DYNEGY INC.
Form 10-Q
November 07, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

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

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

No x

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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 ¨

Indicate the number of shares outstanding of our classes of common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 99,999,196 shares outstanding as of November 2, 2012.

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DEFINITIONS

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

ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BTA	Best technology available
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CCR	Coal Combustion Residuals
CEQA	California Environmental Quality Act
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CO2	Carbon Dioxide
CRCG	Commodity Risk Control Group
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DCIH	Dynegy Coal Investments Holdings, LLC
DGIN	Dynegy Gas Investments, LLC
DH	Dynegy Holdings, LLC (formerly known as Dynegy Holdings Inc.)
DMSLP	Dynegy Midstream Services L.P.
EBITDA	Earnings before interest, taxes, depreciation and amortization
EMA	Energy Management Agency Services Agreement
EMT	Executive Management Team
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles of the United States of America
GHG	Greenhouse Gas
ICC	Illinois Commerce Commission
IFRS	International Financial Reporting Standards
IMA	In-market asset availability
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LC	Letter of Credit
LIBOR	London Interbank Offered Rate
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	One million British thermal units
MW	Megawatts
MWh	Megawatt hour
NM	Not Meaningful
NOL	Net operating loss

NOx	Nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRG	NRG Energy, Inc.

NYISO	New York Independent System Operator
NYSDEC	New York State Department of Environmental Conservation
OTC	Over-the-counter
PJM	PJM Interconnection, LLC
RFO	Request for offer
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SCE	Southern California Edison
SEC	U.S. Securities and Exchange Commission
SIP	State Implementation Plan
SO2	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
VaR	Value at Risk
VIE	Variable Interest Entity
VLGC	Very Large Gas Carrier

Item 1—FINANCIAL STATEMENTS

DYNEGY INC.
DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited) (in millions)

	September 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$677	$398
Restricted cash and investments	357	159
Accounts receivable, net of allowance for doubtful accounts of $29 and $12, respectively	131	147
Accounts receivable, affiliates	—	26
Interest receivable, affiliates	—	8
Inventory	125	65
Assets from risk-management activities	563	2,615
Assets from risk-management activities, affiliates	—	2
Broker margin account	43	23
Intangible assets	211	49
Prepayments and other current assets	124	77
Total Current Assets	2,231	3,569
Property, Plant and Equipment	4,436	3,911
Accumulated depreciation	(1,166)	(1,090)
Property, Plant and Equipment, Net	3,270	2,821
Other Assets		
Restricted cash and investments	289	455
Assets from risk-management activities	16	26
Intangible assets	96	92
Undertaking receivable, affiliate	—	1,250
Deferred income taxes	—	44
Other long-term assets	69	54
Total Assets	$5,971	$8,311

See the notes to condensed consolidated financial statements.

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DYNEGY INC.
DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited) (in millions, except share data)

	September 30, 2012	December 31, 2011
LIABILITIES AND STOCKHOLDERS' AND MEMBER'S EQUITY (DEFICIT)		
Current Liabilities		
Accounts payable	$92	$80
Accounts payable, affiliates	—	47
Accrued interest	1	1
Deferred income taxes	—	50
Accrued liabilities and other current liabilities	133	64
Liabilities from risk-management activities	625	2,798
Liabilities from risk-management activities, affiliates	—	4
Notes payable and current portion of long-term debt	16	7
Total Current Liabilities	867	3,051
Liabilities subject to compromise	4,290	4,012
Long-term debt	1,661	1,069
Other Liabilities		
Liabilities from risk-management activities	48	20
Liabilities from risk-management activities, affiliates	—	3
Other long-term liabilities	255	124
Total Liabilities	7,121	8,279
Commitments and Contingencies (Note 14)		
Stockholders'/Member's Equity (Deficit)		
Common Stock, $0.01 par value, 420,000,000 shares authorized at September 30, 2012; 123,630,089 shares issued and outstanding at September 30, 2012	1	—
Member's Contribution	—	5,135
Affiliate Receivable	—	(846)
Additional paid-in capital	5,159	—
Accumulated other comprehensive loss, net of tax	(24)	1
Accumulated deficit	(6,286)	(4,258)
Total Stockholders'/Member's Equity (Deficit)	(1,150)	32
Total Liabilities and Stockholders'/Member's Equity (Deficit)	$5,971	$8,311

See the notes to condensed consolidated financial statements.

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DYNEGY INC.
DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(unaudited) (in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues	$477	$467	$1,042	$1,298
Cost of sales	(332)	(278)	(697)	(781)
Gross margin, exclusive of depreciation shown separately below	145	189	345	517
Operating and maintenance expense, exclusive of depreciation shown separately below	(84)	(87)	(196)	(303)
Depreciation and amortization expense	(45)	(60)	(110)	(261)
Impairment and other charges	—	(3)	—	(6)
General and administrative expenses	(29)	(25)	(66)	(87)
Operating income (loss)	(13)	14	(27)	(140)
Bankruptcy reorganization charges	18	—	(252)	—
Interest expense	(48)	(105)	(121)	(283)
Debt extinguishment costs	—	(21)	—	(21)
Impairment of Undertaking receivable, affiliate	—	—	(832)	—
Other income and expense, net	—	7	31	11
Loss before income taxes	(43)	(105)	(1,201)	(433)
Income tax benefit (expense) (Note 17)	2	(24)	9	109
Net loss	$(41)	$(129)	$(1,192)	$(324)

See the notes to condensed consolidated financial statements.

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DYNEGY INC.
DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(unaudited) (in millions)

	Three Months Ended September 30,	
	2012	2011
Net loss	$(41)	$(129)
Amortization of unrecognized prior service cost and actuarial loss (net of tax expense of zero and zero)	1	1
Total Other comprehensive income, net of tax	1	1
Comprehensive loss	$(40)	$(128)

	Nine Months Ended September 30,	
	2012	2011
Net loss	$(1,192)	$(324)
Amortization of unrecognized prior service cost and actuarial loss (net of tax expense of zero and $1)	—	2
Total Other comprehensive income, net of tax	—	2
Comprehensive loss	$(1,192)	$(322)

See the notes to condensed consolidated financial statements.

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DYNEGY INC.
DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited) (in millions)

	Nine Months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(1,192)	$(324)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation and amortization	118	278
Bankruptcy reorganization charges	213	—
Impairment and other charges	—	2
Impairment of Undertaking receivable, affiliate	832	—
Risk-management activities	(79)	142
Risk-management activities, affiliate	(3)	(2)
Deferred income taxes	(9)	(109)
Debt extinguishment costs	—	21
Amortization of intangibles	79	30
Other	2	3
Changes in working capital:		
Accounts receivable	9	54
Inventory	7	17
Broker margin account	(12)	(53)
Prepayments and other assets	(31)	(40)
Affiliate transactions	19	(47)
Accounts payable and accrued liabilities	26	91
Changes in non-current assets	(16)	(69)
Changes in non-current liabilities	—	2
Net cash used in operating activities	(37)	(4)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(63)	(163)
Maturities of short-term investments	—	444
Purchases of short-term investments	—	(269)
Decrease in restricted cash and investments	88	178
Acquisitions/divestitures	256	(441)
Payments received for Undertaking, receivable affiliate	16	—
Other investing	3	10
Net cash provided by (used in) investing activities	300	(241)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	—	2,022
Repayments of borrowings	(11)	(1,623)
Recapitalization of Legacy Dynegy	27	—
Debt extinguishment costs	—	(21)
Net cash provided by financing activities	16	378
Net increase in cash and cash equivalents	279	133
Cash and cash equivalents, beginning of period	398	253
Cash and cash equivalents, end of period	$677	$386

Other non-cash investing activity:		
Non-cash capital expenditures	$(3)	$(3)
Other non-cash financing activity:		
Undertaking agreement, affiliate	$—	$(1,250)
DMG Acquisition	$466	$—

See the notes to condensed consolidated financial statements.

DYNEGY INC.
DEBTOR-IN-POSSESSION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2012 and 2011

EXPLANATORY NOTE

On September 30, 2012, pursuant to the terms of the Joint Chapter 11 Plan of Reorganization (the “Plan”) for Dynegy Holdings, LLC (“DH”) and Dynegy Inc. (“Dynegy”), DH merged with and into Dynegy, with Dynegy continuing as the surviving legal entity (the “Merger”). As described in Note 1—Basis of Presentation and Organization, the accounting treatment of the Merger is reflected as a recapitalization of DH and, similar to a reverse merger, DH is the surviving accounting entity for financial reporting purposes. Therefore, our historical results for periods prior to the Merger are the same as DH's historical results; accordingly, we refer to Dynegy as "Legacy Dynegy" for periods prior to the Merger.

Note 1—Basis of Presentation and Organization

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. 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 direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy or DH are clearly noted in such sections or areas and specific defined terms may be introduced for use only in those sections or areas. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three segments in our consolidated financial statements: (i) the Coal segment (“Coal”); (ii) the Gas segment (“Gas”) and (iii) the Dynegy Northeast segment (“DNE”).

The Gas segment includes Dynegy Power, LLC (“DPC”), which owns, directly and indirectly, substantially all of our wholly-owned natural gas-fired power generation facilities. DPC, a bankruptcy remote entity, and its direct and indirect subsidiaries are organized into a ring-fenced group for the benefit of the creditors of DPC.

The Coal segment includes Dynegy Midwest Generation, LLC (“DMG”), which owns, directly and indirectly, substantially all of the coal-fired power generation facilities. DMG, also a bankruptcy remote entity, and its direct and indirect subsidiaries are organized into a ring-fenced group for the benefit of the creditors of DMG. On September 1, 2011, DH sold 100 percent of the outstanding membership interests of Dynegy Coal Holdco (“Coal Holdco”) to Dynegy (the “DMG Transfer”). Therefore, the results of our Coal segment are only included in our consolidated results for the period from January 1, 2011 through August 31, 2011. On June 5, 2012, in connection with the Settlement Agreement (as defined and discussed below), DH reacquired Coal Holdco (including its subsidiary, DMG) from Dynegy (the “DMG Acquisition”). Therefore, the results of our Coal segment are only included in our consolidated results for the period from June 6, 2012 through September 30, 2012. Please read Note 5—Merger and Acquisition—DMG Acquisition for further discussion.

On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy, with Legacy Dynegy continuing as the surviving legal entity. Immediately prior to the Merger, Legacy Dynegy had no substantive operations, and our Coal, Gas and DNE operations were primarily conducted through subsidiaries of DH. Further, as a result of the DH Chapter 11 Cases in 2011, under applicable accounting standards, Dynegy was no longer deemed to have a controlling financial interest in DH and its wholly-owned subsidiaries; therefore, DH and its consolidated subsidiaries were no longer consolidated in Dynegy's consolidated financial statements as of November 7, 2011. As a result of these factors, the Merger was accounted for in a manner similar to a reverse merger, whereby DH is the surviving accounting entity for financial reporting purposes. Further, the net assets contributed by Legacy Dynegy, which amounted to $54 million, did not constitute a business and were therefore treated in a manner similar to a recapitalization and were credited to stockholder's equity. Prior to the Merger, DH was organized as a limited liability company and the capital structure of DH did not change until September 30, 2012. Although Legacy Dynegy's shares were publicly traded, DH did not have any publicly traded shares for any period presented; therefore, no earnings per share is presented on our unaudited condensed consolidated statement of operations for any period presented.

The year-end condensed consolidated balance sheet data was derived from the audited consolidated financial statements of DH but does not include all disclosures required by accounting principles generally accepted in the United States of America ("GAAP"). These interim financial statements should be read together with the consolidated financial statements

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DYNEGY INC.
DEBTOR-IN-POSSESSION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
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and notes thereto included in DH's annual report on Form 10-K for the year ended December 31, 2011, filed on September 18, 2012, which, as a result of the Merger, we refer to as our “Form 10-K.”

Chapter 11 Filing by Certain Subsidiaries. On November 7, 2011, DH and four of its wholly-owned subsidiaries, Dynegy Northeast Generation, Inc. (“Dynegy Northeast Generation”), Hudson Power, L.L.C. (“Hudson”), Dynegy Danskammer, L.L.C. (“Danskammer”) and Dynegy Roseton, L.L.C. (“Roseton”, and together with DH, DNE, Hudson and Danskammer, the “DH Debtor Entities”) filed voluntary petitions (the “DH Chapter 11 Cases”) for relief under Chapter 11 of Title 11 of the United States Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of New York, Poughkeepsie Division (the “Bankruptcy Court”). The DH Chapter 11 Cases were assigned to the Honorable Cecelia G. Morris and are being jointly administered for procedural purposes only. On July 6, 2012, Legacy Dynegy filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court (the “Dynegy Chapter 11 Case,” and together with the DH Chapter 11 Cases, the “Chapter 11 Cases”). The Dynegy Chapter 11 Case was also assigned to the Honorable Cecelia G. Morris, but was separately administered under the caption In re: Dynegy Inc., Case No. 12-36728. Only Legacy Dynegy and the DH Debtor Entities filed voluntary petitions for relief under the Bankruptcy Code, and none of our other direct or indirect subsidiaries are or were debtors thereunder. Consequently, our other direct or indirect subsidiaries continued to operate their business in the ordinary course. Legacy Dynegy and the DH Debtor Entities (together, the “Debtor Entities”) remained in possession of their property and continued to operate their business as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The Dynegy Chapter 11 Case was a necessary step to facilitate the restructuring contemplated by the Plan, the Settlement Agreement and the Plan Support Agreement (each as defined and described in Note 3—Chapter 11 Cases), including the Merger.

On September 10, 2012, the Bankruptcy Court entered an order confirming the Plan and on October 1, 2012, (the “Effective Date”), we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. Dynegy Northeast Generation, Hudson, Danskammer and Roseton (the “DNE Entities”) remain in Chapter 11 bankruptcy and continue to operate their businesses as “debtors-in-possession” (the “DNE Bankruptcy Cases”).

The consolidated financial statements as of and for all periods as included herein have neither been adjusted to reflect any changes in our capital structure as a result of the Plan nor have they been adjusted to reflect any changes in the fair value of assets and liabilities as a result of the adoption of fresh start accounting. Such adjustments will be applied to our financial statements from the Effective Date, and will be reported in our Form 10-K for the year ending December 31, 2012. Accordingly, our financial statements for periods subsequent to the Effective Date will not be comparable to previous periods as such previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities that might be necessary as a consequence of the Plan or the related application of fresh start accounting. Additional details regarding the status of the Chapter 11 Cases are included herein under Note 3—Chapter 11 Cases.

Going Concern

Our previously issued consolidated financial statements included cautionary language about our ability to continue as a going concern due to the Chapter 11 Cases. Dynegy, excluding the DNE Entities, emerged from Chapter 11 protection on October 1, 2012 and we believe we have sufficient liquidity to fund our operations. Please read Note 3—Chapter 11 Cases for further information.

Note 2—Accounting Policies

Use of Estimates

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

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Accounting Principles Adopted During the Current Period

Fair Value Measurement Disclosures. In May 2011, the FASB issued Accounting Standards Update ("ASU") No. 2011-04—Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS ("ASU No. 2011-04"). This authoritative guidance changes the wording used to describe the requirements in GAAP for measuring fair value and requires additional disclosure about fair value measurements. ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The implementation of this guidance has been reflected in our fair value disclosures.

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05—Comprehensive Income (Topic 220): Presentation of Comprehensive Income ("ASU No. 2011-05"). The FASB's objective in issuing this guidance is to improve the comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. ASU No. 2011-05 eliminates the option of presenting components of other comprehensive income as part of the statement of changes in stockholders' equity. The standard requires that all non-owner changes in stockholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We have elected to present comprehensive income as two separate consecutive statements.

