DYNEGY INC.
Form 10-Q
August 04, 2016

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 June 30, 2016

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	Smaller reporting company o
(Do not check if a smaller reporting company)	

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, 117,288,474 shares outstanding as of July 14, 2016.

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DEFINITIONS

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

CAA	Clean Air Act
CAISO	The California Independent System Operator
CPUC	California Public Utility Commission
CT	Combustion Turbine
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
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
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
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
S&P	Standard & Poor’s Ratings Services
SEC	U.S. Securities and Exchange Commission

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

	June 30, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$1,142	$ 505
Restricted cash	104	39
Accounts receivable, net of allowance for doubtful accounts of $1 and $1, respectively	392	402
Inventory	520	597
Assets from risk management activities	64	100
Intangible assets	70	102
Prepayments and other current assets	149	187
Total Current Assets	2,441	1,932
Property, Plant and Equipment, Net	7,588	8,347
Investment in unconsolidated affiliate	185	190
Restricted cash	2,000	—
Assets from risk management activities	26	18
Goodwill	799	797
Intangible assets	34	62
Other long-term assets	89	113
Total Assets	$13,162	$ 11,459

See the notes to consolidated financial statements.

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

	June 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$286	$ 292
Accrued interest	76	74
Intangible liabilities	45	85
Accrued liabilities and other current liabilities	119	125
Liabilities from risk management activities	37	103
Asset retirement obligations	45	50
Debt, current portion, net	141	80
Total Current Liabilities	749	809
Debt, long-term portion, net	9,365	7,129
Liabilities from risk management activities	79	105
Asset retirement obligations	238	230
Deferred income taxes	38	29
Intangible liabilities	45	55
Other long-term liabilities	184	183
Total Liabilities	10,698	8,540
Commitments and Contingencies (Note 14)		
Stockholders' Equity		
Preferred stock, $0.01 par value, 20,000,000 shares authorized:		
Series A 5.375% mandatory convertible preferred stock, $0.01 par value; 4,000,000 shares issued and outstanding, respectively	400	400
Common stock, $0.01 par value, 420,000,000 shares authorized; 128,614,596 shares issued and 117,288,474 shares outstanding at June 30, 2016; 128,228,477 shares issued and 116,902,355 outstanding at December 31, 2015	1	1
Additional paid-in capital	3,547	3,187
Accumulated other comprehensive income, net of tax	17	19
Accumulated deficit	(1,497)	(686)
Total Dynegy Stockholders' Equity	2,468	2,921
Noncontrolling interest	(4)	(2)
Total Equity	2,464	2,919
Total Liabilities and Equity	$13,162	$ 11,459

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues	$904	$990	$2,027	$1,622
Cost of sales, excluding depreciation expense	(493)	(496)	(1,038)	(873)
Gross margin	411	494	989	749
Operating and maintenance expense	(256)	(250)	(477)	(361)
Depreciation expense	(160)	(175)	(331)	(239)
Impairments	(645)	—	(645)	—
Loss on sale of assets, net	—	(1)	—	(1)
General and administrative expense	(39)	(35)	(76)	(65)
Acquisition and integration costs	3	(23)	(1)	(113)
Other	(16)	—	(16)	—
Operating income (loss)	(702)	10	(557)	(30)
Earnings from unconsolidated investments	1	3	3	3
Interest expense	(141)	(132)	(283)	(268)
Other income and expense, net	30	4	31	(1)
Loss before income taxes	(812)	(115)	(806)	(296)
Income tax benefit (expense) (Note 15)	9	501	(7)	501
Net income (loss)	(803)	386	(813)	205
Less: Net loss attributable to noncontrolling interest	(2)	(2)	(2)	(3)
Net income (loss) attributable to Dynegy Inc.	(801)	388	(811)	208
Less: Dividends on preferred stock	6	6	11	11
Net income (loss) attributable to Dynegy Inc. common stockholders	$(807)	$382	$(822)	$197
Earnings (Loss) Per Share (Note 18):				
Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders	$(6.73)	$2.98	$(6.97)	$1.56
Diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders	$(6.73)	$2.73	$(6.97)	$1.49
Basic shares outstanding	120	128	118	126
Diluted shares outstanding	120	142	118	140

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$(803)	$386	$(813)	$205
Other comprehensive loss before reclassifications:				
Actuarial loss (net of tax of zero for each respective period)	—	(5)	—	(5)
Amounts reclassified from accumulated other comprehensive income:				
Amortization of unrecognized prior service credit (net of tax of zero for each respective period)	(1)	(1)	(2)	(2)
Other comprehensive loss, net of tax	(1)	(6)	(2)	(7)
Comprehensive income (loss)	(804)	380	(815)	198
Less: Comprehensive loss attributable to noncontrolling interest	(2)	(2)	(2)	(3)
Total comprehensive income (loss) attributable to Dynegy Inc.	$(802)	$382	$(813)	$201

See the notes to consolidated financial statements.

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

	Six Months Ended June 30, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$(813)	$205
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation expense	331	239
Non-cash interest expense	23	15
Amortization of intangibles	13	(9)
Risk management activities	(89)	(66)
Loss on sale of assets, net	—	1
Earnings from unconsolidated investments	(3)	(3)
Deferred income taxes	7	(501)
Impairment of long-lived assets	645	—
Change in value of common stock warrants	(2)	2
Other	18	23
Changes in working capital:		
Accounts receivable, net	15	(17)
Inventory	77	(42)
Prepayments and other current assets	156	49
Accounts payable and accrued liabilities	8	76
Changes in restricted cash	4	—
Changes in non-current assets	(74)	(12)
Changes in non-current liabilities	1	19
Net cash provided by (used in) operating activities	317	(21)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(224)	(102)
Acquisitions, net of cash acquired	—	(6,092)
Decrease (increase) in restricted cash	(2,069)	5,148
Distributions from unconsolidated affiliates	8	—
Other investing	7	(10)
Net cash used in investing activities	(2,278)	(1,056)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of debt issuance costs	2,278	(25)
Repayments of borrowings	(20)	(27)
Proceeds from issuance of equity, net of issuance costs	362	(6)
Preferred stock dividends paid	(11)	(12)
Interest rate swap settlement payments	(9)	(8)
Other financing	(2)	(4)
Net cash provided by (used in) financing activities	2,598	(82)
Net increase (decrease) in cash and cash equivalents	637	(1,159)
Cash and cash equivalents, beginning of period	505	1,870
Cash and cash equivalents, end of period	$1,142	$711

Other non-cash investing and financing activity:		
Non-cash consideration transferred for Acquisitions	$—	$(105)
Change in capital expenditures pursuant to an equipment financing agreement	$4	$(31)

See the notes to consolidated financial statements.

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

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 unaudited 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, 2015, filed with the SEC on February 25, 2016, 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 20—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. Genco's $825 million Senior Notes are non-recourse to Dynegy.

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. The accompanying unaudited consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America. There have been no significant changes to our accounting policies during the six months ended June 30, 2016.

Use of Estimates. The preparation of unaudited 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

Hybrid Financial Instruments. In November 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-16-Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or Equity. The amendments in this ASU clarify how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. Specifically, the amendments clarify that an entity should consider all relevant terms and features, including the embedded derivative feature being evaluated for bifurcation, in evaluating the nature of the host contract. Furthermore, the amendments clarify that no single term or feature would necessarily determine the economic characteristics and risks of the host contract. Rather, the nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument. The amendments in this ASU also clarify that, in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (i.e., the relative strength of the debt-like or

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

equity-like terms and features given the facts and circumstances) when considering how to weight those terms and features. The adoption of this ASU on January 1, 2016, did not have an impact on our unaudited consolidated financial statements.

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 our debt issuance costs are not affected by the amendments in this update.

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

We adopted these ASUs on January 1, 2016, on a retrospective basis affecting presentation on the unaudited consolidated balance sheets for all periods presented. Accordingly, we reclassified $80 million in unamortized debt issuance costs within our unaudited consolidated balance sheet as of December 31, 2015.

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 adoption of this ASU on January 1, 2016, did not have an impact on our unaudited consolidated financial statements.

Extraordinary and Unusual Items. In January 2015, the FASB issued ASU 2015-01-Income Statement-Extraordinary and Unusual Items (Subtopic 225-20). The amendments in this ASU eliminate from GAAP the concept of extraordinary items and will no longer require separate classification of these items within the statement of operations. Presentation and disclosure guidance for items that are unusual in nature or occur infrequently will be retained and will be expanded to include items that are both unusual in nature and infrequently occurring. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this ASU on January 1, 2016, did not have an impact on our unaudited consolidated financial statements.

Accounting Standards Not Yet Adopted

Credit Losses. In June 2016, the FASB issued ASU 2016-13-Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. The amendments in this ASU require the measurement of all expected credit losses for financial assets, which include trade receivables, held at the reporting date based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are currently evaluating this ASU and any potential impacts the adoption of this ASU will have on our unaudited consolidated financial statements.

Compensation. In March 2016, the FASB issued ASU 2016-09-Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The amendments in this ASU simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption of this ASU will have on our unaudited consolidated financial statements.

Debt Instruments. In March 2016, the FASB issued ASU 2016-06-Derivative and Hedging: Contingent Put and Call Options in Debt Instruments. The amendments in this ASU clarify what steps are required when assessing whether the economic characteristics and risks of call (put) options are clearly and closely related to the economic characteristics and risks of their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this ASU is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The amendments are effective for public business entities for fiscal years beginning after December 15, 2016 and interim periods within those fiscal years. All entities have the option of adopting the new requirements early, including adoption in an interim period. If an entity early adopts the new requirements in an interim period, it must reflect any adjustments as of the beginning of the fiscal year that includes that interim period. We are currently evaluating this ASU; however, we do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

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Leases. In February 2016, the FASB issued ASU 2016-02-Leases (Topic 842). The amendments in this ASU will mainly require lessees to recognize lease assets and lease liabilities, for those leases classified as operating leases under GAAP, in their balance sheet. The lease assets recognized in the balance sheet will represent a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The lease liability recognized in the balance sheet will represent the lessee's obligation to make lease payments arising from a lease, measured on a discounted basis. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption of this ASU will have on our unaudited consolidated financial statements.

Going Concern. In August 2014, the FASB issued ASU 2014-15-Presentation of Financial Statements-Going Concern (Subtopic 205-40). The amendments in this ASU require management, in connection with preparing financial statements for each annual and interim reporting period, to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued (or within one year after the date that the financial statements are available to be issued, when applicable). Currently, there is no guidance in GAAP about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern or to provide related footnote disclosures. The amendments in this ASU provide that guidance. In doing so, the amendments should reduce diversity in the timing and content of footnote disclosures. The guidance in this ASU is effective for fiscal years ending after December 15, 2016, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. We are currently evaluating this ASU; however, we do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the FASB and International Accounting Standards Board jointly issued ASU 2014-09-Revenue from Contracts with Customers (Topic 606). This ASU, and subsequently issued amendments to the standard, develop a common revenue standard for GAAP and International Financial Reporting Standards 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 amendments in ASU 2016-08 are intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations. The guidance in this ASU and its amendments 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 evaluating this ASU; however, we do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

Note 3—Acquisitions

Delta Transaction. On February 24, 2016, Atlas Power Finance, LLC ("Atlas" or the "Purchaser"), a wholly owned subsidiary of Atlas Power, LLC ("Atlas Power"), entered into a Stock Purchase Agreement, as amended and restated on June 27, 2016 (the "Delta Stock Purchase Agreement") with GDF SUEZ Energy North America, Inc. ("GSENA") and International Power, S.A. (the "Seller"), indirect subsidiaries of Engie S.A. Pursuant to the Delta Stock Purchase Agreement, the Purchaser will acquire approximately 9,058 MW of generation, including (i) 15 natural gas-fired facilities located in Illinois, Massachusetts, New Jersey, Ohio, Pennsylvania, Texas, Virginia, and West Virginia, (ii) one coal-fired facility in Texas, and (iii) one waste coal-fired facility in Pennsylvania for a base purchase price of approximately $3.3 billion in cash, subject to certain adjustments (the "Delta Transaction").

On June 27, 2016, a wholly owned subsidiary of Dynegy acquired the 35 percent interest in Atlas Power (the "ECP Buyout") held by certain affiliated investment funds of Energy Capital Partners III, LLC (the "ECP Funds"). As a result, Atlas Power became an indirect wholly owned subsidiary of Dynegy. In accordance with the agreement with Energy Capital Partners ("ECP"), Dynegy will pay ECP $375 million (the "ECP Buyout Price") on the later of December 31, 2016 or three months after the closing of the Delta Transaction (the "First Payment Date"). Alternatively, Dynegy may pay the ECP Buyout Price after the First Payment Date, but in such case, the ECP Buyout Price would be subject to quarterly escalation up to a maximum of $468.5 million.

The Purchaser and the Seller have agreed to indemnify the other for breaches of representations, warranties and covenants, and for certain other matters, subject to certain exceptions and limitations. The Delta Stock Purchase Agreement contains certain termination rights for both the Purchaser and the Seller, including if the closing does not occur within 12 months following the date of the Delta Stock Purchase Agreement. In the event the Delta Stock Purchase Agreement is terminated under certain circumstances, including the failure to obtain certain regulatory approvals, the Purchaser must pay GSENA the reverse termination fee of $132 million discussed below.

DYNEGY INC.
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For the Interim Periods Ended June 30, 2016 and 2015

Dynegy also entered into an amended and restated limited guarantee in favor of GSENA, pursuant to which Dynegy guarantees 100 percent of the Purchaser's obligation to pay the reverse termination fee of $132 million if such fee becomes payable. Please read Note 14—Commitments and Contingencies—Indemnifications and Guarantees for further discussion.

The Delta Stock Purchase Agreement includes customary representations, warranties and covenants by the parties. The Delta Transaction is subject to various closing conditions, including (i) expiration of the applicable waiting period, which was received on April 1, 2016, under the Hart-Scott-Rodino Act; (ii) obtaining required approvals from the FERC and the Public Utility Commission of Texas, which was received on July 20, 2016; (iii) no injunction or other orders preventing the consummation of the transactions contemplated under the Delta Stock Purchase Agreement; (iv) the completion of GSENA's internal reorganization in all material respects in accordance with an exhibit attached to the Delta Stock Purchase Agreement; (v) the continuing accuracy of each party's representations and warranties, and (vi) the satisfaction of other customary conditions. On June 8, 2016, we received a letter from FERC requesting additional information, to which we have responded. We expect the Delta Transaction to close in the fourth quarter of 2016 after satisfaction or waiver of these closing conditions.

Delta Transaction Financing. On February 24, 2016, Dynegy entered into a Stock Purchase Agreement with Terawatt Holdings, LP ("Terawatt"), an affiliate of the ECP Funds (the "PIPE Stock Purchase Agreement"), pursuant to which Dynegy will sell and issue to Terawatt at the closing of the Delta Transaction 13,711,152 shares of Dynegy common stock for $150 million (the "PIPE Transaction"). The closing of the PIPE Transaction is contingent on the closing of the Delta Transaction. In addition, Dynegy has agreed to enter into an Investor Rights Agreement, in the form attached to the PIPE Stock Purchase Agreement (the "Investor Rights Agreement"), with Terawatt at the closing of the PIPE Transaction. Under the Investor Rights Agreement, Terawatt will be entitled to certain rights, including certain registration rights, rights of first refusal with respect to issuances of our common stock and the designation of one individual to serve on our Board of Directors as long as Terawatt and its affiliates own at least 10 percent of our common stock. Further, the Investor Rights Agreement subjects Terawatt to certain obligations, including certain voting obligations and customary standstill and lock-up periods.

On June 21, 2016, pursuant to a registered public offering, Dynegy issued 4.6 million tangible equity units ("TEUs") for proceeds of $446 million, net of issuance costs of $14 million. Please read Note 12—Tangible Equity Units for further discussion.

On June 27, 2016, Dynegy Finance IV, Inc. ("Finance IV"), a direct wholly-owned subsidiary of Dynegy, entered into a term loan credit agreement with certain lenders providing for a $2.0 billion, seven-year senior secured term loan facility (the "Tranche C Term Loan"), the net proceeds of which were placed into escrow pending the closing of the Delta Transaction. Under the escrow agreement, the applicable borrowings are subject to full liquidation and release to the lenders if the Delta Transaction is terminated or not consummated by February 24, 2017.

Also, on June 27, 2016, Dynegy entered into a Third Amendment to the Credit Agreement (the "Third Amendment"), which, upon the release of funds from escrow, provides for (i) a $75 million revolving loan commitment increase to the incremental tranche B revolving loan commitments (the "Incremental Tranche B Revolver"), which has terms substantially the same as the terms of the existing incremental tranche B revolving loan commitments under the Credit Agreement, and (ii) conversion of the Tranche C Term Loan to an incremental $2.0 billion senior secured tranche C term loan. Please read Note 13—Debt—Credit Agreement and Finance IV Credit Agreement for further discussion.

During the quarter, Dynegy substantially completed its financing for the Delta Transaction. Upon closing, Dynegy intends to use the net proceeds associated with the PIPE Transaction, the TEUs, the Tranche C Term Loan, borrowings under its revolving credit facilities, and cash-on-hand.

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

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

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

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

Business Combination Accounting. The EquiPower Acquisition and the Duke Midwest Acquisition (collectively, the "Acquisitions") have been accounted for in accordance with Accounting Standards Codification ("ASC") 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition dates, April 1, 2015 and April 2, 2015, respectively. The valuation of these assets and liabilities is classified as Level 3 within the fair value hierarchy.

To fair value working capital, we used available market information. Asset retirement obligations ("AROs") were recorded in accordance with ASC 410, Asset Retirement and Environmental Obligations. To fair value the acquired property, plant and equipment ("PP&E"), we used a discounted cash flow ("DCF") analysis based upon a debt-free, free cash flow model. The DCF model was created for each power generation facility based on its remaining useful life, and included gross margin forecasts for each facility using forward commodity market prices obtained from third party quotations for the years 2015 and 2016. For the years 2017 through 2024, we used gross margin forecasts based upon commodity and capacity price curves developed internally using forward New York Mercantile Exchange natural gas prices and supply and demand factors. For periods beyond 2024, we assumed a 2.5 percent growth rate. We also used management's forecasts of operations and maintenance expense, general and administrative expense, and capital expenditures for the years 2015 through 2019 and assumed a 2.5 percent growth rate, based upon management's view of future conditions, thereafter. The resulting cash flows were then discounted using plant specific discount rates of approximately 8 percent to 10 percent for gas-fired generation facilities and approximately 9 percent to 13 percent for coal-fired generation facilities, based upon the asset's age, efficiency, region and years until retirement. Contracts with terms that were not at current market prices were also valued using a DCF analysis. The cash flows generated by the contracts were compared with their cash flows based on current market prices with the resulting difference recorded as either an intangible asset or liability. The 3,460,053 shares of common stock of Dynegy, issued as part of the consideration for the EquiPower Acquisition, were valued at approximately $105 million based on the closing price of Dynegy's common stock on the EquiPower Closing Date.

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As of June 30, 2016, we have completed our valuation of the assets acquired and liabilities assumed in connection with the Acquisitions. The following table summarizes the consideration paid and the fair value amounts recognized for the assets acquired and liabilities assumed related to the EquiPower Acquisition and Duke Midwest Acquisition, as of the respective acquisition dates, April 1, 2015 and April 2, 2015:

(amounts in millions)	EquiPower Acquisition	Duke Midwest Acquisition	Total
Cash	$ 3,350	$ 2,800	$6,150
Equity instruments (3,460,053 common shares of Dynegy)	105	—	105
Net working capital adjustment	206	(9)	197
Fair value of total consideration transferred	$ 3,661	$ 2,791	$6,452
Cash	$ 267	$ —	$267
Accounts receivable	49	126	175
Inventory	167	105	272
Assets from risk management activities (including current portion of $4 million and $30 million, respectively)	4	33	37
Prepayments and other current assets	32	69	101
Property, plant and equipment	2,773	2,734	5,507
Investment in unconsolidated affiliate	200	—	200
Intangible assets (including current portion of $67 million and $36 million, respectively)	111	84	195
Other long-term assets	28	35	63
Total assets acquired	3,631	3,186	6,817
Accounts payable	27	96	123
Accrued liabilities and other current liabilities	21	10	31
Debt, current portion	39	—	39
Liabilities from risk management activities (including current portion of $41 million and zero, respectively)	57	107	164
Asset retirement obligations	43	49	92
Intangible liabilities (including current portion of $24 million and $58 million, respectively)	73	93	166
Deferred income taxes, net	509	—	509
Other long-term liabilities	—	40	40
Total liabilities assumed	769	395	1,164
Identifiable net assets acquired	2,862	2,791	5,653
Goodwill	799	—	799
Net assets acquired	$ 3,661	$ 2,791	$6,452

No acquisition costs related to the Acquisitions were incurred during the three and six months ended June 30, 2016. We incurred acquisition costs of $2 million and $85 million related to the Acquisitions for the three and six months ended June 30, 2015, respectively. These acquisition costs are included in Acquisition and integration costs in our unaudited consolidated statements of operations.

Revenues of $468 million and $1,129 million and operating income of $20 million and $177 million, attributable to the Acquisitions, are included in our unaudited consolidated statements of operations for the three and six months ended June 30, 2016, respectively. Revenues of $507 million and operating income of $67 million attributable to the

Acquisitions are included in our unaudited consolidated statements of operations for the three and six months ended June 30, 2015, respectively.

