the retail marketing activities 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 the wholesale power from our generation facilities. If the transmission service is 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, 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 the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. 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 all 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 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. We believe 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. We also believe the ring-fenced structure should 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 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.

Risks Related to the Pending Acquisitions

We may be unable to obtain the regulatory approvals (timely or at all) required to complete one or both of the Pending Acquisitions or, in order to do so, we may be required to comply with material restrictions on our conduct or satisfy other material conditions required by various regulatory authorities.

Consummation of the Pending Acquisitions is subject to conditions and governmental approvals, including FERC approval. The closing of each of the Pending Acquisitions is also subject to the condition that there be no injunction or order issued by a court of competent jurisdiction that prevents the consummation of the transactions contemplated by the acquisition agreements. Each Pending Acquisition purchase agreement and related financing contains dates by which all the terms and conditions (including FERC approval) must be satisfied or the applicable transactions may be terminated. We can provide no assurance that all required regulatory approvals will be obtained in a timely manner or at all. There can also be no assurance as to the cost, scope or impact of the actions that may be required to obtain the required regulatory approvals. Furthermore, these actions could have the effect of delaying or preventing completion of the Pending Acquisitions or imposing additional costs, including costs and expenses to maintain our financing, conditions or restrictions on our business and operations, some of which could be material and adversely affect our revenues and profitability following the consummation of the Pending Acquisitions. Further, even if the Pending Acquisitions are consummated, they may not be consummated in the time frame, on the terms or in the manner currently anticipated. There can be no assurance that the conditions to closing of the Pending Acquisitions will be satisfied or waived or that other events will not intervene to delay or result in the failure to close the Pending Acquisitions.

Furthermore, the FERC or other governmental authorities could seek to block or challenge the Pending Acquisitions as they deem necessary or desirable in the public interest at any time, including after completion of the transactions. In addition, in some circumstances, a competitor, customer or other third party could initiate a private action under antitrust laws challenging or seeking to enjoin either or both of the Pending Acquisitions, before or after either or both of them are consummated. We may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

If one or both of the Pending Acquisitions are consummated, we may be unable to successfully integrate the operations with our existing operations or to realize targeted cost savings, revenues and other anticipated benefits of the Pending Acquisitions.

The success of the Pending Acquisitions will depend, in part, on our ability to realize the anticipated benefits and synergies from integrating the Duke Midwest assets and/or the EquiPower assets with our existing business. We may be required to make unanticipated capital expenditures or investments in order to maintain, integrate, improve or sustain our operations, or take unexpected write-offs or impairment charges resulting from the Pending Acquisitions. Further, we may be subject to unanticipated or unknown liabilities relating to the Pending Acquisitions. If any of these factors occur or limit our ability to integrate the businesses successfully or on a timely basis, the expectations of our future financial condition and results of operations on a combined basis following the Pending Acquisitions might not be met.

It is possible that the integration process could result in the loss of key employees, the disruption of each company's ongoing businesses, inefficiencies, or inconsistencies in standards, controls, systems, procedures and policies, any of which could adversely affect our ability to achieve the anticipated benefits of the Pending Acquisitions and could adversely impact our financial performance.

We continue to evaluate and refine our estimates of synergies to be realized from the Pending Acquisitions. Actual cost-savings, including the costs required to realize the cost-savings and the source of the cost-savings, could differ materially from our estimates.

Finally, we may not be able to achieve the targeted operating or long-term strategic benefits of the Pending Acquisitions. If the combined businesses are not able to achieve our objectives, or are not able to achieve our objectives on a timely basis, the anticipated benefits of the Pending Acquisitions may not be realized fully or at all and could have an adverse effect on our future financial condition, results of operations and cash flows.

We will incur significant costs in connection with the Pending Acquisitions.

We expect to incur significant costs associated with the Pending Acquisitions, including costs related to obtaining required governmental approvals, maintaining our financing and combining the operations of our company with the Duke Midwest assets and the EquiPower assets, including costs to achieve targeted cost-savings. The substantial majority of the expenses resulting from the Pending Acquisitions will be composed of transaction costs, systems consolidation costs, and business integration and employment-related costs, including costs for severance, retention and other restructuring. Additionally, we are currently incurring significant interest costs related to the financing for the Pending Acquisitions but are not yet realizing the increased revenues and cash flows that we expect upon closing of the Pending Acquisitions. Additional unanticipated costs may be incurred in the integration of our and the acquired companies' businesses. Even if we consummate the Pending Acquisitions, the anticipated elimination of duplicative costs, as well as the realization of other efficiencies, may not be achieved in the near-term, or at all, in an amount equal to or greater than the related costs.

Disruptions in our, Duke Midwest assets' and EquiPower assets' operations could occur prior to the closing of the Pending Acquisitions.

Disruptions in our, Duke Midwest assets' and EquiPower assets' operations could occur prior to the closing of the Pending Acquisitions. Specifically:

- our, Duke Midwest assets' and EquiPower assets' current and prospective customers and suppliers may experience uncertainty associated with the Pending Acquisitions, including with respect to current or future business relationships with us, Duke Midwest assets, EquiPower assets or the combined company business and may attempt to negotiate changes in existing business;
- the Pending Acquisitions may give rise to potential liabilities; and
- if the EquiPower Acquisition is consummated, the accelerated vesting of equity-based awards and payment of "change in control" benefits to some members of EquiPower assets' management upon consummation of the EquiPower Acquisition could result in increased difficulty or cost in retaining EquiPower assets' officers and employees.

Any of the above disruptions could have an adverse effect on our business, results of operations and financial condition.

In the event that either of the Pending Acquisitions are not consummated or certain escrow account criteria are not satisfied within certain timeframes, we may have to seek alternative financing.

In the event that either Pending Acquisition is not consummated substantially in accordance with the terms and conditions of the relevant purchase agreement, or any of the other conditions to release the escrow account are not satisfied by May 11, 2015 (with respect to the EquiPower Acquisition) or August 24, 2015 (with respect to the Duke Midwest Acquisition), or the applicable purchase agreement, is terminated, or if on the date that is five business days prior to the last business day of any calendar month the funds in an escrow account (as calculated by the applicable Escrow Issuer (as defined herein)) would not be sufficient to fund a special mandatory redemption at the end of the following month, the applicable Escrow Issuer will be obligated to use the funds in the particular escrow account to redeem all of the associated Notes at a redemption price equal to 100 percent of the issue price of such Notes, plus accrued and unpaid interest. Please read Note 11—Debt for further discussion.

Further, in the event that we fail to close either of the Pending Acquisitions by the applicable deadline, resulting in a special mandatory redemption of the Notes, we may be unable to obtain alternative financing to fund the relevant Pending Acquisition or obtain such financing on terms that are acceptable to us. Specifically, if the applicable Escrow Issuer is required to redeem all of the associated Notes with the funds in the relevant escrow accounts it will not impact the escrow account of the other Escrow Issuer; however, we will be required to find alternative financing to fund the applicable Pending Acquisition. In addition, in the event that the financing contemplated by the Revolvers is not available, other alternative financing may not be available on acceptable terms, in a timely manner or at all. If alternative financing becomes necessary and we are unable to secure such additional financing, the relevant Pending Acquisition may not be completed.

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, 2014, we had approximately $7.2 billion of total indebtedness and approximately $249 million of indebtedness net of cash and restricted cash of $1.9 billion and $5.1 billion, respectively. We have secured commitments for two Revolvers totaling $950 million, each of which is expected to close upon consummation of the respective Pending Acquisition, and we completed the issuance of $5.1 billion in Notes which were placed into escrow pending the consummation of the Pending Acquisitions. 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, including the Notes held in escrow, 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.

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 11—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.

Item 3. Legal Proceedings

Please read Note 15—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. Upon our emergence from bankruptcy on October 1, 2012 (the “Plan Effective Date”), all shares of our old common stock were canceled and 100 million shares of new common stock were distributed to the holders of certain classes of claims. The former holders of our old common stock, as the beneficiaries of Legacy Dynegy’s administrative claim against DH under the Joint Chapter 11 Plan of Reorganization, which became effective on October 1, 2012 (the “Plan”), also received distributions of our new common stock and five-year warrants to purchase shares of our new common stock (the “Warrants”). The Warrants entitle the holders to purchase up to 15.6 million shares of our new common stock. Each Warrant entitles the holder to a maximum of one share of our new common stock. The exercise price of each Warrant was set at $40 per warrant. Further, on the Plan Effective Date, a total of approximately 6.1 million shares of our new common stock were available for issuance under our 2012 Long Term Incentive Plan. Please read Note 20—Emergence from Bankruptcy and Fresh-Start Accounting for additional information regarding the bankruptcy. 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. Please read Note 16—Capital Stock for additional information.

Our common stock is listed on the NYSE under the symbol “DYN” and has been trading since October 3, 2012. No established public trading market existed for our new common stock prior to this date. The number of stockholders of record of our common stock as of February 10, 2015, based on information provided by our transfer agent, was 2,632. 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
2015:		
First Quarter (through February 10, 2015)	$31.39	$27.32
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
2013:		
Fourth Quarter	$21.93	$18.50
Third Quarter	$22.79	$19.09
Second Quarter	$24.76	$22.00
First Quarter	$23.99	$19.39
2012:		
Fourth Quarter	$19.35	$17.35

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. As part of the Plan, we entered into a registration rights agreement (the “Registration Rights Agreement”) with Franklin Advisers, Inc., which owns approximately 13 percent of our outstanding common stock as of February 10, 2015. Pursuant to the Registration Rights Agreement, among other things, we were required to use reasonable best efforts to file within 90 days after the Plan Effective Date a registration statement on any permitted form that qualifies (the “Shelf”), and is available, for the resale of “Registrable Securities,” as defined below, with the SEC. Such Shelf was filed in December 2012 and was effective in 2013. Upon Dynegy becoming a well-known seasoned issuer, which occurred on October 1, 2013, we were required to promptly register the sale of all of the Registrable Securities under an automatic shelf registration statement, and to cause such registration statement to remain effective thereafter until there are no longer Registrable Securities. We converted our Form S-1 registration statement into the automatic shelf registration statement on October 2, 2013.

Registrable Securities are shares of our common stock, par value $0.01 per share issued or issuable on or after the Plan Effective Date to any of the original parties to the Registration Rights Agreement, including, without limitation, upon the conversion of our outstanding Warrants, and any securities paid, issued or distributed in respect of any such new common stock, but excluding shares of common stock acquired in the open market after the Plan Effective Date. At any time prior to the five-year anniversary of the Plan Effective Date and from time to time after the later of (i) when the Shelf has been declared effective by the SEC and (ii) 210 days after the Plan Effective Date, any one or more holders of Registrable Securities may request to sell all or any portion of their Registrable Securities in an underwritten offering, provided that such holder or holders will be entitled to make such demand only if the total offering price of the Registrable Securities to be sold in such offering is reasonably expected to exceed 5 percent of the market value of our then issued and outstanding common stock or the total offering price is reasonably expected to exceed $250 million. We are not obligated to effect more than two such underwritten offerings during any period of 12 consecutive months after the Plan Effective Date and are not obligated to effect such an underwritten offering within 120 days after the pricing of a previous underwritten offering. 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 provided for in the Registration Rights Agreement.

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, 2014, 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 consists 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, 2014.

	October 3, 2012	December 31, 2012	December 31, 2013	December 31, 2014
Dynegy Inc.	$100.00	$99.12	$111.50	$157.25
S&P Midcap 400	$100.00	$104.44	$139.42	$153.04
Peer Group	$100.00	$102.88	$118.36	$122.99

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.

Unregistered Sales of Equity Securities and Use of Proceeds. We did not have any purchases of equity securities during the quarter ended December 31, 2014. We do not have a stock repurchase program.