Accounting Principles Not Yet Adopted

Disclosures about Offsetting Assets and Liabilities. In December 2011, the FASB issued ASU 2011-11—Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This statement requires entities to disclose both gross and net information about instruments and transactions eligible for offsetting in the statement of financial position, as well as instruments and transactions subject to an agreement similar to a master netting arrangement. Implementation of this guidance would affect disclosures around financial derivative contracts, however would have no impact on the statement of financial position or the statement of operations. This guidance is effective for the quarter ending March 31, 2013.

Note 3—Chapter 11 Cases

On November 7, 2011, the DH Debtor Entities commenced the DH Chapter 11 Cases. On July 6, 2012, we commenced the Dynegy Chapter 11 Case. Throughout the pendency of the Chapter 11 Cases, the Debtor Entities remained in possession of their property and continued to operate their businesses as "debtors-in-possession" under the jurisdiction of and in accordance with the orders of the Bankruptcy Court and the Bankruptcy Code.

Only the Debtor Entities sought relief under the Bankruptcy Code, and none of our other direct or indirect subsidiaries were or are debtors thereunder. Coal Holdco and Dynegy GasCo Holdings, LLC and their indirect, wholly-owned subsidiaries (including DMG and DPC) were not included in the Chapter 11 Cases. The normal day-to-day operations of the coal-fired power generation facilities held by DMG and the gas-fired power generation facilities held by DPC continued without interruption during the Chapter 11 Cases (and continue, notwithstanding the ongoing DNE Bankruptcy Cases). The commencement of the Chapter 11 Cases did not constitute an event of default under either the DMG Credit Agreement or the DPC Credit Agreement.

On May 1, 2012, Dynegy and certain of its subsidiaries, including the DH Debtor Entities, entered into a settlement agreement with certain of DH's creditors, including certain beneficial holders of DH's then-outstanding senior notes, the owners and lessors of the Roseton and part of the Danskammer facilities, and U.S. Bank, in its capacity as trustee under an indenture governing certain lease certificates guaranteed by DH (the "Original Settlement Parties"). On May 30, 2012, the Original Settlement Parties, holders of a majority of DH's then-outstanding subordinated notes, and, solely with respect to certain sections of the Settlement Agreement, Wells Fargo N.A., as successor trustee under the indenture governing DH's subordinated notes, entered into an amended and restated settlement agreement (the "Settlement Agreement").

The Bankruptcy Court entered an order approving the Settlement Agreement on June 1, 2012 (the "Approval Order") and the Settlement Agreement became effective on June 5, 2012. Pursuant to the Settlement Agreement and the Approval Order, Dynegy and DH took certain steps towards their emergence from Chapter 11 bankruptcy, including the DMG Acquisition and the filing of the Plan. In addition, parties to certain prepetition litigations (as discussed in Note 14—Commitments and Contingencies—Legal Proceedings—Creditor Litigation) and adversary proceedings (relating to the Roseton

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(Unaudited)
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and Danskammer facilities) filed stipulations of dismissals in their respective litigations or proceedings and certain intercompany receivables pursuant to an agreement by Dynegy to make specified payments to Dynegy Gas Investments, LLC ("DGIN") (the "Undertaking Agreement") and a related DH promissory note were cancelled.

On September 10, 2012, the Bankruptcy Court entered an order confirming the Plan (the "Confirmation Order"). On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Dynegy, thereby consummating the Merger. On the Effective Date, we consummated our reorganization under Chapter 11 pursuant to the Plan and exited bankruptcy. The DNE Entities remain in Chapter 11 bankruptcy and continue to operate their businesses as "debtors-in-possession." Capitalized terms used, but not defined, in this section only shall have the meanings ascribed to them in the Plan.

In addition to the Merger, the Plan included the following key elements:

- On the Effective Date, all of Dynegy's Equity Interests, including Dynegy's old common stock, were cancelled.
- Each holder of Allowed General Unsecured Claims received its Pro Rata Share of (a) 99 million shares of Dynegy Common Stock and (b) a $200 million cash payment (the "Plan Cash Payment").
- In full satisfaction of the Dynegy Administrative Claim (otherwise referred to herein as the "Administrative Claim"), the beneficial holders thereof (which were the holders of Dynegy's old common stock) received their Pro Rata Share of (a) one million shares of Dynegy Common Stock and (b) warrants to purchase approximately 15.6 million shares of Dynegy Common Stock for an exercise price of $40 per share (subject to adjustment) expiring on October 2, 2017 (the "Warrants").
- In addition, each holder of an Allowed General Unsecured Claim will receive, as applicable, their Pro Rata Share of the proceeds of the sale of the Roseton and Danskammer generation facilities (the "Facilities") allocated to Dynegy (the "Facilities Sale") according to the Settlement Agreement (the amount of which, if any, is to be determined); provided that, the Lease Trustee (on behalf of itself and the Lease Certificate Holders) will not receive a distribution of any amounts paid pursuant to the Facilities Sale in its capacity as holder of the Lease Guaranty Claim.

On the Effective Date, and pursuant to the Plan, outstanding obligations of approximately $4 billion in aggregate principal amount, were cancelled. These obligations included the following series of notes and related indentures and guaranties, as applicable:

- DH's 8.75 percent senior notes due 2012;
- DH's 7.5 percent senior unsecured notes due 2015;
- DH's 8.375 percent senior unsecured notes due 2016;
- DH's 7.125 percent senior debentures due 2018;
- DH's 7.75 percent senior unsecured notes due 2019;
- DH's 7.625 percent senior notes due 2026; and
- DH's Series B 8.316 percent subordinated debentures due 2027 (the "2027 Notes").

In addition, on the Effective Date, in connection with the cancellation of the 2027 Notes, the Series B 8.316 percent subordinated capital income securities due 2027 (the "NGC Notes") issued by NGC Corporation Capital Trust I were cancelled, DH's guarantee of the NGC Notes was terminated and the indenture governing the NGC Notes was cancelled.

Finally, on the Effective Date, DH's obligations as a guarantor of the leases of the Facilities under the guaranty dated as of May 1, 2001, made by DH with respect to Roseton Units 1 and 2 and the guaranty, dated as of May 1, 2001, made by DH with respect to Danskammer Units 3 and 4 (the “Guaranties”) and all obligations thereunder were cancelled. In connection with the cancellation of the Guaranties, DH's obligations as a lessee guarantor under the Pass Through Trust Agreement, dated as of May 1, 2001 (the “Pass Through Trust Agreement”), among Roseton, Danskammer, and The Chase Manhattan Bank, as pass through trustee were terminated.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2012 and 2011

We continue to be obligated to the terms of DH's $26 million cash collateralized letter of credit facility, which is collateralized by $27 million in restricted cash, as well as our approximately $1 million cash collateralized letter of credit facility.

Accounting Impact of Emergence

Upon emergence, we will apply fresh start accounting to our consolidated financial statements because (i) the reorganization value of the assets of the emerging entity immediately before the date of confirmation was less than the total of all post-petition liabilities and allowed claims and (ii) the holders of the existing voting shares of the predecessor's common stock immediately before confirmation received less than 50 percent of the voting shares of the emerging entity. Our Annual Report on Form 10-K for the fiscal year ending December 31, 2012 will reflect the consummation of the Plan and the adoption of fresh start accounting.

In the application of fresh start accounting, we will allocate our reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. The amount remaining after allocation of the reorganization value to the fair value of identified tangible and intangible assets and liabilities, if any, will be reflected as goodwill and subject to periodic evaluation for impairment. In addition to fresh start accounting, our future consolidated financial statements will reflect all effects of the transactions contemplated by the Plan. Accordingly, our future financial statements will not be comparable in many respects to our consolidated financial statements for periods prior to the adoption of fresh start accounting and prior to accounting for the effects of the Plan.

Under the terms of the Plan, in exchange for the elimination of approximately $4 billion in debt and other obligations, unsecured creditors received approximately 99 million shares of Dynegy Common Stock and $200 million in cash on or about October 1, 2012. Legacy stockholders, as beneficiaries of the Administrative Claim, received (i) approximately one million shares of Dynegy Common Stock and (ii) Warrants that expire October 2, 2017, to purchase up to approximately 15.6 million shares of Dynegy Common Stock (on a fully-diluted basis) to be exercisable at $40 per share. Dynegy initiated the distributions of Dynegy Common Stock and the Plan Cash Payment to creditors and beneficial holders of the Dynegy Administrative Claim, according to the terms of the Plan, starting on the Effective Date. Dynegy has approximately 15.6 million Warrants outstanding (with shares of Dynegy Common Stock authorized and reserved for issuance on a one-for-one basis), and approximately 6.1 million shares of Dynegy Common Stock authorized and reserved for issuance for distributions to be made under Dynegy's long term incentive plan.

The Bankruptcy Court approved a range of $2.3 billion to $3.6 billion for our reorganization value. While we are currently in the process of determining the adjustments that will result from the application of fresh start accounting, we expect our final reorganization value to be at the lower end of the range approved by the Bankruptcy Court.

As discussed above, the DNE Entities have not emerged from Chapter 11 protection; Therefore, the DNE Entities will be deconsolidated as of October 1, 2012.

Note 4—DMG Transfer and Undertaking Agreement

On September 1, 2011, we completed the DMG Transfer which resulted in the transfer of our Coal segment (including DMG) to Legacy Dynegy in exchange for the Undertaking Agreement. In connection with the DMG Transfer, we recognized a loss of $1.77 billion, which was recorded as a reduction of member's equity because the transaction was between entities that were under common control at that time.

Note 5—Merger and Acquisition

Merger. On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy with Legacy Dynegy continuing as the surviving legal entity of the Merger. Immediately prior to the Merger, Legacy Dynegy had no substantive operations, and our Coal, Gas and DNE operations were primarily conducted through subsidiaries formerly held by DH. There was no consideration exchanged in the transaction and Legacy Dynegy, as the accounting acquiree, did not meet the definition of a business; therefore, we accounted for DH's acquisition of Legacy Dynegy as a “recapitalization.” Under this method of accounting, the net assets of $54 million contributed by Legacy Dynegy were credited directly to stockholder's

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equity. Furthermore, the surviving legal entity's historical results for periods prior to the Merger are the same as DH's historical results.

DMG Acquisition. On June 5, 2012, pursuant to the Settlement Agreement, Legacy Dynegy and DH consummated the DMG Acquisition. The DMG Acquisition was accounted for as a business combination in DH's financial statements as Legacy Dynegy deconsolidated DH, effective November 7, 2011, as a result of the DH Chapter 11 Cases. Accordingly, the assets acquired and liabilities assumed were recognized at their fair value as of the acquisition date.

The purchase price was approximately $466 million. Consideration given by DH consisted of (i) approximately $402 million for the fair value of the Undertaking receivable, affiliate that was extinguished in connection with the transaction and (ii) approximately $64 million for the fair value of the Administrative Claim issued to Dynegy in the DH Chapter 11 Cases.

The following table summarizes the fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

Cash	$ 256	
Restricted cash (including $75 million current)	117	
Accounts receivable	3	
Inventory	69	
Assets from risk management activities (including $84 million current)	85	
Prepaids and other current assets	46	
Property, plant and equipment	514	
Intangible assets (including $162 million current)	257	
Total assets acquired	1,347	
Current liabilities and accrued liabilities	(60	)
Liabilities from risk management activities (including $66 million current)	(76	)
Long-term debt (including $9 million current)	(610	)
Asset retirement obligations	(53	)
Unfavorable coal contract (including $15 million current)	(38	)
Pension liabilities	(44	)
Total liabilities assumed	(881	)
Net assets acquired	$ 466	

In connection with the DMG Acquisition, we recorded intangible assets and liabilities related to rail transportation agreements and coal purchase agreements. These amounts are being amortized over their remaining contract terms which expire at the end of 2013 and 2015. The following table summarizes the activity related to these intangibles:

	Coal Contracts (in millions)	
December 31, 2011	$ —	
DMG Acquisition	219	
Amortization expense	(49	)
September 30, 2012	$ 170	

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Pro Forma Results. Revenue and net loss attributable to the DMG Acquisition is included in our unaudited condensed consolidated statements of operations since the date of the acquisition of June 5, 2012. For the nine months ended September 30, 2012, the DMG Acquisition contributed approximately $166 million to our revenue and increased our net loss by approximately $87 million.

The unaudited pro forma financial results for the nine months ended September 30, 2012 show the effect of the DMG Acquisition as if the acquisition had occurred as of January 1, 2012. The unaudited pro forma financial results for the nine months ended September 30, 2011 disregard the DMG Transfer that occurred on September 1, 2011. This is presented for informational purposes only and is not indicative of future operations or results that would have been achieved had the acquisitions been completed as of January 1, 2011.

	Nine Months Ended September 30,	
	2012	2011
	(in millions)	
Revenue	$1,272	$1,347
Net loss	$(447)	$(259)

Note 6—Condensed Combined Financial Statements of the Debtor Entities

Condensed combined financial statements of the Debtor Entities are set forth below (in millions):

Condensed Combined Balance Sheet

	September 30, 2012 (1)	December 31, 2011 (2)
Cash	$292	$33
Restricted cash and investments (including $27 million current)	30	27
Accounts receivable	26	8
Inventory	23	34
Investment in consolidated subsidiaries	6,431	5,568
Risk management, affiliate	3	—
Accrued interest from affiliate	—	8
Undertaking receivable from affiliate	—	1,250
Deferred income taxes	—	44
Other	33	14
Total assets	$6,838	$6,986
Current liabilities and accrued liabilities	$60	$10
Liabilities subject to compromise	4,290	4,012
Intercompany payable	465	1,577
Intercompany accrued interest	799	10
Long-term debt to affiliates	2,255	1,262
Deferred income taxes	—	50
Other	119	33
Total liabilities	$7,988	$6,954

Total member's equity	$(1,150)	$32
Total liabilities and member's equity	$6,838	$6,986

(1) Includes all Debtor Entities as of September 30, 2012, including the amounts acquired in the Merger.

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(2) Includes only DH Debtor Entities at December 31, 2011.

See Note 15—Liabilities Subject to Compromise for additional discussion of liabilities subject to compromise.

Condensed Combined Statement of Operations

	Three Months Ended September 30, 2012 (1)	Nine Months Ended September 30, 2012 (1)
Revenues	$ 35	$ 61
Cost of sales	(21)	(35)
Operating expenses	(16)	(46)
General and administrative expenses	(3)	(7)
Operating loss	(5)	(27)
Bankruptcy reorganization charges	18	(252)
Equity losses	(46)	(1,373)
Interest expense, affiliate	—	(1)
Other income and expense, net	(10)	452
Income tax expense	2	9
Net loss	$ (41)	$ (1,192)

(1) DH Debtor Entities included for the periods July 1, 2012 through September 30, 2012 and January 1, 2012 to September 30, 2012 for the three and nine months ended September 30, 2012, respectively.

Condensed Combined Statement of Cash Flows

	Nine Months Ended September 30, 2012
Net cash provided by:	
Operating activities	$ 32
Investing activities	27
Financing activities	200
Net increase in cash and cash equivalents	259
Cash and cash equivalents, beginning of period	33
Cash and cash equivalents, end of period	$ 292

Basis of Presentation. The condensed combined financial statements only include the financial statements of the Debtor Entities. Transactions and balances of receivables and payables among the Debtor Entities are eliminated in consolidation. However, the condensed combined balance sheet includes receivables from related parties and payables to related parties that are not Debtor Entities. Actual settlement of these related party receivables and payables is, by historical practice, made on a net basis.

Interest Expense. The Debtor Entities have discontinued recording interest on unsecured liabilities subject to compromise ("LSTC"). Contractual interest on LSTC not reflected in the condensed combined financial statements was approximately $74 million and $217 million for the three and nine months ended September 30, 2012, respectively.