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Pro Forma Results. The unaudited pro forma financial results for the six months ended June 30, 2015 assume the EquiPower Acquisition and the Duke Midwest Acquisition occurred on January 1, 2014. The unaudited pro forma financial results may not be indicative of the results that would have occurred had the acquisition been completed as of January 1, 2014, nor are they indicative of future results of operations.

(amounts in millions)	Six Months Ended June 30, 2015
Revenues	$2,612
Net income	$466
Net loss attributable to noncontrolling interests	$(3)
Net income attributable to Dynegy Inc.	$469

Note 4—Unconsolidated Investments

Equity Method Investments

In connection with the EquiPower Acquisition, we acquired a 50 percent interest in Elwood Energy LLC, a limited liability company ("Elwood Energy") and Elwood Expansion LLC, a limited liability company ("Elwood Expansion" and, together with Elwood Energy, "Elwood"). Elwood Energy owns a 1,576 MW natural gas-fired facility located in Elwood, Illinois. At June 30, 2016 and December 31, 2015, our equity method investment included in our unaudited consolidated balance sheets was $185 million and $190 million, respectively. Upon the acquisition of our Elwood investment, we recognized basis differences in the net assets of approximately $89 million related to working capital, PP&E, debt, and intangibles. These basis differences are being amortized over their respective useful lives. Our risk of loss related to our equity method investment is limited to our investment balance. Holders of the debt of our unconsolidated investment do not have recourse to us and our other subsidiaries.

For the three and six months ended June 30, 2016, we recorded $1 million and $3 million in equity earnings related to our investment in Elwood, respectively, which is reflected in Earnings from unconsolidated investments in our unaudited consolidated statements of operations. For the six months ended June 30, 2016, we received a distribution of $8 million, all of which was considered a return of investment. For the six months ended June 30, 2015, we did not receive any distributions. In July 2016, we received a distribution of $7 million. At June 30, 2016 and December 31, 2015, we have $13 million and $3 million in accounts receivable due from Elwood, respectively, which is included in Accounts receivable, net in our unaudited consolidated balance sheets.

On March 28, 2016, Dynegy Marketing and Trade, LLC ("DMT"), a subsidiary of Dynegy, entered into (i) an Asset Management Agreement and (ii) a Fuel Supply and Fuel Management Services Agreement with Elwood Energy. Under these agreements, DMT provides gas supply and management services to meet Elwood Energy's fuel supply requirements. As of June 30, 2016, we have $11 million in accounts receivable due from Elwood Energy related to these agreements, which is included in Accounts receivable, net in our unaudited consolidated balance sheets. For the three and six months ended June 30, 2016, we recorded $11 million in revenues related to these agreements, which is reflected in Revenues in our unaudited consolidated statements of operations.

Note 5—Risk Management Activities, Derivatives, and Financial Instruments

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

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

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our 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,

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normal sale," in accordance with ASC 815, Derivatives and Hedging. As a result, the gains and losses with respect to these arrangements are not reflected in our unaudited consolidated financial statements until the delivery occurs.

Quantitative Disclosures Related to Financial Instruments and Derivatives

As of June 30, 2016, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type	Quantity	Unit of Measure	Fair Value (1)
(dollars and quantities in millions)	Purchases (Sales)		Asset (Liability)
Commodity contracts:			
Electricity derivatives (2)	(26)	MWh	$ (22)
Electricity basis derivatives (3)	(40)	MWh	$ (9)
Natural gas derivatives (2)	315	MMBtu	$ (10)
Natural gas basis derivatives	82	MMBtu	$ (1)
Diesel fuel	1	Gallon	$ (1)
Coal derivatives (4)	—	Metric Ton	$ (17)
Emissions derivatives	4	Metric Ton	$ (2)
Interest rate swaps	773	U.S. Dollar	$ (45)
Common stock warrants (5)	16	Warrant	$ (6)

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(1) Includes both asset and liability risk management positions but excludes margin and collateral netting of $81 million.
(2) Mainly comprised of swaps, options, and physical forwards.
(3) Comprised of FTRs and swaps.
(4) Our net position rounds to less than 1 million tons.
(5) Each warrant is convertible into one share of Dynegy common stock.

Derivatives on the Balance Sheet. The following tables present the fair value and balance sheet classification of derivatives in our unaudited consolidated balance sheets as of June 30, 2016 and December 31, 2015. As of June 30, 2016 and December 31, 2015, there were no gross amounts available to be offset that were not offset in our unaudited consolidated balance sheets.

		June 30, 2016			
			Gross amounts offset in the balance sheet		
Contract Type	Location on Balance Sheet	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	$384	$(294)	$ —	$90
Total derivative assets		$384	$(294)	$ —	$90
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(446)	$294	$ 81	$(71)
Interest rate contracts	Liabilities from risk management activities	(45)	—	—	(45)
Common stock warrants	Other long-term liabilities	(6)	—	—	(6)

Total derivative liabilities	$(497)	$294	$ 81	$(122)
Total derivatives	$(113)	$—	$ 81	$(32)

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

Certain of our derivative instruments have credit limits that require us to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as our established credit limit with the respective counterparty. If our credit rating were to change, the counterparties could require us to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in our credit rating as well as the requirements of the individual counterparty. The aggregate fair value of all commodity derivative instruments with credit-risk-related contingent features that are in a liability position that are not fully collateralized (excluding transactions with our clearing brokers that are fully collateralized) as of June 30, 2016, is $28 million for which we have posted $11 million in collateral. Our remaining derivative instruments do not have credit-related collateral contingencies as they are included within our first-lien collateral program.

The following table summarizes our cash collateral posted as of June 30, 2016 and December 31, 2015, within Prepayments and other current assets in our unaudited consolidated balance sheets and the amount applied against short-term risk management activities:

Location on Balance Sheet	June 30, 2016	December 31, 2015
(amounts in millions)		
Gross collateral posted with counterparties	$ 127	$ 162

Less: Collateral netted against risk management liabilities	81	106
Net collateral within Prepayments and other current assets	$ 46	$ 56

Impact of Derivatives on the Unaudited Consolidated Statements of Operations

The following discussion and table 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.

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Our unaudited consolidated statements of operations for the three and six months ended June 30, 2016 and 2015 include the impact of derivative financial instruments as presented below:

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
(amounts in millions)					
Commodity contracts	Revenues	$ 23	$ 53	$ 215	$ 72
Interest rate contracts	Interest expense	$ (4)	$ 1	$ (12)	$ (8)
Common stock warrants	Other income and (expense), net	$ —	$ 3	$ 1	$ (2)

Note 6—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 June 30, 2016 and December 31, 2015, and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid:

(amounts in millions)	Fair Value as of June 30, 2016			
	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$253	$25	$278
Natural gas derivatives	—	93	9	102
Emissions derivatives	—	1	—	1
Coal derivatives	—	1	2	3
Total assets from commodity risk management activities	$—	$348	$36	$384
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(260)	$(49)	$(309)
Natural gas derivatives	—	(89)	(24)	(113)
Emissions derivatives	—	(3)	—	(3)
Diesel fuel derivatives	—	(1)	—	(1)
Coal derivatives	—	(19)	(1)	(20)
Total liabilities from commodity risk management activities	—	(372)	(74)	(446)
Liabilities from interest rate contracts	—	(45)	—	(45)
Liabilities from outstanding common stock warrants	(6)	—	—	(6)

Total liabilities	$(6)	$(417)	$(74)	$(497)

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

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

Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measurement of our commodity instruments categorized within Level 3 of the fair value hierarchy include estimates of forward congestion, power price spreads, natural gas and coal pricing, and the difference between our plant locational prices to liquid hub prices. Power price spreads, natural gas and coal pricing, and the difference between our plant locational prices to liquid hub prices are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price of the spread on a buy or sell position in isolation would result in a higher/lower fair value measurement. The significant unobservable inputs used in the valuation of Dynegy's contracts classified as Level 3 as of June 30, 2016 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Input	Significant Unobservable Input Range
(dollars in millions)						
Electricity derivatives:						

Forward contracts—power (1)	(4)	Million MWh	$ (23)	Basis spread + liquid location	Basis spread	$5.00 - $7.00
FTRs	(34)	Million MWh	$ (1)	Historical congestion	Forward price	$0 - $8.00
Natural gas derivatives (1)	57	Million MMBtu	$ (15)	Illiquid location fixed price	Forward price	$1.80 - $2.20
Coal derivatives (1)	—	Thousand Tons	$ 1	Illiquid location fixed price	Forward price	$5.60 - $6.80

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

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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:

(amounts in millions)	Three Months Ended June 30, 2016 Electricity Derivatives	Natural Gas Derivatives	Coal Derivatives	Total
Balance at March 31, 2016	$(17)	$ (18)	$ 1	$(34)
Total losses included in earnings	(12)	—	—	(12)
Settlements (1)	5	3	—	8
Balance at June 30, 2016	$(24)	$ (15)	$ 1	$(38)
Unrealized losses relating to instruments held as of June 30, 2016	$(12)	$ —	$ —	$(12)

(amounts in millions)	Six Months Ended June 30, 2016 Electricity Derivatives	Natural Gas Derivatives	Coal Derivatives	Total
Balance at December 31, 2015	$(18)	$ (32)	$ 2	$(48)
Total gains (losses) included in earnings	(5)	3	—	(2)
Settlements (1)	(1)	14	(1)	12
Balance at June 30, 2016	$(24)	$ (15)	$ 1	$(38)
Unrealized gains (losses) relating to instruments held as of June 30, 2016	$(5)	$ 3	$ —	$(2)

(amounts in millions)	Three Months Ended June 30, 2015 Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at March 31, 2015	$4	$ —	$ —	$ —	$4
Acquisitions	(54)	(14)	(9)	5	(72)
Total gains (losses) included in earnings	(2)	3	—	—	1
Settlements (1)	(2)	—	2	(1)	(1)
Balance at June 30, 2015	$(54)	$ (11)	$ (7)	$ 4	$(68)
Unrealized gains (losses) relating to instruments held as of June 30, 2015	$(2)	$ 3	$ —	$ —	$1

(amounts in millions)	Six Months Ended June 30, 2015 Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at December 31, 2014	$(4)	$ —	$ —	$ —	$(4)
Acquisitions	(54)	(14)	(9)	5	(72)
Total gains included in earnings	1	3	—	—	4
Settlements (1)	3	—	2	(1)	4
Balance at June 30, 2015	$(54)	$ (11)	$ (7)	$ 4	$(68)
Unrealized gains relating to instruments held as of June 30, 2015	$1	$ 3	$ —	$ —	$4

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

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Gains and losses recognized for Level 3 recurring items are included in Revenues in 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 and six months ended June 30, 2016 and 2015.

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 such assets and liabilities and their placement within the fair value hierarchy.

During the three and six months ended June 30, 2016, as a result of impairment testing, we measured our Baldwin facility at fair value. See Note 9—Property, Plant and Equipment for further discussion. During the three and six months ended June 30, 2015, we fair valued the EquiPower and Duke Midwest acquisitions. See Note 3—Acquisitions for further discussion. Each of these valuations is classified as Level 3 within the fair value hierarchy.

Fair Value of Financial Instruments. The following table discloses the fair value of financial instruments recognized in 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 June 30, 2016 and December 31, 2015, respectively.

		June 30, 2016		December 31, 2015	
(amounts in millions)	Fair Value Hierarchy	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Dynegy Inc.:					
6.75% Senior Notes, due 2019 (1)	Level 2	$(2,080)	$(2,100)	$(2,077)	$(1,985)
Tranche B-2 Term Loan, due 2020 (1)	Level 2	$(763)	$(759)	$(766)	$(754)
7.375% Senior Notes, due 2022 (1)	Level 2	$(1,730)	$(1,698)	$(1,729)	$(1,531)
5.875% Senior Notes, due 2023 (1)	Level 2	$(492)	$(440)	$(491)	$(404)
7.625% Senior Notes, due 2024 (1)	Level 2	$(1,235)	$(1,200)	$(1,235)	$(1,078)
7.00% Amortizing Notes, due 2019 (TEUs) (1)	Level 1	$(84)	$(86)	$—	$—
Forward capacity agreement (1)	Level 3	$(201)	$(201)	$—	$—
Inventory financing agreements	Level 3	$(135)	$(135)	$(136)	$(137)
Equipment financing agreements (1)	Level 3	$(66)	$(66)	$(61)	$(61)
Interest rate derivatives	Level 2	$(45)	$(45)	$(42)	$(42)
Commodity-based derivative contracts (2)	Various	$(62)	$(62)	$(154)	$(154)
Common stock warrants	Level 1	$(6)	$(6)	$(7)	$(7)
Dynegy Finance IV, Inc.:					
Tranche C Term Loan, due 2023 (1)	Level 2	$(1,996)	$(1,985)	$—	$—
Genco:					
7.00% Senior Notes Series H, due 2018 (1)	Level 2	$(281)	$(119)	$(276)	$(204)
6.30% Senior Notes Series I, due 2020 (1)	Level 2	$(216)	$(99)	$(213)	$(148)
7.95% Senior Notes Series F, due 2032 (1)	Level 2	$(226)	$(107)	$(225)	$(162)

(1) Carrying amounts include unamortized discounts and debt issuance costs. Please read Note 13—Debt for further details.

(2) Carrying amounts exclude $81 million and $106 million of cash posted as collateral, as of June 30, 2016 and December 31, 2015, respectively.

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Note 7—Accumulated Other Comprehensive Income

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

(amounts in millions)	Six Months Ended June 30, 2016	2015
Beginning of period	$19	$20
Other comprehensive loss before reclassifications:		
Actuarial loss (net of tax of zero and zero, respectively)	—	(5)
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero and zero, respectively) (1)	(2)	(1)
Net current period other comprehensive loss, net of tax	(2)	(6)
End of period	$17	$14

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(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 16—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 8—Inventory

A summary of our inventories is as follows:

(amounts in millions)	June 30, 2016	December 31, 2015
Materials and supplies	$ 177	$ 175
Coal (1)	294	350
Fuel oil (1)	17	17
Emissions allowances (2)	30	51
Other	2	4
Total	$ 520	$ 597

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(1) At June 30, 2016 and December 31, 2015, approximately $44 million and $16 million of the coal and fuel oil inventory, respectively, were part of an inventory financing agreement. Please read Note 13—Debt—Brayton Point Inventory Financing for further discussion.

(2) At June 30, 2016 and December 31, 2015, a portion of this inventory was held as collateral by one of our counterparties as part of an inventory financing agreement. Please read Note 13—Debt—Emissions Repurchase Agreements for further discussion.

Note 9—Property, Plant and Equipment

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

(amounts in millions)	June 30, 2016	December 31, 2015
Power generation	$7,679	$ 8,178
Buildings and improvements	936	956
Office and other equipment	103	101
Property, plant and equipment	8,718	9,235

Accumulated depreciation	(1,130)	(888)
Property, plant and equipment, net	$7,588	$ 8,347

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On May 3, 2016, Dynegy announced the shutdown of two of the three units at its Baldwin power generation facility in Baldwin, Illinois and one of the two units at its Newton power generation facility in Newton, Illinois. MISO has approved the shutdown of one unit at Baldwin by October 17, 2016 and one unit at Newton by September 15, 2016. Subject to the approval of MISO, we expect to shut down the other Baldwin unit by March 31, 2017.

In the second quarter of 2016, due to the recent MISO auction results and the impact of certain unit shutdowns, we performed an impairment analysis on our MISO plants. We performed step one of the impairment analysis using undiscounted cash flows for the estimated useful lives of the facilities and determined the book value of the Baldwin facility would not be recovered. We performed step two of the impairment analysis using a DCF model, utilizing a 13 percent discount rate, and assuming normal operations for the estimated useful lives of the facilities. For the model, gross margin was based on forward commodity market prices obtained from third party quotations for the years 2016 through 2018. For the years 2019 through 2025, we used commodity and capacity price curves developed internally utilizing supply and demand factors. We also used management’s forecasts of operations and maintenance expense, general and administrative expense, and capital expenditures for the years 2016 through 2025 and assumed a 2.5 percent growth rate thereafter, based upon management’s view of future conditions. The model resulted in a fair value of the Baldwin facility of $97 million, resulting in an impairment charge of $645 million recorded to Impairments in our unaudited consolidated statements of operations for the three and six months ended June 30, 2016. The valuation is classified as Level 3 within the fair value hierarchy.

Note 10—Joint Ownership of Generating Facilities

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

The following tables present the ownership interests of the jointly owned facilities as of June 30, 2016 and December 31, 2015 included in our unaudited consolidated balance sheets. Each facility is co-owned with one or more other generation companies.

	June 30, 2016				
(dollars in millions)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress	Total
Miami Fort	64.0%	$ 207	$ (28)	$ 2	$181
Stuart (1)	39.0%	$ 35	$ (6)	$ 24	$53
Conesville (1)	40.0%	$ 61	$ (2)	$ 4	$63
Zimmer	46.5%	$ 106	$ (17)	$ 12	$101
Killen (1)	33.0%	$ 18	$ (1)	$ 1	$18

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

(1) Facilities not operated by Dynegy.

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Note 11—Intangible Assets and Liabilities

The following table summarizes the components of our intangible assets and liabilities as of June 30, 2016 and December 31, 2015:

(amounts in millions)	June 30, 2016 Gross Carrying Amount	June 30, 2016 Accumulated Amortization	June 30, 2016 Net Carrying Amount	December 31, 2015 Gross Carrying Amount	December 31, 2015 Accumulated Amortization	December 31, 2015 Net Carrying Amount
Intangible Assets:						
Electricity contracts	$260	$ (167)	$ 93	$260	$ (126)	$ 134
Gas transport contracts	46	(35)	11	46	(16)	30
Total intangible assets	$306	$ (202)	$ 104	$306	$ (142)	$ 164
Intangible Liabilities:						
Electricity contracts	$(28)	$ 25	$ (3)	$(30)	$ 19	$ (11)
Coal contracts	(93)	67	(26)	(134)	82	(52)
Coal transport contracts	(104)	78	(26)	(104)	64	(40)
Gas transport contracts	(41)	6	(35)	(64)	27	(37)
Total intangible liabilities	$(266)	$ 176	$ (90)	$(332)	$ 192	$ (140)
Intangible assets and liabilities, net	$40	$ (26)	$ 14	$(26)	$ 50	$ 24

The following table presents our amortization expense (revenue) of intangible assets and liabilities for the three and six months ended June 30, 2016 and 2015:

(amounts in millions)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Electricity contracts, net (1)	$17	$25	$33	$32
Coal contracts, net (2)	(11)	(20)	(23)	(23)
Coal transport contracts, net (2)	(7)	(9)	(14)	(15)
Gas transport contracts, net (2)	—	(1)	17	(3)
Total	$(1)	$(5)	$13	$(9)

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(1) The amortization of these contracts is recognized in Revenues 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 12—Tangible Equity Units

On June 21, 2016, we issued 4.6 million, 7 percent TEUs at $100 per unit and received proceeds of $446 million, net of issuance costs of $14 million.

Each TEU is comprised of: (i) a prepaid stock purchase contract (“SPC”) issued by Dynegy, and (ii) an amortizing note (“Amortizing Note”), with an initial principal amount of $18.95 that pays an equal quarterly cash installment of $1.75 per Amortizing Note on January 1, April 1, July 1, and October 1 of each year, with the exception of the first installment payment of $1.94 due on October 1, 2016. In the aggregate, the annual quarterly cash installments will be equivalent to a 7 percent cash payment per year. Each installment cash payment constitutes a payment of interest and a partial repayment of principal. Each TEU may be separated by a holder into its constituent SPC and Amortizing Note after the initial issuance date of the TEUs, and the separate components may be combined to create a TEU after the initial issuance date, in accordance with the terms of the SPC. The TEUs are listed on the New York Stock Exchange under the symbol "DYNC".

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We allocated the proceeds from the issuance of the TEUs to equity and debt based on the relative fair value of the respective components of each TEU as follows:

(in millions, except price per TEU)	SPC	Amortizing Note	Total
Price per TEU	$81	$ 19	$100
Gross proceeds	$373	$ 87	$460
Less: Issuance costs	(11)	(3)	(14)
Net proceeds	$362	$ 84	$446

The fair value of the SPCs was recorded as additional paid in capital, net of issuance costs. The fair value of the Amortizing Notes was recorded as debt, with deferred financing costs recorded as a reduction of the carrying amount of the debt in our unaudited consolidated balance sheet. Deferred financing costs related to the Amortizing Notes will be amortized through the maturity date using the effective interest rate method.

Unless settled early at the holder's or Dynegy's election or redeemed by Dynegy in connection with an acquisition termination redemption, on July 1, 2019, Dynegy will deliver to the SPC holders a number of shares of common stock based on the 20 day volume-weighted average price ("VWAP") of our common stock as follows:

VWAP of Dynegy Common Stock	Common Shares Issued
Equal to or greater than $19.92	5.0201 shares (minimum settlement rate)
Less than $19.92, but greater than $16.13	$100 divided by VWAP
Less than or equal to $16.13	6.1996 shares (maximum settlement rate)

In addition, on any business day during the period beginning on, and including, the business day immediately following the date of initial issuance of the TEUs to, but excluding, the third business day immediately preceding the mandatory settlement date, any holder of an SPC may settle any or all of its SPCs early, and Dynegy will deliver a number of shares of Common Stock equal to the minimum settlement rate. Additionally, the SPCs may be redeemed in the event of a fundamental change or under an acquisition termination event, both as defined in the SPC.