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, 2014 and 2013 and for the years ended December 31, 2014 and 2013, the period from October 2 through December 31, 2012 and the period from January 1 through October 1, 2012 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 described in Note 3—Merger and Acquisitions, Legacy Dynegy merged with DH on September 30, 2012 (the "Merger"). The accounting treatment of the Merger is reflected as a "reverse recapitalization," whereby DH is the surviving accounting entity for financial reporting purposes. Therefore, our historical results for periods prior to the Merger are the same as DH's historical results.

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. Additionally, on the Plan Effective Date, DNE, Hudson, Danskammer and Roseton (the "DNE Debtor Entities") did not emerge from bankruptcy; therefore, we deconsolidated our investment in these entities as of October 1, 2012. Accordingly, the results of operations of the DNE Debtor Entities are presented in discontinued operations for all periods presented.

(in millions, except per share data)	Successor Year Ended December 31, 2014	Year Ended December 31, 2013 (1)	October 2 Through December 31, 2012	Predecessor January 1 Through October 1, 2012 (2)(3)	Year Ended December 31, 2011 (4)	2010
Statements of Operations Data:						
Revenues	$2,497	$1,466	$312	$981	$1,333	$2,059
Depreciation expense	$(247)	$(216)	$(45)	$(110)	$(295)	$(397)
Impairment and other charges	$—	$—	$—	$—	$(5)	$(146)
General and administrative expense	$(114)	$(97)	$(22)	$(56)	$(102)	$(158)
Operating income (loss)	$(19)	$(318)	$(104)	$5	$(189)	$(32)
Bankruptcy reorganization items, net	$3	$(1)	$(3)	$1,037	$(52)	$—
Interest expense and debt extinguishment costs (5)	$(223)	$(108)	$(16)	$(120)	$(369)	$(363)
Income tax benefit	$1	$58	$—	$9	$144	$194
Income (loss) from continuing operations	$(267)	$(359)	$(113)	$130	$(431)	$(259)
Income (loss) from discontinued operations, net of taxes (6)	$—	$3	$6	$(162)	$(509)	$17
Net loss	$(267)	$(356)	$(107)	$(32)	$(940)	$(242)
Net loss attributable to Dynegy Inc.	$(273)	$(356)	$(107)	$(32)	$(940)	$(242)
Basic loss per share from continuing operations attributable to Dynegy Inc. common stockholders (7)	$(2.65)	$(3.59)	$(1.13)	N/A	N/A	N/A
Basic income per share from discontinued operations attributable to Dynegy Inc. common stockholders (7)	$—	$0.03	$0.06	N/A	N/A	N/A
Basic loss per share attributable to Dynegy Inc. common stockholders (7)	$(2.65)	$(3.56)	$(1.07)	N/A	N/A	N/A
Cash Flow Data:						
Net cash provided by (used in) operating activities	$163	$175	$(44)	$(37)	$(1)	$423
Net cash provided by (used in) investing activities	$(5,262)	$474	$265	$278	$(229)	$(520)
Net cash provided by (used in) financing activities	$6,126	$(154)	$(328)	$(184)	$375	$(69)
Capital expenditures, acquisitions and investments	$(132)	$136	$(46)	$193	$(21)	$(517)

(amounts in millions)	Successor December 31, 2014	2013	2012	Predecessor December 31, 2011	2010
Balance Sheet Data:					
Current assets	$2,674	$1,685	$1,043	$3,569	$2,180
Current liabilities	$681	$721	$347	$3,051	$1,562
Property, plant and equipment, net	$3,255	$3,315	$3,022	$2,821	$6,273
Total assets	$11,232	$5,291	$4,535	$8,311	$9,949
Notes payable and current portion of long-term debt	$31	$13	$29	$7	$148
Long-term debt (excluding current portion) (8)(9)	$7,075	$1,979	$1,386	$1,069	$4,626
Total equity	$3,023	$2,207	$2,503	$32	$2,719

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

(2) We completed the acquisition of CoalHoldco from Legacy Dynegy (the "DMG Acquisition") effective June 5, 2012; therefore, the results of our Coal segment are only included subsequent to June 5, 2012. Please read Note 3—Merger and Acquisitions—DMG Transfer and DMG Acquisition for further discussion.

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

(4) We completed the DMG Transfer effective September 1, 2011; therefore, the results of our Coal segment are only included prior to September 1, 2011. Please read Note 22—Dispositions and Discontinued Operations for further discussion.

(5) The year ended December 31, 2014 includes $66 million of interest related to our Notes issued on October 27, 2014. The years ended December 31, 2013 and 2011 include $11 million and $21 million of debt extinguishment costs, respectively.

(6) Discontinued operations include the results of operations from the DNE Debtor Entities. Please read Note 22—Dispositions and Discontinued Operations for further discussion of the sale of the DNE facilities.

(7) 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.

(8) The year ended December 31, 2014 includes $5.1 billion related to our Notes issued on October 27, 2014. Associated cash is being held in escrow subject to the completion of the Pending Acquisitions.

(9) As a result of the DH Chapter 11 Cases, we reclassified approximately $3.6 billion in long-term debt to liabilities subject to compromise as of December 31, 2011. These liabilities were settled upon our emergence from bankruptcy on the Plan Effective Date. Please read Note 20—Emergence from Bankruptcy and Fresh-Start Accounting for further discussion.

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. In connection with our emergence from bankruptcy on the Plan Effective Date, we deconsolidated the DNE Debtor Entities, which constituted our previously reported Dynegy Northeast Generation, Inc. ("DNE") segment, and began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified the results of the previously reported DNE segment as discontinued operations in the consolidated financial statements for all periods presented.
Acquisitions
In August 2014, we entered into the Duke Midwest Acquisition for a purchase price of $2.8 billion in cash, subject to certain adjustments, and the EquiPower Acquisition for a purchase price of approximately $3.25 billion in cash and $200 million of our common stock, subject to certain adjustments. These acquisitions will expand our fleet to 35 power plants in eight states and increase our generation capacity by approximately 12,500 MW to nearly 26,000 MW. Consummation of the Pending Acquisitions is subject to conditions and governmental approvals, including FERC approval. On February 6, 2015, we responded to a letter from FERC requesting additional information to process the applications filed with FERC on September 11, 2014. Please read Note 3—Merger and Acquisitions for further discussion.
Business Discussion
We generate earnings and cash flows in the three segments within 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;
- our ability to maintain sufficient coal inventories, which is 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;

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- 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 as we become subject to proposed capacity performance in PJM and new performance incentives in ISO-NE;
- our ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- our ability to maintain the necessary permits to continue to operate our Moss Landing facility with once-through, seawater cooling systems;
- the costs incurred to demolish and/or remediate the South Bay and Vermilion facilities;
- 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 Net Operating Losses and Alternative Minimum Tax ("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, fixed capacity payments and 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 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.

Acquisition Financing

On August 21, 2014, to ensure the financing of the Pending Acquisitions, we obtained commitments for the Revolvers and the Bridge Loan Facilities. The Bridge Loan Facilities were terminated on October 27, 2014 as we completed our permanent financings for the Pending Acquisitions as discussed below. The Revolvers expand the credit available to us by an aggregate of $950 million ($600 million for the Duke Midwest Acquisition and $350 million for the EquiPower Acquisition) which will be used to support the collateral and liquidity requirements of the acquired businesses. Each Revolver is conditional on the closing of the applicable acquisition. We expect to have at least $800 million available, net of expected letters of credit outstanding, for future borrowings under our current and incremental revolving credit facilities immediately following the completion of the Pending Acquisitions.

On October 14, 2014, pursuant to registered public offerings, we issued 22.5 million shares of our common stock at $31.00 per share for gross proceeds of approximately $698 million, before underwriting discounts and commissions, and 4 million shares of our mandatory convertible preferred stock at $100 per share, for gross proceeds of approximately $400 million, before underwriting discounts and commissions. Please read Note 16—Capital Stock for further discussion.

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On October 27, 2014, we completed the issuance of $5.1 billion in aggregate principal amount of unsecured senior notes at a weighted average interest rate of 7.18 percent in tranches with maturities ranging from 2019 to 2024. The gross proceeds from the issuance of the Notes, less initial purchasers' discounts and expenses, were placed into escrow pending the consummation of the Pending Acquisitions. In order to prevent a special mandatory redemption, at the end of each month we are required to pre-fund 30 days of interest in escrow, in addition to all accrued interest to date. Under our escrow agreement related to the Notes, the applicable borrowings for each of the Pending Acquisitions are subject to mandatory redemption, at par, if the acquisitions are not consummated by May 11, 2015, in the case of the EquiPower Acquisition, and August 24, 2015, in the case of the Duke Midwest Acquisition. Please read Note 11—Debt for further discussion.

On November 13, 2014, pursuant to the partial exercise by the underwriters of their option to purchase additional shares of common stock in connection with the previously announced public offering on October 14, 2014, we issued 1.5 million shares of our common stock at $31.00 per share for gross proceeds of approximately $46 million, before underwriting discounts and commissions. Please read Note 16—Capital Stock for further discussion.

Letter of Credit Facilities

On January 29, 2014, IPM entered into a fully cash collateralized Letter of Credit and Reimbursement Agreement with Union Bank, N.A., as amended on May 16, 2014 ("LC Agreement"), pursuant to which Union 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 Union 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, 2014, IPM had $10.5 million deposited with Union Bank and $10 million in letters of credit outstanding. Please read Note 11—Debt—Letter of Credit Facilities for further discussion.

On September 18, 2014, Dynegy entered into a Letter of Credit Reimbursement Agreement with Macquarie Bank Limited ("Macquarie Bank") and Macquarie Energy LLC, (the "Lender"), pursuant to which the Lender agreed to cause Macquarie Bank to issue a single-use standby letter of credit in an amount not to exceed $55 million. The facility has a one-year tenor and may be extended at the Lender's option up to one additional year. At December 31, 2014, there was $55 million outstanding under this letter of credit. Please read Note 11—Debt—Letter of Credit Facilities for further discussion.

Liquidity. The following table summarizes our liquidity position at December 31, 2014.

	December 31, 2014		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolving Facility and LC capacity (3)	$530	$—	$530
Less: Outstanding letters of credit	(178)	—	(178)
Revolving Facility and LC availability	352	—	352
Cash and cash equivalents	1,696	174	1,870
Total available liquidity (4)	$2,048	$174	$2,222

(1) Includes Cash and cash equivalents of $126 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) Includes $475 million of available capacity related to the five-year senior secured revolving credit facility (the "Revolving Facility") and $55 million related to a letter of credit with Macquarie Bank. Please read Note 11—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, 2014, there was $17 million outstanding on the note.

Operating Activities

Historical Operating Cash Flows. 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 related to our Credit Agreement and Senior Notes of $69 million, interest payments on the Notes issued in 2014 of $65 million funded into the escrow account related to those Notes, interest payments on the Genco Senior Notes of $59 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 expense. In addition, we had $56 million in positive working capital and other changes, which includes $34 million for the return of collateral.

Cash used in operations totaled $44 million for the 2012 Successor Period. During the period, our power generation business used cash of $55 million primarily due to losses incurred during the period. Corporate and other activities used cash of approximately $23 million primarily due to payments to advisors, employee-related payments and other general and administrative expense. In addition, we had $34 million in positive working capital and other changes, which includes $30 million for the return of collateral.

Cash used in operations totaled $37 million for the 2012 Predecessor Period. During the period, our power generation business used cash of $56 million primarily due to increased collateral postings to satisfy our counterparty collateral demands and other negative working capital changes. Corporate and other activities provided cash of approximately $19 million primarily due to interest payments received from Legacy Dynegy on the Undertaking, partially offset by payments to advisors and other general and administrative expense.

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 contemplated in our PRIDE initiative. Additionally, our future operating cash flows will also be impacted by our Pending Acquisitions and the interest on the acquisition financings.