Bankruptcy Reorganization Charges. Bankruptcy reorganization charges represent the direct and incremental costs of bankruptcy, such as professional fees, pre-petition liability claim adjustments and losses related to terminated contracts that are probable and can be estimated. Bankruptcy reorganization charges, as shown in the condensed combined statement of operations above, consist of expense or income incurred or earned as a direct and incremental result of the bankruptcy filings. The table below lists the significant items within this category for the three and nine months ended September 30, 2012.

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	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
	(in millions)	
Adjustments of estimated allowable claims:		
DNE Leases (1)	$ —	$ (395)
Subordinated notes (1)	—	161
Write-off of note payable, affiliate (2)	—	10
Other	(1)	(5)
Total adjustments for estimated allowable claims	(1)	(229)
Change in value of Administrative Claim (3)	26	17
Professional fees (4)	(7)	(40)
Total Bankruptcy reorganization charges	$ 18	$ (252)

(1) The estimated allowable claims related to the Facilities and the Subordinated Capital Income Securities were adjusted based on the terms of the Settlement Agreement. Please read Note 3—Chapter 11 Cases for further discussion.

(2) It was determined that no claim related to a Note payable, affiliate would be made. Therefore, the estimated amount was reduced to zero.

(3) The Administrative Claim was issued on the effective date of the Settlement Agreement. Please read Note 8—Fair Value Measurements—Fair Value of Financial Instruments and Note 3—Chapter 11 Cases for further discussion.

(4) Professional fees relate primarily to the fees of attorneys and consultants working directly on the Chapter 11 Cases.

Note 7—Risk Management Activities, Derivatives and Financial Instruments

The nature of our business necessarily involves market and financial risks. Specifically, we are exposed to commodity price variability related to our power generation business. Our commercial team manages these commodity price risks with financially settled and other types of contracts consistent with our commodity risk management policy. Our commercial team also uses financial instruments in an attempt to capture the benefit of fluctuations in market prices in the geographic regions where our assets operate. Our treasury team manages our financial risks and exposures associated with interest expense variability.

Our commodity risk management strategy gives us the flexibility to sell energy and capacity through a combination of spot market sales and near-term contractual arrangements (generally over a rolling 1 to 3 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. Increasing collateral requirements and our liquidity position could impact our ability to effectively employ our risk management strategy.

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our unaudited condensed consolidated statements of operations. We also manage commodity price risk by entering into capacity forward sales arrangements, tolling arrangements, RMR contracts, fixed price coal purchases and other arrangements that do not receive recurring fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as “normal purchase normal sales.” As a result, the gains and losses with respect to these arrangements are not reflected in the unaudited condensed consolidated statements of operations until the delivery occurs.

Quantitative Disclosures Related to Financial Instruments and Derivatives

The following disclosures and tables present information concerning the impact of derivative instruments on our unaudited condensed consolidated balance sheets and statements of operations. In the table below, commodity contracts primarily consist of derivative contracts related to our power generation business that we have not designated as accounting hedges that are entered into for purposes of economically hedging future fuel requirements and sales commitments and securing commodity prices. We elect not to designate any of our commodity instruments as accounting hedges. As of September 30, 2012, our commodity derivatives were comprised of both purchases and sales of commodities. As of September 30, 2012, we

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had net purchases and sales of commodity derivative contracts and notional interest swaps outstanding in the following quantities:

Contract Type	Hedge Designation	Quantity (in millions)	Unit of Measure	Net Fair Value (in millions)
Commodity contracts:				
Electric energy (1)	Not designated	(30)	MWh	$(13)
Natural gas (1)	Not designated	10	MMBtu	$(42)
Heat rate derivatives	Not designated	(3)/21	MWh/MMBtu	$(2)
Crude oil	Not designated	—	BBL	$—
Interest rate contracts:				
Interest rate swaps	Not designated	1,110	Dollars	$(37)
Interest rate caps	Not designated	1,400	Dollars	$—

(1) Mainly comprised of swaps, options and physical forwards.

Derivatives on the Balance Sheet. We execute a significant volume of transactions through futures clearing managers. Our daily cash payments (receipts) with our futures clearing managers consist of three parts: (i) fair value of open positions (exclusive of options) ("Daily Cash Settlements"); (ii) initial margin requirements of open positions ("Initial Margin"); and (iii) fair value related to options ("Options", and collectively with Daily Cash Settlements and Initial Margin, "Collateral"). We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we do not elect to offset the fair value amounts recognized for the Daily Cash Settlements paid or received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, our unaudited condensed consolidated balance sheets present derivative assets and liabilities, as well as related Collateral, as applicable, on a gross basis.

In addition to the transactions we execute through the futures clearing managers, we also execute transactions through multiple bilateral counterparties. Our transactions with these counterparties are collateralized using cash collateral and first liens. As of September 30, 2012, we had $94 million posted with these counterparties, which is included in Prepayments and other current assets on our unaudited condensed consolidated balance sheets.

The following table presents the fair value and balance sheet classification of derivatives in the unaudited condensed consolidated balance sheet as of September 30, 2012 and the consolidated balance sheet as of December 31, 2011 segregated by type of contract segregated by assets and liabilities.

Contract Type	Balance Sheet Location	September 30, 2012	December 31, 2011
		(in millions)	
Derivative Assets:			
Commodity contracts	Assets from risk management activities	$579	$2,639
Commodity contracts, affiliates	Assets from risk management activities, affiliates	—	2
Interest rate contracts	Assets from risk management activities	—	2
Derivative Liabilities:			
Commodity contracts	Liabilities from risk management activities	(636)	(2,810)
Commodity contracts, affiliates		—	(7)

	Liabilities from risk management activities, affiliates		
Interest rate contracts	Liabilities from risk management activities	(37)	(8)
Total derivatives, net		$(94)	$(182)

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Impact of Derivatives on the Consolidated Statements of Operations
The following discussion and table presents the location and amount of gains and losses on derivative instruments in our consolidated statements of operations. We had no derivatives that were designated in qualifying hedging relationships during the three and nine months ended September 30, 2012 and 2011.
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 the consolidated statements of operations (herein referred to as "mark-to-market accounting treatment"). As a result, these mark-to-market gains and losses are not reflected in the unaudited condensed consolidated statements of operations in the same period as the underlying activity for which the derivative instruments serve as economic hedges.

For the three months ended September 30, 2012, our revenues included approximately $17 million of unrealized mark-to-market gains related to this activity compared to $17 million of unrealized mark-to-market losses in the same period in the prior year. For the nine months ended September 30, 2012, our revenues included approximately $103 million of unrealized mark-to-market gains related to this activity compared to $144 million of unrealized mark-to-market losses in the same period in the prior year.

The impact of derivative financial instruments, including realized and unrealized gains and losses, that have not been designated as hedges on our unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012 and 2011 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross margin we expect to realize when the underlying physical transactions settle.

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives for the Three Months Ended September 30,		Amount of Gain (Loss) Recognized in Income on Derivatives for the Nine Months Ended September 30,	
		2012	2011	2012	2011
		(in millions)			
Commodity contracts	Revenues	$(61)	$(62)	$(60)	$(132)
Commodity contracts, affiliates	Revenues	—	(5)	(6)	(5)
Interest rate contracts	Interest Expense	(12)	—	(24)	—

Note 8—Fair Value Measurements

We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. For example, assets and liabilities from risk management activities may include exchange-traded derivative contracts and OTC derivative contracts. Some exchange-traded derivatives are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets. In such cases, these exchange-traded derivatives are classified within Level 2. OTC derivative trading instruments include swaps, forwards, options and complex structures that are valued at fair value. In certain instances, these instruments may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives trade in less active markets with a lower availability of pricing information. In addition, complex or structured transactions, such as heat-rate call options, can introduce the need for internally-developed model inputs that might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3. We have consistently used this valuation technique for all periods presented. Please read Note 2—Summary of Significant Accounting Policies—Fair Value Measurements in our Form 10-K for further discussion.

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

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

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

The following tables set forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2012 and December 31, 2011. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of September 30, 2012			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$116	$7	$123
Natural gas derivatives	—	450	—	450
Heat rate derivatives	—	—	3	3
Other derivatives	—	3	—	3
Total assets from commodity risk management activities	$—	$569	$10	$579
Assets from interest rate contracts	—	—	—	—
Total	$—	$569	$10	$579
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(137)	$(2)	$(139)
Natural gas derivatives	—	(490)	—	(490)
Heat rate derivatives	—	—	(5)	(5)

Other derivatives	—	(2)	—	(2)
Total liabilities from commodity risk management activities	$—	$(629)	$(7)	$(636)
Liabilities from interest rate contracts	—	—	(37)	(37)
Administrative Claim (1)	—	—	(47)	(47)
Total	$—	$(629)	$(91)	$(720)

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(1) Amount represents the fair value of the Administrative Claim that was issued to Dynegy upon the effective date of the Settlement Agreement. Please read Note 3—Chapter 11 Cases for further discussion.

	Fair Value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$211	$26	$237
Electricity derivatives, affiliates	—	1	1	2
Natural gas derivatives	—	2,387	—	2,387
Other derivatives	—	15	—	15
Total assets from commodity risk management activities:	$—	$2,614	$27	$2,641
Assets from interest rate contracts	—	—	2	2
Total	$—	$2,614	$29	$2,643
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(169)	$(2)	$(171)
Electricity derivatives, affiliates	—	(2)	(5)	(7)
Natural gas derivatives	—	(2,607)	—	(2,607)
Heat rate derivatives	—	—	(17)	(17)
Other derivatives	—	(15)	—	(15)
Total liabilities from commodity risk management activities	$—	$(2,793)	$(24)	$(2,817)
Liabilities from interest rate contracts	—	—	(8)	(8)
Total	$—	$(2,793)	$(32)	$(2,825)

Level 3 Valuation Methods. The electricity contracts classified within level 3 are primarily financial swaps executed in illiquid trading locations and capacity contracts. 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. Additionally, FTRs are classified within the electricity contracts, which are also an illiquid product. The forward market price of FTRs is derived using historical congestion patterns within the marketplace. Heat rate option valuations are derived using a Black-Scholes spread model, which uses forward natural gas and power prices, market implied volatilities and modeled power/natural gas correlation values. The interest rate contracts classified within Level 3 include an implied credit fee that impacted the day one value of the instruments. We revalue the credit fee each quarter in conjunction with revaluing the actual interest rate derivative. The interest rate derivatives are revalued using the forward LIBOR curve each period and the credit fee is revalued by determining the change in credit factors, such as credit default swaps, period over period.

We initially recorded the Administrative Claim granted in the Settlement Agreement at its estimated fair value of $64 million. We estimated the fair value of the Administrative Claim using the market capitalization of Dynegy as of the date of the DMG Acquisition. We believe the market capitalization of Dynegy represents a reasonable estimate of the fair value of the Administrative Claim because the previous holders of Dynegy's common stock became the holders of beneficial interests in the Administrative Claim upon our emergence from bankruptcy. The Administrative Claim had the potential to be settled in cash under certain circumstances, as such we accounted for the Administrative Claim as a liability and adjusted the carrying amount of the claim to its estimated fair value each reporting period. As of September 30, 2012, the fair value of the Administrative Claim was approximately $47 million; therefore, we recorded a credit of approximately $26 million and $17 million in

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Bankruptcy reorganization charges on our unaudited condensed consolidated statement of operations for the three and nine months ended September 30, 2012, respectively. The fair value of the Administrative Claim is classified within Level 3 of the fair value hierarchy. Please read Note 3—Chapter 11 Cases for further discussion.

Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measure of our commodity instruments categorized within Level 3 of the fair value hierarchy are estimates of future price correlation, future market volatility, estimates of forward congestion power price spreads, assumptions of illiquid power location pricing basis to liquid locations, and estimates of counterparty credit risk and our own non-performance risk. These assumptions are generally independent of each other. Volatility curves and power prices spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price or volatility of the spread on a long/short position in isolation would result in a higher/lower fair value measurement. A change in the assumption used for the probability of default is accompanied by a directionally similar change in the adjustment to reflect the estimated default risk of counterparties on their contractual obligations, or the estimated risk of default on our own contractual obligations to counterparties. Any change in the value of the unobservable inputs used for level 3 valuations could have a significant impact on the calculated fair value.

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

	Three Months Ended September 30, 2012				
	Electricity Derivatives	Heat Rate Derivatives	Administrative Claim	Interest Rate Swaps	Total
	(in millions)				
Balance at June 30, 2012	$8	$(8)	$(73)	$(25)	$(98)
Total gains (losses) included in earnings	(1)	(1)	26	(12)	12
Settlements	(2)	7	—	—	5
Issuance of Administrative Claim	—	—	—	—	—
DMG Acquisition	—	—	—	—	—
Balance at September 30, 2012	$5	$(2)	$(47)	$(37)	$(81)
Unrealized gains (losses) relating to instruments held as of September 30, 2012	$(15)	$(1)	$26	$(12)	$(2)

	Nine Months Ended September 30, 2012				
	Electricity Derivatives	Heat Rate Derivatives	Administrative Claim	Interest Rate Swaps	Total
	(in millions)				
Balance at December 31, 2011	$20	$(17)	$—	$(6)	$(3)
Total gains (losses) included in earnings	(33)	1	17	(24)	(39)
Settlements	14	14	—	—	28
Issuance of Administrative Claim	—	—	(64)	—	(64)
DMG Acquisition	4	—	—	(7)	(3)
Balance at September 30, 2012	$5	$(2)	$(47)	$(37)	$(81)
Unrealized gains (losses) relating to instruments (net of affiliates) held as of September 30, 2012	$(11)	$1	$17	$(28)	$(21)

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	Three Months Ended September 30, 2011			
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Total
	(in millions)			
Balance at June 30, 2011	$35	$—	$(23)	$12
Total losses included in earnings	(14)	(2)	(1)	(17)
Settlements	(2)	—	5	3
Balance at September 30, 2011	$19	$(2)	$(19)	$(2)
Unrealized losses relating to instruments (net of affiliates) held as of September 30, 2011	$(4)	$(2)	$(5)	$(11)

	Nine Months Ended September 30, 2011			
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Total
	(in millions)			
Balance at December 31, 2010	$49	$5	$(31)	$23
Total losses included in earnings	(22)	(7)	(2)	(31)
Settlements	(8)	—	14	6
Balance at September 30, 2011	$19	$(2)	$(19)	$(2)
Unrealized gains (losses) relating to instruments (net of affiliates) held as of September 30, 2011	$2	$(7)	$(4)	$(9)

Gains and losses (realized and unrealized) for Level 3 recurring items are included in Revenues, Interest expense and Bankruptcy reorganization charges on the unaudited condensed consolidated statements of operations for commodity derivatives, interest rate swaps and the Administrative Claim, respectively. 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 nine months ended September 30, 2012 and 2011.

Fair Value of Financial Instruments. We have determined the estimated fair-value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair-value amounts.

The carrying values of financial assets and liabilities (cash, accounts receivable, restricted cash and investments, short-term investments and accounts payable) not presented in the table below approximate fair values due to the short-term maturities of these instruments. The $846 million Accounts receivable, affiliate balance with Dynegy classified within member's equity as of December 31, 2011 did not have a fair value as there were no defined payment terms, was not evidenced by any promissory notes, and there had never been an intent for payment to occur. The Accounts receivable, affiliate balance was settled on June 5, 2012. Please read Note 16—Related Party Transactions—Accounts receivable, affiliate for further discussion. 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 for the periods ending September 30, 2012 and December 31, 2011, respectively.

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	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Undertaking receivable, affiliate (1)	$—	$—	$1,250	$728
Interest rate derivatives not designated as accounting hedges (2)	(37)	(37)	(6)	(6)
Commodity-based derivative contracts not designated as accounting hedges (2)	(57)	(57)	(176)	(176)
DPC Credit Agreement due 2016 (3)	(1,071)	(1,145)	(1,076)	(1,118)
DMG Credit Agreement due 2016 (4)	(606)	(616)	—	—
Administrative Claim (5)	(47)	(47)	—	—

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(1) The fair value of the Undertaking receivable is classified within Level 3 of the fair value hierarchy. Our December 31, 2011 estimate of the fair value of the Undertaking receivable represents the $750 million fair value as of November 7, 2011, less the $22 million payment in December 2011. Pursuant to the Settlement Agreement on June 5, 2012, the Undertaking Agreement was terminated. Please read Note 3—Chapter 11 Cases and Note 5—Merger and Acquisition for further discussion.