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Note 13—Debt

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

(amounts in millions)	June 30, 2016	December 31, 2015
Secured Obligations:		
Dynegy Inc.:		
Tranche B-2 Term Loan, due 2020	$776	$ 780
Revolving Facility	—	—
Forward Capacity Agreement	219	—
Inventory Financing Agreements	135	136
Dynegy Finance IV, Inc.:		
Tranche C Term Loan, due 2023 (1)	2,000	—
Subtotal secured obligations	3,130	916
Unsecured Obligations:		
Dynegy Inc.:		
7.00% Amortizing Notes, due 2019 (TEUs)	87	—
6.75% Senior Notes, due 2019	2,100	2,100
7.375% Senior Notes, due 2022	1,750	1,750
5.875% Senior Notes, due 2023	500	500
7.625% Senior Notes, due 2024	1,250	1,250
Equipment Financing Agreements	88	75
Subtotal unsecured obligations	5,775	5,675
Total Dynegy Inc. and Dynegy Finance IV, Inc.	8,905	6,591
Genco Unsecured Obligations:		
7.00% Senior Notes Series H, due 2018	300	300
6.30% Senior Notes Series I, due 2020	250	250
7.95% Senior Notes Series F, due 2032	275	275
Total Genco	825	825
Total debt obligations	9,730	7,416
Unamortized debt discounts and issuance costs (2)	(224)	(207)
	9,506	7,209
Less: Current maturities, including unamortized debt discounts and issuance costs, net	141	80
Total Long-term debt	$9,365	$ 7,129

(1) At June 30, 2016, the Tranche C Term Loan, under the Finance IV Credit Agreement, was secured by first-priority liens on amounts in the applicable escrow account which was classified as long-term Restricted cash in our unaudited consolidated balance sheet. Upon the closing of the Delta Transaction, this debt obligation will become Dynegy Inc.'s secured obligation. Please read Finance IV Credit Agreement below for further discussion.

(2) Includes $102 million and $111 million of unamortized debt discounts and issuance costs as of June 30, 2016 and December 31, 2015, respectively, relating to the Genco unsecured obligations.

Credit Agreement and Finance IV Credit Agreement

As of June 30, 2016, we had a $2.225 billion credit agreement, as amended, that consisted of (i) an $800 million seven-year senior secured term loan facility (the "Tranche B-2 Term Loan") and (ii) $1.425 billion in senior secured revolving credit facilities (the "Revolving Facility," and collectively with the Tranche B-2 Term Loan the "Credit Agreement"). Additionally as

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of June 30, 2016, we had a $2.0 billion, seven-year senior Tranche C Term Loan, under the Finance IV Credit Agreement, as defined below.

At June 30, 2016, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit ("LCs") of approximately $332 million, which reduce the amount available under the Revolving Facility. The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a Senior Secured Leverage Ratio (as defined in the Credit Agreement) calculated on a rolling four quarters basis. Based on the calculation outlined in the Credit Agreement, we are in compliance as of June 30, 2016.

Finance IV Credit Agreement. On June 27, 2016 (the "Term Loan Closing Date"), Finance IV entered into a term loan credit agreement which provides for a $2.0 billion, seven-year Tranche C Term Loan, and matures on June 27, 2023. The Tranche C Term Loan bears interest at either (i) 4 percent per annum plus LIBOR, subject to a floor of one percent with respect to any LIBOR Loan or (ii) 3 percent per annum plus the Base Rate with respect to any Base Rate Loan. Amounts available under the Tranche C Term Loan were fully drawn on the Term Loan Closing Date, and the net proceeds were placed into escrow (see "Escrow Agreement" described below) pending the consummation of the Delta Transaction. The Finance IV Credit Agreement contains limited events of default and affirmative covenants and one negative covenant, which restricts the activities of Finance IV to those primarily relating to the Delta Transaction and financing. The obligations of Finance IV under the Finance IV Credit Agreement are secured by the related amounts placed in escrow from time to time.

Escrow Agreement. On the Term Loan Closing Date, Finance IV borrowed the full amount of the Tranche C Term Loan and placed the net proceeds into an escrow account (the "Escrow Account"). Additionally, Dynegy contributed $70 million into escrow so that the aggregate funds in the Escrow Account would be sufficient to repay the Tranche C Term Loan plus any interest that may accrue for a period of six months from the Term Loan Closing Date. Pursuant to the Escrow Agreement, interest payments on the Tranche C Term Loan will be paid from the amounts in the escrow account until the release of funds on the Escrow Release Date. As of June 30, 2016, we had $2.0 billion classified as long-term Restricted cash and $70 million classified as short-term Restricted cash in our unaudited consolidated balance sheet related to the Escrow Agreement. The $70 million represents a payment to the escrow account of (i) $50 million of pre-funded interest and (ii) $20 million of pre-funded original issue discount which is contingent upon the closing of the Delta Transaction.

Upon the release of funds from escrow upon the satisfaction of the Delta Transaction Escrow Conditions, as defined in the Finance IV Credit Agreement (the "Escrow Release Date"), Finance IV will merge with and into Dynegy, with Dynegy as the surviving entity, and Dynegy will use the amounts released from escrow to fund a portion of the Delta Transaction. The Finance IV Credit Agreement provides that, upon the effectiveness of the Conversion and Deemed Issuance, as defined in the Finance IV Credit Agreement, the latter will (a) cease to be of force or effect and (b) be superseded by the provisions of the Credit Agreement, as amended by the Third Amendment. If the Delta Transaction Escrow Conditions are not satisfied on or prior to February 24, 2017 (the "Delta Transaction Deadline") or if the Delta Stock Purchase Agreement is terminated or Finance IV has determined that the Delta Transaction will not be consummated on or before the Delta Transaction Deadline, the escrow agent will, within one business day, liquidate all escrowed property held in escrow and release all amounts to the lenders under the Finance IV Credit Agreement.

Credit Agreement Third Amendment. In order to facilitate the merger of Finance IV with and into Dynegy upon the closing of the Delta Transaction, on June 27, 2016, Dynegy entered into the Third Amendment of its Credit Agreement. The Third Amendment provides, upon the Escrow Release Date, for (i) a $75 million Incremental Tranche B Revolver to the Revolving Facility, which has terms substantially the same as the terms of the Revolving Facility and will mature on April 2, 2020 and (ii) an incremental $2.0 billion, seven-year senior secured Tranche C Term Loan which has terms substantially the same as the Finance IV Credit Agreement discussed above. In addition, as requested by the Seller in the Delta Transaction, on June 27, 2016, Dynegy, the guarantors, the lenders and other parties thereto entered into a waiver to the Credit Agreement (the "Waiver"), providing a waiver from the lenders party thereto of the Incremental Ratio Tests (as defined in the Credit Agreement) and confirmation that notwithstanding the terms of the Credit Agreement or other related Credit Document (as defined in the Credit Agreement), Dynegy may incur the Tranche C Term Loan and the Incremental Tranche B Revolver without regard to the satisfaction of the Incremental Ratio Tests and no default or event of default will occur as a result of any breach of the Incremental Ratio Tests.

Upon the Escrow Release Date, the Credit Agreement will be comprised of (i) an $800 million, seven-year Tranche B-2 Term Loan, (ii) a $2.0 billion, seven-year Tranche C Term Loan, and (iii) a $1.5 billion Revolving Facility consisting of three tranches of revolving commitments including: (a) a $475 million tranche which will mature on April 23, 2018, (b) a $350 million tranche which will mature April 1, 2020, and (c) a $675 million tranche, which includes the Incremental Tranche B Revolver and will mature on April 2, 2020.

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Interest Rate Swaps. During 2013, 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 $773 million at an average fixed rate of 3.19 percent with a floor of one percent, and expire during the second quarter of 2020. In lieu of paying the breakage fees related to terminating the old swaps and issuing the new swaps, the costs were incorporated into the terms of the new swaps. As a result, any cash flows related to the settlement of the swaps are reflected as a financing activity in our unaudited consolidated statements of cash flows.

Letter of Credit Facilities

On January 29, 2014, Illinois Power Marketing Company ("IPM") entered into a fully cash collateralized LC 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 LCs 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 LC plus an additional percentage. As of June 30, 2016, IPM had $14 million deposited with the issuing bank and $13 million in LCs outstanding.

On September 18, 2014, Dynegy entered into an LC Reimbursement Agreement with an issuing bank, and its affiliate (the "Lender"), for an LC in an amount not to exceed $55 million. The facility expires in September 2016. At June 30, 2016, there was $55 million outstanding under this LC.

On March 27, 2015, IPM entered into an LC facility with the Lender for up to $25 million. The facility, which is collateralized by Illinois Power Resources Generating, LLC ("IPRG") 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 LCs. At June 30, 2016, there was $14 million outstanding under this LC facility.

On February 24, 2016, Dynegy entered into a bilateral letter of credit facility commitment letter with an issuing bank for $50 million, which is contingent upon the closing of the Delta Transaction.

Forward Capacity Agreement

On March 18, 2016, we entered into a bilateral contract with a financial institution to sell a portion of our forward cleared PJM capacity auction volumes. In exchange, we received $198 million in cash proceeds during the first quarter of 2016. The buyer in this transaction will receive capacity payments from PJM during the Planning Years 2017-2018 and 2018-2019 in the amounts of $110 million and $109 million, respectively. Dynegy will continue to be subject to the performance obligations as well as any associated performance penalties and bonus payments for those planning years. The transaction is accounted for as a debt issuance of $219 million with an implied interest rate of 4.45 percent. As of June 30, 2016, there was $201 million, in aggregate, outstanding under these agreements.

Inventory Financing Agreements

Brayton Point Inventory Financing. In connection with the EquiPower Acquisition, we assumed an inventory financing agreement (the "Inventory Financing Agreement") for coal and fuel oil inventories at our Brayton Point facility, consisting of a debt obligation for existing and subsequent inventories, as well as a $15 million line of credit. Balances in excess of the $15 million line of credit are cash collateralized.

As the materials are purchased and delivered to our facilities, our debt obligation and line of credit increase based on the then market rate of the materials, transportation costs, and other expenses. The debt obligation increases for 85 percent of the total cost of the coal and for 90 percent of the total cost of the fuel oil. The line of credit increases for the remaining 15 percent and 10 percent for coal and oil costs, respectively. We repay the debt obligation and line of credit from revenues received, at the then market price, for the amount of the materials consumed, on a weekly basis. As of June 30, 2016, there was $57 million outstanding under this agreement. Both the debt obligation related to coal and the base level of fuel oil, as well as the line of credit, bear interest at an annual interest rate of the 3-month LIBOR plus 5.6 percent. An availability fee is calculated on a per annum rate of 0.75 percent. Additionally, we had collateral postings of approximately $8 million. The Inventory Financing Agreement terminates, and the remaining obligation, if any, becomes due and payable, on May 31, 2017.

Emissions Repurchase Agreements. On August 14, 2015, we entered into a repurchase transaction with a third party in which we sold approximately $58 million of RGGI inventory and received cash. We are obligated to repurchase a portion of the inventory in February 2017 and the remaining inventory in February 2018 at a specified price with an annualized carry cost of approximately 3.56 percent. On August 20, 2015, we entered into an additional repurchase transaction with a third party in which we sold $20 million of RGGI inventory and received cash. We are obligated to repurchase the additional RGGI inventory in February 2017 at a specified price with an annualized carry cost of approximately 3.31 percent. As of June 30, 2016, there was $78 million, in aggregate, outstanding under these agreements.

Amortizing Notes

On June 21, 2016, in connection with the issuance of the TEUs, Dynegy issued the Amortizing Notes with a principal amount of approximately $87 million. The Amortizing Notes mature on July 1, 2019. Each installment payment of $1.75 (or, in the case of the installment payment due on October 1, 2016, $1.94) per Amortizing Note will be paid in cash and will constitute a partial repayment of principal and a payment of interest, computed at an annual rate of 7 percent. Interest will be calculated on the basis of a 360 day year consisting of twelve 30 day months. Payments will be applied first to the interest due and payable and then to the reduction of the unpaid principal amount, allocated as set forth in the Indenture. Please read Note 12—Tangible Equity Units for further information on the TEUs.

The Indenture limits, among other things, the ability of Dynegy to consolidate, merge, sell, or dispose all or substantially all of its assets. If a fundamental change occurs, or if Dynegy elects to settle the SPCs early or to redeem the SPCs in connection with a termination of the Delta Stock Purchase Agreement, then the holders of the Amortizing Notes will have the right to require Dynegy to repurchase the Amortizing Notes at a repurchase price equal to the principal amount of the Amortizing Notes as of the repurchase date (as described in the supplemental indenture) plus accrued and unpaid interest. The Indenture also contains customary events of default which would permit the holders of the Amortizing Notes to declare those Amortizing Notes to be immediately due and payable if not cured within applicable grace periods, including the failure to make timely installment payments on the Amortizing Notes or other material indebtedness, the failure to satisfy covenants, and specified events of bankruptcy and insolvency.

Dynegy Senior Notes

As of June 30, 2016, we had $5.6 billion in senior notes that consisted of (i) $2.1 billion, 6.75 percent senior notes, due 2019, (ii) $1.75 billion, 7.375 percent senior notes, due 2022, (iii) $500 million, 5.875 percent senior notes, due 2023, and (iv) $1.25 billion, 7.625 percent senior notes, due 2024 (collectively, the “Senior Notes”).

Equipment Financing Agreements

Under certain of our contractual service agreements in which we receive maintenance and capital improvements for our gas-fueled generation fleet, we have obtained parts and equipment intended to increase the output, efficiency, and availability of our generation units. We have financed these parts and equipment under agreements with maturities ranging from 2017 to 2025. The portion of future payments attributable to principal will be classified as cash outflows from financing activities, and the portion of future payments attributable to interest will be classified as cash outflows from operating activities in our unaudited consolidated statements of cash flows. As of June 30, 2016, there was $88 million outstanding under these agreements. The related assets were recorded at the net present value of the payments of $66 million. The $22 million discount is currently amortized as interest expense over the life of the payments.

Genco Senior Notes

Genco’s approximately $825 million in aggregate principal amount of unsecured senior notes (the “Genco Senior Notes”) are an obligation of Genco, a subsidiary of IPH. 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. The Genco Senior Notes are non-recourse to Dynegy. Please read Note 1—Basis of Presentation and Organization for further discussion.

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. 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.

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The following table summarizes these required ratios:

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

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(1) As of the date of 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 external, third-party sources are included in the definition of indebtedness and are subject to these incurrence tests.

Based on June 30, 2016 calculations, Genco did not meet the ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

As a result of continued weak energy prices, unsold capacity volumes, on-going required maintenance and environmental expenditures, upcoming interest payments, as well as consideration of a $300 million debt maturity in 2018, Dynegy and Genco have each engaged their own advisors and have begun strategic reviews of IPH's Genco subsidiary. While Genco's projected future cash flow is sufficient to cover its obligations through December 31, 2016, it may not have sufficient future operating cash flow to satisfy its debt maturity in 2018, absent a debt refinancing or restructuring. Actions to resolve this situation could include one or more of the following: (i) restructuring the Genco debt to achieve a more sustainable business model; (ii) transitioning ownership of Genco's assets to its debt holders; (iii) deferring discretionary capital expenditures to the extent possible; (iv) continued shut down of uneconomic generation; and/or (v) seeking bankruptcy protection.

Note 14—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, the nature of damages sought, and the probability of success. Management regularly reviews all new information with respect to such contingencies and adjusts its assessments and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties including unfavorable rulings or developments, it is possible that the ultimate resolution of our legal proceedings could involve amounts that are different from our currently recorded accruals, and that such differences could be material.

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

Gas Index Pricing Litigation. We, through our subsidiaries, and other energy companies are named as defendants in several lawsuits claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications from 2000-2002. The cases allege that the defendants engaged in an antitrust conspiracy to inflate natural gas prices in three states (Kansas, Missouri, and Wisconsin) during the relevant time period. The cases are consolidated in a multi-district litigation proceeding pending in the United States District Court for Nevada. At this time we cannot reasonably estimate a potential loss.

Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company ("IGC") received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC ("PPE"). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award. On May 23, 2014, the Texas Supreme Court vacated the arbitration award based upon the evident partiality of one of the arbitrators. On November 20, 2014, PPE initiated a new arbitration against IGC and its co-respondents, but the Dallas District Court enjoined the arbitration from proceeding against IGC while any dispute over IGC's $17 million payment remains pending. On December 16, 2014, the Dallas District Court entered a judgment requiring the return of the $17 million to IGC and an additional $2.5 million payment to

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IGC for interest. PPE paid the $17 million principal to IGC (not the $2.5 million in interest), but simultaneously appealed the judgment. On July 14, 2016, the Dallas Court of Appeals affirmed the judgment. The case remains subject to potential appeal to the Texas Supreme Court.

Other Contingencies

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

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

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

New Source Review and CAA Matters.

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

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

Wood River CAA Section 114 Information Request. In 2014, we received an information request from the EPA concerning our Wood River facility's compliance with the Illinois State Implementation Plan ("SIP") and associated permits. We responded to the EPA's request and believe that there are no issues with Wood River's compliance, but we are unable to predict the EPA's response, if any. As of June 1, 2016, our Wood River facility has been retired.

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

Edwards CAA Citizen Suit. In April 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility. The District Court has scheduled the trial date for February 2017. We dispute the allegations and will defend the case vigorously.

Ultimate resolution of any of these CAA matters could have a material adverse impact on our future financial condition, results of operations, and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve these matters.

Stuart National Pollutant Discharge Elimination System ("NPDES") Permit Appeal. In January 2013, the Ohio EPA reissued the NPDES permit for the co-owned Stuart facility. The operator of Stuart, The Dayton Power and Light Company, appealed various aspects of the permit, including provisions regarding thermal discharge limitations, to the Ohio Environmental Review Appeals Commission. Depending on the outcome of the appeal, the effects on Stuart's operations could be material. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve this matter.

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

At Baldwin, with approval of the Illinois EPA, we performed a comprehensive evaluation of the Baldwin Coal Combustion Residuals ("CCR") surface impoundment system beginning in 2013. Based on the results of that evaluation, we recommended to the Illinois EPA in 2014 that the closure process for the inactive east CCR surface impoundment begin and that a geotechnical investigation of the existing soil cap on the inactive old east CCR surface impoundment be undertaken. We also submitted a supplemental groundwater modeling report that indicates no known offsite water supply wells will be impacted under the various Baldwin CCR surface impoundment closure scenarios modeled. In April 2016, we submitted closure and post-closure care plans to the Illinois EPA for the Baldwin old east, east, and west fly ash CCR surface impoundments. We await Illinois EPA action on our plans.

We initiated an investigation at Baldwin in 2011 at the request of the Illinois EPA to determine if the facility's CCR surface impoundment system impacts offsite groundwater. Results of the offsite groundwater quality investigation, as submitted to the Illinois EPA in 2012, indicate two localized areas where Class I groundwater standards were exceeded. Based on the data and groundwater flows, we do not believe that the exceedances are attributable to the Baldwin CCR surface impoundment system.

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

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

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

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

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

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

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

Other Commitments

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

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. We have accrued no amounts with respect to the indemnifications as of June 30, 2016 because none were probable of occurring, nor could they be reasonably estimated.

Delta Transaction Guarantee. In connection with the Delta Stock Purchase Agreement executed on June 27, 2016, Dynegy entered into a guarantee agreement under which Dynegy has agreed to guarantee 100 percent of the Purchaser's obligation to pay the reverse termination fee of $132 million if such fee becomes payable under the terms and conditions of the Delta Stock Purchase Agreement.

Note 15—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.

For the three and six months ended June 30, 2016, we recorded a tax benefit of $3 million for the additional release of our valuation allowance as a result of increased net deferred tax liabilities related to the final purchase price allocation for the EquiPower Acquisition. In addition, we recorded a tax benefit of $4 million and $4 million for the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance and a $2 million state tax benefit and a $14 million state tax expense as a result of a change to our corporate tax structure for the three and six months ended June 30, 2016, respectively.

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For the three and six months ended June 30, 2015, we released $480 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition, we recorded a tax benefit of $21 million for discreet items, including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance.

As of June 30, 2016, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction as they arise as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future.

Note 16—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 further described in Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans in our Form 10-K.

In the second quarter of 2015, upon the close of the Duke Midwest Acquisition, we assumed certain benefit plan obligations and the associated plan assets were transferred to us. As a result, we increased our net liability by approximately $13 million. These benefit plan obligations and related plan assets were merged into our pension and other post-employment benefit plans. The Duke employees began participating in our plans upon acquisition, which as a result triggered a re-measurement of our plans. As a result of the re-measurements, we recorded a loss through other comprehensive income and increased our net liability by approximately $5 million during the second quarter of 2015.

