DYNEGY INC.
Form 10-Q
May 07, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2015

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________ to ________

Commission file number: 001-33443

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

State of Incorporation	I.R.S. Employer Identification No.
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)

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 ¨

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 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

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 ¨

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Indicate the number of shares outstanding of our class of common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 128,149,345 shares outstanding as of April 21, 2015.

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DEFINITIONS

As used in this Form 10-Q, the abbreviations contained herein have the meanings set forth below.

CAISO	The California Independent System Operator
CPUC	California Public Utility Commission
EGU	Electric Generating Units
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
HAPs	Hazardous Air Pollutants, as defined by the Clean Air Act
IMA	In-market Asset Availability
IPCB	Illinois Pollution Control Board
IPH	IPH, LLC (formerly known as Illinois Power Holdings, LLC)
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing
MAAC	Mid-Atlantic Area Council
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
Moody’s	Moody’s Investors Service Inc.
MW	Megawatts
MWh	Megawatt Hour
NM	Not Meaningful
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PRIDE	Producing Results through Innovation by Dynegy Employees
RFO	Request for Offers
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
SEMA/RI	Southeastern Massachusetts and Rhode Island
TVA	Tennessee Valley Authority
VaR	Value at Risk

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PART I. FINANCIAL INFORMATION
Item 1—FINANCIAL STATEMENTS
DYNEGY INC.
CONSOLIDATED BALANCE SHEETS
(unaudited) (in millions, except share data)

	March 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$1,734	$1,870
Restricted cash	205	113
Accounts receivable, net of allowance for doubtful accounts of $1 and $2, respectively	268	270
Inventory	224	208
Assets from risk management activities	80	78
Intangible assets	25	27
Prepayments and other current assets	121	108
Total Current Assets	2,657	2,674
Property, Plant and Equipment	3,698	3,685
Accumulated depreciation	(471)	(430)
Property, Plant and Equipment, Net	3,227	3,255
Other Assets		
Restricted cash	5,100	5,100
Assets from risk management activities	4	2
Intangible assets	33	38
Deferred income taxes	32	20
Other long-term assets	162	143
Total Assets	$11,215	$11,232

See the notes to consolidated financial statements.

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

	March 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$248	$216
Accrued interest	184	80
Deferred income taxes	32	20
Intangible liabilities	39	45
Accrued liabilities and other current liabilities	198	157
Liabilities from risk management activities	111	132
Debt, current portion	8	31
Total Current Liabilities	820	681
Debt, long-term portion	7,077	7,075
Other Liabilities		
Liabilities from risk management activities	36	31
Asset retirement obligations	211	205
Other long-term liabilities	236	217
Total Liabilities	8,380	8,209
Commitments and Contingencies (Note 9)		
Stockholders’ Equity		
Preferred stock, $0.01 par value, 20,000,000 shares authorized at March 31, 2015 and December 31, 2014:		
Series A 5.375% mandatory convertible preferred stock, $0.01 par value; 4,000,000 shares issued and outstanding at March 31, 2015 and December 31, 2014	400	400
Common stock, $0.01 par value, 420,000,000 shares authorized at March 31, 2015 and December 31, 2014; 124,667,804 shares and 124,436,941 shares issued and outstanding at March 31, 2015 and December 31, 2014, respectively	1	1
Additional paid-in capital	3,332	3,338
Accumulated other comprehensive income, net of tax	19	20
Accumulated deficit	(916)	(736)
Total Dynegy Stockholders’ Equity	2,836	3,023
Noncontrolling interest	(1)	—
Total Equity	2,835	3,023
Total Liabilities and Equity	$11,215	$11,232

See the notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2015	2014
Revenues	$632	$762
Cost of sales, excluding depreciation expense	(377)	(552)
Gross margin	255	210
Operating and maintenance expense	(111)	(110)
Depreciation expense	(64)	(67)
General and administrative expense	(30)	(26)
Acquisition and integration costs	(90)	(6)
Operating income (loss)	(40)	1
Interest expense	(136)	(30)
Other income and expense, net	(5)	(6)
Loss before income taxes	(181)	(35)
Income tax expense (Note 10)	—	(2)
Net loss	(181)	(37)
Less: Net income (loss) attributable to noncontrolling interest	(1)	4
Net loss attributable to Dynegy Inc.	(180)	(41)
Less: Dividends on preferred stock	5	—
Net loss attributable to Dynegy Inc. common stockholders	$(185)	$(41)
Loss Per Share (Note 12):		
Basic and diluted loss per share attributable to Dynegy Inc. common stockholders	$(1.49)	$(0.41)
Basic and diluted shares outstanding	124	100

See the notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2015	2014
Net loss	$(181)	$(37)
Other comprehensive loss before reclassifications:		
Actuarial loss (net of tax of zero and zero, respectively)	—	(3)
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service cost (credit) and actuarial loss (gain) (net of tax of zero and zero, respectively)	(1)	(1)
Other comprehensive loss, net of tax	(1)	(4)
Comprehensive loss	(182)	(41)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(1)	3
Total comprehensive loss attributable to Dynegy Inc.	$(181)	$(44)

See the notes to consolidated financial statements.

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

	Three Months Ended March 31, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(181)	$(37)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation expense	64	67
Non-cash interest expense	7	5
Amortization of intangibles	(4)	16
Risk management activities	(27)	52
Deferred income taxes	—	2
Change in value of common stock warrants	5	6
Other	11	9
Changes in working capital:		
Accounts receivable, net	1	23
Inventory	(18)	—
Prepayments and other current assets	(10)	(31)
Accounts payable and accrued liabilities	83	55
Changes in non-current assets	(4)	(2)
Changes in non-current liabilities	18	1
Net cash provided by (used in) operating activities	(55)	166
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(40)	(17)
Net cash used in investing activities	(40)	(17)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	—	11
Repayments of borrowings	(25)	(2)
Dividends paid	(7)	—
Interest rate swap settlement payments	(4)	(4)
Other financing	(5)	(1)
Net cash provided by (used) in financing activities	(41)	4
Net increase (decrease) in cash and cash equivalents	(136)	153
Cash and cash equivalents, beginning of period	1,870	843
Cash and cash equivalents, end of period	$1,734	$996

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2015 and 2014

Note 1—Basis of Presentation and Organization

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. The year-end consolidated balance sheet data was derived from audited consolidated financial statements but does not include all disclosures required by the Generally Accepted Accounting Principles of the United States of America ("GAAP"). The unaudited consolidated financial statements contained in this report include all material adjustments of a normal recurring nature that, in the opinion of management, are necessary for a fair presentation of the results for the interim periods. Certain prior period amounts in our consolidated financial statements have been reclassified to conform to current year presentation. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2014, filed with the SEC on February 25, 2015, which we refer to as our "Form 10-K." Unless the context indicates otherwise, throughout this report, the terms "Dynegy," "the Company," "we," "us," "our," and "ours" are used to refer to Dynegy Inc. and its direct and indirect subsidiaries.

Our current business operations are focused primarily on the unregulated power generation sector of the energy industry. We report the results of our power generation business as three segments in our unaudited consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). All significant intercompany transactions have been eliminated. Please read Note 14—Segment Information for further discussion.

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

On April 1, 2015, we completed the acquisition of EquiPower Resources Corp. and Brayton Point Holdings, LLC from Energy Capital Partners for an aggregate base purchase price of approximately $3.35 billion in cash plus $100 million in common stock of Dynegy, subject to certain adjustments. On April 2, 2015, we completed the acquisition of Duke Energy's commercial generation assets and retail business in the Midwest for a base purchase price of approximately $2.80 billion in cash, subject to certain adjustments. Please read Note 15—Subsequent Events for further discussion.

Note 2—Accounting Policies

The accounting policies followed by the Company are set forth in Note 2—Summary of Significant Accounting Policies in our Form 10-K. There have been no significant changes to these policies during the three months ended March 31, 2015.

The preparation of consolidated financial statements in conformity with GAAP requires management to make informed estimates and judgments that affect our reported financial position and results of operations based on currently available information. Actual results could differ materially from our estimates. The results of operations for the interim periods presented in this Form 10-Q are not necessarily indicative of the results to be expected for the full year or any other interim period due to seasonal fluctuations in demand for our energy products and services, changes in commodity prices, timing of maintenance and other expenditures and other factors.

Accounting Standards Adopted During the Current Period

Reporting Discontinued Operations and Asset Disposals. In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-08-Presentation of Financial Statements (Topic 205) and

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

Accounting Standards Not Yet Adopted

Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03-Interest-Imputation of Interest (Subtopic 835-30). The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. The guidance in this ASU is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The adoption of this ASU should be applied on a retrospective basis, affecting all balance sheet periods presented. We do not anticipate the adoption of this ASU will have a material impact on the presentation of our consolidated balance sheets.

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

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

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

Note 3—Risk Management Activities, Derivatives and Financial Instruments

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

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

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our unaudited consolidated statements of operations. We have other contractual arrangements such as capacity forward sales arrangements, tolling arrangements, fixed price coal purchases and retail power sales which do not receive recurring fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as “normal purchase,

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2015 and 2014

normal sale," in accordance with Accounting Standards Codification ("ASC") 815. As a result, the gains and losses with respect to these arrangements are not reflected in the unaudited consolidated statements of operations until the delivery occurs.

Quantitative Disclosures Related to Financial Instruments and Derivatives

As of March 31, 2015, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type (dollars and quantities in millions)	Quantity Purchases (Sales)	Unit of Measure	Fair Value (1) Asset (Liability)
Commodity contracts:			
Electricity derivatives (2)	(18)	MWh	$80
Electricity basis derivatives (3)	(12)	MWh	$(6)
Natural gas derivatives (2)	85	MMBtu	$(81)
Natural gas basis derivatives	22	MMBtu	$(2)
Diesel fuel derivatives	6	Gallon	$(5)
Coal derivatives	—	Metric Ton	$(1)
Crude oil derivatives	—	Barrel	$(2)
Emissions derivatives	5	Metric Ton	$1
Interest rate swaps	783	U.S. Dollar	$(49)
Common stock warrants (4)	16	Warrant	$(66)

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

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

		March 31, 2015			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$118	$(34)	$	$84
Total derivative assets		$118	$(34)	$—	$84
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(134)	$34	$2	$(98)
Interest rate contracts		(49)	—	—	(49)

	Liabilities from risk management activities				
Common stock warrants	Other long-term liabilities	(66)	—	—	(66)
Total derivative liabilities		$(249)	$34	$2	$(213)
Total derivatives		$(131)	$—	$2	$(129)

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

Certain of our derivative instruments have credit limits that require us to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as our established credit limit with the respective counterparty. If our credit rating were to change, the counterparties could require us to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in our credit rating as well as the requirements of the individual counterparty. The aggregate fair value of all commodity derivative instruments with credit-risk-related contingent features that are in a liability position that are not fully collateralized (excluding transactions with our clearing brokers that are fully collateralized) at March 31, 2015 is $1 million for which we have posted no collateral. Our remaining derivative instruments do not have credit-related collateral contingencies as they are included within our first-lien collateral program.
The following table summarizes our total cash collateral posted as of March 31, 2015 and December 31, 2014, along with the location on the balance sheet and the amount applied against our short-term risk management liabilities.

Location on balance sheet	March 31, 2015	December 31, 2014
(amounts in millions)		
Gross collateral posted with counterparties	$59	$49
Less: Collateral netted against risk management liabilities	2	9
Net collateral within Prepayments and other current assets	$57	$40

Impact of Derivatives on the Consolidated Statements of Operations
The following discussion and tables present the location and amount of gains and losses on derivative instruments in our unaudited consolidated statements of operations.
Financial Instruments Not Designated as Hedges. We elect not to designate derivatives related to our power generation business and interest rate instruments as cash flow or fair value hedges. Thus, we account for changes in the fair value of these derivatives within our unaudited consolidated statements of operations.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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For the Interim Periods Ended March 31, 2015 and 2014

The recognized impact of derivative financial instruments on our unaudited consolidated statements of operations for the three months ended March 31, 2015 and 2014 is presented below.

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended March 31, 2015	2014
(amounts in millions)			
Commodity contracts	Revenues	$19	$(173)
Interest rate contracts	Interest expense	$(9)	$3
Common stock warrants	Other income (expense), net	$(5)	$(6)

Note 4—Fair Value Measurements

We apply the market approach for recurring fair value measurements, employing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We have consistently used the same valuation techniques for all periods presented. Please read Note 2—Summary of Significant Accounting Policies—Fair Value Measurements in our Form 10-K for further discussion.

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

	Fair Value as of March 31, 2015			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$96	$17	$113
Natural gas derivatives	—	4	—	4
Emissions derivatives	—	1	—	1
Total assets from commodity risk management activities	$—	$101	$17	$118
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(26)	$(13)	$(39)
Natural gas derivatives	—	(87)	—	(87)
Diesel fuel derivatives	—	(5)	—	(5)
Crude oil derivatives	—	(2)	—	(2)
Coal derivatives	—	(1)	—	(1)
Total liabilities from commodity risk management activities	—	(121)	(13)	(134)
Liabilities from interest rate contracts	—	(49)	—	(49)
Liabilities from outstanding common stock warrants	(66)	—	—	(66)
Total liabilities	$(66)	$(170)	$(13)	$(249)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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For the Interim Periods Ended March 31, 2015 and 2014

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

Level 3 Valuation Methods. The electricity derivatives classified within Level 3 include physical sales and financial swaps executed in illiquid trading locations and FTRs. The curves used to generate the fair value of the physical sales and financial swaps are based on basis adjustments applied to forward curves for liquid trading points, while the forward market price of FTRs is derived using historical congestion patterns within the marketplace.

Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measure of our commodity instruments categorized within Level 3 of the fair value hierarchy are estimates of forward congestion power price spreads and illiquid power location pricing basis to liquid locations. These estimates are generally independent of each other. Power price spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price of the spread on a buy or sell position in isolation would result in a higher/lower fair value measurement. The significant unobservable inputs used in the valuation of Dynegy’s contracts classified as Level 3 as of March 31, 2015 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Input	Significant Unobservable Inputs Range
(dollars in millions)						
Electricity derivatives:						
Forward contracts—power (1)	(4)	Million MWh	$5	Basis spread + liquid location	Basis spread	$5.00-$7.00

FTRs	7	Million MWh	$(1)	Historical congestion	Forward price	$0.00-$3.00

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

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

	Three Months Ended March 31, 2015	
(amounts in millions)	Electricity Derivatives	Total
Balance at December 31, 2014	$(4)	$(4)
Total gains included in earnings	3	3
Settlements (1)	5	5
Balance at March 31, 2015	$4	$4
Unrealized gains relating to instruments held as of March 31, 2015	$3	$3

	Three Months Ended March 31, 2014		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at December 31, 2013	$11	$(1)	$10
Total losses included in earnings	(23)	—	(23)
Settlements (1)	2	—	2
Balance at March 31, 2014	$(10)	$(1)	$(11)
Unrealized losses relating to instruments held as of March 31, 2014	$(23)	$—	$(23)

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

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

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

We did not have any material nonfinancial assets or liabilities measured at fair value on a non-recurring basis during the three months ended March 31, 2015 and 2014.

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

(amounts in millions)	March 31, 2015 Carrying Amount	March 31, 2015 Fair Value	December 31, 2014 Carrying Amount	December 31, 2014 Fair Value
Dynegy Inc.:				
Tranche B-2 Term Loan, due 2020 (1)(2)	$(783)	$(786)	$(785)	$(775)
5.875% Senior Notes, due 2023 (2)	$(500)	$(486)	$(500)	$(475)
Emissions Repurchase Agreements (2)	$—	$—	$(23)	$(23)
Interest rate derivatives (2)	$(49)	$(49)	$(44)	$(44)
Commodity-based derivative contracts (3)	$(16)	$(16)	$(48)	$(48)
Common stock warrants (4)	$(66)	$(66)	$(61)	$(61)
Dynegy Finance I, Inc.:				
6.75% Senior Notes, due 2019 (2)	$(840)	$(874)	$(840)	$(853)
7.375% Senior Notes, due 2022 (2)	$(700)	$(739)	$(700)	$(711)
7.625% Senior Notes, due 2024 (2)	$(500)	$(531)	$(500)	$(509)
Dynegy Finance II, Inc.:				
6.75% Senior Notes, due 2019 (2)	$(1,260)	$(1,310)	$(1,260)	$(1,279)
7.375% Senior Notes, due 2022 (2)	$(1,050)	$(1,108)	$(1,050)	$(1,066)
7.625% Senior Notes, due 2024 (2)	$(750)	$(797)	$(750)	$(763)
Genco:				
7.95% Senior Notes Series F, due 2032 (2)(5)	$(224)	$(240)	$(224)	$(241)
7.00% Senior Notes Series H, due 2018 (2)(5)	$(270)	$(278)	$(268)	$(264)
6.30% Senior Notes Series I, due 2020 (2)(5)	$(208)	$(217)	$(206)	$(208)

(1) Carrying amount includes an unamortized discount of $3 million as of March 31, 2015 and December 31, 2014. Please read Note 8—Debt for further discussion.
(2) The fair values of these financial instruments are classified as Level 2 within the fair value hierarchy levels.
(3) Carrying amount of commodity-based derivative contracts excludes $2 million and $9 million of cash posted as collateral, as of March 31, 2015 and December 31, 2014, respectively.
(4) The fair value of the common stock warrants is classified as Level 1 within the fair value hierarchy levels.
(5) Combined carrying amounts as of March 31, 2015 and December 31, 2014 include unamortized discounts of $123 million and $127 million, respectively. Please read Note 8—Debt for further discussion.

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Note 5—Accumulated Other Comprehensive Income

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

	Three Months Ended March 31,	
(amounts in millions)	2015	2014
Beginning of period	$20	$58
Other comprehensive loss before reclassifications:		
Actuarial loss (net of tax of zero and zero, respectively)	—	(2)
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service cost (credit) and actuarial loss (gain) (net of tax of zero and zero, respectively) (1)	(1)	(1)
Net current period other comprehensive loss, net of tax	(1)	(3)
End of period	$19	$55

(1) Amounts are associated with our defined benefit pension and other post-employment benefit plans and are included in the computation of net periodic pension cost (gain). Please read Note 11—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 6—Inventory

A summary of our inventories is as follows:

(amounts in millions)	March 31, 2015	December 31, 2014
Materials and supplies	$84	$83
Coal	134	119
Fuel oil	3	3
Emissions allowances	2	2
Other	1	1
Total	$224	$208

Note 7—Intangible Assets and Liabilities

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

	March 31, 2015			December 31, 2014		
(amounts in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Intangible Assets:						
Electricity contracts	$111	$(53)	$58	$111	$(46)	$65
Total intangible assets	$111	$(53)	$58	$111	$(46)	$65
Intangible Liabilities:						
Electricity contracts	$(20)	$14	$(6)	$(20)	$14	$(6)
Coal contracts	(122)	63	(59)	(122)	54	(68)
Gas transport contracts	(24)	19	(5)	(24)	17	(7)
Total intangible liabilities	$(166)	$96	$(70)	$(166)	$85	$(81)
Intangible assets and liabilities, net	$(55)	$43	$(12)	$(55)	$39	$(16)

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The following table presents our amortization expense (revenue) of intangible assets and liabilities for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
(amounts in millions)	2015	2014
Electricity contracts, net (1)	$7	$29
Coal contracts, net (1)	(9)	(11)
Gas transport contracts (2)	(2)	(2)
Total	$(4)	$16

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

Note 8—Debt

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

(amounts in millions)	March 31, 2015	December 31, 2014
Dynegy Inc.:		
Tranche B-2 Term Loan, due 2020	$786	$788
5.875% Senior Notes, due 2023	500	500
Revolving Facility	—	—
Emissions Repurchase Agreements	—	23
Dynegy Finance I, Inc.:		
6.75% Senior Notes, due 2019	840	840
7.375% Senior Notes, due 2022	700	700
7.625% Senior Notes, due 2024	500	500
Dynegy Finance II, Inc.:		
6.75% Senior Notes, due 2019	1,260	1,260
7.375% Senior Notes, due 2022	1,050	1,050
7.625% Senior Notes, due 2024	750	750
Genco:		
7.95% Senior Notes Series F, due 2032	275	275
7.00% Senior Notes Series H, due 2018	300	300
6.30% Senior Notes Series I, due 2020	250	250
	7,211	7,236
Unamortized discounts on debt, net	(126)	(130)
	7,085	7,106
Less: Current maturities, including unamortized discounts, net	8	31
Total Long-term debt	$7,077	$7,075

Debt Issuance

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 “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 Acquisitions. Please read Note 11—Debt in our Form 10-K and Note 15—Subsequent Events—Acquisition Financing for further discussion.

Credit Agreement

As of March 31, 2015, we had a $1.275 billion credit agreement that consisted of (i) an $800 million seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan”) and (ii) a $475 million five-year senior secured revolving credit facility (the “Revolving Facility,” and collectively with the Tranche B-2 Term Loan, the “Credit Agreement”). Dynegy and its Subsidiary Guarantors (as defined in the Credit Agreement) also entered into an indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of unsecured senior notes (the “Senior Notes”) at par. Following the closings of the Acquisitions in April 2015, the acquired entities were added as additional subsidiary guarantors. Please read Note 15—Subsequent Events—Acquisition Financing for further discussion.

At March 31, 2015, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit of approximately $128 million, which reduces the amount available under the Revolving Facility.

The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a Senior Secured Leverage Ratio (as defined in the Credit Agreement) calculated on a rolling four quarters basis. Based on the calculation outlined in the Credit Agreement, we are in compliance at March 31, 2015.

In connection with the closings of the Acquisitions in April 2015, we entered into amendments to the Credit Agreement which provide for incremental revolving credit facilities that expand the credit available to us by an aggregate of $950 million ($600 million for the Duke Midwest Acquisition and $350 million for the EquiPower Acquisition). Please read Note 15—Subsequent Events—Acquisition Financing for further discussion.

Genco Senior Notes

On December 2, 2013, in connection with the acquisition of New Ameren Energy Resources, LLC (“AER”), Genco’s approximately $825 million in aggregate principal amount of unsecured senior notes (the “Genco Senior Notes”) remained outstanding as an obligation of Genco, a subsidiary of IPH.

Genco’s indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make principal or interest payments on subordinated borrowings, to make loans to or investments in affiliates, or to incur additional external, third-party indebtedness.

The following table summarizes these required ratios:

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

(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.

Genco’s debt incurrence-related ratio restrictions under the indenture may be disregarded if both Moody’s and S&P reaffirm the ratings in place at the time of the debt incurrence after considering the additional indebtedness.

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

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Letter of Credit Facilities

On January 29, 2014, Illinois Power Marketing Company ("IPM") entered into a fully cash collateralized Letter of Credit and Reimbursement Agreement with an issuing bank., as amended on May 16, 2014 ("LC Agreement"), pursuant to which the issuing bank agreed to issue from time to time, one or more standby letters of credit in an aggregate stated amount not to exceed $25 million at any one time to support performance obligations and other general corporate activities of IPM, provided that IPM deposits in an account controlled by the issuing bank an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereon. As of March 31, 2015, IPM had $10.5 million deposited with the issuing bank and $10 million in letters of credit outstanding.

On September 18, 2014, Dynegy entered into a Letter of Credit Reimbursement Agreement with an issuing bank, and its affiliate (the "Lender"), for a 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 March 31, 2015, there was $55 million outstanding under this letter of credit.

IPM Revolving Credit Facility

On March 27, 2015, IPM entered into a revolving credit facility with the Lender for up to $25 million. The facility, which is collateralized by receivables, has a two-year tenor and may be extended if agreed to by both parties for one additional year. Interest on the facility is LIBOR plus 500 basis points on issued letters of credit. At March 31, 2015, there were no amounts outstanding under this revolving facility.

Emissions Repurchase Agreements

In 2013, we entered into two repurchase transactions with a third party in which we sold $6 million in California Carbon Allowance ("CCA") credits and $11 million of Regional Greenhouse Gas Initiative ("RGGI") inventory and received cash. In the first quarter 2014, we entered into an additional repurchase agreement with a third party in which we sold $12 million of RGGI inventory and received cash. In October 2014, we repurchased all $6 million of the previously sold CCA credits and in February 2015, we repurchased all $23 million of the previously sold RGGI inventory.

Interest Rate Swaps

Subsequent to executing the Credit Agreement and issuing the Senior Notes, we amended our interest rate swaps to more closely match the terms of our Tranche B-2 Term Loan. The swaps have an aggregate notional value of approximately $783 million at an average fixed rate of 3.19 percent with a floor of one percent and expire during the second quarter 2020. In lieu of paying the breakage fees related to terminating the old swaps and issuing the new swaps, the costs were incorporated into the terms of the new swaps. As a result, any cash flows related to the settlement of the new swaps are reflected as a financing activity in our consolidated statement of cash flows.

Note 9—Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. We record accruals for estimated losses from contingencies when available information indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition, we disclose matters for which management believes a material loss is reasonably possible. In all instances, management has assessed the matters below based on current information and made judgments concerning their potential outcome, giving consideration to the nature of the claim, the amount, if any, and nature of damages sought and the probability of success. Management regularly reviews all new information with respect to such contingency and adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties including unfavorable rulings or developments, it is possible that the ultimate resolution of our legal proceedings could involve amounts that are different from our currently recorded accruals and that such differences could be material.

In addition to the matters discussed below, we are party to other routine proceedings arising in the ordinary course of business or related to discontinued business operations. Any accruals or estimated losses related to these matters are not material. In management’s judgment, the ultimate resolution of these matters will not have a material effect on our financial condition, results of operations or cash flows.

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Stockholder Litigation Relating to the 2011 Prepetition Restructuring. In connection with the prepetition restructuring and corporate reorganization of the Dynegy Holdings, LLC Debtor Entities and their non-debtor affiliates in 2011 (the "2011 Prepetition Restructuring"), and specifically the transfer of Dynegy Midwest Generation, LLC ("DMG"), a putative class action stockholder lawsuit captioned Charles Silsby v. Carl C. Icahn, et al., Case No. 12CIV2307 (the "Securities Litigation"), was filed in the U.S. District Court for the Southern District of New York. The lawsuit challenged certain disclosures made in connection with the transfer of DMG. As a result of the filing of the voluntary petition for bankruptcy by Dynegy Inc., this lawsuit was stayed as against Dynegy Inc. and, as a result of the confirmation of the Joint Chapter 11 Plan (the "Plan"), the claims against Dynegy Inc. in the Securities Litigation are permanently enjoined. On August 24, 2012, the lead plaintiff in the Securities Litigation filed an objection to the confirmation of the Plan asserting, among other things, that lead plaintiff should be permitted to opt-out of the non-debtor releases and injunctions (the "Non-Debtor Releases") in the Plan on behalf of all putative class members. We opposed that relief. On October 1, 2012, the Bankruptcy Court ruled that lead plaintiff did not have standing to object to the Plan and did not have authority to opt-out of the Non-Debtor Releases on behalf of any other party-in-interest. Accordingly, the Securities Litigation may only proceed against the non-debtor defendants with respect to members of the putative class who individually opted out of the Non-Debtor Releases. The lead plaintiff filed a notice of appeal on October 10, 2012. On June 4, 2013, the District Court dismissed the appeal. On October 31, 2014, the Second Circuit affirmed the District Court's dismissal based upon the lead plaintiff's lack of standing. The lead plaintiff did not appeal to the U.S. Supreme Court.