(2) Included in both current and non-current assets and liabilities on the unaudited condensed consolidated balance sheets.

(3) Carrying amount includes unamortized discounts of $18 million and $21 million at September 30, 2012 and December 31, 2011.

(4) Includes unamortized premiums of $12 million as of September 30, 2012. We completed the DMG Acquisition on June 5, 2012.

(5) Amount represents the fair value of the Administrative Claim that was issued to Dynegy upon the effective date of the Settlement Agreement. Please read Note 3—Chapter 11 Cases for further discussion.

Note 9—Accumulated Other Comprehensive Income

Accumulated other comprehensive income, net of tax, is included in stockholders' equity (deficit) and member's equity on our unaudited condensed consolidated balance sheets as follows:

	September 30, 2012	December 31, 2011
	(in millions)	
Cash flow hedging activities, net	$—	$1
Unrecognized prior service cost and actuarial loss, net	(24)	—
Accumulated other comprehensive gain (loss), net of tax	$(24)	$1

Note 10—Inventory

A summary of our inventories is as follows:

	September 30, 2012	December 31, 2011
	(in millions)	
Materials and supplies	$59	$40
Coal	57	16
Fuel	8	8

Emissions allowances	1	1
Total	$125	$65

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Note 11—Asset Retirement Obligations

We record the present value of our legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. A summary of changes in our AROs is as follows:

	Nine Months Ended September 30,	
	2012	2011
	(in millions)	
Beginning of period	$ 50	$ 120
Accretion expense	3	5
Revision of previous estimate (1)	(15)	(1)
DMG Transfer (2)	—	(53)
DMG Acquisition (2)	51	—
Other	—	—
End of period	$ 89	$ 71

(1) The South Bay ARO was revised downward during the first quarter 2012 based on revised cost estimates related to the plant demolition.
(2) As a result of the DMG Transfer on September 1, 2011, the AROs associated with the Coal segment (including DMG) were transferred from DH to Dynegy and subsequently, as a result of the DMG Acquisition, the AROs were transferred back to DH on June 5, 2012.

Note 12—Property, Plant, & Equipment

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

	September 30,	December 31,
	2012	2011
	(in millions)	
Generation assets:		
Coal (1)	$ 543	$ —
Gas	3,551	3,532
DNE	267	268
IT systems and other	75	111
Property, plant and equipment	4,436	3,911
Accumulated depreciation	(1,166)	(1,090)
Property, plant and equipment, net	$ 3,270	$ 2,821

(1) Amounts related to the Coal segment (including DMG) were acquired effective June 5, 2012. Please read Note 5—Merger and Acquisition for further discussion.

Total interest costs incurred were $41 million and $97 million for the three and nine months ended September 30, 2012, respectively, and $104 million and $277 million for the three and nine months ended September 30, 2011, respectively. Interest capitalized related to costs of construction projects in process totaled $4 million and $5 million for the three and nine months ended September 30, 2012, respectively, and $4 million and $13 million for the three and nine months ended September 30, 2011, respectively.

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Note 13—Debt

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

	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
DPC Credit Agreement, due 2016 (1)	$ 1,089	$ 1,145	$ 1,097	$ 1,118
DMG Credit Agreement, due 2016 (2)	594	616	—	—
	1,683		1,097	
Unamortized premium (discount) on debt, net	(6)		(21)	
	1,677		1,076	
Less: Amounts due within one year, including non-cash amortization of basis adjustments	16		7	
Total Long-Term Debt	$ 1,661		$ 1,069	

(1) Please read Note 20—Debt in our Form 10-K for further discussion.
(2) Please read DMG Credit Agreement below for further discussion.

DMG Credit Agreement
As a result of the DMG Acquisition, we recorded DMG's senior secured term loan facility with an aggregate outstanding principal amount of $597 million (the “DMG Credit Agreement”). The DMG Credit Agreement will mature on August 5, 2016 and will amortize in equal quarterly installments in aggregate annual amounts equal to one percent of the original principal amount of the DMG Credit Agreement with the balance payable on August 5, 2016.
All obligations of DMG under the DMG Credit Agreement (the “DMG Borrower Obligations”) are unconditionally guaranteed jointly and severally on a senior secured basis (the “DMG Guarantees”) by each existing and subsequently acquired or organized direct or indirect material domestic subsidiary of DMG (the “DMG Guarantors”) as permitted by applicable law, regulation and contractual provision and to the extent such guarantee would not result in adverse tax consequences as reasonably determined by DMG. DMG may also elect to have the obligations under the Hedging/Cash Management Arrangements for it and its subsidiaries covered by such DMG Guarantees. None of DMG's parent companies are obligated to repay the DMG Borrower Obligations or any guaranteed Hedging/Cash Management Arrangements.

The DMG Borrower Obligations, and the DMG Guarantees are secured by first priority liens on and security interests in 100 percent of the capital stock of DMG and substantially all of the present and after-acquired assets of DMG and each DMG Guarantor. Accordingly, such assets are only available for the creditors of Dynegy Coal Investments Holdings, LLC (“DCIH”) and its subsidiaries.

Interest Costs. The DMG Credit Agreement bears interest, at DMG's option, at either (a) 7.75 percent per annum plus LIBOR, subject to a LIBOR floor of 1.50 percent, with respect to any Eurodollar term loan or (b) 6.75 percent per annum plus the alternate base rate with respect to an ABR term loan. DMG may elect from time to time to convert all or a portion of the term loan from any ABR Borrowing into a Eurodollar Borrowing or vice versa. With some exceptions, the DMG Credit Agreement is non-callable for the first 2 years and is subject to a prepayment premium.

Prepayment Provisions. The DMG Credit Agreement contains mandatory prepayment provisions. The outstanding loan under the DMG Credit Agreement is to be prepaid with (a) 100 percent of the net cash proceeds of all asset sales by DMG and its subsidiaries, subject to the right of DMG to reinvest such proceeds if such proceeds are reinvested (or committed to be reinvested) within 12 months and, if so committed to reinvestment, reinvested within 6 months after such initial 12 month period, (b) 50 percent of the net cash proceeds of issuance of equity securities of DMG and its subsidiaries (except to the extent used (x) to prepay the Loans, (y) for capital expenditures and (z) for permitted acquisitions), (c) commencing with the first full fiscal year of DMG to occur after the closing date, 100 percent of excess cash flow; provided that (i) excess cash flow shall be determined after reduction for amounts used for capital expenditures, and restricted payments made and (ii) any voluntary

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prepayments of the term loans shall be credited against excess cash flow prepayment obligations and (d) 100 percent of the net cash proceeds of issuances, offerings or placements of debt obligations of DMG and its subsidiaries (other than all permitted debt).

Covenants and Events of Default. The DMG Credit Agreement contains customary events of default and affirmative and negative covenants including, subject to certain specified exceptions, limitations on amendments to constitutive documents, liens, capital expenditures, acquisitions, subsidiaries and joint ventures, investments, the incurrence of debt, fundamental changes, asset sales, sale-leaseback transactions, hedging arrangements, restricted payments, changes in nature of business, transactions with affiliates, burdensome agreements, amendments of debt and other material agreements, accounting changes and prepayment of indebtedness or repurchases of equity interests.

The DMG Credit Agreement contains a requirement that DMG shall establish and maintain a segregated account, subject to the control of the Collateral Trustee (the “DMG Collateral Posting Account”), into which a specified collateral posting amount shall be deposited. DMG may withdraw amounts from the DMG Collateral Posting Account: (i) for the purpose of meeting collateral posting requirements of DMG and the DMG Guarantors; (ii) to prepay the term loan under the DMG Credit Agreement; (iii) to repay certain other permitted indebtedness; and (iv) to the extent any excess amounts are determined to be in the DMG Collateral Posting Account.

The DMG Credit Agreement limits distributions to $90 million per year provided the borrower and its subsidiaries possess at least $50 million of cash and cash equivalents and short-term investments as of the date of the proposed distribution.

Letter of Credit Facility. We also acquired DMG's $100 million fully cash collateralized Letter of Credit Reimbursement and Collateral Agreement pursuant to which letters of credit will be issued at DMG’s request provided that DMG deposits in an account an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereof.

Sithe Senior Notes

On August 26, 2011, Sithe/Independence Funding Corporation (“Sithe”) commenced a cash tender offer (the “Sithe Tender Offer”) to purchase Sithe’s outstanding $192 million in principal amount of nine percent Secured Bonds due 2013 (the “Sithe Senior Notes”). Sithe also solicited consents to certain proposed amendments to the indenture governing the Sithe Senior Notes. At the expiration of the early consent period on September 9, 2011, Sithe entered into a supplemental indenture, which eliminated or modified substantially all of the restrictive covenants, certain events of default and certain other provisions. On September 12, 2011, Sithe accepted for purchase all Sithe Senior Notes validly tendered prior to the consent date and satisfied and discharged the indenture and remaining Sithe Senior Notes. Also on September 12, 2011, Sithe/Independence Power Partners, LP (“SIPP”) filed with the New York State Public Service Commission (the “NYPSC”), and certain other parties, a verified petition for approval of financing, seeking NYPSC authorization for SIPP to grant liens/security interests in its assets and properties as collateral security for the DPC Credit Agreement. On the final payment date, September 26, 2011, Sithe accepted for purchase all of the Sithe Senior Notes that were validly tendered (and not validly withdrawn) on or prior to the consent date, and discharged the indenture and the remaining Sithe Senior Notes. The NYPSC issued an order approving the petition described above on December 21, 2011 and SIPP joined the DPC Credit Agreement and pledged its assets as security therefore on June 12, 2012.

Sithe purchased the Sithe Senior Notes at a price of 108 percent of the principal amount plus consent fees. Total cash paid to purchase the Sithe Senior Notes, including fees and accrued interest, was $217 million, which was funded from proceeds from the DPC Credit Agreement. We recorded a charge of approximately $16 million associated with this transaction, of which $21 million is included in Debt extinguishment costs offset by the write-off of $5 million of premiums included in Interest expense on our unaudited condensed consolidated statements of operations. As a result of the successful cash tender offer and consent solicitation, $43 million in restricted cash previously held at Sithe was returned to DPC when the transaction closed.

We also made scheduled repayments of the Sithe Senior Notes totaling $33 million during the second quarter 2011.

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Restricted Cash and Investments

The following table depicts our restricted cash:

	September 30, 2012	December 31, 2011
	(in millions)	
DPC LC facilities (1)	$252	$455
DH LC facility (1)	28	27
DPC Collateral Posting Account (2)	257	132
DMG LC Facility (3)	34	—
DMG Collateral Posting (2)	72	—
Other (4)	3	—
Total restricted cash	$646	$614

(1) Includes cash posted to support the respective letter of credit reimbursement and collateral agreement.

(2) Amounts are restricted and may be used for future collateral posting requirements or released per the terms of the applicable credit agreement. On November 6, 2012, we notified the DPC and DMG lenders that we intend to use the funds in the Collateral Posting Account to repay $325 million of the debt outstanding under the DPC and DMG Credit Agreements.

(3) Includes cash posted to support the letter of credit reimbursement and collateral agreements under the DMG LC facility. Please read "Letter of Credit Facility" above for further discussion.

(4) Includes cash posted to support the letter of credit issued by Dynegy and collateral for the corporate card program.

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

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

Creditor Litigation. On September 21, 2011, an ad-hoc group of our bondholders (the "Avenue Plaintiffs") filed a complaint in the Supreme Court of the State of New York, captioned Avenue Investments, L.P. et al v. Dynegy Inc., Dynegy Holdings, LLC, Dynegy Gas Investments, LLC, Clint C. Freeland, Kevin T. Howell and Robert C. Flexon

(Index No. 652599/11) (the “Avenue Investments Litigation”). The Avenue Plaintiffs challenged the DMG Transfer. On September 27, 2011, the Lease Trustee filed a complaint in the Supreme Court of the State of New York, captioned The Successor Lease Indenture Trustee et al v. Dynegy Inc., Dynegy Holdings, LLC, Dynegy Gas Investments, LLC, E. Hunter Harrison, Thomas W. Elward, Michael J. Embler, Robert C. Flexon, Vincent J. Intrieri, Samuel Merksamer, Felix Pardo, Clint C. Freeland, Kevin T. Howell, John Doe 1, John Doe 2, John Doe 3, Etc. (Index No. 652642/2011) (the “Lease Trustee Litigation”). On November 4, 2011, certain of the PSEG Entities as owner-lessors of the Facilities filed a lawsuit in the Supreme Court of the State of New York, captioned Resources Capital Management Corp., Roseton OL, LLC and Danskammer OL, LLC, v. Dynegy Inc., Dynegy

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Holdings, Inc., Dynegy Holdings, LLC, Dynegy Gas Investments, LLC, Thomas W. Elward, Michael J. Embler, Robert C. Flexon, E. Hunter Harrison, Vincent J. Intrieri, Samuel J. Merksamer, Felix Pardo, Clint C. Freeland, Kevin T. Howell, Icahn Capital LP, and Seneca Capital Advisors, LLC (Index No. 635067/11) (the "PSEG Litigation"). The Avenue Investments Litigation, the Lease Trustee Litigation and the PSEG Litigation are collectively referred to as the "Prepetition Litigation."

The Prepetition Litigation challenged the DMG Transfer. Plaintiffs in all three actions alleged, among other claims, breach of contract, breach of fiduciary duties, and violations of prohibitions on fraudulent transfers in connection with the DMG Transfer and also sought to have the DMG Transfer set aside, and requested unspecified damages as well as attorneys' fees. We filed motions to dismiss the Avenue Investments Litigation and Lease Trustee Litigation on October 31, 2011. The complaint in the PSEG Litigation was never served on the Defendants. On November 7, 2011, Dynegy, DH and certain consenting holders of DH's debt securities agreed to enter into a stipulation staying the Avenue Investments Litigation.

Pursuant to the Settlement Agreement, on the effective date of the Settlement Agreement, the plaintiffs or parties (as applicable) to the Prepetition Litigation filed necessary papers to dismiss and discontinue with prejudice each of the Avenue Investments Litigation, the Lease Trustee Litigation and the PSEG Litigation and any potential claims relating to or arising from disputes with respect to such actions were released by the parties thereto. For additional information see Note 3—Chapter 11 Cases.

On April 2, 2012, a putative class action lawsuit on behalf of bondholders was filed in the Southern District of New York captioned Shirlee Schwartz v. Dynegy Inc., et al, however, plaintiffs voluntarily dismissed the case shortly after filing.

Derivative Litigation. All pending derivative litigations were released in connection with the consummation of the Plan and our emergence from Chapter 11 bankruptcy. The pending derivative litigations that were released included (i) a stockholder derivative action commenced on or about May 4, 2012 in Dallas County Court of the State of Texas captioned Bryce Nicolle v. Robert C. Flexon, et al. (Case No. CC-12-2703-A) (the "Nicolle Litigation") and (ii) a putative stockholder derivative action filed on or about May 16, 2012 in the Court of Chancery of the State of Delaware captioned Cleo A. Zahariades v. Thomas W. Elward, et al., (Case No. 7539-VCP) (the "Zahariades Litigation"). On September 19, 2012, the Court of Chancery dismissed the Zahariades Litigation with prejudice.