Components of Net Periodic Benefit Cost (Gain). The components of net periodic benefit cost (gain) were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(amounts in millions)	2016	2015	2016	2015
Service cost benefits earned during period	$4	$ 4	$—	$ —
Interest cost on projected benefit obligation	5	5	1	1
Expected return on plan assets	(6)	(6)	(1)	(1)
Amortization of prior service credit	—	(1)	(1)	—
Net periodic benefit cost (gain)	$3	$ 2	$(1)	$ —

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
(amounts in millions)	2016	2015	2016	2015
Service cost benefits earned during period	$8	$ 7	$—	$—
Interest cost on projected benefit obligation	10	9	2	2
Expected return on plan assets	(12)	(11)	(2)	(2)
Amortization of prior service credit	—	(1)	(2)	(1)
Net periodic benefit cost (gain)	$6	$ 4	$(2)	$(1)

Note 17—Capital Stock

Dividends

We pay quarterly dividends on our Mandatory Convertible Preferred Stock on February 1, May 1, August 1, and November 1 of each year, if declared by our Board of Directors. For the three months ended June 30, 2016 and 2015, we paid $5 million in dividends on May 2, 2016 and May 1, 2015, respectively. For the six months ended June 30, 2016 and 2015, we paid an aggregate of $11 million and $12 million in dividends, respectively.

On July 1, 2016, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million in the aggregate. The dividend is for the dividend period beginning on May 1, 2016 and ending on July 31, 2016. Such dividends were paid on August 1, 2016 to stockholders of record as of July 15, 2016.

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TEUs
On June 21, 2016, pursuant to a registered public offering, we issued 4.6 million, 7 percent TEUs at $100 per unit. Each TEU is comprised of a prepaid stock purchase contract and an amortizing note which are accounted for as separate instruments. Please read Note 12—Tangible Equity Units for further discussion.

Note 18—Earnings (Loss) Per Share

Basic earnings (loss) per share is based on the weighted average number of common shares outstanding during the period. Diluted earnings (loss) is based on the weighted average number of common shares used for the basic earnings (loss) per share computation, adjusted for the incremental issuance of shares of common stock assuming (i) our stock options and warrants are exercised, (ii) our restricted stock units and performance stock units are fully vested under the treasury stock method, and (iii) our mandatory convertible preferred stock and the SPCs are converted into common stock under the if-converted method. Please read Note 17—Capital Stock in our Form 10-K and Note 12—Tangible Equity Units for further discussion.

The basic and diluted earnings (loss) per share from continuing operations attributable to our common stockholders during the three and six months ended June 30, 2016 and 2015 is shown in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2016	2015	2016	2015
Income (loss) from continuing operations	$(803)	$386	$(813)	$205
Less: Net loss attributable to noncontrolling interest	(2)	(2)	(2)	(3)
Income (loss) from continuing operations attributable to Dynegy Inc.	(801)	388	(811)	208
Less: Dividends on preferred stock	6	6	11	11
Income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for basic earnings (loss) per share	(807)	382	(822)	197
Add: Dividends on preferred stock (1)	—	6	—	11
Adjusted income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for diluted earnings (loss) per share	$(807)	$388	$(822)	$208
Basic weighted-average shares (2)	120	128	118	126
Effect of dilutive securities (3)	—	14	—	14
Diluted weighted-average shares	120	142	118	140
Earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders:				
Basic (2)	$(6.73)	$2.98	$(6.97)	$1.56
Diluted (3)	$(6.73)	$2.73	$(6.97)	$1.49

(1) Excluded for the three and six months ended June 30, 2016 due to a net loss from continuing operations for both periods.

(2) For the three and six months ended June 30, 2016, the TEUs are assumed to be outstanding at the minimum settlement amount for weighted-average shares for basic earnings (loss) per share. Please read Note 12—Tangible Equity Units for further discussion.

(3) 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 used the basic shares outstanding amount to calculate both basic and diluted loss per share for the three and six months ended June 30, 2016.

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For the three and six months ended June 30, 2016 and 2015, the following potentially dilutive securities were not included in the computation of diluted per share amounts because the effect would be anti-dilutive:

(in millions of shares)	2016	2015
Stock options	2.8	—
Restricted stock units	1.3	—
Performance stock units	1.2	—
Warrants	15.6	15.6
Series A 5.375% mandatory convertible preferred stock	12.9	—
Prepaid stock purchase contract (TEUs)	5.4	—
Total	39.2	15.6

Note 19—Condensed Consolidating Financial Information

The following condensed consolidating financial statements present the financial information of (i) Dynegy (“Parent”), which is the parent and issuer of the $5.6 billion Senior Notes, on a stand-alone, unconsolidated basis, (ii) the guarantor subsidiaries of Dynegy, (iii) the non-guarantor subsidiaries of Dynegy, and (iv) the eliminations necessary to arrive at the information for Dynegy on a consolidated basis. The 100 percent owned subsidiary guarantors, jointly, severally, fully, and unconditionally, guarantee the payment obligations under the Senior Notes. Not all of Dynegy’s subsidiaries guarantee the Senior Notes including Dynegy’s indirect, wholly-owned subsidiary, IPH. Please read Note 13—Debt for further discussion.

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 unaudited condensed consolidating financial statements, a portion of our intercompany receivable, which we do not consider to be likely of settlement, has been classified as equity as of June 30, 2016 and December 31, 2015.

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Condensed Consolidating Balance Sheet as of June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$965	$ 69	$ 108	$ —	$ 1,142
Restricted cash	—	—	104	—	104
Accounts receivable, net	34	2,062	136	(1,840)	392
Inventory	—	269	251	—	520
Other current assets	12	237	40	(6)	283
Total Current Assets	1,011	2,637	639	(1,846)	2,441
Property, plant and equipment, net	—	7,078	510	—	7,588
Investment in affiliates	12,489	185	—	(12,489)	185
Restricted cash	—	—	2,000	—	2,000
Goodwill	—	799	—	—	799
Other long-term assets	6	96	47	—	149
Intercompany note receivable	17	—	—	(17)	—
Total Assets	$13,523	$ 10,795	$ 3,196	$ (14,352)	$ 13,162
Current Liabilities					
Accounts payable	$1,387	$ 241	$ 498	$ (1,840)	$ 286
Other current liabilities	119	207	143	(6)	463
Total Current Liabilities	1,506	448	641	(1,846)	749
Debt, long-term portion	6,353	303	2,709	—	9,365
Intercompany note payable	3,042	—	17	(3,059)	—
Other long-term liabilities	154	298	132	—	584
Total Liabilities	11,055	1,049	3,499	(4,905)	10,698
Stockholders’ Equity					
Dynegy Stockholders’ Equity	2,468	12,788	(299)	(12,489)	2,468
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders’ Equity	2,468	9,746	(299)	(9,447)	2,468
Noncontrolling interest	—	—	(4)	—	(4)
Total Equity	2,468	9,746	(303)	(9,447)	2,464
Total Liabilities and Equity	$13,523	$ 10,795	$ 3,196	$ (14,352)	$ 13,162

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Condensed Consolidating Balance Sheet as of December 31, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$327	$ 94	$ 84	$ —	$ 505
Restricted cash	—	—	39	—	39
Accounts receivable, net	499	1,503	130	(1,730)	402
Inventory	—	331	266	—	597
Other current assets	13	335	55	(14)	389
Total Current Assets	839	2,263	574	(1,744)	1,932
Property, plant and equipment, net	—	7,813	534	—	8,347
Investment in affiliates	13,017	190	—	(13,017)	190
Other long-term assets	10	133	50	—	193
Goodwill	—	797	—	—	797
Intercompany note receivable	17	—	—	(17)	—
Total Assets	$13,883	$ 11,196	$ 1,158	$ (14,778)	$ 11,459
Current Liabilities					
Accounts payable	$1,388	$ 238	$ 396	$ (1,730)	$ 292
Other current liabilities	92	277	162	(14)	517
Total Current Liabilities	1,480	515	558	(1,744)	809
Long-term debt	6,293	122	714	—	7,129
Intercompany note payable	3,042	—	17	(3,059)	—
Other long-term liabilities	147	317	138	—	602
Total Liabilities	10,962	954	1,427	(4,803)	8,540
Stockholders' Equity					
Dynegy Stockholders' Equity	2,921	13,284	(267)	(13,017)	2,921
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,921	10,242	(267)	(9,975)	2,921
Noncontrolling interest	—	—	(2)	—	(2)
Total Equity	2,921	10,242	(269)	(9,975)	2,919
Total Liabilities and Equity	$13,883	$ 11,196	$ 1,158	$ (14,778)	$ 11,459

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Condensed Consolidating Statements of Operations for the Three Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 711	$ 193	$ —	$ 904
Cost of sales, excluding depreciation expense	—	(382)	(111)	—	(493)
Gross margin	—	329	82	—	411
Operating and maintenance expense	—	(192)	(64)	—	(256)
Depreciation expense	—	(140)	(20)	—	(160)
Impairments	—	(645)	—	—	(645)
General and administrative expense	(1)	(31)	(7)	—	(39)
Acquisition and integration costs	—	(2)	5	—	3
Other	—	—	(16)	—	(16)
Operating loss	(1)	(681)	(20)	—	(702)
Earnings from unconsolidated investments	—	1	—	—	1
Equity in losses from investments in affiliates	(683)	—	—	683	—
Interest expense	(119)	(3)	(20)	1	(141)
Other income and expense, net	2	15	14	(1)	30
Income (loss) before income taxes	(801)	(668)	(26)	683	(812)
Income tax benefit	—	9	—	—	9
Net income (loss)	(801)	(659)	(26)	683	(803)
Less: Net loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Net income (loss) attributable to Dynegy Inc.	$(801)	$ (659)	$ (24)	$ 683	$ (801)

Condensed Consolidating Statements of Operations for the Six Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 1,598	$ 429	$ —	$ 2,027
Cost of sales, excluding depreciation expense	—	(794)	(244)	—	(1,038)
Gross margin	—	804	185	—	989
Operating and maintenance expense	—	(351)	(126)	—	(477)
Depreciation expense	—	(286)	(45)	—	(331)
Impairments	—	(645)	—	—	(645)
General and administrative expense	(3)	(59)	(14)	—	(76)
Acquisition and integration costs	(3)	(3)	5	—	(1)
Other	—	—	(16)	—	(16)
Operating income (loss)	(6)	(540)	(11)	—	(557)
Earnings from unconsolidated investments	—	3	—	—	3
Equity in losses from investments in affiliates	(565)	—	—	565	—
Interest expense	(243)	(4)	(37)	1	(283)
Other income and expense, net	3	15	14	(1)	31
Income (loss) before income taxes	(811)	(526)	(34)	565	(806)
Income tax expense	—	(7)	—	—	(7)

Net income (loss)	(811)	(533)	(34)	565	(813)
Less: Net loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Net income (loss) attributable to Dynegy Inc.	$(811)	$ (533)	$ (32)	$ 565	$ (811)

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Condensed Consolidating Statements of Operations for the Three Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 841	$ 258	$ (109)	$ 990
Cost of sales, excluding depreciation expense	—	(438)	(167)	109	(496)
Gross margin	—	403	91	—	494
Operating and maintenance expense	—	(165)	(85)	—	(250)
Depreciation expense	—	(144)	(31)	—	(175)
Loss on sale of assets, net	—	(1)	—	—	(1)
General and administrative expense	(2)	(26)	(7)	—	(35)
Acquisition and integration costs	—	(23)	—	—	(23)
Operating income (loss)	(2)	44	(32)	—	10
Earnings from unconsolidated investments	—	3	—	—	3
Equity in earnings from investments in affiliates	501	—	—	(501)	—
Interest expense	(114)	—	(18)	—	(132)
Other income and expense, net	3	1	—	—	4
Income (loss) before income taxes	388	48	(50)	(501)	(115)
Income tax benefit (expense)	—	518	(17)	—	501
Net income (loss)	388	566	(67)	(501)	386
Less: Net loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Net income (loss) attributable to Dynegy Inc.	$388	$ 566	$ (65)	$ (501)	$ 388

Condensed Consolidating Statements of Operations for the Six Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 1,144	$ 587	$ (109)	$ 1,622
Cost of sales, excluding depreciation expense	—	(609)	(373)	109	(873)
Gross margin	—	535	214	—	749
Operating and maintenance expense	—	(221)	(140)	—	(361)
Depreciation expense	—	(196)	(43)	—	(239)
Loss on sale of assets, net	—	(1)	—	—	(1)
General and administrative expense	(3)	(43)	(19)	—	(65)
Acquisition and integration costs	—	(113)	—	—	(113)
Operating income (loss)	(3)	(39)	12	—	(30)
Earnings from unconsolidated investments	—	3	—	—	3
Equity in earnings from investments in affiliates	447	—	—	(447)	—
Interest expense	(234)	—	(34)	—	(268)
Other income and expense, net	(2)	1	—	—	(1)
Income (loss) before income taxes	208	(35)	(22)	(447)	(296)
Income tax benefit (expense)	—	518	(17)	—	501
Net income (loss)	208	483	(39)	(447)	205
Less: Net loss attributable to noncontrolling interest	—	—	(3)	—	(3)

Net income (loss) attributable to Dynegy Inc.	$208	$ 483	$ (36)	$ (447)	$ 208

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended June 30, 2016

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(801)	$ (659)	$ (26)	$ 683	$ (803)
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 loss	(802)	(659)	(26)	683	(804)
Less: Comprehensive loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Total comprehensive loss attributable to Dynegy Inc.	$(802)	$ (659)	$ (24)	$ 683	$ (802)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Six Months Ended June 30, 2016

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(811)	$ (533)	$ (34)	$ 565	$ (813)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(2)	—	—	—	(2)
Other comprehensive loss, net of tax	(2)	—	—	—	(2)
Comprehensive loss	(813)	(533)	(34)	565	(815)
Less: Comprehensive loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Total comprehensive loss attributable to Dynegy Inc.	$(813)	$ (533)	$ (32)	$ 565	$ (813)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended June 30, 2015

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$388	$ 566	$ (67)	$ (501)	$ 386
Other comprehensive loss before reclassifications:					
Actuarial loss, net of tax of zero	(5)	—	—	—	(5)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit, net of tax of zero	(1)	—	—	—	(1)
Other comprehensive loss, net of tax	(6)	—	—	—	(6)
Comprehensive income (loss)	382	566	(67)	(501)	380

Less: Comprehensive loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Total comprehensive income (loss) attributable to Dynegy Inc.	$382	$ 566	$ (65)	$ (501)	$ 382

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Six Months Ended June 30, 2015

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$208	$ 483	$ (39)	$ (447)	$ 205
Other comprehensive loss before reclassifications:					
Actuarial loss, net of tax of zero	(5)	—	—	—	(5)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(2)	—	—	—	(2)
Other comprehensive loss, net of tax	(7)	—	—	—	(7)
Comprehensive income (loss)	201	483	(39)	(447)	198
Less: Comprehensive loss attributable to noncontrolling interest	—	—	(3)	—	(3)
Total comprehensive income (loss) attributable to Dynegy Inc.	$201	$ 483	$ (36)	$ (447)	$ 201

Condensed Consolidating Statements of Cash Flow for the Six Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(162)	$ 457	$ 22	$ —	$ 317
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(203)	(21)	—	(224)
Increase in restricted cash	—	—	(2,069)	—	(2,069)
Net intercompany transfers	380	—	—	(380)	—
Distributions from unconsolidated affiliates	—	8	—	—	8
Other investing	—	7	—	—	7
Net cash used in investing activities	380	(188)	(2,090)	(380)	(2,278)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowing on long-term debt, net of issuance costs	84	198	1,996	—	2,278
Proceeds from issuance of equity, net of issuance costs	362	—	—	—	362
Repayments of borrowings	(4)	(16)	—	—	(20)
Dividends paid	(11)	—	—	—	(11)
Net intercompany transfers	—	(476)	96	380	—
Interest rate swap settlement payments	(9)	—	—	—	(9)
Other financing	(2)	—	—	—	(2)
Net cash provided by financing activities	420	(294)	2,092	380	2,598
Net increase (decrease) in cash and cash equivalents	638	(25)	24	—	637
Cash and cash equivalents, beginning of period	327	94	84	—	505
Cash and cash equivalents, end of period	$965	$ 69	$ 108	$ —	$ 1,142

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Condensed Consolidating Statements of Cash Flow for the Six Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(140)	$ 355	$ (236)	$ —	$ (21)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(73)	(29)	—	(102)
Acquisition, net of cash acquired	(6,221)	15	114	—	(6,092)
Decrease in restricted cash	5,148	—	—	—	5,148
Net intercompany transfers	(68)	—	—	68	—
Other investing	—	(10)	—	—	(10)
Net cash provided by (used in) investing activities	(1,141)	(68)	85	68	(1,056)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of issuance costs	(31)	—	6	—	(25)
Repayments of borrowings	(4)	(23)	—	—	(27)
Financing cost from equity issuance	(6)	—	—	—	(6)
Dividends paid	(12)	—	—	—	(12)
Net intercompany transfers	—	(81)	149	(68)	—
Interest rate swap settlement payments	(8)	—	—	—	(8)
Other financing	(4)	—	—	—	(4)
Net cash provided by (used in) financing activities	(65)	(104)	155	(68)	(82)
Net increase (decrease) in cash and cash equivalents	(1,346)	183	4	—	(1,159)
Cash and cash equivalents, beginning of period	1,642	54	174	—	1,870
Cash and cash equivalents, end of period	$296	$ 237	$ 178	$ —	$ 711

Note 20—Segment Information

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

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three and six months ended June 30, 2016 and 2015 is presented below:
Segment Data as of and for the Three Months Ended June 30, 2016

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$241	$166	$486	$ —	$893
Intercompany and affiliate revenues	(11)	(1)	23	—	11
Total revenues	$230	$165	$509	$ —	$904
Depreciation expense	$(33)	$(5)	$(120)	$ (2)	$(160)
Impairment expense	(645)	—	—	—	(645)
General and administrative expense	—	—	—	(39)	(39)
Acquisition and integration costs	—	8	—	(5)	3
Operating income (loss)	$(749)	$3	$90	$ (46)	$(702)
Earnings from unconsolidated investments	—	—	1	—	1
Interest expense	(2)	(17)	(2)	(120)	(141)
Other income and expense, net	6	14	12	(2)	30
Loss before income taxes					(812)
Income tax benefit	—	—	—	9	9
Net loss					(803)
Less: Net income attributable to noncontrolling interest					(2)
Net loss attributable to Dynegy Inc.					$(801)
Total assets—domestic	$1,522	$902	$7,636	$ 3,102	$13,162
Investment in unconsolidated affiliate	$—	$—	$185	$ —	$185
Capital expenditures	$(20)	$(10)	$(125)	$ (4)	$(159)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Segment Data as of and for the Six Months Ended June 30, 2016

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$634	$334	$1,048	$ —	$2,016
Intercompany and affiliate revenues	(24)	(2)	37	—	11
Total revenues	$610	$332	$1,085	$ —	$2,027
Depreciation expense	$(72)	$(14)	$(242)	$ (3)	$(331)
Impairments	(645)	—	—	—	(645)
General and administrative expense	—	—	—	(76)	(76)
Acquisition and integration costs	—	8	—	(9)	(1)
Operating income (loss)	$(695)	$17	$210	$ (89)	$(557)
Earnings from unconsolidated investments	—	—	3	—	3
Interest expense	(3)	(34)	(3)	(243)	(283)
Other income and expense, net	6	14	12	(1)	31
Loss before income taxes					(806)
Income tax expense	—	—	—	(7)	(7)
Net loss					(813)
Less: Net income attributable to noncontrolling interest					(2)
Net loss attributable to Dynegy Inc.					$(811)
Total assets—domestic	$1,522	$902	$7,636	$ 3,102	$13,162
Investment in unconsolidated affiliate	$—	$—	$185	$ —	$185
Capital expenditures	$(39)	$(21)	$(156)	$ (8)	$(224)

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Segment Data as of and for the Three Months Ended June 30, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$317	$186	$485	$ 2	$990
Intercompany revenues	(10)	(1)	13	(2)	—
Total revenues	$307	$185	$498	$ —	$990
Depreciation expense	$(47)	$(8)	$(119)	$ (1)	$(175)
General and administrative expense	—	—	—	(35)	(35)
Acquisition and integration costs	—	—	—	(23)	(23)
Operating income (loss)	$(5)	$(14)	$86	$ (57)	$10
Earnings from unconsolidated investments	—	—	3	—	3
Interest expense	—	—	—	(132)	(132)
Other income and expense, net	—	—	—	4	4
Loss before income taxes					(115)
Income tax benefit	—	—	—	501	501
Net income					386
Less: Net loss attributable to noncontrolling interest					(2)
Net income attributable to Dynegy Inc.					$388
Total assets—domestic	$2,637	$992	$7,997	$ 523	$12,149
Investment in unconsolidated affiliate	$—	$—	$199	$ —	$199
Capital expenditures	$(16)	$(18)	$(25)	$ (3)	$(62)

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2016 and 2015

Segment Data as of and for the Six Months Ended June 30, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$460	$405	$755	$ 2	$1,622
Intercompany revenues	(11)	(1)	14	(2)	—
Total revenues	$449	$404	$769	$ —	$1,622
Depreciation expense	$(57)	$(16)	$(164)	$ (2)	$(239)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(65)	(65)
Acquisition and integration costs	—	—	—	(113)	(113)
Operating income (loss)	$2	$8	$138	$ (178)	$(30)
Earnings from unconsolidated investments	—	—	3	—	3
Interest expense	—	—	—	(268)	(268)
Other income and expense, net	—	—	—	(1)	(1)
Loss before income taxes					(296)
Income tax benefit	—	—	—	501	501
Net income					205
Less: Net loss attributable to noncontrolling interest					(3)
Net income attributable to Dynegy Inc.					$208
Total assets—domestic	$2,637	$992	$7,997	$ 523	$12,149
Investment in unconsolidated affiliate	$—	$—	$199	$ —	$199
Capital expenditures	$(19)	$(29)	$(49)	$ (5)	$(102)

Note 21—Subsequent Event

On August 3, 2016, Dynegy announced that it has entered into an agreement to sell its 50 percent equity interest in the Elwood Energy facility in Elwood, IL, to J-Power USA Development Co. Ltd. for $172.5 million. Additionally, approximately $35 million of previously posted collateral will be returned to Dynegy at closing. The sale is expected to close in the fourth quarter of 2016.