Additionally, on July 19, 2013, the defendants filed a substantive motion to dismiss the plaintiff's remaining claims by any opt-out plaintiffs against the non-debtor defendants. On April 30, 2014, the District Court granted the defendants' motion and dismissed the action. Plaintiff is appealing this decision to the Second Circuit, but no decision has been issued.

Gas Index Pricing Litigation. We, several of our affiliates, our former joint venture affiliate and other energy companies were named as defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications in the 2000-2002 time frame. Many of the cases have been resolved. All of the remaining cases contain similar claims that we individually, and in conjunction with other energy companies, engaged in an illegal scheme to inflate natural gas prices in four states by providing false information to natural gas index publications. In July 2011, the court granted defendants' motions for summary judgment, thereby dismissing all of plaintiffs' claims. Plaintiffs appealed the decision to the U.S. Court of Appeals for the Ninth Circuit which reversed the summary judgment on April 10, 2013. On August 26, 2013, we and the other defendants filed a request for review with the U.S. Supreme Court. On April 21, 2015, the Supreme Court issued its opinion affirming the Ninth Circuit's decision and remanding the matter to the Nevada District Court for further proceedings.

Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company ("IGC") received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC ("PPE"). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award in the District Court of Dallas County, Texas. In March 2010, the Dallas District Court vacated the award, finding that one of the arbitrators had exhibited evident partiality. PPE appealed that decision to the Fifth District Court of Appeals in Dallas, Texas. Coincident with the appeal, IGC filed a claim against PPE seeking recovery of the $17 million plus interest. In September 2010, the Dallas District Court ordered PPE to deposit the $17 million principal in an interest-bearing escrow account jointly owned by IGC and PPE. On August 20, 2012, the Dallas Court of Appeals reversed the Dallas District Court and reinstated the award. IGC and the other respondents filed a petition for review with the Texas Supreme Court on December 5, 2012. On May 23, 2014, the Texas Supreme Court reversed the Dallas Court of Appeals and reinstated the trial court's judgment vacating the arbitration award. The Texas Supreme Court denied rehearing on August 22, 2014. On November 20, 2014, PPE initiated a new arbitration against IGC and its co-respondents, but the Dallas District Court enjoined the arbitration from proceeding against IGC while any dispute over the escrow account remains pending. On December 16, 2014, the Dallas District Court entered a judgment requiring a full distribution of the escrow account to IGC and an additional $2.5 million in interest. PPE paid the $17 million principal to IGC from the escrow account, but filed a notice of appeal regarding the $17 million and $2.5 million interest judgment in March 2015.

Other Contingencies

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 coal combustion residual ("CCR") surface impoundments. The EPA assessments found all of our surface impoundments to be in satisfactory or fair condition, with the exception of the surface impoundments at the Baldwin and Hennepin facilities.

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The Baldwin and Hennepin reports rate the 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 asset retirement obligation ("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 the first quarter 2015, we submitted to the EPA engineering design information concerning repairs of the affected south berm at the Baldwin CCR surface impoundment and a deformation analysis of the Baldwin CCR surface impoundment's north berm. 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.

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 provisions under the Clean Air Act ("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 CAA Section 114 Information Requests. 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, Title V permitting and other requirements. We believe our 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 overturned, this decision may provide an additional defense to the allegations in the Newton facility Notice of Violation.

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.

Ultimate resolution of these matters could have a material adverse impact on our future financial condition, results of operations and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties. At this time we are unable to make

a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve these matters.
Edwards CAA Litigation. In April 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility. The District Court has scheduled the trial date for May 2016. IPH disputes the allegations and will defend the case vigorously. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve this matter.

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

Groundwater monitoring results indicate that the CCR surface impoundment 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 impacts offsite groundwater. Results of the offsite groundwater quality investigation at Baldwin, as submitted to the Illinois EPA on April 24, 2012, indicate two localized areas where Class I groundwater standards were exceeded. The cause of the exceedances is uncertain. If offsite groundwater impacts are ultimately attributed to the Baldwin CCR surface impoundment 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.

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 CCR surface impoundment and the north CCR 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 surface impoundments impact groundwater quality onsite and that such groundwater migrates offsite to the north of the property and to the adjacent Middle Fork of the Vermilion River. The proposed corrective action plans include groundwater monitoring and recommend closure of both CCR surface 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 that 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, are not anticipated to be completed until late 2015. In June 2014, we submitted the results of our evaluation at Baldwin 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 Baldwin out-of-service 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 Groundwater. 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 impoundments. 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, in April 2015, we submitted an assessment monitoring report to the Illinois EPA concerning previously reported groundwater quality standard exceedances at the Newton facility's active CCR landfill. The report identifies the Newton facility's inactive unlined landfill as the likely source of the contamination and recommends various measures to minimize the effects of that source on the groundwater monitoring results of the active landfill. The Illinois EPA also has required assessment monitoring at the Duck Creek facility's active CCR landfill, 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 CCR surface impoundments that impact groundwater in exceedance of applicable groundwater standards. 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 all power generating facilities in Illinois. The site-specific rulemaking, which now covers IPH CCR surface impoundments, has been stayed to allow the Illinois EPA proposed rulemaking to proceed.

At this time we cannot reasonably estimate the costs or range of costs of resolving the IPH groundwater matters, but resolution of these matters may cause IPH to incur significant costs that could have a material adverse effect on its financial condition, results of operations and cash flows.

Station Power Proceedings. On May 4, 2010, the U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. Circuit”) vacated FERC’s acceptance of station power rules for the CAISO market and remanded the case for further proceedings at FERC. On August 30, 2010, FERC issued an Order on Remand (“remand order”) effectively disclaiming jurisdiction over how the states impose retail station power charges. Due to reservation-of-rights language in the California utilities’ state-jurisdictional station power tariffs, the California utilities have argued that FERC’s ruling requires California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO’s station power program. The remand order could impact FERC’s station power policies in all of the organized markets throughout the nation.

On November 18, 2011, Pacific Gas and Electric Company (“PG&E”) filed with the CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively. On August 15, 2014, the CPUC approved a Draft Resolution that orders retroactive charges to be assessed against generators dating back to August 30, 2010. In March of 2015, Dynegy settled its total retroactive charges for station power with PG&E. We had previously accrued for this settlement.

Other Commitments

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, design and construction, plant sites, power generation assets and liquefied petroleum gas vessel charters. The following describes the more significant commitments outstanding at March 31, 2015.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. Recently we have undertaken several measures to restructure our existing maintenance agreements as well as negotiate new long-term maintenance service agreements with proven turbine service providers. The term of these agreements will be determined by the maintenance cycles of the respective facility. We currently estimate these agreements will be in effect for a period of 15 or more years. Either party can terminate the agreements based on certain events as specified in the contracts. As of March 31, 2015, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $159 million and $214 million in the event all contracts are terminated by us or the counterparty, respectively.

Coal Commitments. During the three months ended March 31, 2015, we entered into three new contracts to purchase coal for our generation facilities from 2015 through 2020 with aggregate minimum commitments of $145 million. 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. During the three months ended March 31, 2015, we executed two new coal transportation contracts for our generation facilities from 2015 through 2027 with aggregate minimum commitments of $254 million.

Charter Agreements. In addition, we are party to two charter agreements related to very large gas carriers (“VLGCs”) previously utilized in our former global liquids business. The primary term of one charter expired at the end of

September 2013 but has been extended annually, through September 2016, at the option of the counterparty. The primary term of the second charter was through September 2014 but has been extended through September 2016 at the option of the counterparty. The first charter will terminate at the end of September 2016, and the second charter has one optional one-year extension remaining. Both of these VLGCs have been sub-chartered to a wholly-owned subsidiary of Transammonia Inc. on terms that are identical to the terms of the original charter agreements. The aggregate minimum base commitments of the charter party agreements are approximately $11 million for each of the years ended December 31, 2015 and 2016. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreement and has not exercised the remaining optional extension.

DYNEGY INC.
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Indemnifications and Guarantees

In the ordinary course of business, we routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, asset sales agreements, and procurement and construction contracts. Some agreements contain indemnities that cover the other party's negligence or limit the other party's liability with respect to third party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be remote.

LS Power Indemnities. In connection with the transaction with LS Power we agreed in the purchase and sale agreement to indemnify LS Power against claims regarding any breaches in our representations and warranties and certain other potential liabilities. Even though Dynegy was discharged from any claims pursuant to the order confirming the Plan (the "Confirmation Order"), Dynegy Power Generation Inc., Dynegy Power, LLC ("DPC"), DMG and Dynegy Power Marketing, LLC remain jointly and severally liable for any indemnification claims. Although certain of the indemnification obligations are indefinite, some have exceeded the survival period in the relevant transaction agreements or have exceeded the applicable statute of limitations. In addition, some of these indemnification obligations are subject to individual thresholds and/or maximum aggregate limits depending on the terms of the transaction agreement. We have accrued no amounts with respect to the indemnifications as of March 31, 2015 because none were probable of occurring, nor could they be reasonably estimated.

EquiPower Acquisition. In connection with the ECP Purchase Agreement, the ECP Purchasers agreed to indemnify the ECP Sellers against claims regarding breaches in the covenants and representations and warranties of the ECP Purchasers and certain other potential liabilities. The indemnification obligations of the ECP Purchasers shall survive for one year for most covenants and representations and warranties of the ECP Purchasers, two years for fundamental representations, and indefinitely for certain other matters. The ECP Sellers shall, in the aggregate, not be entitled to indemnification in excess of $276 million. We have accrued no amounts with respect to this indemnification as of March 31, 2015 because none were probable of occurring, nor could they be reasonably estimated. Please read Note 15—Subsequent Events—Acquisitions for further discussion.

Duke Midwest Acquisition. In connection with the Duke Midwest Purchase Agreement, Dynegy Resource I, LLC ("DRI") agreed to indemnify Duke Energy against claims regarding breaches in the covenants and representations and warranties of DRI and certain other potential liabilities. The indemnification obligations of DRI shall survive for one year for most covenants and representations and warranties of DRI, three years for fundamental representations, 30 days after the applicable statute of limitations for certain tax matters, and indefinitely for certain other matters. We have accrued no amounts with respect to this indemnification as of March 31, 2015 because none were probable of occurring, nor could they be reasonably estimated. Dynegy has guaranteed, up to maximum liability of $2.80 billion, the obligations of DRI under the Duke Midwest Purchase Agreement and related Transition Services Agreement. Please read Note 15—Subsequent Events—Acquisitions for further discussion.

Limited Guaranty. In connection with the acquisition of AER, Dynegy has provided a Limited Guaranty of certain obligations of IPH up to $25 million. Concurrently with the execution of the AER transaction agreement, Dynegy entered into the Limited Guaranty, capped at $25 million in favor of Ameren Corporation ("Ameren"), for a period of two years after the closing (subject to certain exceptions) with respect to IPH's indemnification obligations and certain reimbursement obligations under the AER transaction agreement. We have accrued no amounts with respect to the guaranty as of March 31, 2015 because none were probable of occurring, nor could they be reasonably estimated.

Note 10—Income Taxes

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs.

As of March 31, 2015, we continued to maintain a valuation allowance against our net deferred tax assets as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future. We expect that a significant portion of the valuation allowance will be released in the second quarter of 2015 as a result of increased deferred tax liabilities related to the EquiPower Acquisition. Please read Note 15—Subsequent Events for further discussion.

DYNEGY INC.
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Note 11—Pension and Other Post-Employment Benefit Plans

We sponsor and administer defined benefit plans and defined contribution plans for the benefit of our employees and also provide other post-employment benefits to retirees who meet age and service requirements which are more fully described in Note 17—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans in our Form 10-K.

The components of net periodic benefit cost (gain) were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,			
(amounts in millions)	2015	2014	2015	2014
Service cost benefits earned during period	$3	$3	$—	$—
Interest cost on projected benefit obligation	4	4	1	1
Expected return on plan assets	(5)	(5)	(1)	(1)
Amortization of:				
Prior service credit	—	—	(1)	(1)
Net periodic benefit cost (gain)	$2	$2	$(1)	$(1)

Note 12—Loss Per Share

The basic and diluted loss per share from continuing operations attributable to our common stockholders during the three months ended March 31, 2015 and 2014 is shown in the following table. Please read Note 16—Capital Stock in our Form 10-K for further discussion.

	Three Months Ended March 31,	
(in millions, except per share amounts)	2015	2014
Loss from continuing operations	$(181)	$(37)
Less: Net income (loss) attributable to noncontrolling interest	(1)	4
Loss from continuing operations attributable to Dynegy Inc.	(180)	(41)
Less: Dividends on preferred stock	5	—
Loss from continuing operations attributable to Dynegy Inc. common stockholders	$(185)	$(41)
Basic and diluted weighted-average shares (1)	124	100
Basic and diluted loss per share from continuing operations attributable to Dynegy Inc. common stockholders (1)	$(1.49)	$(0.41)

(1) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the three months ended March 31, 2015 and 2014.