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, 2014 and 2013:

(amounts in millions)	December 31, 2014	December 31, 2013
Dynegy Inc.:		
Cash (1)	$14	$22
Letters of credit	178	157
Total Dynegy Inc.	192	179
IPH:		
Cash (1) (2)	32	7
Letters of credit (3)	10	—
Total IPH	42	7
Total	$234	$186

(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, 2014 and 2013, $9 million and $4 million of cash posted as collateral were netted against Liabilities from risk management activities on our consolidated balance sheets, respectively.
(2) Includes cash of $5 million and $1 million related to Genco as of December 31, 2014 and 2013, respectively.
(3) Relates to the $25 million cash-backed LC facility at IPM.

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.

Collateral postings increased from December 31, 2013 to December 31, 2014 primarily due to new wholesale and retail transactions, rate increases on our natural gas transportation contracts, mark-to-market changes on commodity derivatives and other changes in our commercial activity.

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The fair value of our derivatives collateralized by first priority liens included liabilities of $141 million and $145 million at December 31, 2014 and 2013, 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:

(amounts in millions)	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012
Coal (1)	$39	$42	$26	$33
IPH	45	1	—	—
Gas	44	53	19	23
Other	4	2	1	7
Total (2)	$132	$98	$46	$63

(1) Since we completed the DMG Acquisition on June 5, 2012, capital expenditures are included only from June 6, 2012 to October 1, 2012 for the 2012 Predecessor Period. Including the period that Coal was not included in our consolidated financial statements, Coal capital expenditures were $75 million for the 2012 Predecessor Period.
(2) Includes capitalized interest of $9 million, $2 million, zero and $5 million for the years ended December 31, 2014 and 2013, the 2012 Successor Period and the 2012 Predecessor Period, 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.
We expect capital expenditures for 2015 to be approximately $211 million, which is comprised of $82 million, $71 million, $49 million and $9 million in Coal, IPH, Gas and Other, respectively. The capital budget is subject to revision as opportunities arise or circumstances change and does not reflect expected expenditures related to the assets included in our Pending Acquisitions.
Other Investing Activities. 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 11—Debt and Note 22—Dispositions and Discontinued Operations 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—Merger and Acquisitions for further discussion.
During the 2012 Successor Period, there was a $311 million cash inflow related to restricted cash balances due to a reduction in the Collateral Posting account. These proceeds were used to fund a portion of the repayment of the DMG and DPC Credit Agreement as further discussed below.
In connection with the DMG Acquisition on June 5, 2012, we acquired $256 million in cash and received $16 million in principal payments related to the Undertaking during the 2012 Predecessor Period. There was an $88 million cash inflow related to restricted cash balances associated with the DPC LC facilities and DPC Credit Agreement during the 2012 Predecessor Period. In addition, during the 2012 Predecessor Period, we requested the release of unused cash

collateral related to the DPC LC facilities. These inflows were offset by a reduction of $22 million in cash as a result of the deconsolidation of the DNE Debtor Entities.

Future Cash Flow from Investing Activities. Upon the closing of our Pending Acquisitions, our investing cash flows will be reduced by the funds used for the acquisitions.

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Financing Activities

Historical Cash Flow from Financing Activities. 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) $719 million and $387 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 the Macquarie Bank letter of credit, (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 11—Debt and Note 16—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 repurchase agreements related to emissions credits. Please read Note 11—Debt for further discussion.

Cash used in financing activities totaled $328 million during the 2012 Successor Period due to repayments of borrowings on the DMG and the DPC credit agreements.

Cash used in financing activities totaled $184 million for the 2012 Predecessor Period due to $200 million paid to unsecured creditors upon our emergence from bankruptcy on the Plan Effective Date and $11 million in repayments of borrowings on the DMG and the DPC credit agreements, offset by an increase of $27 million in connection with the recapitalization of Legacy Dynegy.

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, 2014 and 2013:

(amounts in millions)	December 31, 2014	December 31, 2013
Dynegy Inc.:		
Secured obligations	$788	$796
Unsecured obligations	500	500
Emissions Repurchase Agreements	23	17
Unamortized discount	(3)	(4)
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	(127)	(142)
Total long-term debt	$7,106	$1,992

(1) As of December 31, 2014, the Finance I Notes and the Finance II Notes are secured by first-priority liens on amounts in the applicable escrow account which is classified as long-term Restricted cash in our consolidated balance sheet. Upon consummation of the Pending Acquisitions, these debt obligations will be Dynegy Inc.'s general unsecured obligations. Please read Note 11—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 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.

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

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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. Under our escrow agreement related to the Notes, in order to prevent a special mandatory redemption, at the end of each month we are required to pre-fund 30 days of interest in escrow, in addition to all accrued interest to date. In addition, the applicable borrowings for each Pending Acquisition are subject to mandatory redemption, at par, if the acquisitions are not consummated by May 11, 2015, in the case of the EquiPower Acquisition, and August 24, 2015, in the case of the Duke Midwest Acquisition. Please read Note 11—Debt for further discussion.

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, 2014 was 26 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, 2014.

Genco Senior Notes. On December 2, 2013, in connection with the AER Acquisition, 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%

(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, 2014 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 11—Debt for further discussion.

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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.

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.

Credit Ratings

Our credit rating status is currently “non-investment grade” and 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, 2014. 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)	$7,236	$31	$16	$2,416	$4,773
Interest payments on debt	3,753	520	1,041	967	1,225
Coal commitments	1,127	346	401	249	131
Coal transportation	530	116	112	100	202
Operating leases	36	14	7	7	8
Gas transportation	118	39	31	32	16
Interconnection obligation	13	1	2	2	8
Contractual service agreements (1)	212	31	80	70	31
Pension funding obligations	167	3	2	34	128
Other obligations	52	28	3	6	15
Total contractual obligations	$13,244	$1,129	$1,695	$3,883	$6,537

(1) The table above includes projected payments through 2026 assuming the contracts remain in full force and effect; however, we currently estimate these agreements will be in effect for a period of 15 or more years. Our minimum obligation related to these agreements is limited to the termination payments.

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 Emissions Repurchase Agreements. Amounts do not include unamortized discounts. Under our escrow agreement related to the issuance of the Notes, the applicable borrowings for each of the Pending Acquisitions are subject to mandatory redemption, at par, if the acquisitions are not consummated by May 11, 2015, in the case of the EquiPower Acquisition, and August 24, 2015, in the case of the

Duke Midwest Acquisition. Please read Note 11—Debt for further discussion.

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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 Emissions Repurchase Agreements. Amounts include the impact of interest rate swap agreements. Please read Note 11—Debt for further discussion.

Coal Commitments. At December 31, 2014, 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, 2014, 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.

Operating Leases. Operating leases include minimum lease payment obligations associated with office space and office equipment leases. Also included in operating leases are two charter agreements previously utilized in our former global liquids business. The aggregate minimum base commitment of the charter agreements is approximately $11 million for the year ended December 31, 2015.

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

Interconnection Obligation. Interconnection obligation represents an obligation with respect to interconnection services for the Ontelaunee facility. This agreement expires in 2027. The obligation under this agreement is approximately $1 million per year through the term of the contract.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. 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 2026 based on anticipated timing of outages and are subject to change as outage dates move. As of December 31, 2014, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $161 million and $217 million in the event all contracts are terminated by us or the counterparty, respectively. Please read Note 15—Commitments and Contingencies—Other Commitments and Contingencies for further discussion.

Pension Funding Obligations. Amounts include our minimum required contributions to our defined benefit pension plans through 2024 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 2015 which would decrease future funding obligations. Please read Note 17—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans for further discussion.

Other Obligations. Other obligations primarily include the following items:

- Obligations of $22 million related to a capital parts agreement for uprate equipment at our Kendall facility;
- Obligations of $15 million related to demolition and restoration of our retired power generation facilities;
- Obligations of $5 million related to information technology-related contracts;
- Obligations of $4 million for harbor support and utility work in connection with Moss Landing;
- Obligations of $4 million under a facilities service agreement to maintain transmission system stability in connection with our Coffeen facility;
- Obligations of $1 million primarily for a water supply agreement and other contracts for our Ontelaunee facility; and
- Obligations of $1 million for a capital lease agreement for coal scraper at our Havana facility.

Commitments and Contingencies

Please read Note 15—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, 2014.

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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, 2014 and 2013, the 2012 Successor Period and the 2012 Predecessor Period. 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. In connection with our emergence from bankruptcy, we deconsolidated the DNE Debtor Entities, which constituted our previously reported DNE segment, and began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified the results of the previously reported DNE segment as discontinued operations in the consolidated financial statements for all periods presented. Subsequent to our emergence from bankruptcy, management does not consider general and administrative expense when evaluating the performance of our Coal, IPH and Gas segments, but instead evaluates general and administrative expense on an enterprise-wide basis. Accordingly, we have recast our segments to present general and administrative expense in Other for all periods presented.

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—Merger and Acquisitions—AER Transaction Agreement for further discussion.

We applied fresh-start accounting as of the Plan Effective Date. Fresh-start accounting requires us to allocate the reorganization value to our assets and liabilities in a manner similar to the acquisition method of accounting for business combinations. Under the provisions of fresh-start accounting, a new entity has been created for financial reporting purposes. As such, our financial information for the Successor is presented on a basis different from, and is therefore not comparable to, our financial information for the Predecessor for the period ended and as of October 1, 2012 or for prior periods. Please read Note 20—Emergence from Bankruptcy and Fresh-Start Accounting for further discussion.

For financial reporting purposes, close of business on October 1, 2012, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor"	The Company, pre-emergence from bankruptcy
"2012 Predecessor Period"	The Company's operations, January 1, 2012 — October 1, 2012
"Successor"	The Company, post-emergence from bankruptcy
"2012 Successor Period"	The Company's operations, October 2, 2012 — December 31, 2012

On June 5, 2012, we reacquired DMG through the DMG Acquisition. Therefore, the results of our Coal segment (including DMG) are included in our 2012 consolidated results for the period of June 6, 2012 through December 31, 2012.

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 earnings before interest, taxes, depreciation and amortization ("EBITDA") and Adjusted EBITDA. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our Generally Accepted Accounting Principles ("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, internal reorganization and bankruptcy proceedings, (iv) income or loss associated with discontinued operations, (v) income or expense on up front premiums received or paid for financial options in periods other than the strike periods and (vi)

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income or loss attributable to noncontrolling interest. Adjusted EBITDA includes the Adjusted EBITDA for Legacy Dynegy for the periods prior to the Merger.

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, gains and losses on sales of assets, 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, 2014 Compared to Year Ended December 31, 2013

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

(amounts in millions)	Year Ended December 31, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
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 %

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

	Year Ended December 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$605	$846	$1,058	$(12)	$2,497
Cost of sales, excluding depreciation expense	(346)	(596)	(719)	—	(1,661)
Gross margin	259	250	339	(12)	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)	$52	$(2)	$79	$(148)	$(19)

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

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	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—Merger and 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 $138 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 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 22—Dispositions and Discontinued Operations 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 Pending Acquisitions, partially offset by $4 million in lower costs related to the integration of the AER Acquisition.

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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 22—Dispositions and Discontinued Operations 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 11—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 13—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 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 22—Dispositions and 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.