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended June 30, 2016 and 2015

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 power generation sector of the energy industry. We currently own approximately 26,000 MW of generating capacity in eight states and also provide retail electricity to 968,000 residential customers and 38,000 commercial, industrial, and municipal customers in Illinois, Ohio, and Pennsylvania. We report the results of our power generation business as three separate segments in our unaudited consolidated financial statements: (i) Coal, (ii) IPH, and (iii) Gas.

On February 24, 2016, through Atlas Power, we signed the Delta Stock Purchase Agreement to acquire GSENA consisting of 9,058 MW of generation capacity located in ERCOT, PJM, and ISO-NE. We expect the Delta Transaction to close in the fourth quarter of 2016 after satisfaction or waiver of customary closing conditions, including approval from FERC.

On March 18, 2016, we entered into a bilateral contract to sell 2,300 MW of cleared PJM capacity (1,500 MW of Base Capacity and 800 MW of Capacity Performance ("CP") Product) in Planning Year 2017-2018 and 1,900 MW of cleared PJM capacity (1,000 MW of Base Capacity and 900 MW of CP Product) in Planning Year 2018-2019. In exchange, we received $198 million in cash proceeds in the first quarter of 2016. The buyer in this transaction will receive capacity payments from PJM during the Planning Years 2017-2018 and 2018-2019 in the amounts of $110 million and $109 million, respectively. Dynegy will continue to be subject to the performance obligations as well as any associated performance penalties and bonus payments for those planning years.

During June 2016, we raised $2.0 billion from Finance IV's seven-year Tranche C Term Loan and $446 million from the issuance of TEUs, net of $14 million of issuance costs, thereby substantially completing the financing related to the Delta Transaction.

On June 27, 2016, Dynegy completed the ECP Buyout, and Atlas Power became an indirect, wholly-owned subsidiary of Dynegy. Under the terms of the ECP Buyout, Dynegy will pay $375 million by the First Payment Date. Alternatively, Dynegy may pay the ECP Buyout Price after the First Payment Date, but in such case, the ECP Buyout Price would be subject to quarterly escalation up to a maximum of $468.5 million.

Please read Note 3—Acquisitions, Note 12—Tangible Equity Units, and Note 13—Debt for further discussion.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, contractual obligations, capital expenditures (including required environmental expenditures), and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated 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 LC facilities.

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

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of these entities without meeting certain requirements as set forth in the governing documents. Genco's $825 million senior notes are non-recourse to Dynegy.

On June 21, 2016, Dynegy issued 4.6 million, 7 percent TEUs at $100 per unit. We received proceeds of $446 million, net of $14 million of issuance costs. The TEUs are comprised of SPCs and Amortizing Notes, with $362 million in net proceeds related to the SPCs, and $84 million in net proceeds related to the Amortizing Notes. Please read Note 12—Tangible Equity Units and Note 13—Debt for further discussion.

On June 27, 2016, Finance IV entered into the Finance IV Credit Agreement. The Finance IV Credit Agreement provides for the $2.0 billion, seven-year Tranche C Term Loan, which matures on June 27, 2023. Amounts available under the Tranche C Term Loan were fully drawn on the Term Loan Closing Date, and the net proceeds were placed into escrow pending the consummation of the Delta Transaction. The obligations of Finance IV under the Finance IV Credit Agreement are secured by the related amounts placed in escrow. Under the Escrow Agreement, the applicable borrowings are subject to full liquidation and release to the lenders if the Delta Stock Purchase Agreement is terminated or if the Delta Transaction is not consummated by February 24, 2017. Such amount is included in long-term Restricted cash in our unaudited consolidated balance sheet. Please read Note 13—Debt for further discussion.

Additionally, on June 27, 2016, Dynegy entered into the Third Amendment to the Credit Agreement. Upon the Escrow Release Date, the Third Amendment provides for (i) a $75 million Incremental Tranche B Revolver which will mature on April 2, 2020 and (ii) conversion of the Tranche C Term loan to an incremental $2.0 billion, seven-year, senior secured tranche C term loan.

On February 24, 2016, Dynegy entered into a bilateral letter of credit facility commitment letter with an issuing bank for $50 million, which will be available upon the Escrow Release Date.

Liquidity. The following table summarizes our liquidity position at June 30, 2016, and excludes amounts classified as restricted cash in our unaudited consolidated balance sheet:

	June 30, 2016		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolving facilities and LC capacity (3)	$1,480	$39	$1,519
Less: Outstanding LCs	(387)	(27)	(414)
Revolving facilities and LC availability	1,093	12	1,105
Cash and cash equivalents	1,066	76	1,142
Total available liquidity (4)	$2,159	$88	$2,247

(1) Includes Cash and cash equivalents of $42 million related to Genco.

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

(3) Dynegy includes: (i) $950 million of aggregate available capacity related to our incremental revolving credit facilities, (ii) $475 million of available capacity related to the five-year senior secured revolving credit facility, and (iii) $55 million related to an LC. IPH includes (i) up to a maximum of $25 million related to the two-year secured LC facility and (ii) $14 million related to our fully cash collateralized LC and reimbursement agreement. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

(4) On December 2, 2013, Dynegy and Illinois Power Resources, LLC entered into an intercompany revolving promissory note of $25 million. At June 30, 2016, there was approximately $25 million outstanding on the note, which is not reflected in the table above.

The following table presents net cash from operating, investing, and financing activities for the six months ended June 30, 2016 and 2015:

Six Months Ended
June 30,

(amounts in millions)	2016	2015
Net cash provided by (used in) operating activities	$317	$(21)
Net cash used in investing activities	$(2,278)	$(1,056)
Net cash provided by (used in) financing activities	$2,598	$(82)

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Operating Activities

Historical Operating Cash Flows. Cash provided by operations totaled $317 million for the six months ended June 30, 2016. During the period, our power generation business provided cash of $462 million primarily due to the operation of our power generation facilities and retail operations. Corporate and other activities used cash of $250 million primarily due to interest payments on our various debt agreements. Changes in working capital and other, net of general and administrative expenses, provided cash of $105 million during the period.

Cash used in operations totaled $21 million for the six months ended June 30, 2015. During the period, our power generation business provided cash of $317 million primarily due to the operation of our power generation facilities and retail operations. Corporate and other activities used cash of $332 million primarily due to interest payments on our various debt agreements of $247 million and payments for acquisition-related costs of $102 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 $6 million, net, during the period.

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 Energized” initiative.

Collateral Postings. We use a portion of our capital resources in the form of cash and LCs to satisfy counterparty collateral demands. The following table summarizes our collateral postings to third parties at June 30, 2016 and December 31, 2015:

(amounts in millions)	June 30, 2016	December 31, 2015
Dynegy Inc.:		
Cash (1)	$ 124	$ 159
LCs	387	475
Total Dynegy Inc.	511	634
IPH:		
Cash (1) (2)	19	11
LCs (3) (4)	27	45
Total IPH	46	56
Total	$ 557	$ 690

(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets in our unaudited consolidated balance sheets. At June 30, 2016 and December 31, 2015, $81 million and $106 million, respectively, of cash posted as collateral were netted against Liabilities from risk management activities in our unaudited consolidated balance sheets.

(2) Includes cash of approximately $7 million and $1 million related to Genco at June 30, 2016 and December 31, 2015, respectively.

(3) Includes LCs of approximately $13 million and $20 million outstanding as of June 30, 2016 and December 31, 2015, respectively, related to the cash-backed LC facility at IPM. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

(4) Includes LCs of approximately $14 million related to the two-year secured LC entered into by IPM and collateralized by IPRG receivables.

Collateral postings decreased from December 31, 2015 to June 30, 2016 primarily due to reduced collateral requirements for gas purchases, reduced collateral for tolls, and release of collateral related to jointly owned facilities. The fair value of our derivatives collateralized by first priority liens included liabilities of $177 million and $167 million at June 30, 2016 and December 31, 2015, respectively.

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Investing Activities

Historical Investing Cash Flows. During the six months ended June 30, 2016, non-current restricted cash increased by $2.0 billion from proceeds from the Tranche C Term Loan being held in escrow for the Delta Transaction and $69 million in related pre-funded interest and original issuance discount. Additionally, during the six months ended June 30, 2016, we paid $224 million in capital expenditures, received an $8 million cash inflow related to distributions from our unconsolidated investment in Elwood, and received $7 million in proceeds from an insurance claim. Our capital spending by reportable segment was as follows:

	Six Months Ended June 30,	
(amounts in millions)	2016	2015
Coal	$39	$19
IPH	21	29
Gas	156	49
Other	8	5
Total (1)	$224	$102

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(1) Includes capitalized interest of $7 million and $6 million for the six months ended June 30, 2016 and 2015, respectively.

Future Investing Cash Flows. We expect capital expenditures for the remainder of 2016 to be approximately $73 million, which is comprised of $16 million, $15 million, $39 million, and $3 million in Coal, IPH, Gas, and Other, respectively. The capital budget is subject to revision as opportunities arise or circumstances change. Additionally, our future investing cash flows will be reduced by funds used for the Delta Transaction and the ECP Buyout.

Financing Activities

Historical Financing Cash Flows. Cash provided by financing activities totaled $2.598 billion for the six months ended June 30, 2016 primarily due to (i) $2.0 billion in proceeds related to the Tranche C Term Loan, (ii) $446 million in net proceeds from our TEUs, and (iii) $198 million of proceeds related to our forward capacity agreement, partially offset by (iv) $20 million in repayments associated with our equipment financing agreements and Tranche B-2 Term Loan, (v) $11 million in dividend payments on our preferred stock, and (vi) $9 million in interest rate swap settlement payments. Please read Note 13—Debt and Note 17—Capital Stock for further discussion.

Cash used in financing activities totaled $82 million for the six months ended June 30, 2015 primarily due to (i) $37 million in financing costs related to our debt and equity issuances, (ii) $27 million in repayments associated with our inventory financing agreements and term loan, (iii) $12 million in dividend payments on our preferred stock and, (iv) $8 million in interest rate swap settlement payments. Please read Note 13—Debt and Note 17—Capital Stock for further discussion.

Future Financing Cash Flows. We are obligated to pay dividends on our mandatory convertible preferred stock of $5.4 million quarterly on a cumulative basis when declared by our Board of Directors or upon conversion. We may pay declared dividends in cash or, subject to certain limitations, in shares of our common stock or by delivery of any combination of cash and shares of our common stock. Our future cash flows from financing activities will include principal payments on our debt instruments as they become due, as well as periodic payments to settle our interest rate swap agreements. Please read Note 17—Capital Stock for further discussion. Our future cash flows will be increased by proceeds from the issuance of our common stock to ECP and from anticipated draws on our Revolving Facility to fund the Delta Transaction.

Financing Trigger Events. Our debt instruments and certain of our other financial obligations and all the Genco Senior Notes include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events include the violation of covenants (including, in the case of the Credit Agreement under certain circumstances, the senior secured leverage ratio covenant discussed below), defaults on scheduled principal or interest payments, including any indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions, insolvency events, acceleration of other financial obligations, and in the case of the Credit Agreement, change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events. Please read Note 13—Debt in our Form 10-K for further discussion.

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Financial Covenants

Credit Agreement. Our 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.

Under the terms of the Credit Agreement, existing balances under our Forward Capacity Agreement, Inventory Financing Agreements, and Equipment Financing Agreements are excluded from Net Debt. Further, the balance of the Tranche C Term Loan is excluded from Net Debt until the closing of the Delta Transaction, whereupon it becomes Dynegy Inc.'s secured obligation.

Our revolver usage at June 30, 2016 was 23 percent of the aggregate revolver commitment due to outstanding LCs; therefore, we tested the covenant and were in compliance at June 30, 2016.

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

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 external, third-party sources are included in the definition of indebtedness and are subject to these incurrence tests.

Based on June 30, 2016 calculations, Genco did not meet the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

As a result of continued weak energy prices, unsold capacity volumes, on-going required maintenance and environmental expenditures, upcoming interest payments, as well as consideration of a $300 million debt maturity in 2018, Dynegy and Genco have each engaged their own advisors and have begun strategic reviews of IPH's Genco subsidiary. While Genco's projected future cash flow is sufficient to cover its obligations through December 31, 2016, it may not have sufficient future operating cash flow to satisfy its debt maturity in 2018, absent a debt refinancing or restructuring. Actions to resolve this situation could include one or more of the following: (i) restructuring the Genco debt to achieve a more sustainable business model; (ii) transitioning ownership of Genco's assets to its debt holders; (iii) deferring discretionary capital expenditures to the extent possible; (iv) continued shut down of uneconomic generation; and/or (v) seeking bankruptcy protection.

Please read Note 13—Debt for further discussion.

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

We pay quarterly dividends on our Mandatory Convertible Preferred Stock on February 1, May 1, August 1, and November 1 of each year, if declared by our Board of Directors. For the three months ended June 30, 2016 and 2015, we paid $5 million in dividends on May 2, 2016 and May 1, 2015, respectively. For the six months ended June 30, 2016 and 2015, we paid an aggregate of $11 million and $12 million in dividends, respectively.

On July 1, 2016, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million in the aggregate. The dividend is for the dividend period beginning on May 1, 2016 and ending on July 31, 2016. Such dividends were paid on August 1, 2016 to stockholders of record as of July 15, 2016.

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	Caa3	CCC+

During the three months ended June 30, 2016, Moody’s and S&P assigned ratings of Ba3 and BB, respectively, to the Finance IV $2.0 billion Tranche C Term Loan.

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results

In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three and six months ended June 30, 2016 and 2015. Following 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). All references to hedging within this Form 10-Q relate to economic hedging activities as we do not elect hedge accounting.

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

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Consolidated Summary Financial Information — Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

The following table provides summary financial data regarding our unaudited consolidated results of operations for the three months ended June 30, 2016 and 2015, respectively:

(amounts in millions)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues				
Energy	$715	$785	$ (70)	(9)%
Capacity	204	175	29	17 %
Mark-to-market income, net	(21)	33	(54)	(164)%
Contract amortization	(18)	(27)	9	33 %
Other	24	24	—	— %
Total revenues	904	990	(86)	(9)%
Cost of sales, excluding depreciation expense	(493)	(496)	3	1 %
Gross margin	411	494	(83)	(17)%
Operating and maintenance expense	(256)	(250)	(6)	(2)%
Depreciation expense	(160)	(175)	15	9 %
Impairments	(645)	—	(645)	NM
Loss on sale of assets, net	—	(1)	1	100 %
General and administrative expense	(39)	(35)	(4)	(11)%
Acquisition and integration costs	3	(23)	26	113 %
Other	(16)	—	(16)	NM
Operating income (loss)	(702)	10	(712)	NM
Earnings from unconsolidated investments	1	3	(2)	(67)%
Interest expense	(141)	(132)	(9)	(7)%
Other income and expense, net	30	4	26	NM
Loss before income taxes	(812)	(115)	(697)	NM
Income tax benefit	9	501	(492)	(98)%
Net income (loss)	(803)	386	(1,189)	NM
Less: Net loss attributable to noncontrolling interest	(2)	(2)	—	— %
Net income (loss) attributable to Dynegy Inc.	$(801)	$388	$ (1,189)	NM

The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended June 30, 2016 and 2015, respectively:

(amounts in millions)	Three Months Ended June 30, 2016 Coal	IPH	Gas	Other	Total
Revenues	$230	$165	$509	$—	$904
Cost of sales, excluding depreciation expense	(183)	(101)	(209)	—	(493)
Gross margin	47	64	300	—	411
Operating and maintenance expense	(118)	(48)	(90)	—	(256)
Depreciation expense	(33)	(5)	(120)	(2)	(160)
Impairments	(645)	—	—	—	(645)
General and administrative expense	—	—	—	(39)	(39)
Acquisition and integration costs	—	8	—	(5)	3
Other	—	(16)	—	—	(16)
Operating income (loss)	$(749)	$3	$90	$(46)	$(702)

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	Three Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$307	$185	$498	$—	$990
Cost of sales, excluding depreciation expense	(134)	(131)	(231)	—	(496)
Gross margin	173	54	267	—	494
Operating and maintenance expense	(131)	(60)	(61)	2	(250)
Depreciation expense	(47)	(8)	(119)	(1)	(175)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(35)	(35)
Acquisition and integration costs	—	—	—	(23)	(23)
Operating income (loss)	$(5)	$(14)	$86	$(57)	$10

Discussion of Consolidated Results of Operations

Revenues. Revenues decreased by $86 million from $990 million for the three months ended June 30, 2015 to $904 million for the three months ended June 30, 2016. This was primarily driven by lower realized energy prices, lower generation volumes at our Gas and IPH segments due to planned outages, as well as losses associated with our economic hedging transactions. This was partially offset by higher capacity and retail revenues.

The following table summarizes the change in revenues by segment:

(amounts in millions)	Coal	IPH	Gas	Total
Lower prices	$(25)	$(4)	$(14)	$(43)
Higher (lower) generation volumes	18	(36)	(32)	(50)
Higher wholesale capacity revenues	4	12	13	29
Mark-to-market gains (losses) on hedging transactions	(164)	7	31	(126)
Higher retail revenues, net of hedges	80	1	—	81
Lower (higher) contract amortization	7	3	(3)	7
Other	3	(3)	16	16
Total change in revenues	$(77)	$(20)	$11	$(86)

Cost of Sales. Cost of sales decreased by $3 million from $496 million for the three months ended June 30, 2015 to $493 million for the three months ended June 30, 2016, primarily driven by a reduction in natural gas prices and generation volumes, partially offset by lower contract amortization.

The following table summarizes the change in cost of sales by segment:

(amounts in millions)	Coal	IPH	Gas	Total
Higher (lower) coal and freight costs at the Coal and IPH segments and lower transportation costs at the Gas segment due to favorable contract rates	$ 37	$(37)	$(4)	$ (4)
Lower gas costs due to lower natural gas prices and generation volumes	—	—	(28)	(28)
Higher retail costs	1	4	—	5
Lower (higher) contract amortization	9	(1)	3	11
Other	2	4	7	13
Total change in cost of sales	$ 49	$(30)	$(22)	$ (3)

Operating and Maintenance Expense. Operating and maintenance (“O&M”) expense increased by $6 million from $250 million for the three months ended June 30, 2015 to $256 million for the three months ended June 30, 2016 primarily due to planned major maintenance outages at our Gas segment.

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Depreciation Expense. Depreciation expense decreased by $15 million from $175 million for the three months ended June 30, 2015 to $160 million for the three months ended June 30, 2016 primarily due to a lower depreciable base of certain generation facilities at our Coal and Gas segments as a result of a fourth quarter 2015 impairment at our Brayton Point facility and a downward revision in AROs, respectively.

Impairments. Impairments of $645 million for the three months ended June 30, 2016 are due to the impairment of our Baldwin generating facility. Please read Note 9—Property, Plant and Equipment for further discussion.

General and Administrative Expense. General and administrative expense increased by $4 million from $35 million for the three months ended June 30, 2015 to $39 million for the three months ended June 30, 2016. This increase was primarily due to higher legal fees and higher overhead associated with the Acquisitions.

Acquisition and Integration Costs. Acquisition and integration costs decreased by $26 million from $23 million of expense for the three months ended June 30, 2015 to $3 million of income for the three months ended June 30, 2016 primarily due to $12 million in severance, retention, and payroll costs related to the Acquisitions in 2015 and $14 million in lower advisory and consulting fees.

Other. Other decreased by $16 million due to the termination of an above market coal supply contract.

Interest Expense. Interest expense increased by $9 million from $132 million for the three months ended June 30, 2015 to $141 million for the three months ended June 30, 2016 primarily due to $4 million in interest on our Tranche C Term Loan and Inventory Financing Agreements, $3 million in amortization of debt discounts, and $4 million in mark-to-market losses on interest rate swaps. Please read Note 13—Debt for further discussion.

Other Income and Expense, Net. Other income and expense, net increased by $26 million from income of $4 million for the three months ended June 30, 2015 to $30 million for the three months ended June 30, 2016 primarily due to $14 million in previously contingent proceeds received related to the AER Acquisition, a $12 million supplier settlement, and a $6 million casualty loss insurance reimbursement, net.

Income Tax Benefit (Expense). We reported $9 million and $501 million of income tax benefit for the three months ended June 30, 2016 and 2015, respectively. During the three months ended June 30, 2015, we released $480 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition, we recorded an additional tax benefit of $21 million for discreet items including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance.

As of June 30, 2016, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction as they arise, as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future.

Net income (loss) attributable to Dynegy Inc. We reported a net loss of $801 million and net income of $388 million for the three months ended June 30, 2016 and 2015, respectively. The $1.189 billion decrease was primarily due to a $480 million deferred tax valuation allowance release in the second quarter of 2015, which did not reoccur in 2016, and a $645 million impairment of our Baldwin generating facility in the second quarter of 2016.

Discussion of Adjusted EBITDA

Non-GAAP Performance Measures. In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including earnings before interest, taxes, depreciation, and amortization (“EBITDA”) and Adjusted EBITDA. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our 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.