Stockholder Litigation Relating to the Blackstone and Icahn Merger Agreements. In connection with the 2010 and 2011 terminations of the merger agreement with an affiliate of The Blackstone Group L.P. ("Blackstone") and the merger agreement with an affiliate of Icahn Enterprises L.P. ("Icahn"), respectively, numerous stockholder lawsuits and one [putative] stockholder derivative lawsuit previously filed in the District Courts of Harris County, Texas, the Southern District of Texas, and the Court of Chancery of the State of Delaware were commenced. In July 2011, the Harris County District Court granted the motion of the plaintiff's lead class counsel for an award of attorney's fees and expenses in the amount of approximately $2 million. We have appealed the decision.

Stockholder Litigation Relating to the 2011 Prepetition Restructuring. In connection with the prepetition restructuring and corporate reorganization of the DH Debtor Entities and their non-debtor affiliates in 2011 (the "2011 Prepetition Restructuring"), and specifically the DMG Transfer, a putative class action stockholder lawsuit captioned Charles Silsby v. Carl C. Icahn, et al., Case No. 12CIV2307 (the "Securities Litigation"), was filed in the United States District Court of the Southern District of New York. The lawsuit challenged certain disclosures made in connection with the

DMG Transfer. We believe the plaintiff's complaint lacks merit and we will oppose the Securities Litigation vigorously. As a result of the filing of the voluntary petition for bankruptcy by Dynegy Inc., this lawsuit was stayed as against Dynegy Inc. and as a result of the confirmation of the Plan, the claims against Dynegy Inc. in the Securities Litigation are permanently enjoined.

On August 24, 2012, the Lead Plaintiff in the Securities Litigation filed an objection to the confirmation of the Plan asserting, among other things, that Lead Plaintiff should be permitted to opt-out of the non-debtor releases and injunctions (the “Non-Debtor Releases”) in the Plan on behalf of all putative class members. We opposed that relief. On October 1, 2012, the Bankruptcy Court ruled that Lead Plaintiff did not have standing to object to the Plan and did not have authority to opt-out of the Non-Debtor Releases on behalf of any other party-in-interest. Accordingly, the Securities Litigation may only proceed against the non-debtor defendants with respect to members of the putative class who individually opted out of the Non-Debtor Releases. The Lead Plaintiff filed a notice of appeal on October 10, 2012.

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Gas Index Pricing Litigation. We, several of our affiliates, our former joint venture affiliate and other energy companies were named as defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications in the 2000-2002 timeframe. Many of the cases have been resolved. All of the remaining cases contain similar claims that individually, and in conjunction with other energy companies, we engaged in an illegal scheme to inflate natural gas prices in four states by providing false information to natural gas index publications. In July 2011, the court granted defendants' motions for summary judgment, thereby dismissing all of plaintiffs' claims. Plaintiffs have appealed the decision to the Ninth Circuit Court of Appeals which heard oral argument on October 19, 2012.

Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company ("IGC") received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC ("PPE"). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award in the District Court of Dallas County, Texas. In March 2010, the Dallas District Court vacated the award, finding that one of the arbitrators had exhibited evident partiality. PPE appealed that decision to the Fifth District Court of Appeals in Dallas, Texas. Coincident with the appeal, IGC filed a claim against PPE seeking recovery of the $17 million plus interest. In September 2010, the Dallas District Court ordered PPE to deposit the $17 million principal in an interest-bearing escrow account jointly owned by IGC and PPE. On August 20, 2012, the Dallas Court of Appeals reversed the Dallas District Court and reinstated the award. IGC and the other respondents' deadline to file a petition for review with the Texas Supreme Court is December 5, 2012. As a result of the uncertainty surrounding the outcome of PPE's appeal, our receivable from PPE is fully accrued for at September 30, 2012.

Pacific Northwest Refund Proceedings. Dynegy Power Marketing, LLC ("DYPM"), along with numerous other companies that sold power in the Pacific Northwest in 2000-2001, are parties to a complaint filed in 2001 with FERC challenging bilateral contract pricing by claiming manipulation of the electricity market in California produced unreasonable prices in the Pacific Northwest. DYPM previously settled all California refund claims, but did not settle with certain complainants seeking refunds in the Pacific Northwest. In December 2011, DYPM received a Notice of Settlement from The City of Seattle ("Seattle") claiming that it paid approximately $2 million to DYPM above the mitigated market clearing price set for the California market in 2000-2001. In May 2012, Seattle made an initial settlement demand of $744 thousand plus interest. DYPM and Seattle reached a settlement whereby DYPM agreed to pay Seattle $180 thousand (inclusive of all interest) to settle all claims between Seattle and DYPM in these proceedings. The settlement agreement was filed with FERC on October 2, 2012, and will be effective upon issuance of a FERC Order approving the settlement agreement. In addition to Seattle's claim, there is the risk for "ripple claims" from other sellers, but the efficacy of these claims is currently being litigated and any potential impact to DYPM from ripple claims is impossible to predict at this stage.

Other Commitments and Contingencies

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, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at September 30, 2012.

Icahn Merger Agreement. On December 15, 2010, Legacy Dynegy's Board of Directors unanimously approved us entering into a merger agreement with an affiliate of Icahn. In connection with the merger agreement, Icahn launched a tender offer on December 22, 2010 for all of our issued and outstanding shares of common stock at $5.50 per share. At the expiration of the tender offer on February 18, 2011, an insufficient number of shares had been tendered in response to the tender offer, and as a result the merger agreement automatically terminated. In connection with the termination, we paid $5 million to Icahn with respect to expenses incurred by Icahn related to the merger agreement in February 2011, with the possibility of additional fees of $11 million had we consummated certain alternative transactions within 18 months of February 18, 2011. This potential obligation expired on August 18, 2012.

Consent Decree. In 2005, we settled a lawsuit filed by the EPA and the United States Department of Justice in the U.S. District Court for the Southern District of Illinois that alleged violations of the Clean Air Act and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating station. A consent decree (the "Consent Decree") was finalized in July 2005. Among other provisions of the Consent Decree, we are required to not operate certain of our power generating facilities after specified dates unless certain emission control equipment is installed. As of September 30, 2012, only Baldwin Unit 2 has material Consent Decree work yet to be performed, which is scheduled to be completed by the end of 2012. We have spent approximately $911 million through September 30, 2012 related to these Consent Decree projects.

Vermilion and Baldwin Groundwater. We have implemented hydrogeologic investigations for the CCR surface impoundment at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility in response to a request by the Illinois EPA. Groundwater monitoring results indicate that these CCR surface impoundments impact onsite groundwater at these sites.

At the request of the Illinois EPA, in late 2011 we initiated an investigation at the Baldwin facility to determine if the facility's CCR surface impoundment impacts offsite groundwater. Results of the offsite groundwater quality investigation at Baldwin, as submitted to the Illinois EPA on April 24, 2012, indicate two localized areas where Class I groundwater standards were exceeded. If these offsite groundwater results are ultimately attributed to the Baldwin CCR surface impoundment and remediation measures are necessary in the future, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. At this time we cannot reasonably estimate the costs of corrective action that ultimately may be required at Baldwin.

On April 2, 2012, we submitted to the Illinois EPA proposed corrective action plans for two of the CCR surface impoundments at the Vermilion facility. The proposed corrective action plans reflect the results of a hydrogeologic investigation, which indicate that the facility's old east and north CCR impoundments impact groundwater quality onsite and that such groundwater migrates offsite to the north of the property and to the adjacent Middle Fork of the Vermilion River. The proposed corrective action plans include groundwater monitoring and recommend closure of both CCR impoundments, including installation of a geosynthetic cover. In addition, we submitted an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. The preliminary estimated cost of the recommended closure alternative for both impoundments, including post-closure care, is approximately $14 million. The Vermilion facility also has a third CCR surface impoundment, the new east impoundment that is lined and is not known to impact groundwater. Although not part of the proposed corrective action plans, if we decide to close the new east impoundment by removing its CCR contents concurrent with the recommended closure alternative for the old east and north impoundments, the preliminary total estimated closure cost for all three impoundments would be approximately $16 million.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In response, we submitted to the Illinois EPA a proposed compliance commitment agreement for each facility. For Vermilion, we proposed to implement the previously submitted corrective action plans and, for Baldwin, we proposed to perform additional studies of hydrogeologic conditions and apply for a groundwater management zone in preparation for submittal, as necessary, of a corrective action plan. In October 2012, the Illinois EPA notified us that it would not issue proposed compliance commitment agreements for Vermilion and Baldwin and, instead, would consider referral of the matters to the Illinois Office of the Attorney General. At this time we cannot reasonably estimate the costs of resolving these matters, but resolution of these matters may cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows.

Cooling Water Intake Permits. The cooling water intake structures at several of our power generation facilities are regulated under Section 316(b) of the Clean Water Act. This provision generally provides that standards set for power generation facilities require that the location, design, construction and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through the NPDES permits or individual SPDES permits on a case-by-case basis.

The environmental groups that participate in our NPDES and SPDES permit proceedings generally argue that only closed cycle cooling meets the BTA requirement. The issuance and renewal of NPDES or SPDES permits for three of our power generation facilities (Danskammer, Moss Landing and Roseton) have been challenged on this basis. The Danskammer SPDES permit, which was renewed and issued in June 2006, does not require installation of a closed cycle cooling system; however, it does require aquatic organism mortality reductions resulting from NYSDEC's determination of BTA requirements under its regulations. All appeals of this permit have been exhausted. The Moss Landing NPDES permit, which was issued in 2000, does not require closed cycle cooling and was challenged by a local environmental group. In August 2011, the Supreme Court of California affirmed the appellate court's decision upholding the permit.

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The Roseton SPDES Permit challenge remains pending. In April 2005, the NYSDEC issued a Draft SPDES Permit renewal for the Roseton plant. The permit is opposed by environmental groups challenging the BTA determination. In October 2006, various holdings in the administrative law judge's ruling admitting the environmental group petitioners to party status and setting forth the issues to be adjudicated in the permit renewal hearing were appealed to the Commissioner of NYSDEC by the petitioners, NYSDEC staff and us. The permit renewal hearing will be scheduled after the Commissioner rules on those appeals. We believe that the petitioners' claims lack merit and we have opposed those claims vigorously. Roseton remains in Chapter 11 bankruptcy and continues to operate its business as a “debtor-in-possession.” The DNE Entities, with the cooperation of the PSEG entities, will use commercially reasonable efforts to sell the Facilities with the proceeds of any sale to pay transaction expenses and to be distributed as set forth in the Settlement Agreement and the Plan. Please see Note 3—Chapter 11 Cases for further information.

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

In September 2012, the Illinois EPA issued a renewal NPDES permit for the Havana Power Station. In October 2012, environmental interest groups filed a petition for review with the Illinois Pollution Control Board challenging the permit. The petitioners allege that the permit does not adequately address the discharge of wastewaters associated with newly installed air pollution control equipment (i.e., a spray dryer absorber and activated carbon injection system to reduce SO_2 and mercury air emissions) at Havana. We dispute the allegations and will defend the permit vigorously. The permit remains in effect during the appeal. While the outcome of the appeal is uncertain, an adverse result could cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations, and cash flows.

Station Power Proceedings. On May 4, 2010, the U.S. Court of Appeals for the D.C. Circuit (the "D.C. Circuit") vacated FERC's acceptance of station power rules for the CAISO market, and remanded the case for further proceedings at FERC. On August 30, 2010, FERC issued an Order on Remand (“remand order”) effectively disclaiming jurisdiction over how the states impose retail station power charges. Due to reservation-of-rights language in the California utilities' state-jurisdictional station power tariffs, the California utilities have argued that FERC's ruling requires California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO's station period program. The remand order could impact FERC's station power policies in all of the organized markets throughout the nation. On February 28, 2011, the FERC issued an order denying rehearing of the remand order. Dynegy Moss Landing, LLC, together with other generators, filed an appeal of the remand order in the D.C. Circuit. Oral argument occurred on September 19, 2012. We expect a decision from the D.C. Circuit in the first quarter of 2013.

On November 18, 2011, PG&E filed with the CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively, which the Company and other generators have challenged. Dynegy Morro Bay, LLC, Dynegy Moss Landing, LLC and Dynegy Oakland, LLC filed a protest with the CPUC objecting to PG&E's filing. That protest is still pending. At this time we cannot predict the outcome of the appeal of the FERC remand order in the D.C. Circuit or the outcome of the CPUC proceeding. While the outcome of these matters is uncertain, any adverse decision by the D.C Circuit Court or the CPUC could cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. However, at this time, we cannot reasonably estimate the costs that may be incurred in connection with the imposition of retail station power charges.

SCE Termination. In May 2012, Southern California Edison ("SCE") notified Dynegy Morro Bay, LLC ("Morro Bay") and Dynegy Moss Landing, LLC ("Moss Landing") that it was terminating certain energy and capacity contracts with those entities. The validity of the purported terminations and subsequent actions by SCE are being disputed by Dynegy. We intend to vigorously pursue all remedies and amounts due to us under these contracts.

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Indemnifications and Guarantees

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

Indemnities

The indemnifications discussed below were settled or discharged pursuant to the Plan and the Confirmation Order with respect to Dynegy. We have accrued approximately $1 million as of September 30, 2012 related to such indemnities.

LS Power Indemnities. In connection with the LS Power Transactions we agreed in the purchase and sale agreement to indemnify LS Power against claims regarding any breaches in our representations and warranties and certain other potential liabilities. Even though Dynegy was discharged from any claims pursuant to the Plan and Confirmation Order, Dynegy Power Generation Inc., DPC, DMG and DYPM remain jointly and severally liable for any indemnification claims (the "LS Indemnity Entities"). Claims for indemnification shall survive until twelve months subsequent to closing with exceptions for tax claims, which shall survive for the applicable statute of limitations plus 30 days, and certain other representations and potential liabilities, which shall survive indefinitely. The indemnifications provided to LS Power are limited to $1.3 billion in total; however, several categories of indemnifications are not available to LS Power until the liabilities incurred in the aggregate are equal to or exceed $15 million and are capped at a maximum of $100 million. Further, the purchase and sale agreement provides in part that the LS Indemnity Entities may not reduce or avoid liability for a valid claim based on a claim of contribution. In addition to the above indemnities related to the LS Power Transactions, the LS Indemnity Entities may be required to indemnify LS Power against claims related to the Riverside/Foothills Project for certain aspects of the project. Namely, LS Power has been indemnified for any disputes that arise as to ownership, transfer of bonds related to the project, and any failure by us to obtain approval for the transfer of the payment in-lieu of taxes program already in place. The indemnities related solely to the Riverside/Foothills Project are capped at a maximum of $180 million and extend until the earlier of the expiration of the tax agreement or December 26, 2026. At this time, no significant expenses have been incurred under these indemnities. Please read Note 5—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—LS Power Transactions in our Form 10-K for further discussion.

West Coast Power Indemnities. In connection with the sale of our 50 percent interest in West Coast Power, LLC ("West Coast Power") to NRG on March 31, 2006, an agreement was executed to allocate responsibility for managing certain litigation and provide for certain indemnities with respect to such litigation. The indemnification agreement in relevant part provides that NRG assumes responsibility for all defense costs and any risk of loss, subject to certain conditions and limitations, arising from a February 2002 complaint filed at FERC by the California Public Utilities

Commission alleging that several parties, including West Cost Power subsidiaries, overcharged the State of California for wholesale power. FERC found the rates charged by wholesale suppliers to be just and reasonable; however, this matter was appealed and ultimately remanded back to FERC for further review. On May 24, 2011 and May 26, 2011, FERC issued two orders in these dockets. The first order denied the request of the California Parties for consolidation of various dockets and denied their request for summary disposition on market manipulation issues. The second order addressed treatment of settled parties and the scope of hearing issues in the ongoing proceedings. In April 2012, NRG and West Coast Power settled all claims brought by the California Parties. The settlement did not exceed NRG's indemnity obligation to Dynegy, therefore, we have no exposure in connection with the settlement.