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Discussion of Adjusted EBITDA

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)
Net income attributable to noncontrolling interest					6
Income tax benefit					(1)
Bankruptcy reorganization items, net					(3)
Interest expense					223
Earnings from unconsolidated investments					(10)
Other items, net					39
Operating income (loss)	$52	$(2)	$79	$(148)	$(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	—	—	—	(39)	(39)
EBITDA	97	28	307	(180)	252
Bankruptcy reorganization items, net	—	—	—	(3)	(3)
Acquisition and integration costs	—	16	—	19	35
Mark-to-market (income) loss, net	(44)	38	22	12	28
Change in fair value of common stock warrants	—	—	—	40	40
Net income attributable to noncontrolling interest	—	(6)	—	—	(6)
Gain on sale of assets, net	—	—	(18)	—	(18)
Other	9	7	—	3	19
Adjusted EBITDA	$62	$83	$311	$(109)	$347

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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)
Bankruptcy reorganization items, net					1
Interest expense					97
Loss on extinguishment of debt					11
Earnings from unconsolidated investments					(2)
Other items, net					(8)
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	—	—	2	6	8
EBITDA	(31)	(16)	298	(93)	158
Bankruptcy reorganization items, net	—	—	—	1	1
Acquisition and integration costs	—	20	—	—	20
Mark-to-market loss, net	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

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 is 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

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	$638	$519	$119	23 %
Capacity	5	4	1	25 %
Mark-to-market gain (loss), net	44	(25)	69	NM
Other (1)	(82)	(31)	(51)	(165)%
Total operating revenues	605	467	138	30 %
Operating Costs				
Cost of sales	(352)	(333)	(19)	(6)%
Contract amortization	6	(126)	132	105 %
Total operating costs	(346)	(459)	113	25 %
Gross margin	259	8	251	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)	52	(207)	259	125 %
Depreciation expense	51	50	1	2 %
Amortization expense	(6)	126	(132)	(105)%
EBITDA	97	(31)	128	NM
Mark-to-market (gain) loss, net	(44)	25	(69)	NM
Other	9	2	7	NM
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 %

(1) For the years ended December 31, 2014 and 2013, respectively, Other includes ($86) million and ($31) million in financial settlements, $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 $52 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 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.

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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, 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	$856	$65	$791	*
Capacity	44	1	43	*
Mark-to-market loss, net	(38)	(8)	(30)	*
Contract amortization	(40)	(3)	(37)	*
Other (1)	24	12	12	*
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	*
Mark-to-market loss, net	38	8	30	*
Acquisition and integration costs	16	20	(4)	*
Net income attributable to noncontrolling interest	(6)	—	(6)	*
Other	7	—	7	*
Adjusted EBITDA	$83	$12	$71	*
Million Megawatt Hours Generated (2)	25.1	2.4	*	*
IMA for IPH Facilities (3)	89%	90%		
Average Capacity Factor for IPH Facilities (4)	68%	75%		
Average Quoted Market Power Prices ($/MWh) (5):				
On-Peak: Indiana (Indy Hub)	$48.28	$40.32	*	*
Off-Peak: Indiana (Indy Hub)	$32.52	$30.82	*	*

* 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 $28 million and $5 million in financial settlements, ($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.

(3) 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.

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(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	$888	$649	$239	37%
Capacity	246	237	9	4%
Mark-to-market loss, net	(22)	(4)	(18)	NM
Contract amortization	(71)	(135)	64	47%
Other (1)	17	185	(168)	(91)%
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	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 loss, net	22	4	18	NM
Gain on sale of assets	(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 (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 (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 ($95) million and ($43) million in financial settlements, $59 million and $89 million in natural gas sales, $33 million and $30 million in ancillary services, $14 million and $96 million in tolls and $6 million and $13 million in RMR, option premiums 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 22—Dispositions and Discontinued Operations for further discussion.

(3) Reflects the percentage of generation available when market prices are such that these units could be profitably dispatched.

(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.

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Consolidated Summary Financial Information—Year Ended December 31, 2013, 2012 Successor Period and 2012 Predecessor Period

The following table provides summary financial data regarding our consolidated results of operations for the year ended December 31, 2013, the 2012 Successor Period and the 2012 Predecessor Period, respectively:

	Successor		Predecessor
(amounts in millions)	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012
Revenues	$1,466	$312	$981
Cost of sales, excluding depreciation expense	(1,145)	(268)	(662)
Gross margin	321	44	319
Operating and maintenance expense	(308)	(81)	(148)
Depreciation expense	(216)	(45)	(110)
Gain on sale of assets, net	2	—	—
General and administrative expense	(97)	(22)	(56)
Acquisition and integration costs	(20)	—	—
Operating income (loss)	(318)	(104)	5
Bankruptcy reorganization items, net	(1)	(3)	1,037
Earnings from unconsolidated investments	2	2	—
Interest expense	(97)	(16)	(120)
Loss on extinguishment of debt	(11)	—	—
Impairment of Undertaking receivable, affiliate	—	—	(832)
Other income and expense, net	8	8	31
Income (loss) from continuing operations before income taxes	(417)	(113)	121
Income tax benefit	58	—	9
Income (loss) from continuing operations	(359)	(113)	130
Income (loss) from discontinued operations, net of tax	3	6	(162)
Net loss	(356)	(107)	(32)
Less: Net income (loss) attributable to noncontrolling interest	—	—	—
Net loss attributable to Dynegy Inc.	$(356)	$(107)	$(32)

The following tables provide summary financial data regarding our operating income (loss) by segment for the year ended December 31, 2013, the 2012 Successor Period and the 2012 Predecessor Period, respectively:

	Successor				
	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—Merger and Acquisitions for further discussion.

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	Successor October 2 Through December 31, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$107	$205	$—	$312
Cost of sales, excluding depreciation expense	(110)	(158)	—	(268)
Gross margin	(3)	47	—	44
Operating and maintenance expense	(38)	(42)	(1)	(81)
Depreciation expense	(8)	(36)	(1)	(45)
General and administrative expense	—	—	(22)	(22)
Operating loss	$(49)	$(31)	$(24)	$(104)

	Predecessor January 1 Through October 1, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$166	$815	$—	$981
Cost of sales, excluding depreciation expense	(161)	(501)	—	(662)
Gross margin	5	314	—	319
Operating and maintenance expense	(55)	(95)	2	(148)
Depreciation expense	(13)	(91)	(6)	(110)
General and administrative expense	—	—	(56)	(56)
Operating income (loss)	$(63)	$128	$(60)	$5

Discussion of Consolidated Results of Operations

Successor

Revenues. During the year ended December 31, 2013, revenues were $1.466 billion. Revenues for the year were primarily the result of $1.233 billion in power revenues with contributions of $519 million, $65 million and $649 million from the Coal, IPH and Gas segments, respectively. These revenues were associated with 20 million MWh, 2 million MWh and 16 million MWh of power generation during the year by the Coal, IPH and Gas segments, respectively. Also contributing to revenue was $162 million in capacity revenue, $39 million in tolling revenue, $46 million in ancillary and other revenue and $88 million in gas revenue, each primarily generated by the Gas segment. These contributions were offset by mark-to-market losses of $38 million consisting of $26 million, $8 million and $4 million in the Coal, IPH and Gas segments, respectively, as well as $64 million in negative financial settlements.

During the 2012 Successor Period, revenues were $312 million. Revenues for the period were primarily the result of $223 million in power revenues with contributions of $105 million and $118 million from the Coal and Gas segments, respectively. These revenues were associated with 5 million MWh and 4 million MWh of power generation during the period by the Coal and Gas segments, respectively. Also contributing to revenue was $31 million in capacity revenue, $11 million in tolling revenue, $8 million in ancillary and other revenue and $49 million in gas revenue, each primarily generated by the Gas segment. Additionally, revenues included $6 million and $39 million in mark-to-market gains from the Coal and Gas segments, respectively. These contributions were offset by $55 million in settlement losses due to the negative settlement of legacy put options, primarily in the Gas segment.

Cost of Sales. During the year ended December 31, 2013, cost of sales was $1.145 billion. Cost of sales for the year primarily consisted of $640 million in Gas segment fuel costs which consist primarily of natural gas purchase and transportation costs and $459 million in Coal segment fuel costs and $46 million in IPH segment fuel costs which all consist of primarily coal purchase and transportation costs.

During the 2012 Successor Period, cost of sales was $268 million. Cost of sales for the period primarily consisted of $158 million in Gas segment fuel costs, which consist primarily of natural gas purchase and transportation costs, and $110 million in Coal segment fuel costs, which consist primarily of coal purchase and transportation costs.

Operating and Maintenance Expense. During the year ended December 31, 2013, operating and maintenance expense was $308 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling

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and environmental costs. The Coal segment accounted for $167 million, the IPH segment accounted for $15 million, the Gas segment accounted for $125 million and Other accounted for $1 million.

During the 2012 Successor Period, operating and maintenance expense was $81 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling and environmental costs. Operating and maintenance expense for the period was $38 million for the Coal segment, $42 million for the Gas segment and $1 million in Other.

Depreciation Expense. During the year ended December 31, 2013, depreciation expense was $216 million. Depreciation expense for the period was $50 million for the Coal segment, $3 million for the IPH segment, $160 million for the Gas segment and $3 million for Other.

During the 2012 Successor Period, depreciation expense was $45 million. Depreciation expense for the period was $8 million for the Coal segment, $36 million for the Gas segment and $1 million for Other. As part of fresh-start accounting on October 1, 2012, our fixed assets were recorded at fair value and this new basis will be depreciated over the remaining useful lives.

General and Administrative Expense. During the year ended December 31, 2013, general and administrative expense was $97 million. General and administrative expense for the period primarily consisted of $72 million in labor and benefit costs, $7 million in legal and professional fees, $5 million in insurance costs, $3 million in office leases and $10 million in office expenses and other costs.

During the 2012 Successor Period, general and administrative expense was $22 million. General and administrative expense for the period primarily consisted of $16 million in labor and benefit costs, $1 million in professional service fees and $5 million in office expenses and other costs.

Acquisition and Integration Costs. During the year ended December 31, 2013, acquisition and integration costs were $20 million, which were incurred in connection with the AER Acquisition and consisted of $9 million in severance expenses, $7 million in legal and consulting fees and $4 million in other costs. Please read Note 3—Merger and Acquisitions for further discussion.

Interest Expense. During the year ended December 31, 2013, interest expense was $97 million. Interest expense primarily consisted of (i) $24 million and $15 million in interest on the DPC and DMG credit agreements, respectively, which were terminated in April 2013, (ii) $22 million in interest expenses on the Tranche B-2 Term Loan, (iii) $18 million in interest expense on the issuance of $500 million in aggregate principal amount of unsecured senior notes bearing interest at 5.875 percent (the “Senior Notes”), (iv) $5 million in interest expense on Genco’s unsecured senior notes (the “Genco Senior Notes”), (v) $7 million in mark-to-market gains on interest rate swaps, (vi) $5 million in fees related to the Revolving Facility and (vii) $1 million in interest expense on the Tranche B-1 Term Loan, which was terminated on May 20, 2013.

During the 2012 Successor Period, interest expense was $16 million. Interest expense primarily consisted of $22 million and $13 million of interest on the DPC and DMG credit agreements, respectively, partially offset by $3 million in amortization of the premium and $16 million in accelerated amortization of the premium related to the early repayment of $325 million, in aggregate, of the DPC and DMG credit agreements.

Please read Note 11—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. During the year ended December 31, 2013, other income and expense, net was an $8 million gain, which primarily consisted of insurance proceeds, partially offset by a change in the fair value of our common stock warrants issued upon emergence from bankruptcy in October 2012.

During the 2012 Successor Period, other income and expense, net was an $8 million gain due to change in the fair value of our common stock warrants issued upon emergence from bankruptcy in October 2012.
Income Tax Benefit. We reported an income tax benefit of $58 million and zero for the year ended December 31, 2013 and the 2012 Successor Period, respectively. The effective tax rate for the year ended December 31, 2013 and the 2012 Successor Period was 14 percent and zero percent, respectively.

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.

For the 2012 Successor Period, the difference between the effective rate of zero percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

Please read Note 13—Income Taxes for further discussion.

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

During the 2012 Successor Period, income from discontinued operations, net of tax was $6 million, which related to the release of a franchise tax liability related to our former midstream business on which the statute of limitations expired.