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EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit), and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of certain assets, (ii) the impacts of mark-to-market changes on derivatives related to our generation portfolio, as well as interest rate swaps and warrants, (iii) the impact of impairment charges and certain other costs such as those associated with acquisitions, and (iv) other material items. Beginning in 2016, Adjusted EBITDA also excludes non-cash compensation expense.

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

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

Adjusted EBITDA — Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2016:

	Three Months Ended June 30, 2016				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(801)
Loss attributable to noncontrolling interest					(2)
Income tax benefit					(9)
Other income and expense, net					(30)
Interest expense					141
Earnings from unconsolidated investments					(1)
Operating income (loss)	$(749)	$3	$90	$(46)	$(702)
Depreciation and amortization expense	27	3	132	2	164
Earnings from unconsolidated investments	—	—	1	—	1
Other income and expense, net	6	14	12	(2)	30
EBITDA	(716)	20	235	(46)	(507)
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	2	1	—	3
Acquisition and integration costs	—	(8)	—	5	(3)
Mark-to-market adjustments, including warrants	83	(2)	(52)	—	29
Impairments	645	—	—	—	645
Wood River energy margin and O&M	15	—	—	—	15
Non-cash compensation expense	—	—	—	5	5
Other	(1)	(1)	—	2	—
Adjusted EBITDA	$26	$11	$184	$(34)	$187

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2015:

	Three Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$388
Loss attributable to noncontrolling interest					(2)
Income tax benefit					(501)
Other income and expense, net					(4)
Interest expense					132
Earnings from unconsolidated investments					(3)
Operating income (loss)	$(5)	$(14)	$86	$(57)	$10
Depreciation and amortization expense	38	11	124	1	174
Earnings from unconsolidated investments	—	—	3	—	3
Other income and expense, net	—	—	—	4	4
EBITDA	33	(3)	213	(52)	191
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	2	—	—	2
Acquisition and integration costs	—	—	—	23	23
Mark-to-market adjustments, including warrants	(14)	6	(10)	(3)	(21)
Other	—	—	(1)	(1)	(2)
Adjusted EBITDA (1)	$19	$5	$202	$(33)	$193

(1) Not adjusted for the following items which are excluded in 2016: (i) non-cash compensation expense of $8 million, and (ii) Wood River's energy margin and O&M costs of $9 million.

Adjusted EBITDA decreased by $6 million from $193 million for the three months ended June 30, 2015 to $187 million for the three months ended June 30, 2016. The decrease was driven by (i) lower energy margin, net of hedges, in all segments primarily due to lower power prices at our Coal and IPH segments, and lower spark spreads and generation volumes at our Gas segment, and (ii) higher O&M costs primarily associated with planned major maintenance outages at our Gas segment, at which time, plant capacity uprates were installed. This decrease was partially offset by higher capacity revenues in all segments. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the three months ended June 30, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$262	$261	$ 1	— %
Capacity	52	49	3	6 %
Mark-to-market income (loss), net	(81)	10	(91)	NM
Contract amortization	(4)	(12)	8	67 %
Other	1	(1)	2	200 %
Total operating revenues	230	307	(77)	(25)%
Operating Costs				
Cost of sales	(196)	(156)	(40)	(26)%
Contract amortization	13	22	(9)	(41)%
Total operating costs	(183)	(134)	(49)	(37)%
Gross margin	47	173	(126)	(73)%
Operating and maintenance expense	(118)	(131)	13	10 %
Depreciation expense	(33)	(47)	14	30 %
Impairments	(645)	—	(645)	NM
Operating loss	(749)	(5)	(744)	NM
Depreciation and amortization expense	27	38	(11)	(29)%
Other income and expense, net	6	—	6	NM
EBITDA	(716)	33	(749)	NM
Mark-to-market adjustments	83	(14)	97	NM
Impairments	645	—	645	NM
Wood River energy margin and O&M	15	—	15	NM
Other	(1)	—	(1)	NM
Adjusted EBITDA (1)	$26	$19	$ 7	37 %
Million Megawatt Hours Generated	7.7	7.5	0.2	3 %
IMA for Coal-Fired Facilities (2)	82 %	72 %		
Average Capacity Factor for Coal-Fired Facilities (3)	52 %	50 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$31.14	$33.15	$ (2.01)	(6)%
Commonwealth Edison (NI Hub)	$28.87	$31.47	$ (2.60)	(8)%
Mass Hub	$28.17	$29.16	$ (0.99)	(3)%
AD Hub	$30.43	$37.58	$ (7.15)	(19)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$22.37	$23.89	$ (1.52)	(6)%
Commonwealth Edison (NI Hub)	$19.32	$19.70	$ (0.38)	(2)%
Mass Hub	$20.43	$19.25	$ 1.18	6 %
AD Hub	$21.71	$25.92	$ (4.21)	(16)%

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(1) 2015 is not adjusted for Wood River's energy margin and O&M costs of $9 million which are excluded in 2016.

(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. The calculation excludes our Brayton Point facility and CTs. The IMA for our facilities within MISO and PJM (excluding CTs) was 86 percent and 79 percent, respectively, for the three months ended June 30, 2016 and 76 percent and 70 percent, respectively, for the three months ended June 30, 2015.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes our Brayton Point facility and CTs. The average capacity factors for our facilities within MISO and PJM (excluding CTs) were 59 percent and 46 percent, respectively, for the three months ended June 30, 2016 and 56 percent and 45 percent, respectively, for the three months ended June 30, 2015.

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

Operating loss for the three months ended June 30, 2016 was $749 million compared to $5 million for the three months ended June 30, 2015. The $744 million decrease is primarily due to the impairment of our Baldwin generating facility and losses associated with our economic hedging transactions. Adjusted EBITDA, excluding Wood River, was $26 million during the three months ended June 30, 2016 compared to Adjusted EBITDA of $19 million during the three months ended June 30, 2015. The $7 million increase in Adjusted EBITDA was due to higher wholesale capacity revenues and lower O&M costs as a result of reduced planned outages, partially offset by lower energy margin, net of hedges, primarily due to lower power prices.

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IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the three months ended June 30, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$131	$172	$ (41)	(24)%
Capacity	38	25	13	52 %
Mark-to-market income (loss), net	—	(6)	6	100 %
Contract amortization	(4)	(8)	4	50 %
Other	—	2	(2)	(100)%
Total operating revenues	165	185	(20)	(11)%
Operating Costs				
Cost of sales	(110)	(139)	29	21 %
Contract amortization	9	8	1	13 %
Total operating costs	(101)	(131)	30	23 %
Gross margin	64	54	10	19 %
Operating and maintenance expense	(48)	(60)	12	20 %
Depreciation expense	(5)	(8)	3	38 %
Acquisition and integration costs	8	—	8	NM
Other	(16)	—	(16)	NM
Operating income (loss)	3	(14)	17	121 %
Depreciation and amortization expense	3	11	(8)	(73)%
Other income and expense, net	14	—	14	NM
EBITDA	20	(3)	23	NM
Adjustment to exclude noncontrolling interest	2	2	—	— %
Acquisition and integration costs	(8)	—	(8)	NM
Mark-to-market adjustments	(2)	6	(8)	(133)%
Other	(1)	—	(1)	NM
Adjusted EBITDA	$11	$5	$ 6	120 %
Million Megawatt Hours Generated	3.3	4.7	(1.4)	(30)%
IMA for IPH Facilities (1)	91 %	91 %		
Average Capacity Factor for IPH Facilities (2)	38 %	54 %		
Average Quoted Market Power Prices ($/MWh) (3):				
On-Peak: Indiana (Indy Hub)	$31.14	$33.15	$ (2.01)	(6)%
Off-Peak: Indiana (Indy Hub)	$22.37	$23.89	$ (1.52)	(6)%

(1) 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.

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

(3) 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 June 30, 2016 was $3 million compared to an operating loss of $14 million for the three months ended June 30, 2015. The $17 million increase was due to higher capacity revenues and lower O&M. Adjusted EBITDA was $11 million during the three months ended June 30, 2016 compared to $5 million during the three months ended June 30, 2015. The $6 million increase in Adjusted EBITDA was due to higher capacity revenues and lower O&M costs due to fewer planned outages partially offset by lower energy margin, net of hedges, due to lower power prices and generation volumes.

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Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the three months ended June 30, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$322	$352	$ (30)	(9)%
Capacity	114	101	13	13 %
Mark-to-market income (loss), net	60	29	31	107 %
Contract amortization	(10)	(7)	(3)	(43)%
Other	23	23	—	— %
Total operating revenues	509	498	11	2 %
Operating Costs				
Cost of sales	(208)	(233)	25	11 %
Contract amortization	(1)	2	(3)	(150)%
Total operating costs	(209)	(231)	22	10 %
Gross margin	300	267	33	12 %
Operating and maintenance expense	(90)	(61)	(29)	(48)%
Depreciation expense	(120)	(119)	(1)	(1)%
Loss on sale of assets, net	—	(1)	1	100 %
Operating income	90	86	4	5 %
Depreciation and amortization expense	132	124	8	6 %
Earnings from unconsolidated investments	1	3	(2)	(67)%
Other income and expense, net	12	—	12	NM
EBITDA	235	213	22	10 %
Mark-to-market adjustments	(52)	(10)	(42)	NM
Adjustment to reflect Adjusted EBITDA from unconsolidated investment	1	—	1	NM
Other	—	(1)	1	100 %
Adjusted EBITDA	$184	$202	$ (18)	(9)%
Million Megawatt Hours Generated	11.9	12.8	(0.9)	(7)%
IMA for Combined Cycle Facilities (1)	98 %	97 %		
Average Capacity Factor for Combined Cycle Facilities (2):	53 %	61 %		
Average Market On-Peak Spark Spreads ($/MWh) (3):				
Commonwealth Edison (NI Hub)	$14.23	$12.57	$ 1.66	13 %
PJM West	$21.15	$29.38	$ (8.23)	(28)%
North of Path 15 (NP 15)	$10.76	$14.99	$ (4.23)	(28)%
New York—Zone A	$23.98	$22.34	$ 1.64	7 %
Mass Hub	$11.02	$13.48	$ (2.46)	(18)%
AD Hub	$27.53	$24.19	$ 3.34	14 %
Average Market Off-Peak Spark Spreads ($/MWh) (3):				
Commonwealth Edison (NI Hub)	$4.68	$0.80	$ 3.88	NM
PJM West	$11.38	$15.66	$ (4.28)	(27)%
North of Path 15 (NP 15)	$4.71	$7.79	$ (3.08)	(40)%
New York—Zone A	$6.79	$6.54	$ 0.25	4 %
Mass Hub	$3.28	$3.58	$ (0.30)	(8)%

AD Hub	$11.32	$15.72	$ (4.40)	(28)%
Average natural gas price—Henry Hub ($/MMBtu) (4)	$2.11	$2.72	$ (0.61)	(22)%

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(1) 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.
(2) Reflects actual production as a percentage of available capacity.
(3) 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.
(4) 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 June 30, 2016 was $90 million compared to $86 million for the three months ended June 30, 2015. The $4 million increase was primarily driven by higher wholesale capacity revenues and gains associated with our economic hedging transactions, partially offset by higher O&M costs. Adjusted EBITDA was $184 million during the three months ended June 30, 2016 compared to $202 million during the three months ended June 30, 2015. The $18 million decrease in Adjusted EBITDA was primarily driven by higher O&M costs associated with planned major maintenance outages, at which time, plant capacity uprates were installed. Lower energy margin, net of hedges, as a result of lower spark spreads and generation volumes was offset by higher wholesale capacity revenues.

Consolidated Summary Financial Information — Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

The following table provides summary financial data regarding our unaudited consolidated results of operations for the six months ended June 30, 2016 and 2015, respectively:

(amounts in millions)	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues				
Energy	$1,518	$1,328	$ 190	14 %
Capacity	405	226	179	79 %
Mark-to-market income, net	91	64	27	42 %
Contract amortization	(35)	(33)	(2)	(6)%
Other	48	37	11	30 %
Total revenues	2,027	1,622	405	25 %
Cost of sales, excluding depreciation expense	(1,038)	(873)	(165)	(19)%
Gross margin	989	749	240	32 %
Operating and maintenance expense	(477)	(361)	(116)	(32)%
Depreciation expense	(331)	(239)	(92)	(38)%
Impairments	(645)	—	(645)	NM
Loss on sale of assets, net	—	(1)	1	100 %
General and administrative expense	(76)	(65)	(11)	(17)%
Acquisition and integration costs	(1)	(113)	112	99 %
Other	(16)	—	(16)	NM
Operating loss	(557)	(30)	(527)	NM
Earnings from unconsolidated investments	3	3	—	— %
Interest expense	(283)	(268)	(15)	(6)%
Other income and expense, net	31	(1)	32	NM
Loss before income taxes	(806)	(296)	(510)	(172)%
Income tax benefit (expense)	(7)	501	(508)	(101)%
Net income (loss)	(813)	205	(1,018)	NM
Less: Net loss attributable to noncontrolling interest	(2)	(3)	1	33 %

Net income (loss) attributable to Dynegy Inc.	$(811)	$208	$ (1,019)	NM

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The following tables provide summary financial data regarding our operating income (loss) by segment for the six months ended June 30, 2016 and 2015, respectively:

	Six Months Ended June 30, 2016				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$610	$332	$1,085	$—	$2,027
Cost of sales, excluding depreciation expense	(359)	(200)	(479)	—	(1,038)
Gross margin	251	132	606	—	989
Operating and maintenance expense	(229)	(93)	(154)	(1)	(477)
Depreciation expense	(72)	(14)	(242)	(3)	(331)
Impairments	(645)	—	—	—	(645)
General and administrative expense	—	—	—	(76)	(76)
Acquisition and integration costs	—	8	—	(9)	(1)
Other	—	(16)	—	—	(16)
Operating income (loss)	$(695)	$17	$210	$(89)	$(557)

	Six Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$449	$404	$769	$—	$1,622
Cost of sales, excluding depreciation expense	(222)	(269)	(382)	—	(873)
Gross margin	227	135	387	—	749
Operating and maintenance expense	(168)	(111)	(84)	2	(361)
Depreciation expense	(57)	(16)	(164)	(2)	(239)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(65)	(65)
Acquisition and integration costs	—	—	—	(113)	(113)
Operating income (loss)	$2	$8	$138	$(178)	$(30)

Discussion of Consolidated Results of Operations

Revenues. Revenues increased $405 million from $1.622 billion during the six months ended June 30, 2015 to $2.027 billion during the six months ended June 30, 2016, primarily driven by revenues attributable to newly acquired Duke Midwest and EquiPower plants for the first quarter of 2016, higher capacity and retail revenues. This increase was partially offset by lower energy revenues due to lower volumes and energy prices realized as a result of mild winter weather which decreased demand across our key markets and higher mark-to-market losses on hedging transactions. The following table summarizes the change in revenues by segment:

(amounts in millions)	Coal	IPH	Gas	Total
Revenues, net of hedges, attributable to newly acquired Duke Midwest and EquiPower plants for the first quarter of 2016	$269	$—	$392	$661
Lower revenues attributable to our legacy plants, including IPH:				
Lower prices	(27)	(12)	(84)	(123)
Lower generation volumes	(22)	(89)	(41)	(152)
Higher wholesale capacity revenues	8	35	16	59
Mark-to-market gains (losses) on hedging transactions	(144)	36	24	(84)
Higher (lower) retail revenues, net of hedges	66	(38)	—	28
Lower (higher) contract amortization	7	5	(4)	8
Other	4	(9)	13	8
Total change in revenues	$161	$(72)	$316	$405

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Cost of Sales. Cost of sales increased $165 million from $873 million during the six months ended June 30, 2015 to $1.038 billion during the six months ended June 30, 2016, primarily driven by costs incurred in the first quarter of 2016 associated with newly acquired Duke Midwest and EquiPower plants, lower contract amortization, partially offset by lower coal and freight costs and a reduction in natural gas prices and generation volumes.

The following table summarizes the change in cost of sales by segment:

(amounts in millions)	Coal	IPH	Gas	Total
Cost of sales attributable to newly acquired Duke Midwest and EquiPower plants for the first quarter of 2016	$105	$—	$180	$285
Lower cost of sales attributable to our legacy plants, including IPH:				
Higher (lower) coal and freight costs at the Coal and IPH segments and lower transportation costs at the Gas segment due to favorable contract rates	12	(80)	(10)	(78)
Lower gas costs due to lower natural gas prices and generation volumes	—	—	(85)	(85)
Higher retail costs	8	6	—	14
Lower contract amortization	10	1	5	16
Other	2	4	7	13
Total change in cost of sales	$137	$(69)	$97	$165

Operating and Maintenance Expense. O&M expense increased $116 million from $361 million for the six months ended June 30, 2015 to $477 million for the six months ended June 30, 2016, primarily attributable to newly acquired Duke Midwest and EquiPower plants for the first quarter of 2016 and planned major maintenance outages at our Gas segment.

Depreciation Expense. Depreciation expense increased by $92 million from $239 million for the six months ended June 30, 2015 to $331 million for the six months ended June 30, 2016, primarily attributable to newly acquired Duke Midwest and EquiPower plants for the first quarter of 2016, offset by a decrease due to a lower depreciable base of certain generation facilities at our Coal segment as a result of a fourth quarter 2015 impairment at our Brayton Point facility.

Impairments. Impairments of $645 million for the six months ended June 30, 2016 are due to the impairment of our Baldwin generating facility. Please read Note 9—Property, Plant and Equipment for further discussion.

General and Administrative Expense. General and administrative expense increased by $11 million from $65 million for the six months ended June 30, 2015 to $76 million for the six months ended June 30, 2016. This increase was primarily due to higher legal fees and higher overhead associated with the Acquisitions.

Acquisition and Integration Costs. Acquisition and integration costs decreased by $112 million from $113 million for the six months ended June 30, 2015 to $1 million for the six months ended June 30, 2016, primarily due to $12 million in severance, retention, and payroll costs and $48 million in Bridge Loan financing fees related to the Acquisitions in 2015, and $52 million in lower advisory and consulting fees.

Other. Other decreased by $16 million due to the termination of an above market coal supply contract.

Interest Expense. Interest expense increased by $15 million from $268 million for the six months ended June 30, 2015 to $283 million for the six months ended June 30, 2016 primarily due to $5 million in interest on our Tranche C Term Loan and Inventory Financing Agreements, $5 million in amortization of debt discounts, $4 million in amortization of financing costs and fees associated with our revolving facilities, and $3 million in mark-to-market losses on interest rate swaps. Please read Note 13—Debt for further discussion.

Other Income and Expense, net. Other income and expense, net increased by $32 million from expense of $1 million for the six months ended June 30, 2015 to income of $31 million for the six months ended June 30, 2016 primarily due to $14 million in previously contingent proceeds received related to the AER Acquisition, a $12 million supplier settlement, and a $6 million casualty loss insurance reimbursement, net.

Income Tax Benefit (Expense). We reported $7 million of income tax expense and $501 million of income tax benefit for the six months ended June 30, 2016 and 2015, respectively. During the six months ended June 30, 2015, we released $480 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition, we recorded an additional tax benefit of $21 million for discreet items including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance.

As of June 30, 2016, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction

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as they arise, 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.

Net income (loss) attributable to Dynegy Inc. We reported a net loss of $811 million and net income of $208 million for the six months ended June 30, 2016 and 2015, respectively. The $1.019 billion decrease was primarily due to income from a $480 million deferred tax valuation allowance release in the second quarter of 2015, which did not reoccur in 2016, and a $645 million impairment of our Baldwin generating facility in the second quarter of 2016.

Adjusted EBITDA — Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2016:

	Six Months Ended June 30, 2016				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(811)
Loss attributable to noncontrolling interest					(2)
Income tax expense					7
Other income and expense, net					(31)
Interest expense					283
Earnings from unconsolidated investments					(3)
Operating income (loss)	$(695)	$17	$210	$(89)	$(557)
Depreciation and amortization expense	57	13	281	3	354
Earnings from unconsolidated investments	—	—	3	—	3
Other income and expense, net	6	14	12	(1)	31
EBITDA	(632)	44	506	(87)	(169)
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	2	4	—	6
Acquisition and integration costs	—	(8)	—	9	1
Mark-to-market adjustments, including warrants	43	(5)	(114)	(1)	(77)
Impairments	645	—	—	—	645
Wood River energy margin and O&M	20	—	—	—	20
Non-cash compensation expense	—	—	1	11	12
Other	—	(1)	(1)	2	—
Adjusted EBITDA	$76	$32	$396	$(66)	$438

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2015:

	Six Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$208
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(501)
Other income and expense, net					1
Interest expense					268
Earnings from unconsolidated investments					(3)
Operating income (loss)	$2	$8	$138	$(178)	$(30)
Depreciation and amortization expense	48	21	167	2	238
Earnings from unconsolidated investments	—	—	3	—	3
Other income and expense, net	—	—	—	(1)	(1)
EBITDA	50	29	308	(177)	210
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	3	—	—	3
Acquisition and integration costs	—	—	—	113	113
Mark-to-market adjustments, including warrants	(21)	(5)	(23)	2	(47)
Other	—	—	(1)	—	(1)
Adjusted EBITDA (1)	$29	$27	$284	$(62)	$278

(1) Not adjusted for the following items which are excluded in 2016: (i) non-cash compensation expense of $14 million, and (ii) Wood River's energy margin and O&M costs of $8 million.