Targa Indemnities. During 2005, as part of our sale of our midstream business ("DMSLP"), we agreed to indemnify Targa Resources, Inc. ("Targa") against losses it may incur under indemnifications DMSLP provided to purchasers of certain assets, properties and businesses disposed of by DMSLP prior to our sale of DMSLP. Even though Dynegy was discharged from any claims pursuant to the Plan and Confirmation Order, DYPM remains liable for any indemnification claims. No material expense has been incurred under these prior indemnities. An accrual has been recorded of less than $1 million for remediation of groundwater contamination at the Breckenridge Gas Processing Plant sold by DMSLP in 2001. The indemnification provided by DMSLP to the purchaser of the plant has a limit of $5 million.

Illinois Power Indemnities. We have indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power from recovering costs incurred in connection with purchased natural gas and investments in specified items. Even though Dynegy was discharged from any claims pursuant to the Plan and Confirmation Order, Illinova Corporation ("Illinova") remains liable for any indemnification claims. Although there is no absolute limitation on Illinova's liability under this indemnity, the amount of the indemnity is limited to 50 percent of any such losses. We have in the past made certain payments in respect of these indemnities following regulatory action by the ICC, and have established reserves for further potential indemnity claims. Further events, which fall within the scope of the indemnity, may still occur. However, we are not required to accrue a liability in connection with these indemnifications, as management cannot reasonably estimate a range of outcomes or at this time considers the probability of an adverse outcome as only reasonably possible. We intend to contest any proposed regulatory actions.

Other Indemnities. We entered into indemnifications regarding environmental, tax, employee and other representations when completing asset sales such as, but not limited, to the Rolling Hills, Calcasieu, CoGen Lyondell and Heard County power generating facilities. DPC remains the sole entity liable for indemnification claims with respect to Calcasieu and Heard County. As of September 30, 2012, no claims have been made against these indemnities.

Guarantees

Black Mountain Guarantee. Through one of our subsidiaries, we hold a 50 percent ownership interest in Black Mountain (Nevada Cogeneration) (“Black Mountain”), in which our partner is a Chevron subsidiary. Black Mountain owns the Black Mountain power generation facility and has a power purchase agreement with a third party that extends through April 2023. In connection with the power purchase agreement, pursuant to which Black Mountain receives payments which decrease in amount over time, we agreed to guarantee 50 percent of certain payments that may be due to the power purchaser under a mechanism designed to protect it from early termination of the agreement. At September 30, 2012, if an event of default due to early termination had occurred under the terms of the mortgage on the facility entered into in connection with the power purchase agreement, we could have been required to pay the power purchaser approximately $53 million under the guarantee.

VLGC Guarantee. A subsidiary of DH is party to two charter party agreements relating to VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $5 million for the remainder of 2012, and approximately $23 million in aggregate for the period from 2013 through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $5 million and $23 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary term of one charter is through September 2013 while the primary term of the second charter is through September 2014. On January 1, 2003, both VLGCs were sub-chartered to a wholly-owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements. We have guaranteed the obligation of the DH subsidiary related to the charter agreements.

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Note 15—Liabilities Subject to Compromise

A summary of our LSTC as of September 30, 2012 and December 31, 2011 is as follows:

	September 30, 2012	December 31, 2011
	(in millions)	
DNE lease termination claim (1)	$695	$300
Senior Notes:		
8.75 percent due 2012	88	88
7.5 percent due 2015	785	785
8.375 percent due 2016	1,047	1,047
7.125 percent due 2018	175	175
7.75 percent due 2019	1,100	1,100
7.625 percent due 2026	175	175
Subordinated Debentures payable to affiliates, 8.316 percent, due 2027 (2)	55	200
Interest accrued on Senior Notes and Subordinated Debentures as of November 7, 2011 (2)	116	132
Note payable, affiliate (3)	—	10
Administrative Claim (4)	47	—
Other	7	—
Total Liabilities subject to compromise	$4,290	$4,012

(1) The estimated amount of the allowed claim related to the Facilities was increased to approximately $695 million during 2012 as a result of entering into the Settlement Agreement. Please read Note 3—Chapter 11 Cases and Note 5—Merger and Acquisition for further discussion.

(2) The estimated amount of the allowed claim related to the Subordinated Capital Income Securities payable to affiliate, including accrued interest, was reduced to $55 million during the second quarter 2012 as a result of an amendment to the Settlement Agreement. Please read Note 3—Chapter 11 Cases and Note 5—Merger and Acquisition for further discussion.

(3) During the first quarter 2012, it was determined that no claim related to the Note payable, affiliate would be made. Therefore, the estimated amount of the allowed claim was reduced to zero.

(4) Amount represents the fair value of the Administrative Claim that was issued by DH to Dynegy in consideration, among other things, for the DMG Acquisition. The Administrative Claim was transferred to a trust for the benefit of Dynegy's legacy stockholders prior to the Merger.

Note 16—Related Party Transactions

The following tables summarize the Accounts receivable, affiliates, and Accounts payable, affiliates, on our consolidated balance sheet as of December 31, 2011 and cash received (paid) for the three and nine months ended September 30, 2012 related to various agreements with Dynegy Inc., as discussed below. As a result of the Merger, all amounts eliminate in consolidation as of September 30, 2012.

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	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
	Cash Paid	Cash Received
	(in millions)	
Service Agreements	$ (2)	$ 13
EMA Agreements	—	1
Total	$ (2)	$ 14

	December 31, 2011	
	Accounts Receivable, Affiliates	Accounts Payable, Affiliates
	(in millions)	
Service Agreements	$ 4	$ 6
EMA Agreements	22	41
Total	$ 26	$ 47

Service Agreements. Dynegy and certain of our subsidiaries (collectively, the “Providers”) provide certain services (the “Services”) to DCIH and certain of its subsidiaries, and certain of our subsidiaries (collectively, the “Recipients”). Service Agreements between Dynegy and the Recipients, which were entered into in connection with the 2011 Prepetition Restructuring, govern the terms under which such Services are provided.

The Providers act as agents for the Recipients for the limited purpose of providing the Services set forth in the Service Agreements. The Providers may perform additional services at the request of the Recipients, and will be reimbursed for all costs and expenses related to such additional services. Prior to the beginning of each fiscal year in which Services are to be provided pursuant to the Service Agreements, the Providers and the Recipients must agree on a budget for the Services, outlining, among other items, the contemplated scope of the Services to be provided in the following fiscal year and the cost of providing each Service. The Recipients will pay the Providers an annual management fee as agreed in the budget, which shall include reimbursement of out-of pocket costs and expenses related to the provision of the Services and will provide reasonable assistance, such as information, services and materials, to the Providers. As a result of the Merger, transactions executed under the Service Agreements subsequent to September 30, 2012, are no longer considered related party transactions because they eliminate in consolidation.

Energy Management Agreements. Certain of our subsidiaries have entered into an Energy Management Agency Services Agreement (an “EMA”) with DMG. Pursuant to the EMA, our subsidiaries will provide power management services to DMG, consisting of marketing power and capacity, capturing pricing arbitrage, scheduling dispatch of power, communicating with the applicable ISOs or RTOs, purchasing replacement power, and reconciling and settling ISO or RTO invoices. In addition, certain of our subsidiaries will provide fuel management services, consisting of procuring the requisite quantities of fuel and emissions credits, assisting with transportation, scheduling delivery of fuel, assisting DMG with development and implementation of fuel procurement strategies, marketing and selling excess fuel and assisting with the evaluation of present and long-term fuel purchase and transportation options. Our subsidiaries will also assist DMG with risk management by entering into one or more risk management transactions, the purpose of which is to set the price or value any commodity or to mitigate or offset any change in the price or value of any commodity. Our subsidiaries may from time to time provide other services as the parties may agree. Our consolidated statement of operations includes $198 million of power purchased from affiliates, which is reflected in

Revenues for the nine months ended September 30, 2012. Our unaudited condensed consolidated statement of operations also includes $79 million of coal sold to affiliates, which is reflected in Costs of sales, for the nine months ended September 30, 2012. This affiliate activity is presented net of third party activity within Revenue and Cost of sales. Also, please read Note 7—Risk Management Activities, Derivatives and Financial Instruments for derivative balances with affiliates. As a result of the DMG Acquisition, transactions executed under the Energy Management Agreement are not considered related party transactions subsequent to June 5, 2012 because they eliminate in consolidation.

Tax Sharing Agreement. Under U.S. federal income tax law, Dynegy is responsible for the tax liabilities of its subsidiaries, because Dynegy files consolidated income tax returns, which will necessarily include the income and business activities of the ring-fenced entities and Dynegy's other affiliates. To properly allocate taxes among Dynegy and each of its entities, Dynegy and certain of its entities, have entered into a Tax Sharing Agreement under which Dynegy agrees to prepare consolidated returns on behalf of itself and its entities and make all required payments to relevant revenue collection authorities as required by law. Additionally, DPC agreed to make payments to Dynegy of the tax amounts for which DPC and its respective subsidiaries would have been liable if such subsidiaries began business on the restructuring date (August 5, 2011) and were eligible to, and elected to, file a consolidated return on a stand-alone basis beginning on the restructuring date. Further, each of Dynegy GasCo Holdings, LLC, Dynegy Gas Holdco, LLC, and Dynegy Gas Investments Holdings, LLC, agreed to make payments to Dynegy of amounts representing the tax that each such subsidiary would have paid if each began business on the restructuring date and filed a separate corporate income tax return (excluding from income any subsidiary distributions) on a stand-alone basis beginning on the restructuring date.

Cash Management. The Prepetition Restructurings created new companies, some of which are “bankruptcy remote.” These bankruptcy remote entities have an independent manager whose consent is required for certain corporate actions and such entities are required to 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, they conduct business in their own names (other than any business relating to the trading activities of us and our subsidiaries), they observe a higher level of formalities, and they have restrictions on pledging their assets for the benefit of certain other persons. In addition, as part of the Prepetition Restructurings, some companies within our portfolio were reorganized into “ring-fenced” groups. The upper-level companies in such ring-fenced groups are bankruptcy-remote entities governed by limited liability company operating agreements which, in addition to the bankruptcy remoteness provisions described above, contain certain additional restrictions prohibiting any material transactions with affiliates other than the direct and indirect subsidiaries within the ring-fenced group without independent manager approval.

Pursuant to our Cash Management Agreement, our ring-fenced entities maintain cash accounts separate from those of our non-ring-fenced entities. Cash collected by a ring-fenced entity is not swept into accounts held in the name of any non-ring-fenced entity and cash collected by a non-ring-fenced entity is not swept into accounts held in the name of any ring-fenced entity. The cash in deposit accounts owned by a ring-fenced entity is not used to pay the debts and/or operating expenses of any non-ring-fenced entity, and the cash in deposit accounts owned by a non-ring-fenced entity is not used to pay the debts and/or operating expenses of any ring-fenced entity. There were no material payments for the three and nine months ended September 30, 2012 related to the Cash Management Agreement.

DMG Transfer and Undertaking Agreement. During the nine months ended September 30, 2012, we recognized $24 million in interest income related to the Undertaking Agreement which is included in Other income and expense, net, in our unaudited condensed consolidated statement of operations. We did not recognize any interest income subsequent to March 31, 2012 as we impaired the value of the Undertaking as of March 31, 2012. We received payments of $48 million from Legacy Dynegy prior to the termination of the Undertaking Agreement. We had approximately $8 million as of December 31, 2011 in interest receivable related to the undertaking, which is reflected in Interest receivable, affiliates on our consolidated balance sheet. The Undertaking Agreement was terminated on June 5, 2012 in connection with the Settlement Agreement. Please read Note 3—Chapter 11 Cases for further discussion.

Note payable, affiliates. On August 5, 2011, Coal Holdco made a loan to DH of $10 million with a maturity of 3 years and an interest rate of 9.25 percent per annum.

The Note payable, affiliate was written off during the first quarter 2012 as it was determined that no claim would be filed related to the note.

Accounts receivable, affiliates. We have historically recorded intercompany transactions in the ordinary course of business, including the reallocation of deferred taxes between legal entities in accordance with applicable IRS regulations. As a result of such transactions, we have recorded and adjusted over time an affiliate receivable balance in the amount of $846 million at December 31, 2011. This receivable was classified within equity as there were no defined payment terms, it was not evidenced by any promissory note, and there was never an intent for payment to occur. The Accounts receivable, affiliate was settled on June 5, 2012. Please read Note 3—Chapter 11 Cases for further discussion.

DMG Acquisition. On June 5, 2012, pursuant to the Settlement Agreement, Legacy Dynegy and DH consummated the DMG Acquisition. Please read Note 5—Merger and Acquisition for further discussion.

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Merger. On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy with Legacy Dynegy continuing as the surviving legal entity of the Merger. Please read Note 5—Merger and Acquisition for further discussion.

Note 17—Income Taxes

Effective Tax Rate. 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions, except rates)			
Income tax benefit (expense)	$2	$(24)	$9	$109
Effective tax rate	5%	NM	1%	25%

For the three months ended September 30, 2012 and 2011, our overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

For the nine months ended September 30, 2012, the difference between the effective rate of one percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of September 30, 2012, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

For the nine months ended September 30, 2011, the difference between the effective rates of 25 percent and the statutory rate of 35 percent resulted primarily from the impact of state taxes including a benefit of $6 million related to an increase in state NOLs due to the acceptance of amended returns, which we filed as a result of a change in a tax position, partially offset by an expense of $2 million related to an increase in the Illinois statutory rate.

Note 18—Employee Compensation, Savings and Pension Plans

Dynegy sponsors and administers defined benefit plans and defined contribution plans for the benefit of our employees and also provides other post retirement benefits to retirees who meet age and service requirements which are more fully described in Note 24—Employee Compensation, Savings and Pension Plans in our Form 10-K.

The following are inclusive of net periodic benefit costs related to the Dynegy multi-employer pension and other post-retirement benefit plans. The Dynegy sponsored plans were considered DH plans until the DMG Transfer and again upon the DMG Acquisition as DH was the sole participant in the plans during that period. After the DMG Transfer and prior to the DMG Acquisition, we accounted for our participation in these plans as a participant in a multi-employer plan. Please read Note 5—Merger and Acquisition, and Note 4—DMG Transfer and Undertaking Agreement for further discussion.

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Components of Net Periodic Benefit Cost. The components of net periodic benefit cost were:

	Pension Benefits		Other Benefits	
	Three Months Ended September 30,			
	2012	2011	2012	2011
	(in millions)			
Service cost benefits earned during period	$2	$2	$1	$1
Interest cost on projected benefit obligation	3	2	—	1
Expected return on plan assets	(4)	(3)	—	—
Recognized net actuarial loss	2	1	—	—
Net periodic benefit cost	$3	$2	$1	$2

	Pension Benefits		Other Benefits	
	Nine Months Ended September 30,			
	2012	2011	2012	2011
	(in millions)			
Service cost benefits earned during period	$3	$8	$2	$2
Interest cost on projected benefit obligation	4	10	1	3
Expected return on plan assets	(5)	(11)	—	—
Recognized net actuarial loss	2	4	—	—
Net periodic benefit cost	$4	$11	$3	$5

Contributions. During the nine months ended September 30, 2012, we made $16 million in contributions through certain service agreements to our pension plans and $1 million to our other post-retirement benefit plans. We made $9 million in contributions to our pension plans and $1 million to other post-retirement benefit plans during the nine months ended September 30, 2011. We expect to make $4 million in contributions to our pension plans and to our other benefit plans during the remainder of 2012.

Note 19—Segment Information

We report our results as three segments: (i) the Coal segment ("Coal"); (ii) the Gas segment ("Gas") and (iii) the Dynegy Northeast segment ("DNE").