Please read Note 22—Dispositions and Discontinued Operations for further discussion.

Predecessor

Revenues. During the 2012 Predecessor Period, revenues were $981 million. Revenues for the period were primarily the result of $675 million in power revenues with contributions of $183 million and $492 million from the Coal and Gas segments, respectively. These revenues were associated with 7 million MWh and 17 million MWh of power generation during the period by the Coal and Gas segments, respectively. Also contributing to revenue was $166 million in capacity revenues primarily in the Gas segment, $117 million in mark-to-market gains in the Gas segment, partially offset by $14 million in Coal segment mark-to-market losses. Additionally, revenues include $100 million in natural gas revenue, $79 million in tolling revenues, and $34 million of ancillary and other revenue, each primarily generated by the Gas segment. These contributions were offset by negative financial settlements of $7 million for the Coal segment and $169 million for the Gas segment primarily due to legacy put options.

Cost of Sales. During the 2012 Predecessor Period, cost of sales was $662 million. Cost of sales for the period primarily consisted of $501 million in Gas segment fuel costs which consist primarily of natural gas purchase and transportation costs and $161 million in Coal segment fuel costs which consist primarily of coal commodity and transportation costs. These costs were driven by power generation during the period discussed above.

Operating and Maintenance Expense. During the 2012 Predecessor Period, operating and maintenance expense was $148 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling and environmental costs. Operating and maintenance expense for the period primarily consisted of $55 million in the Coal segment and $95 million in the Gas segment.

Depreciation Expense. During the 2012 Predecessor Period, depreciation expense was $110 million. Depreciation expense was $13 million for the Coal segment, $91 million for the Gas segment and $6 million for Other. Depreciation expense for the period primarily consisted of the allocation of the historical costs of our assets over their useful lives and was partially offset by a reduction in our AROs associated with the South Bay facility.

General and Administrative Expense. During the 2012 Predecessor Period, general and administrative expense was $56 million. General and administrative expense for the period primarily consisted of $50 million in labor and benefit costs and $6 million in legal and professional fees and other costs.

Bankruptcy Reorganization Items, net. During the 2012 Predecessor Period, bankruptcy reorganization items, net were a gain of $1.037 billion. Bankruptcy reorganization items, net consisted of a pre-tax gain of $1.197 billion related to the settlement of liabilities subject to compromise as a result of emergence from bankruptcy, a reduction of $161 million and $10 million in the estimated allowable claims related to the subordinated debt and other items, respectively, and a $17 million change in the value of the Administrative Claim. The gains were offset by $299 million in fresh-start adjustments primarily due to the adjustment of assets and liabilities to fair value as a result of the application of fresh-start accounting and $49 million related to the write-off of deferred financing costs and debt discount related to our long-term debt.

Please read Note 20—Emergence from Bankruptcy and Fresh-Start Accounting for further discussion.

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Interest Expense. During the 2012 Predecessor Period, interest expense was $120 million. Interest expense primarily consisted of (i) $77 million and $19 million in interest on the DPC and DMG credit agreements, respectively, (ii) $23 million in mark-to-market gains on interest rate swaps, (iii) $4 million in amortization of financing costs and (iv) $2 million in commitment and other fees, offset by $5 million in capitalized interest related to the Coal segment Consent Decree.

Impairment of Undertaking Receivable, affiliate. During the 2012 Predecessor Period, impairment of Undertaking receivable, affiliate was $832 million. As a result of entering into the Settlement Agreement, the Undertaking receivable was impaired to $418 million as of March 31, 2012, resulting in a charge of approximately $832 million. The carrying value of the Undertaking was adjusted to the value received in the DMG Acquisition plus interest payments received subsequent to March 31, 2012. The Undertaking was settled upon execution of the Settlement Agreement.

Please read Note 3—Merger and Acquisitions—DMG Transfer and DMG Acquisition for further discussion.

Other Income and Expense, net. During the 2012 Predecessor Period, other income and expense, net was a gain of $31 million. Other income and expense, net primarily consisted of $24 million of interest income on the Undertaking receivable, affiliate, a $5 million distribution received related to our retained profits interest in Plum Point and $2 million in certain insurance proceeds.

Income Tax Benefit. We reported an income tax benefit of $9 million for the 2012 Predecessor Period. The effective tax rate for the 2012 Predecessor Period was seven percent.

For the 2012 Predecessor Period, the difference between the effective rates of seven percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

Loss from Discontinued Operations. During the 2012 Predecessor Period, loss from discontinued operations, net of tax was $162 million. Loss from discontinued operations, net of tax primarily related to Bankruptcy reorganization items, net, which included a $395 million charge related to the estimated claim for the rejection of the DNE Facilities Lease and $5 million in other charges, partially offset by a gain of $217 million on the settlement of the DNE lease guaranty claim and a $43 million gain on the deconsolidation of the DNE Entities. Additionally the loss from discontinued operations consisted of $22 million related to the DNE operations. Please read Note 22—Dispositions and Discontinued Operations for further discussion.

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Discussion of Adjusted EBITDA

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

	Successor 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)
Bankruptcy reorganization items, net					1
Interest expense					97
Loss on extinguishment of debt					11
Earnings from unconsolidated investments					(2)
Other items, net					(8)
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	—	—	2	6	8
EBITDA	(31)	(16)	298	(93)	158
Bankruptcy reorganization items, net	—	—	—	1	1
Acquisition and integration costs	—	20	—	—	20
Mark-to-market loss, net	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

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2012, which includes the 2012 Successor and 2012 Predecessor periods:

	Combined (2)			
	Year Ended December 31, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(139)
Loss from discontinued operations, net of tax				156
Income tax benefit				(9)
Impairment of Undertaking receivable, affiliate				832
Bankruptcy reorganization items, net				(1,034)
Interest expense				136
Earnings from unconsolidated investments				(2)
Other items, net				(39)
Operating income (loss)	$(112)	$97	$(84)	$(99)
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	1,034	1,034
Depreciation expense	21	127	7	155
Amortization expense	78	61	—	139
Earnings from unconsolidated investments	—	2	—	2
Other items, net	5	2	32	39
EBITDA	(8)	289	157	438
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(1,034)	(1,034)
Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	3	3
Mark-to-market (gain) loss, net	7	(166)	—	(159)
Premium adjustment	1	(1)	—	—
Changes in fair value of common stock warrants	—	—	(8)	(8)
Adjusted EBITDA from Dynegy	—	122	(74)	48
Adjusted EBITDA from Legacy Dynegy (1)	20	—	(11)	9
Adjusted EBITDA	$20	$122	$(85)	$57

(1) Our 2012 consolidated results reflect the results of our accounting predecessor, DH. Therefore, the results of our Coal segment are not included in our consolidated results for the period from January 1, 2012 through June 5, 2012. However, we have included the Adjusted EBITDA related to the Coal segment for the period from January 1, 2012 through June 5, 2012 in this adjustment because it is part of our ongoing business and management uses Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

(2) For purposes of presenting Adjusted EBITDA for the year ended December 31, 2012, we combined the 2012 Successor Period and the 2012 Predecessor Period in order to reconcile our non-GAAP measure to its nearest comparable GAAP measure. The combined Successor and Predecessor periods are also non-GAAP due to fresh-start accounting. Therefore, the following table is provided to reconcile the combined amounts to the separate Successor and Predecessor periods.

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(amounts in millions)	Successor October 2 Through December 31, 2012	Predecessor January 1 Through October 1, 2012	Total
Net loss	$(107)	$(32)	$(139)
(Income) loss from discontinued operations, net of tax	(6)	162	156
Income tax benefit	—	(9)	(9)
Impairment of Undertaking receivable, affiliate	—	832	832
Bankruptcy reorganization items, net	3	(1,037)	(1,034)
Interest expense	16	120	136
Earnings from unconsolidated investments	(2)	—	(2)
Other items, net	(8)	(31)	(39)
Operating income (loss)	(104)	5	(99)
Impairment of Undertaking receivable, affiliate	—	(832)	(832)
Bankruptcy reorganization items, net	(3)	1,037	1,034
Depreciation expense	45	110	155
Amortization expense	60	79	139
Earnings from unconsolidated investments	2	—	2
Other items, net	8	31	39
EBITDA	$8	$430	$438

Adjusted EBITDA increased by $170 million from $57 million for the year ended December 31, 2012 to $227 million for the year ended December 31, 2013. The increase was primarily related to an increase of $169 million in our Gas segment Adjusted EBITDA due to the absence of negative settlements associated with legacy commercial positions which adversely impacted 2012 results, $12 million of IPH Adjusted EBITDA for the month of December and $8 million of decreased operations and maintenance costs for our Coal and Gas segments. Offsetting these increases was a $19 million decrease in realized energy margin in our Coal segment due to lower realized prices on hedged generation.

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Discussion of Segment Adjusted EBITDA

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the year ended December 31, 2013, the 2012 Successor Period and the 2012 Predecessor Period, respectively. As a result of the DMG Acquisition, 2012 results only include the results of the Coal segment for the period June 6, 2012 through December 31, 2012.

(dollars in millions, except for price information)	Successor Year Ended December 31, 2013	October 2 Through December 31, 2012	Predecessor January 1 Through October 1, 2012
Operating Revenues			
Energy	$519	$105	$184
Capacity	4	—	4
Mark-to-market gain (loss), net	(25)	7	(14)
Other (1)	(31)	(5)	(8)
Total operating revenues	467	107	166
Operating Costs			
Cost of sales	(333)	(82)	(112)
Contract amortization	(126)	(28)	(49)
Total operating costs	(459)	(110)	(161)
Gross margin	8	(3)	5
Operating and maintenance expense	(167)	(38)	(55)
Depreciation expense	(50)	(8)	(13)
Gain on sale of assets, net	2	—	—
Operating loss	(207)	(49)	(63)
Depreciation expense	50	8	13
Amortization expense	126	29	49
Other items, net	—	—	5
EBITDA	(31)	(12)	4
Mark-to-market (gain) loss, net	25	(6)	13
Other	2	1	—
Adjusted EBITDA (2)	$(4)	$(17)	$17
Million Megawatt Hours Generated (3)	20.4	4.7	6.6
IMA for Coal-Fired Facilities (4)	89%	86%	93%
Average Capacity Factor for Coal-Fired Facilities (5)	78%	69%	70%
Average Quoted Market Power Prices ($/MWh) (6):			
On-Peak: Indiana (Indy Hub)	$38.01	$34.76	$39.72
Off-Peak: Indiana (Indy Hub)	$27.49	$25.94	$23.88

(1) For the year ended December 31, 2013, the 2012 Successor Period and the 2012 Predecessor Period, respectively, Other includes ($31) million, ($6) million and ($10) million in financial settlements; $4 million, $1 million and $2 million in ancillary services and ($4) million, zero and zero in other miscellaneous items.

(2) Legacy Dynegy's adjusted EBITDA was $20 million for the period January 1, 2012 through June 5, 2012.

(3) Reflects production volumes in million MWh generated during the periods Coal was included in our consolidated results. Generation volumes were 19.9 million MWh for the full twelve months ended December 31, 2012.

(4) Reflects the percentage of generation available during the period Coal was included in our consolidated results. IMA for coal-fired facilities was 92 percent for the full twelve months ended December 31, 2012.

(5) Reflects actual production as a percentage of available capacity. Average capacity factor for coal-fired facilities was 72 percent for the full twelve months ended December 31, 2012.
(6) Reflects the average of day-ahead quoted prices for the periods Coal was included in our consolidated results and does not necessarily reflect prices we realized. The average of day-ahead quoted prices was $34.61 for the full twelve months ended December 31, 2012.

Operating loss was $207 million for the year ended December 31, 2013, $49 million for the 2012 Successor Period and $63 million for the 2012 Predecessor Period.