The following potentially dilutive securities were not included in the computation of diluted per share amounts because the effect would be anti-dilutive:

	Three Months Ended March 31,	
(in millions of shares)	2015	2014
Stock options	1.8	1.4
Restricted stock units	1.2	1.2
Performance stock units	0.6	0.3
Warrants	15.6	15.6
Series A 5.375% mandatory convertible preferred stock	12.7	—
Total	31.9	18.5

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Note 13—Condensed Consolidating Financial Information
On May 20, 2013, Dynegy issued the Senior Notes, as further described in Note 8—Debt. On October 27, 2014, the Escrow Issuers, wholly-owned subsidiaries of Dynegy, issued the Notes as further described in Note 8—Debt. The 100 percent owned subsidiary guarantors, jointly, severally and unconditionally, guaranteed the payment obligations under the Senior Notes and Notes. Not all of Dynegy's subsidiaries guarantee the Senior Notes and Notes including Dynegy's indirect, wholly-owned subsidiary, IPH, which acquired AER and its subsidiaries on December 2, 2013.
The following condensed consolidating financial statements present the financial information of (i) Dynegy (Parent), which is the parent and issuer of the Senior Notes, on a stand-alone, unconsolidated basis, (ii) Escrow Issuers, which are the finance company issuers of the Notes, (iii) the guarantor subsidiaries of Dynegy, (iv) the non-guarantor subsidiaries of Dynegy and (v) the eliminations necessary to arrive at the information for Dynegy on a consolidated basis.
These statements should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Dynegy. The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements.
For purposes of the condensed consolidating financial information, a portion of our intercompany receivable which we do not consider to be likely of settlement has been classified as equity as of March 31, 2015 and December 31, 2014.
Condensed Consolidating Balance Sheet as of March 31, 2015
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets						
Cash and cash equivalents	$1,438	$—	$ 122	$ 174	$—	$ 1,734
Restricted cash	—	205	—	—	—	205
Accounts receivable, net	15	—	615	163	(525)	268
Inventory	—	—	90	134	—	224
Other current assets	17	7	127	75	—	226
Total Current Assets	1,470	212	954	546	(525)	2,657
Property, Plant and Equipment, Net	—	—	2,781	446	—	3,227
Other Assets						
Investment in affiliates	5,986	—	—	—	(5,986)	—
Other long-term assets	57	54	67	53	—	231
Restricted cash	—	5,100	—	—	—	5,100
Intercompany note receivable	11	—	—	—	(11)	—
Total Assets	$7,524	$5,366	$ 3,802	$ 1,045	$ (6,522)	$ 11,215
Current Liabilities						
Accounts payable	$114	$260	$ 159	$ 240	$ (525)	$ 248
Other current liabilities	71	166	155	180	—	572
Total Current Liabilities	185	426	314	420	(525)	820
Long-term debt	1,275	5,100	—	702	—	7,077
Intercompany note payable	3,042	—	—	11	(3,053)	—
Other long-term liabilities	186	—	109	188	—	483
Total Liabilities	4,688	5,526	423	1,321	(3,578)	8,380
Stockholders' Equity						
Dynegy Stockholders' Equity	2,836	(160)	6,421	(275)	(5,986)	2,836

Intercompany note receivable	—	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,836	(160)	3,379	(275)	(2,944)	2,836
Noncontrolling interest	—	—	—	(1)	—	(1)
Total Equity	2,836	(160)	3,379	(276)	(2,944)	2,835
Total Liabilities and Equity	$7,524	$5,366	$ 3,802	$ 1,045	$ (6,522)	$ 11,215

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Condensed Consolidating Balance Sheet as of December 31, 2014
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets						
Cash and cash equivalents	$1,642	$—	$54	$174	$—	$1,870
Restricted cash	—	113	—	—	—	113
Accounts receivable, net	14	—	672	176	(592)	270
Inventory	—	—	88	120	—	208
Other current assets	9	6	125	73	—	213
Total Current Assets	1,665	119	939	543	(592)	2,674
Property, Plant and Equipment, Net	—	—	2,812	443	—	3,255
Other Assets						
Investment in affiliates	6,133	—	—	—	(6,133)	—
Other long-term assets	46	47	53	57	—	203
Restricted cash	—	5,100	—	—	—	5,100
Intercompany note receivable	17	—	—	—	(17)	—
Total Assets	$7,861	$5,266	$3,804	$1,043	$(6,742)	$11,232
Current Liabilities						
Accounts payable	$310	$166	$112	$220	$(592)	$216
Other current liabilities	51	67	250	97	—	465
Total Current Liabilities	361	233	362	317	(592)	681
Long-term debt	1,277	5,100	—	698	—	7,075
Intercompany note payable	3,042	—	—	17	(3,059)	—
Other long-term liabilities	158	—	105	190	—	453
Total Liabilities	4,838	5,333	467	1,222	(3,651)	8,209
Stockholders' Equity						
Dynegy Stockholders' Equity	3,023	(67)	6,379	(179)	(6,133)	3,023
Intercompany note receivable	—	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	3,023	(67)	3,337	(179)	(3,091)	3,023
Noncontrolling interest	—	—	—	—	—	—
Total Equity	3,023	(67)	3,337	(179)	(3,091)	3,023
Total Liabilities and Equity	$7,861	$5,266	$3,804	$1,043	$(6,742)	$11,232

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
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Condensed Consolidating Statements of Operations for the Three Months Ended March 31, 2015
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$—	$ 413	$ 219	$ —	$ 632
Cost of sales, excluding depreciation expense	—	—	(239)	(138)	—	(377)
Gross margin	—	—	174	81	—	255
Operating and maintenance expense	—	—	(60)	(51)	—	(111)
Depreciation expense	—	—	(56)	(8)	—	(64)
General and administrative expense	(1)	—	(17)	(12)	—	(30)
Acquisition and integration costs	—	—	—	(90)	—	(90)
Operating income (loss)	(1)	—	41	(80)	—	(40)
Equity in losses from investments in affiliates	(147)	—	—	—	147	—
Interest expense	(27)	(93)	—	(16)	—	(136)
Other income and expense, net	(5)	—	—	—	—	(5)
Income (loss) before income taxes	(180)	(93)	41	(96)	147	(181)
Income tax expense	—	—	—	—	—	—
Net income (loss)	(180)	(93)	41	(96)	147	(181)
Less: Net loss attributable to noncontrolling interest	—	—	—	(1)	—	(1)
Net income (loss) attributable to Dynegy Inc.	$ (180)	$ (93)	$ 41	$ (95)	$ 147	$ (180)

Condensed Consolidating Statements of Operations for the Three Months Ended March 31, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 558	$ 204	$ —	$ 762
Cost of sales, excluding depreciation expense	—	(393)	(159)	—	(552)
Gross margin	—	165	45	—	210
Operating and maintenance expense	—	(63)	(47)	—	(110)
Depreciation expense	—	(59)	(8)	—	(67)
General and administrative expense	(2)	(14)	(10)	—	(26)
Acquisition and integration costs	—	—	(6)	—	(6)
Operating income (loss)	(2)	29	(26)	—	1
Equity in losses from investments in affiliates	(39)	—	—	39	—
Interest expense	(16)	—	(14)	—	(30)
Other income and expense, net	(6)	—	—	—	(6)
Income (loss) before income taxes	(63)	29	(40)	39	(35)
Income tax benefit (expense)	22	—	(24)	—	(2)
Net income (loss)	(41)	29	(64)	39	(37)
	—	—	4	—	4

Less: Net income attributable to noncontrolling interest					
Net income (loss) attributable to Dynegy Inc.	$ (41)	$ 29	$ (68)	$ 39	$ (41)

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended March 31, 2015

(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$ (180)	$ (93)	$ 41	$ (96)	$ 147	$ (181)
Amounts reclassified from accumulated other comprehensive income:						
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(1)	—	—	—	—	(1)
Other comprehensive loss, net of tax	(1)	—	—	—	—	(1)
Comprehensive income (loss)	(181)	(93)	41	(96)	147	(182)
Less: Comprehensive loss attributable to noncontrolling interest	—	—	—	(1)	—	(1)
Total comprehensive income (loss) attributable to Dynegy Inc.	$ (181)	$ (93)	$ 41	$ (95)	$ 147	$ (181)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended March 31, 2014

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$ (41)	$ 29	$ (64)	$ 39	$ (37)
Other comprehensive income (loss) before reclassifications:					
Actuarial loss, net of tax of zero	—	—	(3)	—	(3)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(1)	—	—	—	(1)
Other comprehensive income (loss) from investment in affiliates	(3)	—	—	3	—
Other comprehensive income (loss), net of tax	(4)	—	(3)	3	(4)
Comprehensive income (loss)	(45)	29	(67)	42	(41)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(1)	—	3	1	3
Total comprehensive income (loss) attributable to Dynegy Inc.	$ (44)	$ 29	$ (70)	$ 41	$ (44)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Condensed Consolidating Statements of Cash Flow for the Three Months Ended March 31, 2015

(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:						
Net cash provided by (used in) operating activities	$ 2	$ (94)	$ 46	$ (9)	$ —	$ (55)
CASH FLOWS FROM INVESTING ACTIVITIES:						
Capital expenditures	—	—	(29)	(11)	—	(40)
Net intercompany transfers	(188)	—	—	—	188	—
Net cash provided by (used in) investing activities	(188)	—	(29)	(11)	188	(40)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Repayments of borrowings	(2)	—	(23)	—	—	(25)
Dividends paid	(7)	—	—	—	—	(7)
Net intercompany transfers	—	94	74	20	(188)	—
Interest rate swap settlement payments	(4)	—	—	—	—	(4)
Other financing	(5)	—	—	—	—	(5)
Net cash provided by (used in) financing activities	(18)	94	51	20	(188)	(41)
Net increase (decrease) in cash and cash equivalents	(204)	—	68	—	—	(136)
Cash and cash equivalents, beginning of period	1,642	—	54	174	—	1,870
Cash and cash equivalents, end of period	$ 1,438	$ —	$ 122	$ 174	$ —	$ 1,734

Condensed Consolidating Statements of Cash Flow for the Three Months Ended March 31, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (9)	$ 140	$ 35	$ —	$ 166
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(6)	(11)	—	(17)
Net intercompany transfers	113	—	—	(113)	—
Net cash provided by (used in) investing activities	113	(6)	(11)	(113)	(17)
CASH FLOWS FROM FINANCING ACTIVITIES:					
	(1)	12	—	—	11

Proceeds from long-term borrowings, net of financing costs					
Repayments of borrowings	(2)	—	—	—	(2)
Net intercompany transfers	—	(142)	29	113	—
Interest rate swap settlement payments	(4)	—	—	—	(4)
Other financing	(1)	—	—	—	(1)
Net cash provided by (used in) financing activities	(8)	(130)	29	113	4
Net increase in cash and cash equivalents	96	4	53	—	153
Cash and cash equivalents, beginning of period	474	154	215	—	843
Cash and cash equivalents, end of period	$570	$ 158	$ 268	$ —	$ 996

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2015 and 2014

Note 14—Segment Information

We report the results of our operations in three segments: (i) Coal, (ii) IPH and (iii) Gas. The Coal segment includes DMG, which owns, directly and indirectly, certain of our coal-fired power generation facilities, and our Dynegy Energy Services retail business. The IPH segment includes Genco, and Illinois Power Resources Generating, LLC ("IPRG") which also own, directly and indirectly, certain of our coal-fired power generation facilities. IPH also includes our Homefield Energy retail business in Illinois. IPH and its direct and indirect subsidiaries and Genco and its direct and indirect subsidiaries are each organized into ring-fenced groups in order to maintain corporate separateness. The Gas segment includes DPC, which owns, directly or indirectly, substantially all of our natural gas-fired power generation facilities. Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). General and administrative expense is reported in Other for all periods presented.