Adjusted EBITDA was $278 million for the six months ended June 30, 2015 compared to $438 million for the six months ended June 30, 2016. The $160 million increase in Adjusted EBITDA was due to a $209 million contribution from newly acquired Duke Midwest and EquiPower plants in the first quarter of 2016. The offsetting $49 million decrease in Adjusted EBITDA was driven by (i) lower energy margin, net of hedges, in all segments primarily due to lower power prices and generation volumes at our Coal and IPH segments, and lower spark spreads and generation volumes at our Gas segment as a result of mild winter weather across our key markets and (ii) higher O&M costs primarily associated with planned major maintenance outages at our Gas segment, at which time, plant capacity uprates were installed. This decrease was partially offset by higher capacity revenues in all segments. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the six months ended June 30, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating revenues				
Energy	$543	$395	$ 148	37 %
Capacity	104	50	54	108 %
Mark-to-market income (loss), net	(34)	17	(51)	NM
Contract amortization	(6)	(12)	6	50 %
Other	3	(1)	4	NM
Total operating revenues	610	449	161	36 %
Operating costs				
Cost of sales	(385)	(245)	(140)	(57)%
Contract amortization	26	23	3	13 %
Total operating costs	(359)	(222)	(137)	(62)%
Gross margin	251	227	24	11 %
Operating and maintenance expense	(229)	(168)	(61)	(36)%
Depreciation expense	(72)	(57)	(15)	(26)%
Impairments	(645)	—	(645)	NM
Operating income (loss)	(695)	2	(697)	NM
Depreciation and amortization expense	57	48	9	19 %
Other income and expense, net	6	—	6	NM
EBITDA	(632)	50	(682)	NM
Mark-to-market adjustments	43	(21)	64	NM
Impairments	645	—	645	NM
Wood River energy margin and O&M	20	—	20	NM
Adjusted EBITDA (1)	$76	$29	$ 47	162 %
Million Megawatt Hours Generated (5)	15.3	12.3	3.0	24 %
IMA for Coal-Fired Facilities (2)(5)	82 %	79 %		
Average Capacity Factor for Coal-Fired Facilities (3)(5)	49 %	57 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$28.38	$36.21	$ (7.83)	(22)%
Commonwealth Edison (NI Hub)	$28.11	$36.15	$ (8.04)	(22)%
Mass Hub	$31.01	$62.67	$ (31.66)	(51)%
AD Hub	$29.61	$41.42	$ (11.81)	(29)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$21.27	$26.43	$ (5.16)	(20)%
Commonwealth Edison (NI Hub)	$19.93	$23.78	$ (3.85)	(16)%
Mass Hub	$23.32	$47.84	$ (24.52)	(51)%
AD Hub	$22.32	$29.09	$ (6.77)	(23)%

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(1) 2015 is not adjusted for Wood River's energy margin and O&M costs of $8 million which are excluded in 2016.

(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. The calculation excludes our Brayton Point facility and CTs. The IMA for our facilities within MISO and PJM (excluding CTs) was 87 percent and 78 percent, respectively, for the six months ended June 30, 2016 and 86 percent and 70 percent, respectively, for the six months ended June 30, 2015.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes our Brayton Point facility and CTs. The average capacity factors for our facilities within MISO and PJM (excluding CTs) were 54 percent and 44 percent, respectively, for the six months ended June 30, 2016 and 65 percent and 45 percent, respectively, for the six months ended June 30, 2015.

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

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

Operating loss for the six months ended June 30, 2016 was $695 million compared to operating income of $2 million for the six months ended June 30, 2015. The $697 million decrease is primarily due to the impairment of our Baldwin generating facility and losses associated with our economic hedging transactions. Adjusted EBITDA, excluding Wood River, was $76 million for the six months ended June 30, 2016 compared to Adjusted EBITDA of $29 million for the six months ended June 30, 2015. The $47 million increase in Adjusted EBITDA was primarily due to a $56 million contribution from newly acquired Duke Midwest and EquiPower plants in the first quarter of 2016. The offsetting $9 million decrease was driven by lower energy margin, net of hedges, primarily due to lower power prices and generation volumes as a result of mild winter weather. This decrease was partially offset by higher wholesale capacity revenues and higher retail margin.

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IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the six months ended June 30, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating revenues				
Energy	$259	$367	$ (108)	(29)%
Capacity	77	42	35	83 %
Mark-to-market income, net	3	5	(2)	(40)%
Contract amortization	(8)	(14)	6	43 %
Other	1	4	(3)	(75)%
Total operating revenues	332	404	(72)	(18)%
Operating costs				
Cost of sales	(214)	(284)	70	25 %
Contract amortization	14	15	(1)	(7)%
Total operating costs	(200)	(269)	69	26 %
Gross margin	132	135	(3)	(2)%
Operating and maintenance expense	(93)	(111)	18	16 %
Depreciation expense	(14)	(16)	2	13 %
Acquisition and integration costs	8	—	8	NM
Other	(16)	—	(16)	NM
Operating income	17	8	9	113 %
Depreciation and amortization expense	13	21	(8)	(38)%
Other income and expense, net	14	—	14	NM
EBITDA	44	29	15	52 %
Acquisition and integration costs	(8)	—	(8)	NM
Adjustment to exclude noncontrolling interest	2	3	(1)	(33)%
Mark-to-market adjustments	(5)	(5)	—	— %
Other	(1)	—	(1)	NM
Adjusted EBITDA	$32	$27	$ 5	19 %
Million Megawatt Hours Generated	6.6	9.9	(3.3)	(33)%
IMA for IPH Facilities (1)	90 %	92 %		
Average Capacity Factor for IPH Facilities (2)	38 %	56 %		
Average Quoted Market Power Prices ($/MWh) (3):				
On-Peak: Indiana (Indy Hub)	$28.38	$36.21	$ (7.83)	(22)%
Off-Peak: Indiana (Indy Hub)	$21.27	$26.43	$ (5.16)	(20)%

(1) 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.

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

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

Operating income for the six months ended June 30, 2016 was $17 million compared to $8 million for the six months ended June 30, 2015. The $9 million increase was primarily driven by higher wholesale capacity revenues and lower O&M costs. Adjusted EBITDA was $32 million for the six months ended June 30, 2016 compared to $27 million for the six months ended

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June 30, 2015. The $5 million increase in Adjusted EBITDA resulted from higher wholesale capacity revenues and lower O&M costs primarily due to fewer planned outages. This increase was partially offset by (i) lower energy margin, net of hedges, primarily due to lower power prices and generation volumes as a result of mild winter weather, and (ii) lower retail margin.

Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the six months ended June 30, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$716	$566	$ 150	27 %
Capacity	224	134	90	67 %
Mark-to-market income, net	122	42	80	190 %
Contract amortization	(21)	(7)	(14)	(200)%
Other	44	34	10	29 %
Total operating revenues	1,085	769	316	41 %
Operating Costs				
Cost of sales	(462)	(386)	(76)	(20)%
Contract amortization	(17)	4	(21)	NM
Total operating costs	(479)	(382)	(97)	(25)%
Gross margin	606	387	219	57 %
Operating and maintenance expense	(154)	(84)	(70)	(83)%
Depreciation expense	(242)	(164)	(78)	(48)%
Loss on sale of assets, net	—	(1)	1	100 %
Operating income	210	138	72	52 %
Depreciation and amortization expense	281	167	114	68 %
Earnings from unconsolidated investments	3	3	—	— %
Other income and expense, net	12	—	12	NM
EBITDA	506	308	198	64 %
Adjustment to reflect Adjusted EBITDA from unconsolidated investment	4	—	4	— %
Mark-to-market adjustments	(114)	(23)	(91)	NM
Non-cash compensation expense	1	—	1	NM
Other	(1)	(1)	—	— %
Adjusted EBITDA	$396	$284	$ 112	39 %
Million Megawatt Hours Generated (5)	25.2	17.8	7.4	42 %
IMA for Combined Cycle Facilities (1)(5)	97 %	98 %		
Average Capacity Factor for Combined Cycle Facilities (2)(5)	57 %	61 %		
Average Market On-Peak Spark Spreads ($/MWh) (3):				
Commonwealth Edison (NI Hub)	$13.64	$15.13	$ (1.49)	(10)%
PJM West	$19.94	$23.46	$ (3.52)	(15)%
North of Path 15 (NP 15)	$10.74	$13.82	$ (3.08)	(22)%
New York—Zone A	$20.34	$31.07	$ (10.73)	(35)%
Mass Hub	$10.92	$14.21	$ (3.29)	(23)%
AD Hub	$29.68	$40.02	$ (10.34)	(26)%
Average Market Off-Peak Spark Spreads ($/MWh) (3):				

Commonwealth Edison (NI Hub)	$5.47	$2.75	$ 2.72	99 %
PJM West	$12.09	$8.32	$ 3.77	45 %
North of Path 15 (NP 15)	$5.37	$7.51	$ (2.14)	(28)%
New York—Zone A	$5.86	$15.93	$ (10.07)	(63)%
Mass Hub	$3.23	$(0.62)	$ 3.85	NM
AD Hub	$12.64	$16.93	$ (4.29)	(25)%
Average natural gas price—Henry Hub ($/MMBtu) (4)	$2.04	$2.80	$ (0.76)	(27)%

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(1) 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.
(2) Reflects actual production as a percentage of available capacity.
(3) 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.
(4) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.
(5) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating income for the six months ended June 30, 2016 was $210 million compared to $138 million for the six months ended June 30, 2015. The $72 million increase was primarily due to the contribution from newly acquired Duke Midwest and EquiPower plants, higher capacity revenues and gains associated with our economic hedging transactions, partially offset by lower energy margin and higher O&M costs. Adjusted EBITDA was $396 million for the six months ended June 30, 2016 compared to $284 million for the six months ended June 30, 2015. The $112 million increase in Adjusted EBITDA was primarily due to a $153 million contribution from newly acquired Duke Midwest and EquiPower plants, particularly in PJM, in the first quarter of 2016. The offsetting $41 million decrease was driven by lower energy margin, net of hedges, primarily due to lower spark spreads and generation volumes driven by mild winter weather, and higher O&M costs associated with planned major maintenance outages, at which time, plant capacity uprates were installed. This decrease was partially offset by higher capacity revenues.

RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	As of and for the Six Months Ended June 30, 2016
Fair value of portfolio at December 31, 2015	$ (90)
Risk management gains recognized through the statement of operations in the period, net	54
Contracts realized or otherwise settled during the period	35
Changes in collateral/margin netting	(25)
Fair value of portfolio at June 30, 2016	$ (26)

The net risk management liability of $26 million is the aggregate of the following line items in 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 June 30, 2016, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2016	2017	2018	2019	2020	Thereafter
Market quotations (1)(2)	$(69)	$6	$(55)	$(11)	$(7)	$(2)	$ —
Prices based on models (2)	(38)	(26)	(5)	(9)	1	1	—
Total (3)	$(107)	$(20)	$(60)	$(20)	$(6)	$(1)	$ —

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

(3) Excludes $81 million of broker margin that has been netted against Risk management liabilities in our unaudited consolidated balance sheets. Please read Note 5—Risk Management Activities, Derivatives, and Financial Instruments for further discussion.

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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 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 power market prices, if any;
- beliefs and assumptions about market competition, generation capacity, and regional supply and demand characteristics of the wholesale and retail power markets, including the anticipation of plant retirements and higher market pricing over the longer term;
- sufficiency of, access to, and costs associated with coal, fuel oil, and natural gas inventories and transportation thereof;
- the effects of, or changes to, MISO, PJM, CAISO, NYISO, or ISO-NE power and capacity procurement processes;
- expectations regarding, or impacts of, environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations that we are, or could become, subject to, which could increase our costs, result in an impairment of our assets, cause us to limit or terminate the operation of certain of our facilities, or otherwise have a negative financial effect;
- beliefs about the outcome of legal, administrative, legislative, and regulatory matters;
- projected operating or financial results, including anticipated cash flows from operations, revenues, and profitability;
- our focus on safety and our ability to efficiently operate our assets so as to capture revenue generating opportunities and operating margins;
- our ability to mitigate forced outage risk, including managing risk associated with CP in PJM and 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;
- beliefs concerning the strategic review of Genco, including any restructuring options;
- the timing and anticipated benefits to be achieved through our company-wide improvement programs, including our PRIDE initiative;
- anticipated timing, outcome, and impact of the expected retirement of Brayton Point and the shutdown of Baldwin Units 1 and 3 and Newton Unit 2;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the Vermilion and Wood River facilities and any potential future remediation obligations at the South Bay facility;

- expectations regarding the synergies, completion, timing, terms, and anticipated benefits of the Delta Transaction;
- expectations regarding the completion, timing and terms of the Elwood Energy facility sale and anticipated use of proceeds from such sale; and
- beliefs regarding redevelopment efforts for the Morro Bay facility.

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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.

Outlook

Since our emergence from bankruptcy in October 2012, we have continued to reposition our fleet, primarily through acquisitions, to concentrate on the most attractive power markets while maintaining a disciplined cost structure. In 2013, our fleet capacity consisted of 65 percent MISO/CAISO resources and 35 percent PJM/ISO-NE/NYISO resources. Today our fleet capacity is made up of 36 percent MISO/CAISO and 64 percent PJM/ISO-NE/NYISO. Upon closing the Delta Transaction, which is expected to occur in the fourth quarter of 2016, our fleet capacity will consist of 27 percent MISO/CAISO and 73 percent PJM/ISO-NE/ERCOT/NYISO. Additionally, our fuel mix will transition to 64 percent gas and 36 percent coal versus our 2014 mix of 46 percent gas and 54 percent coal.

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

Our Operating Segments

Coal. The Coal segment is comprised of 10 power generation facilities located within the MISO (2,543 MW), PJM (3,886 MW) and the ISO-NE (1,488 MW) regions, with a total generating capacity of 7,917 MW. On June 9, 2016, Dynegy announced that Hennepin will receive firm transmission service for a majority of the facility into the PJM control area beginning with Planning Year 2017-2018. Beginning June 1, 2017, Hennepin will pseudo-tie and offer energy and capacity for 260 MW to PJM. Hennepin's remaining volume of approximately 34 MW will continue to be offered into MISO.

We cleared no volume in the MISO Planning Year 2014-2015 capacity auction and cleared 398 MW in the MISO Planning Year 2015-2016 capacity auction at $150 per MW-day. We cleared no volume in the MISO Planning Year 2016-2017 capacity auction incremental to our retail load obligations.

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

In PJM, we cleared 3,341 MW in the Planning Year 2014-2015 capacity auction and 3,331 MW in the Planning Year 2015-2016 capacity auction. PJM introduced its new CP product beginning with Planning Year 2016-2017 capacity auction. In PJM, we cleared 3,566 MW in the Planning Year 2016-2017 (1,702 MW legacy capacity and 1,864 MW CP), 3,377 MW in the Planning Year 2017-2018 capacity auction (2,027 MW legacy capacity and 1,350 MW CP). Beginning in Planning Year 2018-2019, PJM introduced Base Capacity ("Base"), which, alongside CP, replaced the legacy capacity product. Base capacity resources are those capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year, but are capable of providing energy and reserves during hot weather operations. They are subject to non-performance charges assessed during emergency conditions, from June through September. In PJM, we cleared 3,347 MW in the Planning Year 2018-2019 capacity auction (1,734 MW Base and 1,613 MW CP), and 3,063 MW in the Planning Year 2019-2020 capacity auction (1,356 MW Base and 1,707 MW CP).

On May 3, 2016, Dynegy announced the shutdown of two units, or 1,220 MW at its Baldwin power generation facility in Baldwin, Illinois. MISO has approved the shutdown of Baldwin unit 1 by October 17, 2016. Subject to the approval of MISO, we expect to shut down Baldwin unit 3 by March 31, 2017. This decision was made after the units failed to recover their basic operating costs in the most recent MISO auction. As of June 1, 2016, the final two units at the 465

MW Wood River power generation facility in Alton, Illinois have been retired. Factors influencing these actions included a low power pricing environment, a lack of capacity revenue and significant maintenance and environmental expenditures required to appropriately maintain the facilities. Additionally, our Brayton Point facility is expected to be retired in ISO-NE in June 2017. Upon the completion of the Hennepin to PJM pseudo-tie and the planned retirements and shutdowns, our Coal segment will include 5,209 MW of generation capacity, of which 1,063 MW will operate in MISO and 4,146 MW will operate in PJM.

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As of July 14, 2016, our expected remaining generation volumes, excluding Brayton Point and the planned shutdowns, are approximately 71 percent hedged volumetrically for 2016. Excluding the planned retirements and shutdowns, our generation volumes are approximately 62 percent hedged volumetrically for 2017. We plan to continue our hedging program over a one- to three-year period using various instruments, including retail sales. Dynegy's portfolio beyond the prompt year is primarily open to benefit from possible future power market pricing improvements. We use our retail business, Dynegy Energy Services, to hedge a portion of the output from our facilities.

As of July 14, 2016, excluding Brayton Point, the non-operated jointly-owned generating units, and the planned shutdowns, our expected coal requirements for 2016 are fully contracted and 96 percent priced. Our forecasted coal requirements for 2017, excluding the planned retirements and shutdowns, as well as the non-operated jointly-owned generating units, are 90 percent contracted and 83 percent priced. We look to procure and price additional fuel and transportation opportunistically. Our coal transportation requirements are fully contracted for 2016 and 99 percent contracted for 2017. Our coal transportation requirements are approximately 54 percent contracted for 2018 to 2020. A new long-term coal transportation agreement for our Kincaid facility was completed in 2015. The contract, which begins in 2017, reflects a reduction from the 2016 rate.

IPH. The IPH segment is comprised of five power generation facilities, totaling 4,178 MW and primarily operates in MISO. Joppa, which is within the Electric Energy, Inc. control area, is interconnected to Tennessee Valley Authority and Louisville Gas and Electric Company, but primarily sells its capacity and energy to MISO. We currently offer a portion of our IPH segment generating capacity and energy into PJM. On June 1, 2016, our Coffeen, Duck Creek, E.D. Edwards, and Newton facilities have 937 MW, or 22 percent of IPH's capacity and energy, electrically tied into PJM through pseudo-tie arrangements. IPH will pseudo-tie an additional 240 MW into PJM from our Joppa facility beginning June 1, 2017. As of June 1, 2017, IPH will have 1,177 MW, or 33 percent of its capacity and energy, electrically tied into PJM through pseudo-tie arrangements, after giving effect to the shutdown of one unit at Newton described below.

On February 24, 2016, IPM was awarded a three year capacity and energy sale contract for 959 MW with capacity revenue of $152 million. This contract supports 112 communities in Illinois represented by Good Energy, and commenced on June 1, 2016.

IPH realized capacity sales in the MISO Planning Year 2014-2015 capacity auction, clearing 1,995 MW to offset retail load obligations. IPH cleared 1,864 MW in the MISO Planning Year 2015-2016 capacity auction, including 1,709 MW to offset retail load obligations. IPH only sold 155 MW that received the $150 per MW-day clearing price. IPH cleared 1,828 MW in the MISO Planning Year 2016-2017 capacity auction to offset retail load obligations.

In PJM, we cleared no volume in the Planning Year 2014-2015 capacity auction, 301 MW in the Planning Year 2015-2016 capacity auction, 867 MW in the Planning Year 2016-2017 capacity auction (138 MW legacy capacity and 729 MW CP), 847 MW in the Planning Year 2017-2018 capacity auction (376 MW legacy capacity and 471 MW CP), 835 MW in the Planning Year 2018-2019 capacity auction (all CP), and 616 MW in the Planning Year 2019-2020 capacity auction (260 MW Base and 356 MW CP).

On May 3, 2016, Dynegy announced the shutdown of one of the units at its Newton power generation facility in Newton, Illinois. MISO has approved and we expect to shut down the 615 MW unit by September 15, 2016. This decision was made after Newton failed to recover its basic operating costs in the most recent MISO auction, in addition to a low power pricing environment and significant maintenance and environmental expenditures required to appropriately maintain the facility. Upon the shutdown of the Newton unit, IPH will have 3,563 MW of generating capacity.

As of July 14, 2016, excluding the planned shutdown, IPH's expected remaining generation volumes are approximately 78 percent hedged volumetrically for 2016. Excluding the planned shutdown, IPH is approximately 61 percent hedged volumetrically for 2017. IPH will continue to use our retail business, Homefield Energy, to hedge a portion of the output from our IPH facilities. The retail hedges are well correlated to our facilities due to the close proximity of the hedge and through participation in FTR markets. Homefield Energy's ability to keep and possibly grow its existing market share will impact IPH's hedge levels in the future.

As of July 14, 2016, our expected coal requirements for IPH for 2016, excluding the planned shutdown, are fully contracted and 73 percent priced. Our forecasted coal requirements for 2017, excluding the planned shutdown, are fully contracted and 71 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2016 and 2017. Our coal transportation requirements are approximately 67 percent contracted for 2018 to 2020. On March 31, 2015, we entered into a long-term coal transportation agreement for our Joppa facility which will begin in 2018 and includes a rate reduction from the 2017 rate.