Adjusted EBITDA was a loss of $4 million for the year ended December 31, 2013, which was primarily comprised of $188 million in energy margin and $6 million in other items, offset by $31 million in settlement expense and $167 million in operating expenses.

Adjusted EBITDA was $20 million for the year ended December 31, 2012, which includes the 2012 Successor Period, the 2012 Predecessor Period and Legacy Dynegy, and was primarily comprised of $158 million in energy margin, $5 million in other items and $19 million in settlement revenue offset by $162 million in operating expenses.

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IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the year ended December 31, 2013. 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)	Successor Year Ended December 31, 2013	
Operating Revenues		
Energy	$65	
Capacity	1	
Mark-to-market loss, net	(8	)
Contract amortization	(3	)
Other (1)	12	
Total operating revenues	67	
Operating Costs		
Cost of sales	(51	)
Contract amortization	5	
Total operating costs	(46	)
Gross margin	21	
Operating and maintenance expense	(15	)
Depreciation expense	(3	)
Acquisition and integration costs	(20	)
Operating loss	(17	)
Depreciation expense	3	
Amortization expense	(2	)
EBITDA	(16	)
Mark-to-market loss, net	8	
Acquisition and integration costs	20	
Adjusted EBITDA	$12	
Million Megawatt Hours Generated (2)	2.4	
IMA for IPH Facilities (3)	90	%
Average Capacity Factor for IPH Facilities (4)	75	%
Average Quoted Market Power Prices ($/MWh) (5):		
On-Peak: Indiana (Indy Hub)	$40.32	
Off-Peak: Indiana (Indy Hub)	$30.82	

(1) For the years ended December 31, 2013, Other includes $5 million in financial settlements, ($1) million in ancillary services 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.

(3) 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.

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Operating loss for the year ended December 31, 2013 was $17 million. Adjusted EBITDA was income of $12 million for the year ended December 31, 2013, which consisted of energy margin and revenue from financial settlements, partially offset by operating expenses.

Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the year ended December 31, 2013, the 2012 Successor Period and the 2012 Predecessor Period, respectively:

	Successor		Predecessor
(dollars in millions, except for price information)	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012
Operating Revenues			
Energy	$649	$118	$492
Capacity	237	50	194
Mark-to-market gain (loss), net	(4)	39	117
Contract amortization	(135)	(34)	(32)
Other (1)	185	32	44
Total operating revenues	932	205	815
Operating Costs			
Cost of sales	(648)	(160)	(504)
Contract amortization	8	2	3
Total operating costs	(640)	(158)	(501)
Gross margin	292	47	314
Operating and maintenance expense	(125)	(42)	(95)
Depreciation expense	(160)	(36)	(91)
Operating income (loss)	7	(31)	128
Depreciation expense	160	36	91
Amortization expense	127	32	29
Earnings from unconsolidated investments	2	2	—
Other items, net	2	—	2
EBITDA	298	39	250
Mark-to-market (gain) loss, net	4	(39)	(127)
Premium adjustment	—	(2)	1
Adjusted EBITDA	$302	$(2)	$124
Million Megawatt Hours Generated (2)	16.2	3.5	16.9
IMA for Combined Cycle Facilities (3)	97%	83%	98%
Average Capacity Factor for Combined Cycle Facilities (4)	43%	36%	57%
Average Market On-Peak Spark Spreads ($/MWh) (5)			
Commonwealth Edison (NI Hub)	$11.38	$8.87	$15.77
PJM West	$17.65	$14.72	$20.40
North of Path (NP 15)	$16.21	$8.98	$8.09
New York - Zone A	$20.12	$10.15	$13.28
Mass Hub	$16.35	$22.52	$17.69
Average Market Off-Peak Spark Spreads ($/MWh) (5)			
Commonwealth Edison (NI Hub)	$(0.13)	$(0.91)	$5.21
PJM West	$4.99	$6.32	$7.98
North of Path (NP 15)	$8.46	$0.89	$(0.92)

New York - Zone A	$7.49	$6.43	$4.33
Mass Hub	$(0.16)	$3.03	$6.97
Average natural gas price—Henry Hub ($/MMBtu) (6)	$3.72	$3.39	$2.53

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(1) For the year ended December 31, 2013, the 2012 Successor Period and the 2012 Predecessor Period, respectively, Other includes ($43) million, ($52) million and ($171) million in financial settlements; $89 million, $49 million and $100 million in natural gas sales; $30 million, $7 million and $27 million in ancillary services; $96 million, $25 million and $79 million in tolls and $13 million, $3 million and $9 million in RMR, option premiums and other miscellaneous items.

(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility.

(3) Reflects the percentage of generation available when market prices are such that these units could be profitably dispatched.

(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, 2013 was $7 million, a loss of $31 million for the 2012 Successor Period and income of $128 million for the 2012 Predecessor Period.

Adjusted EBITDA totaled $302 million during the year ended December 31, 2013, which was primarily comprised of $334 million of capacity and tolling revenue, $90 million of physical energy margin and $42 million of ancillary services and other items, offset by $125 million of operating expense and $39 million in negative financial settlements. Adjusted EBITDA was $122 million for the year ended December 31, 2012, which includes the 2012 Successor Period, the 2012 Predecessor Period and Legacy Dynegy, and was primarily comprised of $328 million of capacity and tolling revenue, $93 million of physical energy margin and $48 million of ancillary services and other items, offset by $209 million in negative financial settlements and $138 million of operating expense.

Outlook

We expect that our future financial results will continue to be impacted by fuel and commodity prices. Other factors to which our future financial results will remain sensitive include 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 associated with GHG, the handling and disposal of coal ash, how water used by our power generation facilities is withdrawn and treated before being discharged and more stringent air emission standards. All references to hedging within this Form 10-K relate to economic hedging activities as the Company does not elect hedge accounting.

In August 2014, we entered into the Duke Midwest Acquisition for a purchase price of $2.8 billion in cash, subject to certain adjustments, and the EquiPower Acquisition for a purchase price of approximately $3.25 billion in cash and $200 million of our common stock, subject to certain adjustments. Consummation of the Pending Acquisitions is subject to conditions and governmental approvals, including FERC approval. On February 6, 2015, we responded to a letter from FERC requesting additional information to process the applications filed with FERC on September 11, 2014. Please read Note 3—Merger and Acquisitions for further discussion.

Coal. Currently, the Coal segment consists of four plants, all located in the MISO region, totaling 3,008 MW. Following the close of the Pending Acquisitions, our Coal segment will be comprised of ten operating coal-fired generation facilities and one coal and oil-fired facility located within the MISO, PJM and ISO-NE regions, with a total generating capacity of 8,390 MW. The discussion below excludes the impact of the Pending Acquisitions.

As of February 10, 2015, our Coal expected generation volumes are 69 percent hedged volumetrically for 2015 and approximately 23 percent hedged volumetrically for 2016. We plan to continue our hedging program for Coal over a one- to three-year period using various instruments, which includes the sale of natural gas swaps as a cross-commodity correlated hedge for our power revenue. As a result of the offsetting risks of our Coal and Gas segments, we are able to reduce the costs associated with hedging by executing a portion of Coal's hedges with an internal affiliate. The internal hedges are cross-commodity hedges and we intend to expand this in the future. Beyond 2015, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements.

Due to declining correlations between our MISO LMP prices and trading hub prices, we plan to mitigate the risk of a breakdown between these prices through participation in FTR markets and busbar basis swaps to the extent they are economically available.

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As of February 10, 2015, our expected coal requirements are 90 percent contracted and priced in 2015. Our forecasted coal requirements for 2016 are 44 percent contracted and priced. Our coal transportation requirements are more than 90 percent contracted and priced for the next several years. We look to procure and price additional fuel opportunistically.

For Planning Year 2013-2014, MISO capacity cleared at $1.05 per MW-day for all zones. This low clearing price was likely caused by excess capacity conditions prevailing in MISO for the term of the planning year. For Planning Year 2014-2015, MISO capacity cleared at $16.75 per MW-day for Local Resource Zone 4, in which our assets are located. In the future, we expect to benefit from the potential retirement of approximately 9 GW of marginal MISO coal capacity due to poor economics or expected environmental mandates. In addition, confirmed future capacity exports from MISO to PJM could also increase MISO capacity and energy pricing. Current OTC bilateral capacity transactions in MISO have traded in excess of $65.75 per MW-day for each Planning Year 2015-2016 through Planning Year 2019-2020. In 2014, our Coal segment entered into total bilateral forward capacity sales in MISO in excess of 1,400 MW.

Based on analysis of historical constraints near our generating facilities, we have identified opportunities to invest in transmission facilities upgrades which will help to mitigate the impact of congestion around our Baldwin plant. We are working with the transmission owner to implement these upgrades. We continue to assess grid constraints impacting our other facilities to identify other opportunities to reduce congestion and improve LMPs at our Coal and IPH facilities.

IPH. The IPH segment consists of five plants, totaling 4,057 MW. The Coffeen, Edwards, Duck Creek and Newton facilities are located in the MISO region. Joppa, which is within the EEI control area, is interconnected to MISO, TVA and LGE where it sells its power.

As of February 10, 2015, our IPH expected generation volumes are 67 percent hedged volumetrically for 2015 and approximately 36 percent hedged volumetrically for 2016. The IPH hedging program 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. We may use other instruments to hedge the power revenue. 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 10, 2015, our expected coal requirements for IPH are 91 percent contracted and 73 percent priced for 2015. Our forecasted coal requirements for 2016 are 75 percent contracted and 54 percent priced. Our coal transportation requirements are more than 90 percent contracted and priced for the next several years. We look to procure and price additional fuel opportunistically.

IPH realized capacity sales in the latest MISO Planning Year 2014-2015 capacity auction, clearing 1,995 MW. On May 23, 2014, PJM’s RPM released its results for Planning Year 2017-2018 with a clearing price of $120 per MW-day, of which the IPH segment cleared 847 MW. We have also secured one segment of the transmission path required to offer an additional 240 MW of capacity and energy into PJM. In July 2014, we executed a long-term wholesale contract for up to 120 MW annually for energy and capacity in Illinois from 2018 to 2026 bringing long-term, annual origination sales from the IPH segment to more than 470 MW.

Gas. Currently, the Gas segment consists of six plants, geographically diverse in four markets, totaling 6,109 MW. Following the close of the Pending Acquisitions, our Gas segment will be comprised of 17 operating natural gas-fired power generation facilities located in California, Connecticut, Illinois, Maine, Massachusetts, New York, Ohio and Pennsylvania and two fuel-oil fired power generation facilities located in California and Ohio, totaling 13,315 MW of electric generating capacity. The discussion below excludes the impact of the Pending Acquisitions.

Excluding volumes subject to tolling agreements, as of February 10, 2015, our Gas portfolio is 50 percent hedged volumetrically through 2015 and approximately 7 percent hedged volumetrically for 2016. 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 internal affiliate. We continue to manage our remaining commodity price exposure to changing fuel and power prices in accordance with our risk management policy.

The CAISO capacity market is a bilateral market in which Load Serving Entities (“LSEs”) are required to procure sufficient resources to meet their peak load plus a 15 percent reserve margin. The CAISO faces challenges to ensure system reliability and the ability to integrate renewables into the system given the state’s mandate to have 33 percent renewable resources by 2020. The CAISO and CPUC recently approved the Joint Reliability Plan in which the CAISO and CPUC will collaborate on several initiatives: (i) determination of multi-year resource adequacy procurement obligations for CPUC jurisdictional LSEs; (ii) development of a joint long-term planning assessment and (iii) development of a market-based reliability backstop mechanism to replace the capacity procurement mechanism, which is the administratively-priced mechanism currently used by CAISO. A flexible capacity requirement to support renewable integration has been imposed on CPUC jurisdictional LSEs and will be mandatory starting in 2015. The CAISO Board approved the methodology and “must-offer” obligations for flexible capacity developed through a

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stakeholder process, and the tariff provisions were recently approved by FERC. A Flexible Ramping Product has been developed in the CAISO stakeholder process and approved by the CAISO Board; tariff language is now in development. We do not anticipate a significant near term change in capacity prices because energy efficiency programs and distributed generation of residential and commercial rooftop solar power have kept energy demand growth relatively flat. Additionally, CAISO studies on flexible capacity appear to show ample supplies through 2018. In 2014, we began a strategic review of our California assets. Recently the review was completed, and we have determined that our best alternative is to retain these assets and continue to operate them as part of the Dynegy portfolio.