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three months ended March 31, 2015 and 2014 is presented below:

Segment Data as of and for the Three Months Ended March 31, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$143	$219	$270	$—	$632
Intercompany revenues	(1)	—	1	—	—
Total revenues	$142	$219	$271	$—	$632
Depreciation expense	$(10)	$(8)	$(45)	$(1)	$(64)
General and administrative expense	—	—	—	(30)	(30)
Acquisition and integration costs	—	—	—	(90)	(90)
Operating income (loss)	$7	$22	$52	$(121)	$(40)
Interest expense				(136)	(136)
Other income and expense, net	—	—	—	(5)	(5)
Loss before income taxes					(181)
Income tax expense				—	—
Net loss					(181)
Less: Net loss attributable to noncontrolling interest					(1)
Net loss attributable to Dynegy Inc.					$(180)
Identifiable assets (domestic)	$1,162	$1,037	$2,105	$6,911	$11,215
Capital expenditures	$(3)	$(11)	$(24)	$(2)	$(40)

DYNEGY INC.
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Segment Data as of and for the Three Months Ended March 31, 2014

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$161	$203	$398	$—	$762
Intercompany revenues	(5)	1	4	—	—
Total revenues	$156	$204	$402	$—	$762
Depreciation expense	$(14)	$(8)	$(44)	$(1)	$(67)
General and administrative expense	—	—	—	(26)	(26)
Operating income (loss)	$9	$(16)	$34	$(26)	$1
Interest expense				(30)	(30)
Other income and expense, net	—	—	—	(6)	(6)
Loss before income taxes					(35)
Income tax expense				(2)	(2)
Net loss					(37)
Less: Net income attributable to noncontrolling interest					4
Net loss attributable to Dynegy Inc.					$(41)
Identifiable assets (domestic)	$1,198	$1,203	$2,202	$749	$5,352
Capital expenditures	$(3)	$(11)	$(2)	$(1)	$(17)

Note 15—Subsequent Events

Acquisitions

ECP and ERC Purchase Agreements. On April 1, 2015 (the “EquiPower Closing Date”), pursuant to the terms of the stock purchase agreement dated August 21, 2014, as amended (the “ERC Purchase Agreement”), by and among our wholly-owned subsidiary, Dynegy Resource II, LLC (“ERC Purchaser”) and Energy Capital Partners II, LP (“ECP II”), Energy Capital Partners II-A, LP (“ECP II-A”), Energy Capital Partners II-B, LP (“ECP II-B”), Energy Capital Partners II-C (Direct IP), LP (“ECP II-C”), Energy Capital Partners II-D, LP (“ECP II-D”), and Energy Capital Partners II (EquiPower Co-Invest), LP (“ECP Coinvest” and, collectively with ECP II, ECP II-A, ECP II-B, ECP II-C and ECP II-D, the “ERC Sellers”), EquiPower Resources Corp. (“ERC”), and solely for certain limited purposes set forth therein, each of Energy Capital Partners II-C, LP (“ECP II-C Fund”), and Dynegy, pursuant to which the ERC Purchaser, subject to the terms and conditions in the ERC Purchase Agreement, purchased from the ERC Sellers 100 percent of the equity interests in ERC, thereby acquiring (i) five combined cycle natural gas-fired facilities in Connecticut, Massachusetts and Pennsylvania, (ii) a partial interest in one natural gas-fired peaking facility in Illinois, (iii) two gas and oil-fired peaking facilities in Ohio and (iv) one coal-fired facility in Illinois (the “ERC Acquisition”).

On the EquiPower Closing Date, in a related transaction, pursuant to a stock purchase agreement and plan of merger dated August 21, 2014, as amended (the “Brayton Purchase Agreement” and, together with the ERC Purchase Agreement, the “ECP Purchase Agreement”), by and among our wholly-owned subsidiaries, Dynegy Resource III, LLC (the “Brayton Purchaser” and, together with the ERC Purchaser, the “ECP Purchasers”), and Dynegy Resource III-A, LLC, the (“Merger Sub”), and Energy Capital Partners GP II, LP (“ECP GP”), ECP II, ECP II-A, ECP II-B, ECP II-D, and Energy Capital Partners II-C (Cayman), L.P. (“ECP II-C (Cayman)” and, collectively with ECP GP, ECP II, ECP II-A, ECP II-B and ECP II-D, the “Brayton Sellers” and, together with the ERC Sellers, the “ECP Sellers”), Brayton Point Holdings, LLC (“Brayton”), and, solely for certain limited purposes set forth therein, each of ECP II-C Fund and

Dynegy, pursuant to which Brayton Purchaser purchased from Brayton Sellers and other holders of equity interests in Brayton, through a stock purchase and the related merger of Merger Sub with and into Brayton, 100 percent of the equity interests in Brayton, a coal-fired facility in Massachusetts, (the “Brayton Acquisition”).

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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The ERC Acquisition and the Brayton Acquisition (collectively, the "EquiPower Acquisition") added approximately 6,300 MW of generation in Connecticut, Illinois, Massachusetts, Ohio and Pennsylvania for an aggregate base purchase price of approximately $3.35 billion in cash plus $100 million in common stock of Dynegy, subject to certain adjustments.

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

Duke Midwest Purchase Agreement. On April 2, 2015 (the "Duke Midwest Closing Date"), pursuant to the terms of the purchase and sale agreement dated August 21, 2014, as amended (the "Duke Midwest Purchase Agreement"), by and among our wholly-owned subsidiary, DRI, and Duke Energy SAM, LLC ("Duke Energy SAM") and Duke Energy Commercial Enterprises, Inc. ("Duke Energy CE" and, together with Duke Energy SAM, "Duke Energy"), DRI purchased from Duke Energy 100 percent of the membership interests in Duke Energy Commercial Asset Management, LLC and Duke Energy Retail Sales, LLC, thereby acquiring approximately 6,200 MW of generation in (i) five natural gas-fired power facilities located in Ohio, Pennsylvania and Illinois, (ii) one oil-fired power facility located in Ohio, (iii) partial interests in five coal-fired power facilities located in Ohio and (iv) a retail energy business for a base purchase price of approximately $2.80 billion in cash, subject to certain adjustments (the "Duke Midwest Acquisition" and, together with the EquiPower Acquisition, the "Acquisitions"). We will operate two of the five coal-fired facilities, the Miami Fort and Zimmer facilities, with other owners operating the three remaining facilities.

Under the Duke Midwest Purchase Agreement, DRI and Duke Energy have agreed to indemnify the other applicable parties for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions and limitations. Dynegy has guaranteed, up to a maximum liability of $2.80 billion, the obligations of DRI under the Duke Midwest Purchase Agreement and related Transition Services Agreement. DRI shall, in the aggregate, not be entitled to indemnification in excess of $280 million for most matters and $2.80 billion for certain fundamental representations, tax matters and fraud.

Business Combination Accounting. In connection with our purchase price allocation, we are currently in the process of valuing the assets acquired and liabilities assumed in the Acquisitions. We are currently unable to provide pro forma financial results or the amounts recognized as of the respective acquisition dates for the major classes of assets acquired and liabilities assumed in the Acquisitions. We will provide these disclosures in our quarterly report on Form 10-Q for the second quarter of 2015.

Acquisition Financing

Credit Agreement Amendments. On the EquiPower Closing Date, Dynegy entered into a First Amendment to the Credit Agreement (the "First Amendment") among Dynegy, certain subsidiaries of Dynegy, the lenders party thereto, Credit Suisse AG, Cayman Islands Branch ("Credit Suisse"), as administrative agent, and the other parties thereto. The First Amendment provides for a new $350 million five-year senior secured incremental tranche of revolving commitments (the "Incremental Tranche A Revolving Loan Commitments"), which have terms substantially the same as the terms of the outstanding tranche of revolving loans under the Credit Agreement and will mature on April 1, 2020. Amounts available under the Incremental Tranche A Revolving Loan Commitments are available on a revolving basis, and such amounts that are repaid or prepaid may be re-borrowed. The loans issued pursuant to the Incremental Tranche A Revolving Loan Commitments bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio (as such terms are defined in the Credit Agreement).

Further on the Duke Midwest Closing Date, Dynegy entered into a Second Amendment to the Credit Agreement (the "Second Amendment") among the Company, certain subsidiaries of Dynegy, the lenders party thereto, Credit Suisse, as administrative agent, and the other parties thereto. The Second Amendment provides for a new $600 million five-year senior secured incremental tranche of revolving commitments (the “Incremental Tranche B Revolving Loan Commitments”), which have terms substantially the same as the terms of the outstanding tranche of revolving loans under the Credit Agreement and will mature on April 2, 2020. Amounts available under the Incremental Tranche B Revolving Loan Commitments are available on a revolving basis, and such amounts that are repaid or prepaid may be re-borrowed. The loans issued pursuant to the Incremental Tranche B Revolving Loan Commitments bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio (as such terms are defined in the Credit Agreement).

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

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

The following table sets forth the debt assumed by Dynegy following the EquiPower Closing Date and the Duke Midwest Closing Date:

(amounts in millions)	April 2, 2015
Dynegy Inc.:	
6.75% Senior Notes, due 2019	$2,100
7.375% Senior Notes, due 2022	$1,750
7.625% Senior Notes, due 2024	$1,250

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

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

Senior Notes

On the respective closing dates, Dynegy executed a second and third supplemental indenture adding the EquiPower Guarantors and the Duke Guarantors as guarantors of the $500 million in aggregate principal amount of the Senior Notes.

Dividends

On March 3, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million in the aggregate. The dividend is for the dividend period beginning on February 1, 2015 and ending on April 30, 2015. Such dividends were paid on May 1, 2015 to stockholders of record as of April 15, 2015.

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended March 31, 2015 and 2014

Item 2—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read together with the unaudited consolidated financial statements and the notes thereto included in this report and with the audited consolidated financial statements and the notes thereto included in our Form 10-K.

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 unregulated power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our unaudited consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas"). On April 1, 2015, we completed the acquisition of EquiPower Resources Corp. and Brayton Point Holdings, LLC from Energy Capital Partners for an aggregate base purchase price of approximately $3.35 billion in cash plus $100 million in common stock of Dynegy, subject to certain adjustments. On April 2, 2015, we completed the acquisition of Duke Energy's commercial generation assets and retail business in the Midwest for a base purchase price of approximately $2.80 billion in cash, subject to certain adjustments. With these transactions, we now own approximately 26,000 MW of generating capacity in eight states and also provide retail electricity to 830,000 residential customers and 23,000 commercial, industrial and municipal customers in Illinois, Ohio and Pennsylvania.

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 revolving 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.

In connection with the closings of the Acquisitions, we entered into amendments to the Credit Agreement which provide for incremental revolving credit facilities that expand the credit available to us by an aggregate of $950 million ($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. The loans issued pursuant to these facilities bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio. We had approximately $900 million available as of the closing of the Acquisitions, net of expected letters of credit outstanding, for future borrowings under our current and incremental revolving credit facilities. Please read Note 15—Subsequent Events—Acquisition Financing for further discussion regarding our incremental revolving credit facilities.

On March 27, 2015, IPM entered into a revolving credit facility with an issuing bank for up to $25 million. The facility, which is collateralized by receivables, has a two-year tenor and may be extended if agreed to by both parties for one additional

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year. Interest on the facility is LIBOR plus 500 basis points on issued letters of credit. At March 31, 2015, there were no amounts outstanding under this revolving facility. Please read Note 8—Debt—Letter of Credit Facilities for further discussion.

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

	March 31, 2015		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolving facilities and LC capacity (3)	$530	$25	$555
Less: Outstanding letters of credit	(183)	—	(183)
Revolving facilities and LC availability	347	25	372
Cash and cash equivalents	1,560	174	1,734
Total available liquidity (4)(5)	$1,907	$199	$2,106

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(1) Includes cash of $127 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: (i) $475 million of available capacity related to the five-year senior secured revolving credit facility and $55 million related to a letter of credit and (ii) $25 million related to the two-year secured revolving credit facility. Please read Note 8—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 March 31, 2015, there was $11 million outstanding on the note, which is not reflected in the table above.

(5) After the close of the Acquisitions, our total available liquidity was approximately $1.80 billion.

The following table presents net cash from operating, investing and financing activities for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
(amounts in millions)	2015	2014
Net cash provided by (used in) operating activities	$(55)	$166
Net cash used in investing activities	$(40)	$(17)
Net cash provided by (used in) financing activities	$(41)	$4

Operating Activities

Historical Operating Cash Flows. Cash used in operations totaled $55 million for the three months ended March 31, 2015. During the period, our power generation business provided cash of $111 million primarily due to the operation of our power generation facilities and our retail operations. Corporate and other activities used cash of $99 million primarily due to interest payments on the Notes issued in 2014 of $92 million funded into the escrow account related to those Notes, interest payments related to our Credit Agreement, Senior Notes and Genco Senior Notes of $16 million, and payments for acquisition-related costs of $8 million, offset by $17 million related to the PPE cash receipt. In addition, changes in working capital and other, including general and administrative expenses, used cash of approximately $67 million.

Cash provided by operations totaled $166 million for the three months ended March 31, 2014. During the period, our power generation business provided cash of $151 million primarily due to the operation of our power generation facilities, partially offset by payments for acquisition and integration costs. Corporate and other activities used cash of approximately $31 million primarily due to interest payments to service debt related to our Credit Agreement and Senior Notes, employee-related payments and other general and administrative expense. This use of cash was partially offset by $46 million in positive changes in working capital, net of $38 million of increased collateral postings to satisfy our counterparty collateral demands.

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 Acquisitions and the interest on the acquisition financings.

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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 March 31, 2015 and December 31, 2014:

(amounts in millions)	March 31, 2015	December 31, 2014
Dynegy Inc.:		
Cash (1)	$29	$14
Letters of credit	183	178
Total Dynegy Inc.	212	192
IPH:		
Cash (1) (2)	26	32
Letters of credit (3)	10	10
Total IPH	36	42
Total	$248	$234

(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets on our unaudited consolidated balance sheets. At March 31, 2015 and December 31, 2014, $2 million and $9 million of cash posted as collateral were netted against Liabilities from risk management activities on our unaudited consolidated balance sheets, respectively.

(2) Includes cash of $5 million related to Genco at March 31, 2015 and December 31, 2014.

(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, 2014 to March 31, 2015 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.

The fair value of our derivatives collateralized by first priority liens included liabilities of $118 million and $141 million at March 31, 2015 and December 31, 2014, respectively.

We expect counterparties' future collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. Our ability to use economic hedging instruments in the future could be limited due to the potential collateral requirements of such instruments.

Investing Activities

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

	Three Months Ended March 31,	
(amounts in millions)	2015	2014
Coal	$3	$3
IPH	11	11
Gas	24	2
Other	2	1
Total (1)	$40	$17

(1) Includes capitalized interest of $3 million and $5 million for the three ended March 31, 2015 and 2014, respectively.