On September 1, 2011, we completed the DMG Transfer; therefore, the results of our Coal segment were not included from September 1, 2011 through September 30, 2011. On June 5, 2012, we completed the DMG Acquisition; therefore the results of our Coal segment were included for the period of June 6, 2012 through September 30, 2012. Please read Note 5—Merger and Acquisition for further discussion of the DMG Acquisition.

Reportable segment information, including inter-company transactions accounted for at prevailing market rates, for the three and nine months ended September 30, 2012 and 2011 is presented below:

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Segment Data as of and for the Three Months Ended September 30, 2012
(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Unaffiliated revenues:					
Domestic	$126	$317	$34	$—	$477
Total revenues	$126	$317	$34	$—	$477
Depreciation and amortization	$(9)	$(35)	$—	$(1)	$(45)
General and administrative expense	(7)	(14)	(1)	(7)	(29)
Operating income (loss)	$(53)	$52	$(3)	$(9)	$(13)
Bankruptcy reorganization charges	—	—	—	18	18
Other items, net	—	—	—	—	—
Interest expense					(48)
Loss before income taxes					(43)
Income tax benefit					2
Net loss					$(41)
Identifiable assets (domestic)	$1,176	$4,378	$52	$365	$5,971
Capital expenditures	$(22)	$(3)	$—	$(1)	$(26)

DYNEGY INC.
DEBTOR-IN-POSSESSION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2012 and 2011

Segment Data as of and for the Three Months Ended September 30, 2011
(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Unaffiliated revenues:					
Domestic	$132	$298	$37	$—	$467
Total revenues	$132	$298	$37	$—	$467
Depreciation and amortization	$(26)	$(33)	$—	$(1)	$(60)
Impairment and other charges	—	—	(1)	(2)	(3)
General and administrative expense	(8)	(17)	(2)	2	(25)
Operating income (loss)	$12	$28	$(26)	$—	$14
Other items, net	2	—	—	5	7
Interest expense					(105)
Debt extinguishment costs					(21)
Loss before income taxes					(105)
Income tax benefit					(24)
Net loss					$(129)
Identifiable assets (domestic)	$—	$6,327	$460	$1,490	$8,277
Capital expenditures	$(29)	$(6)	$—	$—	$(35)

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DYNEGY INC.
DEBTOR-IN-POSSESSION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2012 and 2011

Segment Data as of and for the Nine Months Ended September 30, 2012
(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Unaffiliated revenues:					
Domestic	$166	$815	$61	$—	$1,042
Total revenues	$166	$815	$61	$—	$1,042
Depreciation and amortization	$(13)	$(91)	$—	$(6)	$(110)
General and administrative expense	(12)	(44)	(3)	(7)	(66)
Operating income (loss)	$(75)	$84	$(23)	$(13)	$(27)
Impairment of Undertaking receivable, affiliate	—	—	—	(832)	(832)
Bankruptcy reorganization charges	—	—	(589)	337	(252)
Other items, net	5	2	—	24	31
Interest expense					(121)
Loss before income taxes					(1,201)
Income tax benefit					9
Net loss					$(1,192)
Identifiable assets (domestic)	$1,176	$4,378	$52	$365	$5,971
Capital expenditures	$(33)	$(23)	$—	$(7)	$(63)

DYNEGY INC.
DEBTOR-IN-POSSESSION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2012 and 2011

Segment Data as of and for the Nine Months Ended September 30, 2011
(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Unaffiliated revenues:					
Domestic	$460	$743	$95	$—	$1,298
Total revenues	$460	$743	$95	$—	$1,298
Depreciation and amortization	$(156)	$(100)	$—	$(5)	$(261)
Impairment and other charges	—	—	(2)	(4)	(6)
General and administrative expense	(27)	(42)	(9)	(9)	(87)
Operating income (loss)	$(65)	$9	$(65)	$(19)	$(140)
Other items, net	2	1	—	8	11
Interest expense					(283)
Debt extinguishment costs					(21)
Loss before income taxes					(433)
Income tax benefit					109
Net loss					$(324)
Identifiable assets (domestic)	$—	$6,327	$460	$1,490	$8,277
Capital expenditures	$(115)	$(47)	$(1)	$—	$(163)

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DYNEGY INC.

MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS

For the Interim Periods Ended September 30, 2012 and 2011

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

The following discussion should be read together with the unaudited condensed 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 report the results of our power generation business as three separate segments in our unaudited condensed consolidated financial statements: (i) Coal; (ii) Gas and (iii) DNE. On September 1, 2011, we completed the DMG Transfer; therefore, the results of our Coal segment are only included in our consolidated results for the period from January 1, 2011 through August 31, 2011. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition; therefore, the results of our Coal segment are only included for the period from June 6, 2012 through September 30, 2012.

Merger. On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy with Legacy Dynegy continuing as the surviving legal entity in the Merger. Immediately prior to the Merger, Legacy Dynegy had no substantive operations, and our Coal, Gas and DNE operations were primarily conducted through subsidiaries of DH. Further, as a result of the DH Chapter 11 Cases in 2011, under applicable accounting standards, Dynegy was no longer deemed to have a controlling financial interest in DH and its wholly-owned subsidiaries; therefore, DH and its consolidated subsidiaries were no longer consolidated in Dynegy's consolidated financial statements as of November 7, 2011. As a result of these factors, the Merger was accounted for in a manner similar to a reverse merger, whereby DH is the surviving accounting entity for financial reporting purposes. Further, the net assets contributed by Legacy Dynegy, which amounted to $54 million, did not constitute a business and were therefore treated in a manner similar to a recapitalization and were credited to stockholder's equity. Prior to the Merger, DH was organized as a limited liability company and the capital structure of DH did not change until September 30, 2012. Although Legacy Dynegy's shares were publicly traded, DH did not have any publicly traded shares for any period presented; therefore, no earnings per share is presented on our unaudited condensed consolidated statement of operations for any period presented.

Chapter 11 Cases. On November 7, 2011, the DH Debtor Entities filed the DH Chapter 11 Cases. On July 6, 2012, Dynegy commenced the Dynegy Chapter 11 Case. On July 12, 2012, Dynegy and DH, as co-plan proponents, filed the Plan for Dynegy and DH and the related disclosure statement with the Bankruptcy Court. On September 10, 2012, the Bankruptcy Court entered an order confirming the Plan. As discussed above, on September 30, 2012, pursuant to the terms of the Plan, DH and Dynegy consummated the Merger, with Dynegy continuing as the surviving entity. On the Effective Date, we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. At such time, Dynegy's newly issued common stock and warrants were listed on the New York Stock Exchange and director nominees selected by certain creditor parties, as determined by the Plan and confirmed by the Bankruptcy Court, were appointed as the new Board of Directors of Dynegy.

The DNE Entities remain in Chapter 11 bankruptcy and continue to operate their businesses as “debtors-in-possession.” The DNE Entities, with the cooperation of the PSEG entities, will use commercially reasonable efforts to sell the Facilities with the proceeds of any sale to pay transaction expenses and to be distributed as set forth in the Settlement Agreement and the Plan.

Going Concern. Our previously issued consolidated financial statements included cautionary language about our ability to continue as a going concern due to the Chapter 11 Cases. Dynegy emerged from Chapter 11 protection on October 1, 2012 and we believe we have sufficient liquidity to fund our operations. Please read Note 3—Chapter 11 Cases for further information.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, fixed capacity payments and contractual obligations, capital expenditures (including required environmental expenditures) and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll.

Our primary sources of internal liquidity are cash flows from operations and cash on hand. Cash on hand includes cash proceeds from the DPC Credit Agreement and the DMG Credit Agreement, which is limited in use and distribution as further described in footnote 1 to the liquidity table below.

Our primary sources of external liquidity are proceeds from capital market transactions to the extent we engage in such transactions.

Current Liquidity. The following tables summarize our liquidity position at November 2, 2012 and September 30, 2012.

	November 2, 2012			
	DPC	DMG	Other (1)	Total
	(in millions)			
LC capacity, inclusive of required reserves (2)	239	27	28	$294
Less: Required reserves (2)	(8)	(1)	(1)	(10)
Less: Outstanding letters of credit	(221)	(23)	(27)	(271)
LC availability	10	3	—	13
Cash and cash equivalents	41	29	359	429
Collateral posting account (3)	285	76	—	361
Total available liquidity (4)	$336	$108	$359	$803

	September 30, 2012			
	DPC	DMG	Other (1)	Total
	(in millions)			
LC capacity, inclusive of required reserves (2)	$252	$34	$28	$314
Less: Required reserves (2)	(7)	(1)	(1)	(9)
Less: Outstanding letters of credit	(233)	(29)	(27)	(289)
LC availability	12	4	—	16
Cash and cash equivalents	44	47	586	677
Collateral Posting Account (3)	257	72	—	329
Total available liquidity (4)	$313	$123	$586	$1,022

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(1) Other cash consists of zero million and $123 million at Coal Holdco; $1 million and $156 million at Dynegy Gas Holdco, LLC; $5 million and $15 million at Dynegy Administrative Services Company; $332 million and $270 million at the Company; and $21 million and $22 million at Dynegy Northeast Generation, Inc. as of November 2, 2012 and September 30, 2012.

(2)

The LC facilities were collateralized with cash proceeds received under our existing credit agreements. The amount of the LC availability plus any unused required reserves of 3 percent of the unused capacity, may be withdrawn from the LC facilities with three days written notice for unrestricted use in the operations of the applicable entity. LC capacity as of November 2, 2012 and September 30, 2012 reflects a reduction in capacity for DMG and DPC following the requested release of unused cash collateral from restricted cash. Actual commitment amounts under each credit agreement have not been reduced, and DMG and DPC can increase the LC capacity up to the original commitment amount in the future by posting additional cash collateral.

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(3) The collateral posting account included in the above liquidity tables is restricted per the DMG Credit Agreement and the DPC Credit Agreement and may be used for future collateral posting requirements or released per the terms of the applicable credit agreement.
(4) Does not reflect our ability to use the first lien structure as described in "Collateral Postings" below.

Both the DPC and DMG Credit Agreements contain provisions that permit pre-payment of up to $250 million and $100 million, respectively, at par. We intend to use restricted cash contained in the Collateral Posting Accounts at DPC and DMG to repay lenders $325 million in November 2012.

DPC and DMG Restricted Payments. The DPC Credit Agreement and the DMG Credit Agreement allow distributions by DPC and DMG to their parents of up to $135 million and $90 million per year, respectively, provided the borrower and its subsidiaries possess at least $50 million of unrestricted cash and short-term investments as of the date of the proposed distribution. There were no distributions by DPC or DMG during the first half of 2012.

Collateral Postings. We use a significant portion of our capital resources in the form of cash and letters of credit to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our collateral postings to third parties by legal entity at November 2, 2012, September 30, 2012, and December 31, 2011:

	November 2, 2012	September 30, 2012	December 31, 2011
	(in millions)		
Dynegy Power, LLC:			
Cash	$53	$75	$44
Letters of credit	221	234	386
Total DPC	$274	$309	$430
Dynegy Midwest Generation, LLC:			
Cash (1)	$19	$16	$—
Letters of credit	23	29	—
Total DMG	$42	$45	$—
Other			
Cash	$3	$3	$—
Letters of credit	27	27	26
Total DH	$30	$30	$26
Total	$346	$384	$456

(1) Includes Broker margin account on our unaudited condensed consolidated balance sheets, as well as other collateral postings included in Prepayments and other current assets on our unaudited condensed consolidated balance sheets.

The change in letters of credit postings from December 31, 2011 to September 30, 2012 is due to a decision to post cash as collateral from the Collateral Posting Accounts instead of letters of credit, reductions due to ordinary course settlements and market conditions, use of first liens, and the cancellation of certain contracts. Collateral postings decreased from September 30, 2012 to November 2, 2012 primarily due to settlements and market conditions.

In addition to cash and letters of credit posted as collateral, we have granted additional permitted first priority liens on the assets already subject to first priority liens under the DMG Credit Agreement and the DPC Credit Agreement. The additional liens were granted as collateral under certain of our derivative agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to the counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under the DMG Credit Agreement and the DPC Credit Agreement.

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The fair value of DMG's derivatives collateralized by first priority liens included liabilities of $25 million and $16 million at November 2, 2012 and September 30, 2012, respectively. The fair value of DPC's derivatives collateralized by first priority liens included liabilities of $82 million and $89 million at November 2, 2012 and September 30, 2012, respectively.

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

Operating Activities

Historical Operating Cash Flows. Our cash flow used by operations totaled $37 million for the nine months ended September 30, 2012. During the period, our power generation business used cash of $56 million from the operation of our power generation facilities primarily due to increased collateral postings to satisfy our counterparty collateral demands and other negative working capital. Corporate and other operations provided cash of approximately $19 million primarily due to interest payments received from Legacy Dynegy on the Undertaking, partially offset by payments to advisors and other general and administrative expenses.

Our cash flow used in operations totaled $4 million for the nine months ended September 30, 2011. During the period, our power generation business provided positive cash flow from the operation of our power generation facilities, offset by a use of cash from corporate and other operations primarily due to negative working capital.

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, our ability to achieve the cost savings contemplated in our cost reduction programs and our ability to capture value associated with commodity price volatility.

Investing Activities

Capital Expenditures. We had approximately $63 million and $163 million in capital expenditures during the nine months ended September 30, 2012 and 2011, respectively. Our capital spending by reportable segment was as follows:

	For the Nine Months Ended September 30,	
	2012	2011
	(in millions)	
Coal (1)	$33	$115
Gas	23	47
DNE	—	1
Other and eliminations	7	—
Total	$63	$163

(1) On September 1, 2011, we completed the DMG Transfer. On June 5, 2012, we completed the DMG Acquisition. Therefore, capital expenditures are included only from June 6, 2012 to September 30, 2012 for the nine months ended September 30, 2012 and from January 1, 2011 through August 31, 2011 for the nine months ended September 30, 2011. For the nine months ended September 30, 2012 and 2011, including the periods that Coal was included in our

consolidated financial statements, Coal capital expenditures were $75 million and $137 million, respectively.

Other Investing Activities. In connection with the DMG Acquisition on June 5, 2012, we acquired $256 million in cash. During the nine months ended September 30, 2012, we received $16 million in principal payments related to the Undertaking and there was a $88 million cash inflow related to restricted cash balances during the nine months ended September 30, 2012.

There was a $441 million cash outflow related to the DMG Transfer on September 1, 2011. There was a $178 million cash inflow related to restricted cash balances during the nine months ended September 30, 2011 primarily due to (i) the release of $850 million upon the termination of our former Fifth Amended and Restated Credit Agreement, (ii) the release of $43 million upon the completion of the Sithe Tender Offer, and (iii) the release of $50 million related to the expiration of a security and deposit agreement. These decreases in restricted cash were partially offset by increases of $631 million, $103 million and

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$27 million associated with the DPC Credit Agreement, the DMG Credit Agreement, and a Letter of Credit Reimbursement and Collateral Agreement, respectively.

Cash outflow for purchases of short-term investments during the nine months ended September 30, 2011 totaled $269 million. Cash inflow related to maturities of short-term investments for the nine months ended September 30, 2011 was $444 million. Other cash flow from investing activities during the nine months ended September 30, 2011 included $10 million of property insurance claim proceeds.

Financing Activities

Historical Cash Flow from Financing Activities. Cash flow provided by financing activities totaled $16 million for the nine months ended September 30, 2012 due to $27 million in connection with the recapitalization of Legacy Dynegy, offset by $11 million in repayments of borrowings on the DMG and the DPC Credit Agreements.

Cash flow provided by financing activities totaled $378 million for the nine months ended September 30, 2011. Proceeds from long-term borrowings of $2,022 million, net of $44 million of debt issuance costs, consisted of:

- $1,078 million of cash proceeds from the $1,100 million DPC Credit Agreement;
- $588 million of cash proceeds from the $600 million DMG Credit Agreement;
- $400 million from borrowings under the revolving portion of our former Fifth Amended and Restated Credit Agreement.