In New England, where our Casco Bay facility is located, nine forward capacity auctions have been held since the ISO-NE transitioned to a forward capacity market in June 2010. The highest clearing price of $15 per kW-month occurred in the previous auction for Planning Year 2017-2018. However, the "insufficient competition" clause in the ISO-NE tariff was triggered, resulting in existing generation receiving an administrative cap price of $7.025 per kW-month. Due to oversupply conditions, the seven prior annual auctions cleared at the designated floor. For the eighth auction, the floor price was removed and existing generation received the administrative cap due to significant retirements in the region. Two rule changes were implemented for FCA-9 covering Planning Year 2018-2019. These rules include a downward sloping demand curve and performance incentives. The downward sloping demand curve replaces the administrative pricing rules for the entire region. The performance incentive rules have 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. The FCA-9 auction for Planning Year 2018-2019 was held on February 2, 2015. Rest-of-Pool, which includes our Casco Bay facility, cleared at a price of $9.551 per kW-month. SEMA-RI 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 CONE price of $11.080 per kW-month and new resources in the zone receiving the auction starting price of $17.728 per kW-month.

In PJM, where the Kendall and Ontelaunee combined-cycle plants are located, eleven forward capacity auctions (known as RPM) have been held since the transition from a daily capacity market in June 2007. RPM clearing prices have ranged from $16.46 per MW-day (Kendall, Planning Year 2012-2013) and $40.77 per MW-day (Ontelaunee, Planning Year 2007-2008) to $174.29 per MW-day (Kendall, Planning Year 2010-2011) and $226.15 per MW-day (Ontelaunee, Planning Year 2013-2014). The latest RPM auction was for Planning Year 2017-2018, which cleared at $120.00 per MW-day for both Kendall and Ontelaunee. The next RPM auction, for Planning Year 2018-2019, will be conducted in May 2015. PJM has recently proposed sweeping changes to their capacity market with a product called Capacity Performance. Capacity Performance was developed by PJM, the PJM Board, and stakeholders in response to the increased forced-outage rates during the Polar Vortex of January 2014. Capacity Performance features increased availability and flexibility requirements, incentives for performance, severe 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.

Capacity pricing for the NYISO, where our Independence facility is located, is recovering from the low point in 2011. The most recent summer and winter auctions have cleared higher than the previous auctions with summer 2014 at $5.15 per kW-month and winter 2014-2015 at $2.90 per kW-month for the rest of state market. We attribute the rebound in part to the FERC Order on buyer-side mitigation, affecting in-city resources, and retirements. As of February 10, 2015, approximately 84 percent of the 2015 capacity revenue for our Independence facility has been contracted.

On May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") vacated FERC Order No. 745, which provides compensation for demand response resources that participate in the energy markets administered by RTOs and ISOs. FERC requested a review of this decision on July 7, 2014, and the court denied the request on September 17, 2014. On October 20, 2014, the D.C. Circuit Court of Appeals granted FERC's motion for a stay of the mandate, pending the deadline for filing of a petition for writ of certiorari with the U.S. Supreme Court. On January 15, 2015, two petitions were filed with the U.S. Supreme Court seeking review of the D.C. Circuit's decision in the case, one by FERC and one by private parties who intervened in the court of appeals in support of FERC. Briefs in opposition are currently due March 19, 2015. Should the U.S, Supreme Court decide to hear the case, a decision will likely issue sometime in late 2015 or early 2016. Each of the ISO/RTOs is evaluating options for complying with the decision, but it is unclear how Demand Response will participate in the energy, ancillary service and capacity markets, and therefore, it is too early to evaluate market impacts at this time.

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.

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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; and
- Business Combinations.

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 three different ways to account for these types of contracts: (i) as an accrual contract, if the criteria for the "normal purchase, normal sale" exception are met and documented; (ii) as a cash flow or fair value hedge, if the criteria are met and documented; or (iii) 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 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 in earnings. Dynegy does not elect hedge accounting for any of its derivative instruments.
Entities may choose whether or not to offset related assets and liabilities and report the net amounts on their consolidated balance sheet 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 elected to offset the fair value of amounts recognized for the Daily Cash Settlements 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 sheet with the changes in fair value recorded 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 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 and capacity prices. 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

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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). The three levels of the fair value hierarchy are classified 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 listed equities.
- 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, 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 OTC 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.

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 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.

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.

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 sheet. 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 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, 2014. 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 13—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and changes in our valuation allowance.

Business Combinations

U.S. GAAP requires that the purchase price for an acquisition, such as our AER Acquisition, be assigned and allocated to the individual assets and liabilities based upon their fair value (or in the case of fresh-start accounting, the reorganization value as approved by the Bankruptcy Court). Generally, the amount recorded in the financial statements for an acquisition is the purchase price (value of the consideration paid), but a purchase price that exceeds the fair value of the assets acquired will result in the recognition of goodwill. In addition to the potential for the recognition of goodwill, 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 and can impact the timing and the 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 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, our investment value in the entities acquired could have been significantly higher or lower with a corresponding increase or reduction in our asset and liability values. Refer to Note 3—Merger and Acquisitions for further discussion of the AER Acquisition.

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.

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RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	
Fair value of portfolio at December 31, 2013	$(62)
Risk management losses recognized through the statement of operations in the period, net	(56)
Contracts realized or otherwise settled during the period	30
Change in collateral/margin netting	5
Fair value of portfolio at December 31, 2014	$(83)

The net risk management liability of $83 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, 2014, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2015	2016	2017	2018	2019	Thereafter
Market quotations (1) (2)	$(88)	$(60)	$(14)	$(8)	$(4)	$(2)	$—
Prices based on models (2)	(4)	(4)	—	—	—	—	—
Total (3)	$(92)	$(64)	$(14)	$(8)	$(4)	$(2)	$—

(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 $9 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 not 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, 2014 one day VaR compared to December 31, 2013 was primarily due to increased forward prices and positions. The increase in the December 31, 2014 average VaR compared to December 31, 2013

was primarily due to an increase in position as a result of the AER Acquisition.

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Daily and Average VaR for Risk-Management Portfolios

(amounts in millions)	December 31, 2014	December 31, 2013
One day VaR—95 percent confidence level	$10	$7
One day VaR—99 percent confidence level	$14	$10
Average VaR—95 percent confidence level for the rolling twelve months ended	$8	$4

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, 2014 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	$2
Oil and gas producers	2
Utility and power generators	8
Total	$12

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, 2014 and December 31, 2013, respectively:

	December 31, 2014	December 31, 2013
Interest rate swaps (in millions of U.S. dollars)	$785	$796
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, 2014.

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, 2014. 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, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 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, 2014.

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 2015 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, 2014. 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 2015 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, 2014. 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 2015 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, 2014. 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 2015 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, 2014. 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.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth certain information as of December 31, 2014 as it relates to our equity compensation plans for our common stock:

Plan Category	Number of securities to be issued upon exercise of outstanding options and rights (a)	Weighted-average exercise price of outstanding options and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders (1)	2,722,205	$22.05	2,924,626
Equity compensation plans not approved by security holders	—	—	—
Total	2,722,205	$22.05	2,924,626

(1) The plan that is approved by our security holders is the 2012 Long Term Incentive Plan. Please read Note 16—Capital Stock—Stock Award Plans for further discussion.

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 2015 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, 2014. 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 2015 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, 2014. 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.
*2.6	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).

***2.7	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.
***2.8	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.
2.9	Agreement and Plan of Merger between Dynegy Inc. and Dynegy Holdings, LLC, dated September 28, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 2, 2012, File No. 001-33443).
*2.10	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).
*2.11	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).
2.12	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) (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 dated as of December 5, 2013 to the Indenture, dated May 20, 2013, 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	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).

4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).
4.10	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).
4.11	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).
4.12	2019 Unit Agreement, dated October 27, 2014, among Dynegy Finance I, Inc., Dynegy Finance II, Inc. and Wilmington Trust, National Association, as unit agent (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.13	2022 Unit Agreement, dated October 27, 2014, among Dynegy Finance I, Inc., Dynegy Finance II, Inc. and Wilmington Trust, National Association, as unit agent (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.14	2024 Unit Agreement, dated October 27, 2014, among Dynegy Finance I, Inc., Dynegy Finance II, Inc. and Wilmington Trust, National Association, as unit agent (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.15	Finance I 2019 Notes Indenture, dated October 27, 2014, among Dynegy Finance I, Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.16	Finance I 2022 Notes Indenture, dated October 27, 2014, among Dynegy Finance I, Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).

4.17	Finance I 2024 Notes Indenture, dated October 27, 2014, among Dynegy Finance I, Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.6 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
4.18	Finance II 2019 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and Wilmington Trust, National Association, as trustee (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).
4.19	Finance II 2022 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and Wilmington Trust, National Association, as trustee (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).
4.20	Finance II 2024 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and Wilmington Trust, National Association, as trustee (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).

4.21	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).
10.1	Limited Guaranty, dated March 14, 2013, by Dynegy Inc. in favor of Ameren Corporation (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 15, 2013 File No. 001-33443).
10.2	Dynegy Inc. Executive Severance Pay Plan, as amended and restated effective as of January 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 4, 2008, File No. 1-15659).††
10.3	First Amendment to the Dynegy Inc. Executive Severance Pay Plan effective as of January 1, 2010 (incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2009 of Dynegy Inc, File No. 1-15659).††
10.4	Second Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated as of September 20, 2010. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2010 of Dynegy Inc, File No. 1-15659).††
10.5	Third Amendment to the Dynegy Inc. Executive Severance Pay Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2011, File No. 1-33443).††
10.6	Fourth Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated as of August 8, 2011(incorporated by reference to Exhibit 10. 1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.7	Dynegy Inc. Executive Change in Control Severance Pay Plan effective April 3, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 8, 2008, File No. 1-15659).††
10.8	First Amendment to the Dynegy Inc. Executive Change In Control Severance Pay Plan, dated as of September 22, 2010 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2010 of Dynegy Inc, File No. 1-15659).††
10.9	Second Amendment to the Dynegy Inc. Executive Change in Control Severance Pay Plan (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.10	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).††
10.11	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).††
10.12	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).††
10.13	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).††
10.14	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).††
10.15	

	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).††
10.16	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).††
10.17	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).††
10.18	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).††

10.19	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).††
10.20	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).††
10.21	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)††
10.22	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).††
10.23	Assignment Agreement by and between Dynegy Inc. and Dynegy Operating Company, dated July 5, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. on July 10, 2012, File No. 001-33443).††
10.24	Employment Agreement between Dynegy Inc. and Robert Flexon dated June 22, 2011(incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.25	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Robert C. Flexon (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.26	Employment Agreement between Dynegy Inc. and Clint C. Freeland dated June 23, 2011(incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.27	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Clint C. Freeland (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.28	Employment Agreement between Dynegy Inc. and Carolyn J. Burke dated July 5, 2011(incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.29	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Carolyn J. Burke (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.30	Third Amendment to Employment Agreement by and between Dynegy Operating Company and Carolyn J. Burke (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2014 of Dynegy Inc. File No. 001-33443).††
10.31	Employment Agreement between Dynegy Inc. and Catherine Callaway dated September 16, 2011 (incorporated by reference to Exhibit 10. 2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.32	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Catherine B. Callaway (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.33	Employment Agreement by and among Dynegy Operating Company, Dynegy Inc. and Henry D. Jones (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 12, 2013, File No. 001-33443). ††
10.34	First Amendment to Employment Agreement by and between Dynegy Operating Company and Henry D. Jones (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of

	Dynegy Inc. filed on March 22, 2013 File No. 001-33443). ††
10.35	Form Award Agreement for 2012 Long Term Incentive Program Award-Cash (CEO) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 9, 2012 File No. 001-33443).††
10.36	Form Award Agreement for 2012 Long Term Incentive Program Award-Cash (EVP) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 9, 2012 File No. 001-33443).††
10.37	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). ††

10.38	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). ††
10.39	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).††
10.40	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). ††
10.41	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). ††
10.42	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). ††
10.43	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). ††
10.44	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). ††
10.45	Form of Performance Award Agreement (2013 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). ††
10.46	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). ††
10.47	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). ††
10.48	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).
10.49	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).
10.50	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).
10.51	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).
10.52	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).
10.53	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).