Future Cash Flow from Investing Activities. We expect capital expenditures (including expenditures for the newly acquired Duke Midwest and EquiPower assets) for the remainder of 2015 to be approximately $296 million, which is comprised

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of $124 million, $55 million, $109 million and $8 million in Coal, IPH, Gas and Other, respectively. The capital budget is subject to revision as opportunities arise or circumstances change and reflects expected expenditures related to the assets included in the Acquisitions. Additionally, our future investing cash flows will be reduced by the funds used for the Acquisitions, offset by the release of restricted cash.

Financing Activities

Historical Cash Flow from Financing Activities. Cash used in financing activities totaled $41 million for the three months ended March 31, 2015 primarily due to (i) $23 million in repayments associated with repurchase agreements related to emission credits, (ii) $7 million in dividend payments on our Mandatory Convertible Preferred Stock, (iii) $4 million in interest rate swap settlement payments, (iv) $4 million in released restricted stock units for payment of employee withholding taxes in connection with our stock award plans and (v) $2 million in principal payments of borrowings on the Tranche B-2 Term Loan. Please read Note 8—Debt for further discussion.

Cash provided by financing activities totaled $4 million for the three months ended March 31, 2014 due primarily to $12 million in proceeds received from a repurchase agreement related to emission credits, offset by $4 million in interest rate swap settlement payments, $2 million in principal payments of borrowings on the Tranche B-2 Term Loan and $1 million in financing costs in connection with the Credit Agreement and Senior Notes. Please read Note 8—Debt for further discussion.

Future Cash Flow from Financing Activities. As a result of our issuance of $400 million of mandatory convertible preferred stock on October 14, 2014, we are obligated to pay dividends of $5.4 million quarterly on a cumulative basis when declared by our Board of Directors or upon conversion. We may pay declared dividends in cash or, subject to certain limitations, in shares of our common stock or by delivery of any combination of cash and shares of our common stock.

Financing Trigger Events. Our debt instruments and certain of our other financial obligations and all the Genco Senior Notes include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events include the violation of covenants (including, in the case of the Credit Agreement under certain circumstances, the senior secured leverage ratio covenant discussed below), defaults on scheduled principal or interest payments, including any indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions, insolvency events, acceleration of other financial obligations and, in the case of the Credit Agreement, change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events. Please read Note 11—Debt in our Form 10-K 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 March 31, 2015 was 27 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 March 31, 2015.

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Genco Senior Notes. On December 2, 2013, in connection with the acquisition of AER, 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 March 31, 2015 calculations, Genco's interest coverage ratios are less than the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

Please read Note 8—Debt for further discussion.

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

On January 15, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.64 per share, or approximately $7 million in the aggregate. The dividend is for the initial dividend period beginning on October 14, 2014 and ending on January 31, 2015. Such dividends were paid on February 2, 2015 to stockholders of record as of January 15, 2015.

On March 3, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million in the aggregate. The dividend is for the dividend period beginning on February 1, 2015 and ending on April 30, 2015. Such dividends were paid on May 1, 2015 to stockholders of record as of April 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+

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RESULTS OF OPERATIONS

Overview

In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three months ended March 31, 2015 and 2014. 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 unaudited consolidated financial statements: (i) Coal, (ii) IPH and (iii) Gas. Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). General and administrative expense is reported in Other for all periods presented.

Consolidated Summary Financial Information — Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014

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

	Three Months Ended March 31,		Favorable (Unfavorable)	Favorable (Unfavorable)
(amounts in millions)	2015	2014	$ Change	% Change
Revenues	$632	$762	$ (130)	(17)%
Cost of sales, excluding depreciation expense	(377)	(552)	175	32%
Gross margin	255	210	45	21%
Operating and maintenance expense	(111)	(110)	(1)	(1)%
Depreciation expense	(64)	(67)	3	4%
General and administrative expense	(30)	(26)	(4)	(15)%
Acquisition and integration costs	(90)	(6)	(84)	NM
Operating income (loss)	(40)	1	(41)	NM
Interest expense	(136)	(30)	(106)	NM
Other income and expense, net	(5)	(6)	1	17%
Loss before income taxes	(181)	(35)	(146)	NM
Income tax expense	—	(2)	2	100%
Net loss	(181)	(37)	(144)	NM
Less: Net income (loss) attributable to noncontrolling interest	(1)	4	(5)	(125)%
Net loss attributable to Dynegy Inc.	$(180)	$(41)	$ (139)	NM

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

	Three Months Ended March 31, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$142	$219	$271	$—	$632
Cost of sales, excluding depreciation expense	(88)	(138)	(151)	—	(377)
Gross margin	54	81	120	—	255
Operating and maintenance expense	(37)	(51)	(23)	—	(111)
Depreciation expense	(10)	(8)	(45)	(1)	(64)
General and administrative expense	—	—	—	(30)	(30)
Acquisition and integration costs (1)	—	—	—	(90)	(90)
Operating income (loss)	$7	$22	$52	$(121)	$(40)

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	Three Months Ended March 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$156	$204	$402	$—	$762
Cost of sales, excluding depreciation expense	(96)	(159)	(297)	—	(552)
Gross margin	60	45	105	—	210
Operating and maintenance expense	(37)	(47)	(27)	1	(110)
Depreciation expense	(14)	(8)	(44)	(1)	(67)
General and administrative expense	—	—	—	(26)	(26)
Acquisition and integration costs (1)	—	(6)	—	—	(6)
Operating income (loss)	$9	$(16)	$34	$(26)	$1

(1) Relates to costs associated with the AER acquisition, Duke Midwest Acquisition and EquiPower Acquisition. Please read Note 15—Subsequent Events for further discussion.

Discussion of Consolidated Results of Operations

Revenues. Revenues decreased by $130 million from $762 million for the three months ended March 31, 2014 to $632 million for the three months ended March 31, 2015. Gas segment revenues decreased by $131 million primarily due to lower energy prices and the expiration of the ConEd contract at Independence. These decreases were partially offset by higher generation volumes primarily at Kendall and gains on derivative instruments in the three months ended March 31, 2015 compared to losses during the same period in 2014 primarily from rising power prices. Coal segment revenues decreased by $14 million primarily due to lower energy prices and generation volumes partially offset by gains on derivative instruments in the three months ended March 31, 2015 compared to losses during the same period in 2014 primarily from rising power prices. IPH segment revenues increased by $15 million due to higher revenues from gains on derivative instruments in the three months ended March 31, 2015 compared to losses during the same period in 2014 primarily from rising power prices, partially offset by lower energy prices and generation volumes.

Cost of Sales. Cost of sales decreased by $175 million from $552 million for the three months ended March 31, 2014 to $377 million for the three months ended March 31, 2015. Gas segment cost of sales decreased by $146 million primarily driven by lower natural gas prices. IPH and Coal segment cost of sales decreased by $21 million and $8 million, respectively, primarily due to lower coal and transportation costs as a result of lower generation volumes.

Operating and Maintenance Expense. Operating and maintenance expense increased by $1 million from $110 million for the three months ended March 31, 2014 to $111 million for the three months ended March 31, 2015.

Depreciation Expense. Depreciation expense decreased by $3 million from $67 million for the three months ended March 31, 2014 to $64 million for the three months ended March 31, 2015. The decrease in depreciation expense was primarily related to a decrease in the Coal segment due to various equipment retirements in 2014.

General and Administrative Expense. General and administrative expense increased by $4 million from $26 million for the three months ended March 31, 2014 to $30 million for the three months ended March 31, 2015. This increase was primarily due to higher general corporate support and legal costs.

Acquisition and Integration Costs. Acquisition and integration costs increased by $84 million from $6 million for the three months ended March 31, 2014 to $90 million for the three months ended March 31, 2015. Acquisition and integration costs for the three months ended March 31, 2015 consisted of $48 million in Bridge Loan financing fees and $42 million in acquisition advisory and consulting fees. Acquisition and integration costs for the three months ended March 31, 2014 were due to the acquisition of AER. Please read Note 15—Subsequent Events—Acquisitions for further discussion.

Interest Expense. Interest expense increased by $106 million from $30 million for the three months ended March 31, 2014 to $136 million for the three months ended March 31, 2015. This increase was primarily due to a $92 million increase in interest related to the Notes issued in 2014, an $12 million increase in mark-to-market losses on interest rate swaps and a $2 million decrease in capitalized interest. Please read Note 8—Debt for further discussion.

Other Income and Expense, net. Other income and expense, net decreased by $1 million from expense of $6 million for the three months ended March 31, 2014 to expense of $5 million for the three months ended March 31, 2015.
Income Tax Expense. We reported income tax expense of zero and $2 million for the three months ended March 31, 2015 and March 31, 2014, respectively. Our overall effective tax rate is expected to be approximately zero percent as a result of

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the change in our valuation allowance for the three months ended March 31, 2015.

As of March 31, 2015, we continued to maintain a valuation allowance against our net deferred tax assets as there was not sufficient evidence to overcome cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future. We expect that a significant portion of the valuation allowance will be released in the second quarter of 2015 as a result of increased deferred tax liabilities related to the EquiPower Acquisition. Please read Note 15—Subsequent Events for further discussion.

Discussion of Adjusted EBITDA

Non-GAAP Performance Measures. In analyzing and planning for our business, we supplement our use of the Generally Accepted Accounting Principles of the United States of America ("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 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, (iv) income or expense on up front premiums received or paid for financial options in periods other than the strike periods and (v) income or loss attributable to noncontrolling interest.

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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Adjusted EBITDA — Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014

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

	Three Months Ended March 31, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(180)
Loss attributable to noncontrolling interest					(1)
Other items, net					5
Interest expense					136
Operating income (loss)	$7	$22	$52	$(121)	$(40)
Depreciation expense	10	8	45	1	64
Amortization expense	(1)	(1)	(2)	—	(4)
Other items, net	—	—	—	(5)	(5)
EBITDA	16	29	95	(125)	15
Acquisition and integration costs	—	—	—	90	90
Loss attributable to noncontrolling interest	—	1	—	—	1
Mark-to-market income, net	(7)	(11)	(13)	—	(31)
Change in fair value of common stock warrants	—	—	—	5	5
Other	1	3	—	1	5
Adjusted EBITDA	$10	$22	$82	$(29)	$85

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

	Three Months Ended March 31, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(41)
Income attributable to noncontrolling interest					4
Income tax expense					2
Other items, net					6
Interest expense					30
Operating income (loss)	$9	$(16)	$34	$(26)	$1
Depreciation expense	14	8	44	1	67
Amortization expense	(1)	(1)	18	—	16
Other items, net	—	—	—	(6)	(6)
EBITDA	22	(9)	96	(31)	78
Acquisition and integration costs	—	6	—	—	6
Income attributable to noncontrolling interest	—	(4)	—	—	(4)
Mark-to-market loss, net	19	34	8	—	61
Change in fair value of common stock warrants	—	—	—	6	6
Other	1	3	—	1	5
Adjusted EBITDA	$42	$30	$104	$(24)	$152

Adjusted EBITDA decreased by $67 million from $152 million for the three months ended March 31, 2014 to $85 million for the three months ended March 31, 2015. The decrease was primarily due to lower realized power prices as a result of more moderate weather and the expiration of the ConEd contract at Independence. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014

Coal Segment

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

(dollars in millions, except for price information)	Three Months Ended March 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$131	$218	$(87)	(40)%
Capacity	2	2	—	—%
Mark-to-market income (loss), net	7	(19)	26	137%
Other (1)	2	(45)	47	104%
Total operating revenues	142	156	(14)	(9)%
Operating Costs				
Cost of sales	(89)	(97)	8	8%
Contract amortization	1	1	—	—%
Total operating costs	(88)	(96)	8	8%
Gross margin	54	60	(6)	(10)%
Operating and maintenance expense	(37)	(37)	—	—%
Depreciation expense	(10)	(14)	4	29%
Operating income	7	9	(2)	(22)%
Depreciation expense	10	14	(4)	(29)%
Amortization expense	(1)	(1)	—	—%
EBITDA	16	22	(6)	(27)%
Mark-to-market (income) loss, net	(7)	19	(26)	(137)%
Other	1	1	—	—%
Adjusted EBITDA	$10	$42	$(32)	(76)%
Million Megawatt Hours Generated	4.8	5.3	(0.5)	(9)%
IMA for Coal-Fired Facilities (2)	91%	88%		
Average Capacity Factor for Coal-Fired Facilities (3)	74%	82%		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$39.27	$71.36	$(32.09)	(45)%
Off-Peak: Indiana (Indy Hub)	$28.97	$43.10	$(14.13)	(33)%

(1) For the three months ended March 31, 2015 and 2014, respectively, Other includes $2 million and ($46) million in financial settlements and zero and $1 million in ancillary services.

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

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

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

Operating income for the three months ended March 31, 2015 was $7 million compared to $9 million for the three months ended March 31, 2014. Adjusted EBITDA was $10 million during the three months ended March 31, 2015 compared to $42 million during the same period in 2014. The $32 million decrease in Adjusted EBITDA resulted from lower realized power prices

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on the unhedged portion of the fleet and lower generation volumes, which includes a transmission outage in February that negatively impacted both on and off-peak economics.

IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the three months ended March 31, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Three Months Ended March 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$194	$213	$(19)	(9)%
Capacity	12	6	6	100%
Mark-to-market income (loss), net	11	(34)	45	132%
Contract amortization	(6)	(9)	3	33%
Other (1)	8	28	(20)	(71)%
Total operating revenues	219	204	15	7%
Operating Costs				
Cost of sales	(145)	(169)	24	14%
Contract amortization	7	10	(3)	(30)%
Total operating costs	(138)	(159)	21	13%
Gross margin	81	45	36	80%
Operating and maintenance expense	(51)	(47)	(4)	(9)%
Depreciation expense	(8)	(8)	—	—%
Acquisition and integration costs	—	(6)	6	100%
Operating income (loss)	22	(16)	38	238%
Depreciation expense	8	8	—	—%
Amortization expense	(1)	(1)	—	—%
EBITDA	29	(9)	38	NM
Acquisition and integration costs	—	6	(6)	(100)%
(Income) loss attributable to noncontrolling interest	1	(4)	5	125%
Mark-to-market (income) loss, net	(11)	34	(45)	(132)%
Other	3	3	—	—%
Adjusted EBITDA	$22	$30	$(8)	(27)%
Million Megawatt Hours Generated	5.5	6.7	(1.2)	(18)%
IMA for IPH Facilities (2)	93%	90%		
Average Capacity Factor for IPH Facilities (3)	60%	73%		
Average Quoted Market Power Prices ($/MWh) (4):	—			
On-Peak: Indiana (Indy Hub)	$39.27	$71.36	$(32.09)	(45)%
Off-Peak: Indiana (Indy Hub)	$28.97	$43.10	$(14.13)	(33)%

(1) For the three months ended March 31, 2015 and 2014, respectively, Other includes $6 million and $26 million in financial settlements, zero and ($1) million in ancillary services and $2 million and $3 million in other miscellaneous items.

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

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

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

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Operating income for the three months ended March 31, 2015 was $22 million compared to an operating loss of $16 million for the three months ended March 31, 2014. Adjusted EBITDA was $22 million during the three months ended March 31, 2015 compared to $30 million during the same period in 2014. The $8 million decrease in Adjusted EBITDA resulted from lower generation volumes and lower power prices on the unhedged portion of the fleet. These decreases were partially offset by retail energy sales that were made at higher average prices and an increase in capacity sales primarily associated with the segment's cost-based contracts.

Gas Segment

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

(dollars in millions, except for price information)	Three Months Ended March 31, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$228	$416	$(188)	(45)%
Capacity	33	52	(19)	(37)%
Mark-to-market income (loss), net	13	(8)	21	NM
Contract amortization	—	(20)	20	100%
Other (1)	(3)	(38)	35	92%
Total operating revenues	271	402	(131)	(33)%
Operating Costs				
Cost of sales	(153)	(299)	146	49%
Contract amortization	2	2	—	—%
Total operating costs	(151)	(297)	146	49%
Gross margin	120	105	15	14%
Operating and maintenance expense	(23)	(27)	4	15%
Depreciation expense	(45)	(44)	(1)	(2)%
Operating income	52	34	18	53%
Depreciation expense	45	44	1	2%
Amortization expense	(2)	18	(20)	(111)%
EBITDA	95	96	(1)	(1)%
Mark-to-market (income) loss, net	(13)	8	(21)	NM
Adjusted EBITDA	$82	$104	$(22)	(21)%
Million Megawatt Hours Generated (2)	5.0	4.5	0.5	11%
IMA for Combined Cycle Facilities (3)	99%	99%		
Average Capacity Factor for Combined Cycle Facilities (4)	53%	47%		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$17.68	$13.05	$4.63	35%
PJM West	$17.55	$32.30	$(14.75)	(46)%
North of Path 15 (NP 15)	$11.82	$16.48	$(4.66)	(28)%
New York—Zone A	$39.80	$73.97	$(34.17)	(46)%
Mass Hub	$14.92	$28.47	$(13.55)	(48)%
Average Market Off-Peak Spark Spreads ($/MWh) (5):				

Commonwealth Edison (NI Hub)	$4.71	$(25.25)	$29.96	119%
PJM West	$0.98	$(12.38)	$13.36	108%
North of Path 15 (NP 15)	$6.14	$8.05	$(1.91)	(24)%
New York—Zone A	$25.32	$33.91	$(8.59)	(25)%
Mass Hub	$(4.84)	$(19.20)	$14.36	75%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.87	$5.08	$(2.21)	(44)%

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(1) For the three months ended March 31, 2015 and 2014, respectively, Other includes ($20) million and ($93) million in financial settlements, $6 million and $37 million in natural gas sales, $10 million and $16 million in ancillary services, $1 million and $1 million in tolls and zero and $1 million in RMR, option premiums and other miscellaneous items.

(2) The three months ended March 31, 2014 includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility which was subsequently sold on June 27, 2014.

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

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

(5) Reflects the simple average of the 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 three months ended March 31, 2015 was $52 million compared to $34 million for the three months ended March 31, 2014. Adjusted EBITDA totaled $82 million during the three months ended March 31, 2015 compared to $104 million during the same period in 2014. The $22 million decrease in Adjusted EBITDA primarily resulted from the expiration of the ConEd contract at Independence. Lower energy margins, primarily at Independence and Ontelaunee, were offset by higher capacity market revenue at Independence and Kendall.

Outlook

We expect that our future financial results will continue to be impacted by fuel and commodity prices as well as our recent acquisitions. 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 greenhouse gas (“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-Q relate to economic hedging activities as we do not elect hedge accounting.

Our Operating Segments

Coal. As of March 31, 2015, the Coal segment consisted of four plants, all located in the MISO region, totaling 3,008 MW. Effective with the close of the Acquisitions, our Coal segment is comprised of 11 operating generation facilities located within MISO (3,008 MW), PJM (3,877 MW) and the ISO-NE (1,493 MW) regions, with a total generating capacity of 8,378 MW. All coal-fired plants within PJM are in the RTO zone.

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. The Baldwin transformer upgrade is underway and is expected to be completed prior to the summer of 2015. Associated re-conductoring work will be phased in over the next two years. 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 in Illinois. When basis differentials between MISO LMPs and trading hub prices exist, we mitigate the basis risk between these prices through participation in FTR markets and busbar swaps to the extent they are economically available.

As of April 21, 2015, our expected remaining generation volumes are 52 percent hedged volumetrically for 2015 and approximately 24 percent hedged volumetrically for 2016. We plan to continue our hedging program over a one- to three-year period using various instruments, which may include the sale of natural gas swaps as a cross-commodity 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. Beyond 2015, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements.

As of April 21, 2015, excluding non-operated jointly-owned generating units, our expected coal requirements for 2015 are fully contracted and priced. Our forecasted coal requirements for 2016 are 62 percent contracted and 60 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2015 and 2016. In addition, we recently entered into a new long-term coal transportation agreement for our Kincaid facility. The contract, which begins in 2017, reflects a reduction from the expected 2016 rate. Our coal transportation requirements are more than 75 percent contracted for 2017 to 2019.

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

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

In PJM, Coal cleared 3,341 MW in the Planning Year 2014-2015 capacity auction, 3,331 MW in the Planning Year 2015-2016 capacity auction, 3,567 MW in the Planning Year 2016-2017 capacity auction, and 3,372 MW in the Planning Year 2017-2018 capacity auction.

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 in the Electric Energy, Inc. ("EEI") control area, is interconnected to MISO, TVA and Louisville Gas and Electric Company.

As of April 21, 2015, our IPH expected remaining generation volumes are approximately 69 percent hedged volumetrically for 2015 and approximately 41 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 April 21, 2015, our expected coal requirements for IPH for 2015 are fully contracted and 88 percent priced. Our forecasted coal requirements for 2016 are 78 percent contracted and 57 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2015 and 2016. Our coal transportation requirements are more than 70 percent contracted for 2017 to 2019.

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

We have also secured one segment of the transmission path required to offer an additional 240 MW of capacity and energy into PJM for Planning Year 2017-2018 through Planning Year 2021-2022. In July 2014, we executed a long-term wholesale contract for up to 120 MW annually for energy and capacity in Illinois from 2018 through 2026 bringing long-term, annual origination sales from the IPH segment to more than 470 MW.

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

In PJM, IPH cleared no volume in the Planning Year 2014-2015 capacity auction, 301 MW in the Planning Year 2015-2016 capacity auction, 856 MW in the Planning Year 2016-2017 capacity auction, and 847 MW in the Planning Year 2017-2018 capacity auction.

Gas. As of March 31, 2015, the Gas segment consisted of six plants, geographically diverse in four markets, totaling 6,109 MW. Effective with the close of the Acquisitions, our Gas segment is comprised of 19 power generation facilities within PJM (7,081 MW), CAISO (2,694 MW), ISO-NE (2,440 MW) and NYISO (1,108 MW) regions, totaling 13,323 MW of electric generating capacity. All gas-fired plants within PJM are in the RTO zone except for Liberty and Ontelaunee, which are in the MAAC zone.

Excluding volumes subject to tolling agreements, as of April 21, 2015, our Gas portfolio is 37 percent hedged volumetrically through 2015 and approximately 4 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.

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In PJM, Gas cleared 5,922 MW in the Planning Year 2014-2015 capacity auction, 5,996 MW in the Planning Year 2015-2016 capacity auction, 6,201 MW in the Planning Year 2016-2017 capacity auction, and 6,415 MW in the Planning Year 2017-2018 capacity auction.
In New England, Gas cleared 1,890 MW in the Planning Year 2014-2015 capacity auction, 1,956 MW in the Planning Year 2015-2016 capacity auction, 1,893 MW in the Planning Year 2016-2017 capacity auction, 2,147 MW in the Planning Year 2017-2018 capacity auction, and 2,148 MW in the Planning Year 2018-2019 capacity auction. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.
In New York, almost all of our Independence facility's summer capacity had been sold bilaterally prior to the most recent auction, covering the Summer 2015 planning period. As of April 21, 2015, 1,107 MW of capacity were sold for the Winter 2014-2015 planning period; 903 MW were sold for the Summer 2015 planning period; 601 MW were sold for the Winter 2015-2016 planning period; 492 MW were sold for the Summer 2016 planning period; and 81 MW were sold for the Winter 2016-2017 planning period.
In its 2015 Gas Transmission and Storage rate case, which will set gas transportation rates for 2015-2017, PG&E's proposed revenue requirements and allocation proposals, if adopted, would result in a significant increase in the rates for electric generators served by the local transmission system, including Dynegy's Moss Landing Units 1 & 2. Historically, after PG&E's gas transportation rate structure was changed to unbundle the Backbone Transmission System ("BB") rates, PG&E gas transmission and storage rate case settlements have included a bill credit for Moss Landing Units 1 & 2 that effectively reduces the differential between rates for BB and local transmission system service, allowing the plant to compete against other power generators. However, according to PG&E's own estimates, the rate differential between BB and local transmission system rates PG&E proposes in its 2015 proceeding would result in Moss Landing Units 1 & 2 likely experiencing a decline in dispatch hours. Dynegy is actively participating in the hearing process before the CPUC and is advocating positions that would maintain the ability of Moss Landing Units 1 & 2 to compete in California electricity markets. Post-hearing briefing is scheduled for April and May of 2015, with a decision expected in Fall 2015.
Capacity Markets
MISO. We have approximately 7,065 MW of power generation in MISO. The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each Planning Year:

	2013-2014	2014-2015	2015-2016
Price per MW-day	$1.05	$16.75	$150.00

We expect asset retirements and confirmed future capacity exports from MISO to PJM to continue shrinking the supply of generation in the market. MISO has forecasted the reserve margin falling below the needed generation level, known as the Planning Reserve Margin, that is currently 14.2 percent. MISO has forecasted reserve margins of 16.6 percent for Planning Years 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.
ISO-NE. Effective with the close of the Acquisitions, we have approximately 3,933 MW of power generation in ISO-NE. The most recent capacity auction results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each Planning Year:

	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
Price per kW-month	$2.95	$3.21	$3.43	$3.15	$7.03	$9.55

The forecasted 2015 ISO-NE reserve margin is 22.8 percent versus a target reserve margin of 13.9 percent. On February 2, 2015, ISO-NE conducted the capacity auction for Planning Year 2018-2019 (FCA-9). Rest-of-Pool, which includes most of our facilities, cleared at a price of $9.55 per kW-month. The SEMA/RI zone, where our recently acquired Dighton facility is located, had insufficient supply to satisfy its capacity requirements. As a result, the zone separated from Rest-of-Pool, with existing resources in the zone receiving the Net Cost of New Entry ("Net CONE") price of $11.08 per kW-month and new resources in the zone receiving the auction starting price of $17.73 per kW-month. In the most recent auction, a downward sloping demand curve replaced the vertical demand curve and the system-wide administrative pricing rules. Recent retirements were partially offset by limited new entry, resulting in a forecast reserve margin of 22.0 percent for Planning Year 2018-2019, versus an ISO-NE target reserve margin of 13.9

percent. Performance incentive rules went into effect for Planning Year 2018-2019, having the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level.

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PJM. Effective with the close of the Acquisitions, we have approximately 10,958 MW of power generation in PJM. The most recent RPM auction results for PJM's RTO and MAAC zones, in which our assets are located, are as follows for each Planning Year:

	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
RTO zone, price per MW-day	$27.73	$125.99	$136.00	$59.37	$120.00
MAAC zone, price per MW-day	$226.15	$136.50	$167.46	$119.13	$120.00

PJM has recently filed for FERC approval of changes to their capacity market with a product called Capacity Performance. Capacity Performance was developed by PJM in response to concerns about plant performance and system reliability. Capacity Performance features increased availability and flexibility requirements, incentives for performance, significant penalties for non-performance and the ability to bid in a risk premium and recover costs previously disallowed by PJM and the independent market monitor.