Additionally, as a result of continued weak energy prices, unsold capacity volumes, on-going required maintenance and environmental expenditures, upcoming interest payments, as well as consideration of a $300 million debt maturity in 2018, Dynegy

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and Genco have each begun strategic reviews of IPH's Genco subsidiary. Please read Liquidity and Capital Resources - Financing Activities for further discussion.
Gas. The Gas segment is comprised of 19 power generation facilities within the PJM (7,555 MW), CAISO (2,694 MW), ISO-NE (2,429 MW), and NYISO (1,156 MW) regions, totaling 13,834 MW of electric generating capacity.
In PJM, we are installing a total of 290 MW of uprates, which will be accomplished primarily through upgrades to the hot gas path components of our combined cycle gas turbines. The uprates started in the Fall of 2015 and are expected to be completed in the Spring of 2017.
In New England, at our Lake Road and Milford facilities, we cleared 70 MW of new uprates in FCA-10, at a capacity rate of $7.03 per kW-month for seven years beginning with Planning Year 2019-2020 and extending through Planning Year 2025-2026.
In New York, we have completed the installation of uprates on one of the two blocks and expect to complete installation on the other block in November 2016. In aggregate, the uprates are expected to result in 35 MW of additional summer capacity and 79 MW of additional winter capacity.
In PJM, we cleared 5,922 MW in the Planning Year 2014-2015 capacity auction, 5,996 MW in the Planning Year 2015-2016 capacity auction, 6,244 MW in the Planning Year 2016-2017 capacity auction (2,296 MW legacy capacity and 3,948 MW CP), 6,458 MW in the Planning Year 2017-2018 capacity auction (1,771 MW legacy capacity and 4,687 MW CP), 5,708 MW in the Planning Year 2018-2019 capacity auction (all CP), and 6,124 MW in the Planning Year 2019-2020 capacity auction (all CP).
In New England, we cleared 1,890 MW in the Planning Year 2014-2015 FCA, 1,956 MW in the Planning Year 2015-2016 FCA, 1,893 MW in the Planning Year 2016-2017 FCA, 2,147 MW in the Planning Year 2017-2018 FCA, 2,148 MW in the Planning Year 2018-2019 FCA, and 2,226 MW in the Planning Year 2019-2020 FCA. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.
In New York, almost 94 percent of our Independence facility's summer capacity had been sold bilaterally prior to the most recent auction, covering the Summer 2016 planning period. Including bilateral and auction sales as of July 14, 2016, 915 MW were sold for the Summer 2016 planning period, 766 MW were sold for the Winter 2016-2017 planning period, 868 MW were sold for the Summer 2017 planning period, 545 MW were sold for the Winter 2017-2018 planning period, 293 MW were sold for the Winter 2018-2019 planning period, and 225 MW were sold for the Summer 2019.
For our Moss Landing Units 1 and 2 in California, we sold incremental Resources Adequacy ("RA") capacity to various counterparties for 2016. For the third and fourth quarters of 2016, we sold an average incremental 226 MW and 160 MW, respectively. In October 2015, we contracted RA capacity with Southern California Edison for Moss Landing Units 1 and 2 for 575 MW, 400 MW, and 850 MW, for calendar years 2017, 2018, and 2019, respectively. Our Moss Landing 6 and 7 Units have tolling and RA agreements in place that continue through December 31, 2016.
In its 2015 Gas Transmission and Storage rate case, which sets gas transportation rates for 2015-2017, PG&E proposed revenue requirements and allocation proposals which would result in a significant increase in the rates for electric generators served by the local transmission system, including Moss Landing Units 1 and 2. Historically, after PG&E's gas transportation rate structure was changed to unbundle the Backbone Transmission System ("BB") rates, PG&E gas transmission and storage rate case settlements have included a bill credit for Moss Landing Units 1 and 2 that effectively reduced 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 which PG&E proposed in its 2015 proceeding would result in Moss Landing Units 1 and 2 likely experiencing a decline in dispatch hours. Dynegy actively participated in the hearing process before the CPUC and advocated positions that would maintain the ability of Moss Landing Units 1 and 2 to compete in the California electricity market. However, on June 23, 2016, the CPUC approved a rate increase for local transmission customers, including Dynegy, of approximately 200 percent and rejected Dynegy's requests for relief. Dynegy filed a request for rehearing of the CPUC's unfavorable June 23, 2016 decision on August 1, 2016. The request for rehearing does not act as a stay on the rate increase, which went into effect on August 1, 2016. If Dynegy's request for rehearing is denied, Dynegy will explore options for an appeal.

Excluding volumes subject to tolling agreements, as of July 14, 2016, our Gas portfolio is 68 percent hedged volumetrically through 2016 and approximately 38 percent hedged volumetrically for 2017. As a result of the offsetting risks of our Gas and Coal segments, we are able to reduce the costs associated with hedging with third parties by executing a portion of our natural gas hedges with an affiliate. We continue to manage our remaining commodity price exposure to changing fuel and power prices in accordance with our risk management policy.

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Capacity Markets

MISO. We currently have approximately 5,784 MW of power generation in MISO. This excludes the PJM pseudo-tie arrangements from the IPH fleet which began June 1, 2016. With the Hennepin and Joppa pseudo-ties that begin June 1, 2017, the shutdown of two units at Baldwin, and the shutdown of one unit at Newton, we will have approximately 3,449 MW in MISO for Planning Year 2017-2018. The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each Planning Year:

	2014-2015	2015-2016	2016-2017
Price per MW-day	$16.75	$150.00	$72.00

As previously noted, we cleared no volume in the MISO Planning Year 2014-2015 capacity auction. Our Coal and IPH segments cleared 398 MW and 155 MW, respectively, in the MISO Planning Year 2015-2016 capacity auction at $150 per MW-day, incremental to our retail load obligations. Our Coal and IPH segments cleared no incremental volumes, in excess of our retail load obligations, in the MISO Planning Year 2016-2017 capacity auction.

We have sold capacity through the PJM and MISO capacity auctions, retail sales, and wholesale and bilateral transactions. Capacity sold into PJM from our MISO fleet is included in the PJM section. The remaining MISO capacity sales through Planning Year 2019-2020 are as follows:

	2016-2017	2017-2018	2018-2019	2019-2020
Coal Segment:				
Capacity sold (MW)	1,011	579	242	185
Average price per kW-month	$2.75	$2.35	$2.68	$2.60
IPH Segment:				
Capacity sold (MW)	2,246	1,862	1,499	570
Average price per kW-month	$4.30	$4.65	$5.14	$5.20

A majority of the Mercury and Air Toxic Standards (“MATS”) related asset retirements will conclude this year; however, we expect economic retirements to continue reducing reserve margins in MISO. MISO has a Planning Reserve Margin of 15.2 percent and has forecasted reserve margins of 16.1 percent for Planning Year 2016-2017, 16.6 percent for Planning Year 2017-2018, 16.0 percent for Planning Year 2018-2019, 15.2 percent for Planning Year 2019-2020, and 14.7 percent for Planning Year 2020-2021.

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

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

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. Under the order, FERC found that the existing tariff provision, which bases Initial Reference Levels for capacity supply offers on the estimated opportunity cost of exporting capacity to a neighboring region (for example, PJM), are no longer just and reasonable. Accordingly, FERC required MISO to set the Initial Reference Level for capacity at $0 per MW-day for the 2016-2017

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PRA. Capacity suppliers may also request a facility-specific reference level from the MISO IMM. The order did not address the other arguments of the complainants regarding the 2015-2016 PRA and stated that those issues remain under consideration and will be addressed in a future order.

ISO-NE. We have approximately 3,917 MW of power generation in ISO-NE. The most recent FCA results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each Planning Year:

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

The forecasted 2016 ISO-NE reserve margin is 25.2 percent versus a target reserve margin of 15.6 percent. On February 2, 2015, ISO-NE conducted the capacity auction for Planning Year 2018-2019 (FCA-9). Effective for this auction, a downward sloping demand curve replaced the vertical demand curve and the system-wide administrative pricing rules. Performance incentive rules also went into effect for Planning Year 2018-2019, having the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level. Rest-of-Pool, which includes most of our facilities, cleared at a price of $9.55 per kW-month. The Southeastern Massachusetts and Rhode Island zone, where our Dighton facility is located, had insufficient supply to satisfy its capacity requirements. As a result, the zone separated from Rest-of-Pool, with existing resources in the zone receiving the Net Cost of New Entry price of $11.08 per kW-month and new resources in the zone receiving the auction starting price of $17.73 per kW-month. On February 8, 2016, ISO-NE conducted the capacity auction for Planning Year 2019-2020 (FCA-10). In this auction, Rest-of-Pool cleared at $7.03 per kW-month.

We have sold capacity in FCAs, supplemental auctions, and through bilateral transactions. Our capacity sales, aggregated by Planning Year through Planning Year 2019-2020, are as follows:

	2016-2017	2017-2018	2018-2019	2019-2020
Capacity sold (MW)	3,663	2,181	2,195	2,240
Average price per kW-month	$3.25	$6.99	$9.64	$7.03

PJM. We currently have approximately 12,378 MW of power generation in PJM. This includes the PJM pseudo-tie arrangements from the IPH fleet which began June 1, 2016. Our plants within PJM are mixed between Eastern Mid-Atlantic Area Council ("EMAAC") (Liberty), Mid-Atlantic Area Council ("MAAC") (Ontelaunee), Commonwealth Edison ("COMED") (Elwood, Kendall, Lee, and Kincaid), American Transmission Service, Inc. ("ATSI") (Richland/Stryker), and Regional Transmission Organization ("RTO") (balance of plants). PJM has begun the transition of the PJM capacity market to CP product. On August 26-27, 2015, PJM held a transitional auction to convert up to 60 percent of PJM's capacity needs for Planning Year 2016-2017 from legacy capacity to CP. On September 3-4, 2015, PJM held a transitional auction to convert 70 percent of PJM's capacity needs for Planning Year 2017-2018 from legacy capacity to CP. On August 10-14, 2015, PJM held the Base Residual Auction to procure CP for 80 percent and Base for 20 percent of PJM's capacity needs for the Planning Year 2018-2019. On May 11-17, 2016, PJM held the Base Residual Auction to procure CP for 80 percent and Base for 20 percent of PJM's capacity needs for the Planning Year 2019-2020. PJM will procure 100 percent CP beginning with Planning Year 2020-2021. The most recent Reliability Pricing Model auction results for the zones in which our assets are located, are as follows for each Planning Year:

	2014-2015	2015-2016	2016-2017		2017-2018		2018-2019		2019-2020	
	Legacy Capacity	Legacy Capacity	Legacy Capacity	CP	Legacy Capacity	CP	Base	CP	Base	CP
RTO zone, price per MW-day	$ 125.99	$ 136.00	$59.37	$134.00	$120.00	$151.50	$149.98	$164.77	$80.00	$100.00
MAAC zone, price per MW-day	$ 136.50	$ 167.46	$119.13	$134.00	$120.00	$151.50	$149.98	$164.77	$80.00	$100.00
EMAAC zone, price per MW-day	$ 136.50	$ 167.46	$119.13	$134.00	$120.00	$151.50	$210.63	$225.42	$99.77	$119.77
	$ 125.99	$ 136.00	$59.37	$134.00	$120.00	$151.50	$200.21	$215.00	$182.77	$202.77

COMED zone, price per MW-day										
ATSI zone, price per MW-day	$ 125.99	$ 357.00	$ 114.23	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77	$ 80.00	$ 100.00

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We have sold capacity in base residual auctions, incremental auctions, transitional auctions, and through bilateral transactions. Our capacity sales, aggregated by Planning Year and capacity type through Planning Year 2019-2020, are as follows:

	2016-2017	2017-2018	2018-2019	2019-2020
Capacity sold (MW)	9,762	10,623	9,986	9,803
Average price per MW-day	$120.53	$139.50	$181.26	$135.49

NYISO. We have approximately 1,156 MW of power generation in NYISO. The most recent seasonal auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Winter 2014-2015	Summer 2015	Winter 2015-2016	Summer 2016
Price per kW-month	$2.90	$3.50	$1.25	$3.62

We have sold capacity in seasonal strip auctions, supplemental auctions, and through bilateral transactions. Our capacity sales, aggregated by season through Summer 2019, are as follows:

	Summer 2016	Winter 2016-2017	Summer 2017	Winter 2017-2018	Summer 2018	Winter 2018-2019	Summer 2019
Capacity sold (MW)	915	766	868	545	515	293	225
Average price per kW-month	$3.36	$2.64	$3.44	$3.14	$3.69	$3.30	$3.38

CAISO. On April 29, 2016, CAISO published the 2017 Local Capacity Technical Analysis—Final Report and Study Results, which identifies Local Capacity Requirements (“LCR”) and influences procurement decisions of Load Serving Entities. The Moss Landing area has been identified as a critical sub-area and will be included as part of the Greater Bay Area’s LCR criteria. Beginning in 2017, we will have the ability to sell Greater Bay Area RA capacity, in addition to CAISO System RA capacity, from the Moss Landing units.

We have approximately 2,694 MW of power generation in CAISO. The CAISO capacity market is a bilateral market in which Load Serving Entities are required to procure sufficient resources to meet their peak load plus a 15 percent reserve margin. We transact with investor owned utilities, municipalities, community choice aggregators, retail providers, and other marketers through Request for Offers solicitations, broker markets, and directly with bilateral transactions for both the Standard and Flexible RA capacity. Beginning on or after November 1, 2016, CAISO is expected to implement the voluntary capacity auction for annual, monthly, and intra-month procurement to cover for deficiencies in the market. The voluntary competitive solicitation process FERC approved on October 1, 2015 will replace the existing pricing mechanism, Capacity Procurement Mechanism (“CPM”), and will provide another avenue to sell RA capacity. Like CPM, we expect this mechanism to be used infrequently because generation supply has been ample, and demand has been stagnant, mainly due to energy efficiency programs and distributed generation of residential and commercial rooftop solar.

Our capacity sales, aggregated by calendar year for the remainder of 2016 through 2019 for Moss Landing Units 1 and 2, are as follows:

	Remainder of 2016	2017	2018	2019
Capacity sold (Avg MW)	515	725	400	850

Other Market Developments

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

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K and Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations-Outlook-Environmental and Regulatory Matters in our Form 10-Q for the period ended March 31, 2016 for a detailed discussion of our environmental and regulatory matters.

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The Clean Water Act

Effluent Limitation Guidelines ("ELG"). We have evaluated the ELG final rule and at this time, we estimate the cost of our compliance with the ELG rule to be approximately $270 million to $330 million. The majority of ELG compliance expenditures are expected to occur in the 2016-2023 timeframe. As planning and work progress, we continue to review our estimates as well as timing of our capital expenditures. The following table presents the projected capital expenditures by period for ELG compliance as of June 30, 2016:

(amounts in millions)	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years	Total
Coal segment	$ —	$ 97	$ 42	$ 62	$ 201
IPH segment	—	89	11	—	100
Total Consolidated ELGs	$ —	$ 186	$ 53	$ 62	$ 301

The Clean Air Act

Mercury and Air Toxic Standards. In April 2016, the EPA issued its final supplemental finding that consideration of cost does not change the Agency's determination that regulation of hazardous air pollutant emissions from coal- and oil-fired electric generating units is appropriate and necessary under CAA section 112. Petitions for judicial review have been filed. In June 2016, the Supreme Court declined to review the D.C. Circuit's decision remanding the MATS rule without vacating to consider cost.

Coal Combustion Residuals

EPA CCR Rule. At this time, we estimate the cost of our compliance with the Coal Combustion Residuals ("CCR") rule will be approximately $210 million to $260 million with the majority of the expenditures in the 2016-2023 timeframe. This estimate is reflected in our asset retirement obligations ("AROs").

Illinois CCR Rule. The IPCB extended its stay of the Illinois EPA's proposed rulemaking to July 2016.

Coal Segment Groundwater. Please read Note 14—Commitments and Contingencies, Other Contingencies, Coal Segment Groundwater, for further discussion.

Asset Retirement Obligations

AROs are recorded as liabilities in our unaudited consolidated balance sheets at their Net Present Value ("NPV") using interest rates ranging from 8.8 percent to 19.4 percent. The following table presents the NPV and projected obligation as of June 30, 2016:

		Projected Obligation by Period				
(amounts in millions)	NPV	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years	Total
Coal						
CCR	$ 118	$ —	$ 28	$ 41	$ 72	$ 141
Non-CCR	60	2	14	5	113	134
Total Coal segment	178	2	42	46	185	275
Gas						
Non-CCR	22	8	3	—	45	56
Total Gas segment	22	8	3	—	45	56
IPH						
CCR	71	—	6	42	63	111
Non-CCR	12	2	5	10	91	108

Total IPH segment	83	2	11	52	154	219
Total Consolidated AROs	$283	$12	$ 56	$ 98	$ 384	$550

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Coal Segment. At June 30, 2016, Coal segment CCR AROs consisted of projected expenditures of $141 million related to surface impoundments and groundwater monitoring. Non-CCR AROs consisted of projected expenditures of $96 million related to asbestos removal, $30 million related to surface impoundments and groundwater monitoring, and $8 million related to landfill closures.

Gas Segment. At June 30, 2016, Gas segment Non-CCR AROs consisted of projected expenditures of $47 million related to decommissioning, $5 million related to asbestos removal, and $4 million related to surface impoundments and groundwater monitoring.

IPH Segment. At June 30, 2016, IPH segment CCR AROs consisted of projected expenditures of $111 million related to surface impoundments and groundwater monitoring. Non-CCR AROs consisted of projected expenditures of $68 million related to asbestos removal, $29 million related to surface impoundments and groundwater monitoring, and $11 million related to landfill closures.

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 June 30, 2016.

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 June 30, 2016 compared to December 31, 2015 was lower due to a decrease in volatility and price.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	June 30, 2016	December 31, 2015
One day VaR—95 percent confidence level	$ 13	$ 20
One day VaR—99 percent confidence level	$ 18	$ 29
Average VaR—95 percent confidence level for the rolling twelve months ended	$ 11	$ 8

Credit Risk. The following table represents our credit exposure at June 30, 2016 associated with the mark-to-market portion of our risk management portfolio, on a net basis. We had exposure of less than $1 million related to non-investment grade quality counterparties.

Credit Exposure Summary

(amounts in millions)	Investment Grade Quality
Type of Business:	
Financial institutions	$ 41
Oil and gas producers	4
Utility and power generators	26
Total	$ 71

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.

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The absolute notional amounts associated with our interest rate contracts were as follows at June 30, 2016 and December 31, 2015, respectively:

	June 30, 2016	December 31, 2015
Interest rate swaps (in millions of U.S. dollars)	$ 773	$ 777
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 June 30, 2016.

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 June 30, 2016.

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

Please read Note 14—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-Q for the quarterly period ended March 31, 2016 and 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
1.1	Underwriting Agreement, dated as of June 15, 2016, among Dynegy Inc., Morgan Stanley & Co. LLC, and RBC Capital Markets, LLC (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 21, 2016 File No. 001-33443).
2.1	Amended and Restated Stock Purchase Agreement, dated as of June 27, 2016, by and among Atlas Power Finance, LLC, GDF SUEZ Energy North America, Inc. and International Power, S.A.* (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2016 File No. 001-33443).
4.1	Indenture, dated June 21, 2016, between Dynegy Inc. and Wilmington Trust, National Association(incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 21, 2016 File No. 001-33443).
4.2	Supplemental Indenture to the Indenture, dated June 21, 2016, between Dynegy Inc. and Wilmington Trust, National Association (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on June 21, 2016 File No. 001-33443).
4.3	Purchase Contract Agreement, dated June 21, 2016, between Dynegy Inc. and Wilmington Trust, National Association (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K of Dynegy Inc. filed on June 21, 2016 File No. 001-33443).
4.4	Form of Unit (included in Exhibit 4.3).
4.5	Form of Purchase Contract (included in Exhibit 4.3).
4.6	Form of Amortizing Note (included in Exhibit 4.2).
10.1	Amended and Restated Interim Sponsors Agreement, dated as of June 14, 2016, by and between Atlas Power, LLC, Dynegy Inc., Energy Capital Partners III, LP, Energy Capital Partners III-A, LP, Energy Capital Partners III-B, LP, Energy Capital Partners III-C, LP, Energy Capital Partners III-D, LP, and Terawatt Holdings, LP (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2016 File No. 001-33443)
10.2	Term Loan Credit Agreement, dated June 27, 2016, among Dynegy Finance IV, Inc., various lenders and Morgan Stanley Senior Funding, Inc., as administrative agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 27, 2016 File No. 001-33443).
10.3	Escrow Agreement, dated June 27, 2016, among Dynegy Finance IV, Inc., Wilmington Trust, National Association, as escrow agent and securities intermediary, and Morgan Stanley Senior Funding, Inc., as

	administrative agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on June 27, 2016 File No. 001-33443).
10.4	Third Amendment to the Credit Agreement, dated June 27, 2016, among Dynegy Inc., as borrower and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on June 27, 2016 File No. 001-33443).
10.5	Waiver to the Credit Agreement, dated June 27, 2016, among Dynegy Inc., as borrower and the lenders party thereto (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on June 27, 2016 File No. 001-33443).
10.6	Amended and Restated Equity Commitment Letter, dated as of June 27, 2016, by and among Dynegy Inc., Atlas Power Finance, LLC and GDF SUEZ Energy North America, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2016 File No. 001-33443).

**10.7	Amendment No. 3 to Letter of Credit and Reimbursement Agreement by and between Illinois Power Marketing Company and Union Bank, N.A.
**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.

* Schedules and exhibits to the Stock Purchase Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Dynegy will furnish the omitted schedules and exhibits to the Securities and Exchange Commission upon request by the Commission.

† 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:	August 4, 2016	By:	/s/ CLINT C. FREELAND
			Clint C. Freeland
			Executive Vice President and Chief Financial Officer