10.54	Escrow Agreement, dated October 27, 2014, among Dynegy Finance I, Inc., Dynegy Finance II, Inc., Wilmington Trust, National Association, as trustee under each of the indentures and Wilmington Trust, National Association, as escrow agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2014 File No. 001-33443).
10.55	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).
10.56	Guaranty by Illinois Power Generating Company in favor of Ameren Corporation, dated December 2, 2013 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Illinois Power Generating Company filed on December 5, 2013 File No. 333-56594).
10.57	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).
****10.58	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).
10.59	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).
10.60	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).
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.

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, 2015	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, 2015
/s/ CLINT C. FREELAND Clint C. Freeland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2015
/s/ J. CLINTON WALDEN J. Clinton Walden	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2015
/s/ PAT WOOD III Pat Wood III	Chairman of the Board	February 25, 2015
/s/ HILARY E. ACKERMANN Hilary E. Ackermann	Director	February 25, 2015
/s/ PAUL M. BARBAS Paul M. Barbas	Director	February 25, 2015
/s/ RICHARD LEE KUERSTEINER Richard Lee Kuersteiner	Director	February 25, 2015
/s/ JEFFREY S. STEIN Jeffrey S. Stein	Director	February 25, 2015
/s/ JOHN R. SULT John R. Sult	Director	February 25, 2015

DYNEGY INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2014, 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, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2014 consolidated financial statements of Dynegy Inc. and our report dated February 25, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2015

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, 2014 and 2013 (Successor), and the related consolidated statements of operations, comprehensive loss, changes in equity and cash flows for the years ended December 31, 2014 and 2013 (Successor), the period from October 2, 2012 through December 31, 2012 (Successor), and the period from January 1, 2012 through October 1, 2012 (Predecessor). 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, 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, 2014 and 2013 (Successor), and the consolidated results of its operations and its cash flows for the years ended December 31, 2014 and 2013 (Successor), the period from October 2, 2012 through December 31, 2012 (Successor), and the period from January 1, 2012 through October 1, 2012 (Predecessor), in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 2 and 20 to the consolidated financial statements, on September 10, 2012, the Bankruptcy Court entered an order confirming the Joint Chapter 11 Plan of Reorganization, which became effective on October, 1, 2012. Accordingly, the accompanying consolidated financial statements for the period from October 2, 2012 through December 31, 2012 have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, applying fresh-start accounting as described in Notes 2 and 20.

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, 2014, 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, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 25, 2015

Item 1—FINANCIAL STATEMENTS

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

	December 31, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$1,870	$843
Restricted cash	113	—
Accounts receivable, net of allowance for doubtful accounts of $2 and zero respectively	270	420
Inventory	208	181
Assets from risk management activities	78	25
Intangible assets	27	108
Prepayments and other current assets	108	108
Total Current Assets	2,674	1,685
Property, Plant and Equipment	3,685	3,527
Accumulated depreciation	(430)	(212)
Property, Plant and Equipment, Net	3,255	3,315
Other Assets		
Restricted cash	5,100	—
Assets from risk management activities	2	11
Intangible assets	38	68
Deferred income taxes	20	100
Other long-term assets	143	112
Total Assets	$11,232	$5,291

See the notes to consolidated financial statements.

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

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 216	$ 329
Accrued interest	80	13
Deferred income taxes	20	100
Intangible liabilities	45	62
Accrued liabilities and other current liabilities	157	139
Liabilities from risk management activities	132	65
Debt, current portion	31	13
Total Current Liabilities	681	721
Debt, long-term portion	7,075	1,979
Other Liabilities		
Liabilities from risk management activities	31	33
Asset retirement obligations	205	173
Other long-term liabilities	217	178
Total Liabilities	8,209	3,084
Commitments and Contingencies (Note 15)		
Stockholders’ Equity		
Preferred Stock, $0.01 par value, 20,000,000 authorized at December 31, 2014 and 2013:		
Series A 5.375% mandatory convertible preferred stock, $0.01 par value; 4,000,000 shares issued and outstanding at December 31, 2014	387	—
Common stock, $0.01 par value, 420,000,000 shares authorized at December 31, 2014 and 2013; 124,436,941 shares and 100,202,036 shares issued and outstanding at December 31, 2014 and 2013	1	1
Additional paid-in capital	3,351	2,614
Accumulated other comprehensive income, net of tax	20	58
Accumulated deficit	(736)	(463)
Total Dynegy Stockholders’ Equity	3,023	2,210
Noncontrolling interest	—	(3)
Total Equity	3,023	2,207
Total Liabilities and Equity	$ 11,232	$ 5,291

See the notes to consolidated financial statements.

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

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012
Revenues	$2,497	$1,466	$312	$981
Cost of sales, excluding depreciation expense	(1,661)	(1,145)	(268)	(662)
Gross margin	836	321	44	319
Operating and maintenance expense	(477)	(308)	(81)	(148)
Depreciation expense	(247)	(216)	(45)	(110)
Gain on sale of assets, net	18	2	—	—
General and administrative expense	(114)	(97)	(22)	(56)
Acquisition and integration costs	(35)	(20)	—	—
Operating income (loss)	(19)	(318)	(104)	5
Bankruptcy reorganization items, net	3	(1)	(3)	1,037
Earnings from unconsolidated investments	10	2	2	—
Interest expense	(223)	(97)	(16)	(120)
Loss on extinguishment of debt	—	(11)	—	—
Impairment of Undertaking receivable, affiliate	—	—	—	(832)
Other income and expense, net	(39)	8	8	31
Income (loss) from continuing operations before income taxes	(268)	(417)	(113)	121
Income tax benefit (Note 13)	1	58	—	9
Income (loss) from continuing operations	(267)	(359)	(113)	130
Income (loss) from discontinued operations, net of tax (Note 22)	—	3	6	(162)
Net loss	(267)	(356)	(107)	(32)
Less: Net income attributable to noncontrolling interest	6	—	—	—
Net loss attributable to Dynegy Inc.	(273)	(356)	(107)	(32)
Less: Dividends on preferred stock	5	—	—	—
Net loss attributable to Dynegy Inc. common stockholders	$(278)	$(356)	$(107)	$(32)
Loss Per Share (Note 14):				
Basic and diluted loss per share attributable to Dynegy Inc. common stockholders:				
Loss from continuing operations	$(2.65)	$(3.59)	$(1.13)	N/A
Income from discontinued operations	—	0.03	0.06	N/A
Basic and diluted loss per share attributable to Dynegy Inc. common stockholders	$(2.65)	$(3.56)	$(1.07)	N/A
Basic and diluted shares outstanding	105	100	100	N/A

See the notes to consolidated financial statements.

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

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012
Net loss	$(267)	$(356)	$(107)	$(32)
Other comprehensive income (loss) before reclassifications:				
Actuarial gain (loss) and plan amendments (net of tax expense of zero, $31, zero and zero, respectively)	(36)	57	11	—
Amounts reclassified from accumulated other comprehensive income (loss):				
Reclassification of curtailment gain included in net loss (net of tax of zero, zero, zero, and zero, respectively)	—	(7)	—	—
Amortization of unrecognized prior service cost (credit) and actuarial loss (gain) (net of tax of zero, zero, zero and zero, respectively)	(5)	(2)	—	(1)
Other comprehensive income (loss), net of tax	(41)	48	11	(1)
Comprehensive loss	(308)	(308)	(96)	(33)
Less: Comprehensive income attributable to noncontrolling interest	3	1	—	—
Total comprehensive loss attributable to Dynegy Inc.	$(311)	$(309)	$(96)	$(33)

See the notes to consolidated financial statements.

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

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net loss	$(267)	$(356)	$(107)	$(32)
Adjustments to reconcile net loss to net cash flows from operating activities:				
Depreciation expense	247	216	45	110
Loss on extinguishment of debt	—	11	—	—
Non-cash interest expense (benefit)	21	2	(19)	8
Amortization of intangibles	45	251	60	79
Bankruptcy reorganization items, net	—	—	—	(947)
Impairment and other charges	—	—	—	832
Risk management activities	26	38	(46)	(82)
Gain on sale of assets, net	(18)	(2)	—	—
Deferred income taxes	(1)	(56)	—	(9)
Change in value of common stock warrants	40	1	(8)	—
Other	35	14	(3)	(10)
Changes in working capital:				
Accounts receivable, net	161	(75)	—	9
Inventory	(20)	24	1	7
Prepayments and other current assets	22	48	49	(43)
Accounts payable and accrued liabilities	(131)	71	(3)	38
Affiliate transactions	—	—	—	19
Changes in non-current assets	(4)	(12)	(10)	(16)
Changes in non-current liabilities	7	—	(3)	—
Net cash provided by (used in) operating activities	163	175	(44)	(37)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Capital expenditures	(132)	(98)	(46)	(63)
Proceeds from asset sales, net	18	3	—	—
(Increase) decrease in restricted cash	(5,148)	335	311	88
Acquisitions, net of cash acquired/divestitures	—	234	—	256
Deconsolidation of DNE Debtor Entities	—	—	—	(22)
Payments received for Undertaking, receivable affiliate	—	—	—	16
Other investing	—	—	—	3
Net cash provided by (used in) investing activities	(5,262)	474	265	278
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from issuance of preferred stock, net	387	—	—	—
Proceeds from issuance of common stock, net	719	—	—	—
Payment to unsecured creditors	—	—	—	(200)
Proceeds from long-term borrowings, net of financing costs	5,055	1,768	—	—
	(14)	(1,917)	(328)	(11)

Repayments of borrowings, including debt extinguishment costs				
Interest rate swap settlement payments	(18)	(5)	—	—
Recapitalization of Legacy Dynegy	—	—	—	27
Other financing	(3)	—	—	—
Net cash provided by (used in) financing activities	6,126	(154)	(328)	(184)
Net increase (decrease) in cash and cash equivalents	1,027	495	(107)	57
Cash and cash equivalents, beginning of period	843	348	455	398
Cash and cash equivalents, end of period	$1,870	$843	$348	$455

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	Member's Contribution	Affiliate Receivable	AOCI (Loss)	Accumulated Deficit	Total Controlling Interests	Noncontrolling Interest	Total
December 31, 2011 (Predecessor)	$—	$—	$—	$ 5,135	$ (846)	$ 1	$ (4,258)	$ 32	$ —	$ 32
Net loss	—	—	—	—	—	—	(32)	(32)	—	(32)
Other comprehensive loss, net of tax	—	—	—	—	—	(1)	—	(1)	—	(1)
Affiliate activity (Note 12)	—	—	—	—	846	—	(846)	—	—	—
DMG Acquisition	—	—	—	—	—	(24)	—	(24)	—	(24)
Merger	—	1								