On March 31, 2015, FERC issued a deficiency letter to PJM requesting additional information regarding certain elements of Capacity Performance. PJM answered the deficiency letter on April 10, 2015. On April 24, 2015, FERC granted PJM’s request to delay the Planning Year 2018-2019 Base Residual Auction by up to 75 days (but no later than August 10, 2015) to give FERC time to rule on Capacity Performance.

NYISO. We have approximately 1,108 MW of power generation in NYISO. The forecasted 2015 NYISO reserve margin is 22.4 percent versus a target reserve margin of 17 percent. The most recent auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Winter 2013-2014	Summer 2014	Winter 2014-2015	Summer 2015
Price per kW-month	$2.58	$5.15	$2.90	$3.50

CAISO. We have approximately 2,694 MW of power generation in CAISO. The CAISO capacity market is a bilateral market in which Load Serving Entities are required to procure sufficient resources to meet their peak load plus a 15 percent reserve margin. We transact with Investor Owned Utilities, Municipalities, Community Choice Aggregators, retail providers, and other marketers through RFO solicitations, broker markets, and directly with bilateral transactions. We transact both the standard resource adequacy (“RA”) capacity as well as flexible RA capacity. Although the CPUC created the new flexible RA capacity market to address the risk of retirement of flexible gas fired generation, demand for this product is low due to ample supply of generation. In addition, growth for energy demand has been stagnant mainly due to energy efficiency programs and distributed generation of residential and commercial rooftop solar.

Other Market Developments

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. On May 4, 2015, the U.S. Supreme Court issued a notice stating that it has granted the petitions and will consider the case. Oral argument is expected in late 2015, with a decision likely by mid-2016. PJM has announced its intent to include demand response in its next base residual capacity auction, consistent with existing rules as those rules may be enhanced by the PJM Capacity Performance filing. Each of the other 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.

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K for a detailed discussion of our environmental and regulatory matters.

The Clean Air Act

Mercury/HAPs. The U.S. Supreme Court is expected to issue a decision by summer 2015 addressing whether the EPA, in adopting the Mercury and Air Toxic Standards (“MATS”) rule, unreasonably refused to consider costs in determining the appropriateness of regulating hazardous air pollutants emitted by EGUs. Given the air emission controls already employed, we

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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 also continue to monitor the performance of our other units and evaluate approaches to optimizing compliance strategies.

In accordance with our MISO tariff obligations, in December 2014, we requested a one-year extension of the MATS compliance deadline for Edwards Unit 1. We have committed to retire Edwards Unit 1 as soon as the MISO allows us to retire the unit. On April 15, 2015, the Illinois EPA approved a one-year extension of the MATS compliance deadline for Edwards Unit 1.

The EPA revised the MATS rule in November 2014 to require installation and operation of 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.

National Ambient Air Quality Standards ("NAAQS"). The EPA issued a proposed rule in 2014 that would require States to characterize air quality for purposes of the one-hour sulfur dioxide ("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. In March 2015, a federal court approved a consent decree that requires the EPA, by July 2016, to designate as nonattainment those areas that have monitored violations of the one-hour SO_2 NAAQS based on air quality monitoring in the preceding three full calendar years and also issue designations for any areas that contained high-emitting SO_2 sources in 2012 and have not been announced for retirement. Areas designated nonattainment must achieve attainment no later than five years after initial designation.

The EPA previously designated as nonattainment with the one-hour SO_2 NAAQS the area where our IPH segment's Edwards facility is located. 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. In January 2015, IPRG entered a Memorandum of Agreement with the Illinois EPA that voluntarily committed to early limits on Edwards' allowable one-hour SO_2 emission rate that, in conjunction with reductions to be imposed by the state on other sources, will enable the Illinois EPA to demonstrate attainment with the one-hour SO_2 NAAQS in the Edwards area. In March 2015, IPRG withdrew its appeal challenging the EPA's one-hour SO_2 nonattainment designation of the Edwards area.

The Clean Water Act

California Water Intake Policy. On October 9, 2014, we entered into a settlement agreement with the California State Water Resources Control Board ("State Water Board") that would resolve a lawsuit we filed in 2010 with other California power plant owners challenging the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling ("Policy").

Under the settlement agreement, the State Water Board 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. On April 7, 2015, the State Water Board approved the amendment to the Policy. 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.

Climate Change

State Regulation of Greenhouse Gases. The second joint California Air Resources Board (“CARB”) and Québec allowance auction was held in February 2015 with 2015 auction allowances selling at a clearing price of $12.21 per metric tonne and 2018 auction allowances selling at a clearing price of $12.10 per metric tonne. The CARB expects allowance prices to be in the $15 to $30 range by 2020. We have participated in each of the quarterly auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets. The next quarterly auction is scheduled for May 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.

In March 2015, RGGI held its twenty-seventh auction, in which approximately 15 million allocation year 2015 allowances were sold at a clearing price of $5.41 per allowance. RGGI's next quarterly auction is scheduled for June 2015. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

We estimate the cost of RGGI allowances required to operate our affected facilities in New York and Maine 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.

RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	As of and for the Three Months Ended March 31, 2015
Fair value of portfolio at December 31, 2014	$(83)
Risk management losses recognized through the statement of operations in the period, net	(6)
Contracts realized or otherwise settled during the period	33
Changes in collateral/margin netting	(7)
Fair value of portfolio at March 31, 2015	$(63)

The net risk management liability of $63 million is the aggregate of the following line items on our unaudited 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 March 31, 2015, 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)	$(71)	$(28)	$(21)	$(11)	$(7)	$(3)	$(1)
Prices based on models (2)	6	6	—	—	—	—	—
Total (3)	$(65)	$(22)	$(21)	$(11)	$(7)	$(3)	$(1)

(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 3—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

(3) Excludes $2 million of broker margin that has been netted against Risk Management liabilities on our unaudited consolidated balance sheets. Please read Note 3—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-Q 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 quarterly 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 r 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 and anticipated benefits of the Acquisitions;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the South Bay and Vermilion facilities; 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 under Item 1A—Risk Factors of our Form 10-K.

CRITICAL ACCOUNTING POLICIES

Please read “Critical Accounting Policies” in our Form 10-K for a complete description of our critical accounting policies, with respect to which there have been no material changes since the filing of such Form 10-K.

Item 3—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our Form 10-K for a discussion of our exposure to commodity price variability and other market risks related to our net non-trading derivative assets and liabilities, including foreign currency exchange rate risk. The following is a discussion of the more material of these risks and our relative exposures as of March 31, 2015.

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Value at Risk (“VaR”). 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. Please read “VaR” in our Form 10-K for a complete description of our valuation methodology. The daily VaR at March 31, 2015 compared to December 31, 2014 was lower due to a decrease in volatility and price. The average VaR at March 31, 2015 compared to December 31, 2014 decreased due to a change in position.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	March 31, 2015	December 31, 2014
One day VaR—95 percent confidence level	$4	$10
One day VaR—99 percent confidence level	$6	$14
Average VaR—95 percent confidence level for the rolling twelve months ended	$7	$8

Credit Risk. The following table represents our credit exposure at March 31, 2015 associated with the 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	$3
Oil and gas producers	3
Utility and power generators	11
Total	$17

Interest Rate Risk

We are exposed to fluctuating interest rates related to our 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 March 31, 2015 and December 31, 2014, respectively:

	March 31, 2015		December 31, 2014	
Interest rate swaps (in millions of U.S. dollars)	$783		$785	
Fixed interest rate paid (percent)	3.19	%	3.19	%

Item 4—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 our management, including our Chief Executive Officer (“CEO”) and our Chief Financial Officer (“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 Securities Exchange Act of 1934, as amended). 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 March 31, 2015.

Changes in Internal Controls Over Financial Reporting

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

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

Please read Note 9—Commitments and Contingencies—Legal Proceedings to the accompanying unaudited consolidated financial statements for a discussion of the legal proceedings that we believe could be material to us.

Item 1A—RISK FACTORS

Please read Item 1A—Risk Factors of our Form 10-K for factors, risks and uncertainties that may affect future results.

Item 6—EXHIBITS

The following documents are included as exhibits to this Form 10-Q:

Exhibit Number	Description
**2.1*	Letter Agreement to Purchase and Sale Agreement by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein, dated March 30, 2015.
2.2	Amendment to Stock Purchase Agreement, dated as of March 30, 2015, by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-B, LP, Energy Capital Partners II-C (Direct IP), LP, Energy Capital Partners II-D, LP and Energy Capital Partners II (EquiPower Co-Invest), LP, Energy Capital Partners II-C, LP, for the limited purposes set forth therein, EquiPower Resources Corp., Dynegy Resource II, LLC, and Dynegy Inc., for the limited purposes set forth therein(incorporated by reference to Exhibit 2.1 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 1, 2015)
4.1	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.2	First Supplemental Indenture to the 2019 Notes Indenture, dated April 2, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee, pursuant to which the Company assumed the obligations of the Duke Escrow (incorporated by reference to Exhibit 4.2 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.3	Second Supplemental Indenture to the 2019 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, pursuant to which additional guarantors are added (incorporated by reference to Exhibit 4.3 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.4	2022 Notes Indenture, dated October 27, 2014, among Dynegy Finance I, Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.4 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.5	First Supplemental Indenture to the 2022 Notes Indenture, dated April 2, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee, pursuant to which the Company assumed the obligations of the Duke Escrow Issuer (incorporated by reference to Exhibit 4.5 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.6	Second Supplemental Indenture to the 2022 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National

	Association, as trustee, pursuant to which additional guarantors are added (incorporated by reference to Exhibit 4.6 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.7	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.8	First Supplemental Indenture to the 2024 Notes Indenture, dated April 2, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee, pursuant to which the Company assumed the obligations of the Duke Escrow Issuer (incorporated by reference to Exhibit 4.8 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)

4.9	Second Supplemental Indenture to the 2024 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, pursuant to which additional guarantors are added (incorporated by reference to Exhibit 4.8 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.10	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.11	First Supplemental Indenture to the 2019 Notes Indenture, dated April 1, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.8 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
4.12	Second Supplemental Indenture to the 2019 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.9 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
4.13	Third Supplemental Indenture to the 2019 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding the Duke Acquired Entities as guarantors (incorporated by reference to Exhibit 4.13 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.14	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.15	First Supplemental Indenture to the 2022 Notes Indenture, dated April 1, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.11 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
4.16	Second Supplemental Indenture to the 2022 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.12 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
4.17	Third Supplemental Indenture to the 2022 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding the Duke Acquired Entities as guarantors (incorporated by reference to Exhibit 4.17 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.18	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.19	First Supplemental Indenture to the 2024 Notes Indenture, dated April 1, 2015, between Dynegy Inc. and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.14 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
4.20	Second Supplemental Indenture to the 2024 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.15 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)

4.21	Third Supplemental Indenture to the 2024 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding the Duke Acquired Entities as guarantors (incorporated by reference to Exhibit 4.21 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.22	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on October 30, 2014)
4.23	Joinder to the Registration Rights Agreement, dated April 1, 2015, among Dynegy Inc. and the subsidiary guarantors identified therein (incorporated by reference to Exhibit 4.17 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
4.24	Joinder to the Registration Rights Agreement, dated April 2, 2015, among Dynegy Inc. and the subsidiary guarantors identified therein (incorporated by reference to Exhibit 4.24 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
4.25	2023 Notes 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)

4.26	First Supplemental Indenture to the 2023 Notes Indenture, dated as of December 5, 2014, among Dynegy Inc., the Guarantors and Wilmington Trust, National Association as Trustee (incorporated by reference to Exhibit 4.3 to the Annual Report on Form 10-K for the Year Ended December 31, 2013 of Dynegy Inc. File No. 001-33443)
4.27	Second Supplemental Indenture to the 2023 Notes Indenture, dated April 1, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee (incorporated by reference to Exhibit 4.20 to the Current Report on Form 8-K of Dynegy Inc. filed April 7, 2015 File No. 001-33443)
4.28	Third Supplemental Indenture to the 2023 Notes Indenture, dated April 2, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee, pursuant to which the Subsidiary Guarantors are added to the 2023 Notes Indenture (incorporated by reference to Exhibit 4.28 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
10.1	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 24, 2013)
10.2	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 24, 2013)
10.3	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 Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 24, 2013)
10.4	First Amendment to Credit Agreement, dated as of April 1, 2015, among Dynegy Inc., as borrower, and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.4 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 7, 2015)
10.5	Second Amendment to Credit Agreement, dated as of April 2, 2015, among Dynegy Inc., as borrower, and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.5 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on April 8, 2015)
**10.6	Form of Non-Qualified Stock Option Award Agreement (2015 Awards).
**10.7	Form of Stock Unit Award Agreement - Officers (2015 Awards).
**10.8	Form of Performance Award Agreement (2015 Awards).
10.9	Amended and Restated Employment Agreement by and between Dynegy Operating Company and Robert C. Flexon (incorporated by reference to Exhibit 10.1 to Dynegy Inc.'s Current Report on Form 8-K filed with the SEC on May 6, 2015)
**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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** Filed herewith.

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

† 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.

DYNEGY INC.

SIGNATURE

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 thereunto duly authorized.

			DYNEGY INC.
Date:	May 7, 2015	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer

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