These proceeds were partially offset by repayments of borrowings of $1,623 million, which consisted of the following:

- $850 million term facility under our former Fifth Amended and Restated Credit Agreement;
- $400 million under the revolving portion of our former Fifth Amended and Restated Credit Agreement;
- $80 million in repayment of our 6.875 percent senior notes;
- $68 million in repayment of our Tranche B term loan; and
- $225 million of repayments of borrowings on Sithe senior debt.

We also paid debt extinguishment costs of $21 million in connection with the termination of the Sithe senior debt.

Financing Trigger Events. The debt instruments and other financial obligations related to our subsidiaries which did not file for bankruptcy include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events connected to the financing of our non-debtor subsidiaries include the violation of covenants, 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 change of control provisions. Our non-debtor subsidiaries 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.

The DH Debtor Entities have entered into and obtained Bankruptcy Court approval of a $15 million Intercompany Revolving Loan Agreement which includes certain covenants and requirements that, if not met, could require early payment or similar actions.

Financial Covenants. We are not subject to any financial covenants.

Credit Ratings

Our credit rating status is currently “non-investment grade” and our current ratings are as follows:

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	Standard & Poor	Moody’s	Fitch
Dynegy Inc.			
Corporate Family Rating (1)	NR	B2	NR
DPC			
Senior Secured (1)	NR	B2	B

(1) The last update on Dynegy from Standard & Poor was on July 6, 2012. There has not been an update since Dynegy's emergence from Chapter 11 on October 1, 2012. The ratings on the Legacy Dynegy structure are not applicable.

Disclosure of Contractual Obligations and Contingent Financial Commitments

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

The following table summarized our contractual obligations acquired in connection with the DMG Acquisition. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Total	Remainder of 2012	2013-2014	2015-2016	2017 and Beyond
Long-term debt (1)	$ 594	$ 2	$ 12	$ 580	$ —
Interest payments on debt (1)	213	14	109	90	—
Coal transportation (2)	186	—	20	42	124
Pension funding obligations	38	4	34	—	—
Total contractual obligations	$ 1,031	$ 20	$ 175	$ 712	$ 124

(1) The amounts included in Long-term debt and Interest payments on debt relate to the DMG Credit Agreement. Please see Note 13—Debt for further discussion.
(2) In August 2012, we executed new coal transportation contracts which take effect when our current contracts expire. The amounts included in Coal transportation reflect our minimum purchase obligations based on the terms of the contracts.

In addition, we also acquired contingent financial obligations of $29 million related to letters of credit issued by DMG. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

Please read “Disclosure of Contractual Obligations and Contingent Financial Commitments” in our Form 10-K for further discussion. Please read “Uncertainty of Forward-Looking Statements and Information” for additional factors that could impact our future operating results and financial condition.

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RESULTS OF OPERATIONS

Overview

In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three and nine months ended September 30, 2012 and 2011. We have included our outlook for each segment at the end of this section.

On September 1, 2011, we completed the DMG Transfer. Therefore, the results of our Coal segment (including DMG) were included for the period of January 1, 2011 through August 31, 2011. Additionally, on June 5, 2012, we reacquired DMG through the DMG Acquisition. Therefore, the results of our Coal segment (including DMG) are included for the period of June 6, 2012 through September 30, 2012.

Non-GAAP Performance Measures

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

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

EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit), and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of assets, (ii) the impacts of mark-to-market changes on economic hedges related to our generation portfolio, (iii) the impact of impairment charges and certain other costs such as those associated with the internal reorganization, (iv) amortization of intangible assets and liabilities, and (v) income or expense on up front premiums received or paid for financial options in periods other than the strike periods. Our Adjusted EBITDA for the three and nine months ended September 30, 2011, is based on our prior methodology which did not include (i) adjustments for up front premiums, (ii) amortization of intangible assets related to the Sithe acquisition, or (iii) mark-to-market adjustments for financial activity not related to our generation portfolio. Enterprise-wide Adjusted EBITDA includes the Adjusted EBITDA of our parent, Legacy Dynegy, for the periods prior to the Merger.

We believe EBITDA and Adjusted EBITDA provide a meaningful representation of our operating performance. We consider EBITDA as another way to measure financial performance on an ongoing basis. Enterprise-wide 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 gains and losses on sales of assets, and other items that could be considered "non-operating" or "non-core" in nature. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers and evaluate overall financial performance, we believe they provide useful information for our investors. In addition, many analysts, fund managers and other stakeholders that communicate with us typically request our financial results in an EBITDA and Adjusted EBITDA format presented on an enterprise-wide basis.

As prescribed by the SEC, when 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 Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

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Consolidated Summary Financial Information — Three Months Ended September 30, 2012

The following table provides summary financial data regarding our consolidated results of operations for the three months ended September 30, 2012 and 2011, respectively:

	Three Months Ended September 30,			
	2012	2011	$ Change	% Change
	(dollars in millions)			
Revenues	$477	$467	$10	2 %
Cost of sales	(332)	(278)	(54)	(19)%
Gross margin, exclusive of depreciation shown separately below	145	189	(44)	(23)%
Operating and maintenance expense, exclusive of depreciation shown separately below	(84)	(87)	3	3 %
Depreciation and amortization expense	(45)	(60)	15	25 %
Impairment and other charges	—	(3)	3	100 %
General and administrative expenses	(29)	(25)	(4)	(16)%
Operating income (loss)	(13)	14	(27)	(193)%
Interest expense	(48)	(105)	57	54 %
Debt extinguishment costs	—	(21)	21	100 %
Bankruptcy reorganization charges	18	—	18	100 %
Other income and expense, net	—	7	(7)	(100)%
Loss before income taxes	(43)	(105)	62	59 %
Income tax benefit (expense)	2	(24)	26	108 %
Net loss	$(41)	$(129)	$88	68 %

The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended September 30, 2012 and 2011, respectively:

	Three Months Ended September 30, 2012				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$126	$317	$34	$—	$477
Cost of sales	(122)	(190)	(20)	—	(332)
Gross margin, exclusive of depreciation shown separately below	4	127	14	—	145
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(41)	(26)	(16)	(1)	(84)
Depreciation and amortization expense	(9)	(35)	—	(1)	(45)
General and administrative expense	(7)	(14)	(1)	(7)	(29)
Operating income (loss)	$(53)	$52	$(3)	$(9)	$(13)

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	Three Months Ended September 30, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$132	$298	$37	$—	$467
Cost of sales	(60)	(188)	(30)	—	(278)
Gross margin, exclusive of depreciation shown separately below	72	110	7	—	189
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(26)	(32)	(30)	1	(87)
Depreciation and amortization expense	(26)	(33)	—	(1)	(60)
Impairment and other charges	—	—	(1)	(2)	(3)
General and administrative expense	(8)	(17)	(2)	2	(25)
Operating income (loss)	$12	$28	$(26)	$—	$14

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The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended September 30, 2012:

	Three Months Ended September 30, 2012				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss					$(41)
Income tax benefit					(2)
Interest expense					48
Bankruptcy reorganization charges					(18)
Operating income (loss)	$(53)	$52	$(3)	$(9)	$(13)
Depreciation and amortization expense	9	35	—	1	45
Bankruptcy reorganization charges	—	—	—	18	18
EBITDA	(44)	87	(3)	10	50
Bankruptcy reorganization charges	—	—	—	(18)	(18)
Restructuring costs	1	2	—	6	9
Mark-to-market (income) loss, net	11	(53)	1	—	(41)
Amortization of intangible assets (1)	37	9	—	—	46
Adjusted EBITDA	5	45	(2)	(2)	46
Adjusted EBITDA from Legacy Dynegy (2)	—	—	—	2	2
Enterprise-wide Adjusted EBITDA	$5	$45	$(2)	$—	$48

(1) In connection with the DMG Acquisition, we recorded intangible assets and liabilities related to rail transportation and coal contracts, respectively. The amount in the Gas segment is related to the intangible assets related to the Sithe acquisition.

(2) Our 2012 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the three months ended September 30, 2012. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the three months ended September 30, 2012 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating income:

	Three Months Ended September 30, 2012				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Operating income	$—	$—	$—	$25	$25
Bankruptcy reorganization charges	—	—	—	(8)	(8)
EBITDA	—	—	—	17	17
Bankruptcy reorganization charges	—	—	—	8	8
Restructuring charges	—	—	—	(23)	(23)
Adjusted EBITDA from Legacy Dynegy	$—	$—	$—	$2	$2

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The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended September 30, 2011:

	Three Months Ended September 30, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss					$(129)
Income tax expense					24
Interest expense and debt extinguishment costs					126
Other items, net					(7)
Operating income (loss)	$12	$28	$(26)	$—	$14
Other items, net	2	—	—	5	7
Depreciation and amortization expense	26	33	—	1	60
EBITDA	40	61	(26)	6	81
Merger agreement termination fee, restructuring costs and other expenses	(1)	9	1	(4)	5
Mark-to-market (income) loss, net	4	(18)	24	4	14
Adjusted EBITDA	43	52	(1)	6	100
Adjusted EBITDA from Legacy Dynegy (1)	7	—	—	(1)	6
Enterprise-wide Adjusted EBITDA	$50	$52	$(1)	$5	$106

(1) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the three months ended September 30, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from September 1, 2011 through September 30, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the three months ended September 30, 2011 and the Coal segment for the period from September 1, 2011 through September 30, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating loss:

	Three Months Ended September 30, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Operating loss	$(8)	$—	$—	$(1)	$(9)
Depreciation and amortization expense	13	—	—	—	13
Other items, net	(2)	—	—	(5)	(7)
EBITDA	3	—	—	(6)	(3)
Restructuring charges	5	—	—	5	10
Mark-to-market income, net	(1)	—	—	—	(1)
Adjusted EBITDA from Legacy Dynegy	$7	$—	$—	$(1)	$6

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Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $10 million from $467 million for the three months ended September 30, 2011 to $477 million for the three months ended September 30, 2012. An increase of $16 million is due to including the Coal results for three months in 2012 compared to two months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The increase from the DMG Transfer and subsequent DMG Acquisition was partially offset by lower market prices and volumes generated, as well as less premiums paid in 2012 compared to 2011 and the financial settlement of derivative instruments which in turn was offset by higher mark-to-market gains on forward sales, as further described below.

Cost of Sales. Cost of sales increased by $54 million from $278 million for the three months ended September 30, 2011 to $332 million for the three months ended September 30, 2012. Of this increase, $39 million is due to including the Coal results for three months in 2012 compared to two months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The remaining increase is primarily due to the amortization of intangibles recorded in connection with the DMG Acquisition.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense decreased by $3 million from $87 million for the three months ended September 30, 2011 to $84 million for the three months ended September 30, 2012. The decrease is primarily due to a $14 million reduction in lease expense associated with the rejection of the leases of the Roseton and Danskammer power generation facilities and a $2 million reduction in the demolition reserve at Moss Landing, offset by a $17 million increase primarily due to including the Coal results for three months in 2012 compared to two months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012.

Depreciation and Amortization Expense. Depreciation expense decreased by $15 million from $60 million for the three months ended September 30, 2011 to $45 million for the three months ended September 30, 2012. The decrease is primarily due to $21 million reduction due to a lower basis in the Coal assets as a result of the DMG Acquisition. This decrease was partially offset by a $4 million increase due to including the Coal results for three months in 2012 compared to two months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012.

General and Administrative Expenses. General and administrative expenses increased by $4 million from $25 million for the three months ended September 30, 2011 to $29 million for the three months ended September 30, 2012. The increase is primarily due to including the Coal results for three months in 2012 compared to two months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012.

Bankruptcy Reorganization Charges. Bankruptcy reorganization charges for the three months ended September 30, 2012 resulted in a gain of approximately $18 million. The gain is primarily the result of a decrease of approximately $26 million related to the change in value of the Administrative Claim, partially offset by $7 million for expenses incurred related to our advisors. There were no such charges during the three months ended September 30, 2011. Please read Note 3—Chapter 11 Cases and Note 18—Employee Compensation, Savings and Pension Plans for further discussion.

Interest Expense. Interest expense totaled $48 million and $105 million for the three months ended September 30, 2012 and 2011, respectively. The decrease was primarily due to the absence of interest related to our unsecured notes and debentures in the three months ended September 30, 2012 as a result of the DH Chapter 11 Cases and the repayment of our prior credit agreement in 2011, offset by higher interest on the DPC and DMG Credit Agreements which have higher borrowing rates.

Debt Extinguishment Costs. Debt extinguishment costs totaled $21 million for the three months ended September 30, 2011 and were incurred in connection with the termination of the Sithe senior debt. There were no such charges during the three months ended September 30, 2012.

Income Tax (Expense) Benefit. We reported an income tax benefit of $2 million for the three months ended September 30, 2012, compared to an income tax expense from continuing operations of $24 million for the three months ended September 30, 2011. The effective tax rate in 2012 was 5 percent, compared to zero for 2011.

For the three months ended September 30, 2012 and 2011, our overall effective tax rate on continuing operations was different than the statutory rate of 35 percent as a result of a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

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Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA decreased by $58 million from $106 million for the three months ended September 30, 2011 to $48 million for the three months ended September 30, 2012. The decrease is primarily due to lower overall market and capacity prices in 2012 compared to 2011; lower tolling revenue in 2012 due to the cancellation of certain contracts on our Gas assets; and settlement of legacy option positions. Offsetting these decreases are lower operating expense due to lease expense associated with the DNE lease no longer being accrued and lower general and administrative expense due to reductions in headcount.

Discussion of Segment Results of Operations

Coal Segment. Both on-peak and off-peak power prices were lower in the third quarter 2012 compared to the third quarter 2011, partially offset by an increase in generation volumes period over period.

As discussed above, as a result of the DMG Transfer, 2011 results only include the results of the Coal segment through August 31, 2011. The following table provides summary financial data regarding our Coal segment results of operations for the three months ended September 30, 2012 and 2011, respectively:

	Three Months Ended September 30,			
	2012	2011	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$142	$149	$(7)	(5)%
Capacity	4	6	(2)	(33)%
Financial transactions:				
Mark-to-market loss	(12)	(4)	(8)	(200)%
Financial settlements	(9)	(15)	6	40%
Option premiums	2	(2)	4	200%
Total financial transactions	(19)	(21)	2	10%
Other (1)	(1)	(2)	1	50%
Total revenues	126	132	(6)	(5)%
Cost of sales	(122)	(60)	(62)	(103)%
Gross margin	$4	$72	$(68)	(94)%
Million Megawatt Hours Generated (2)	4.9	3.8	1.1	29%
In Market Availability for Coal Fired Facilities (3)	93%	93%		
Average Quoted On-Peak Market Power Prices ($/MWh) (4):	—	—		
Indiana (Indy Hub) (5)	$40	$52	$(12)	(23)%

(1) Other includes ancillary services and other miscellaneous items.

(2) Reflects production volumes in million MWh generated during the periods Coal was included in our consolidated results. Generation volumes were 5.1 million MWh for the full three months ended September 30, 2011.

(3) Reflects the percentage of generation available during periods Coal was included in our consolidated results when market prices are such that these units could be profitably dispatched. In Market Availability for Coal Fired Facilities was 92 percent for the full three months ended September 30, 2011.

(4) Reflects the average of day-ahead quoted prices for the periods Coal was included in our consolidated results and does not necessarily reflect prices we realized. The average of day-ahead quoted prices was $47 for the full three months ended September 30, 2011.

(5) The market reference for 2011 was Cinergy (Cin Hub).

Gross margin for Coal decreased by $68 million from $72 million for the three months ended September 30, 2011, to $4 million for the three months ended September 30, 2012. There was a decrease of approximately $22 million due to including the Coal results for three months in 2012 compared to two months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. While this would generally result in an increase in gross margin, we had a negative gross margin in the extra month due to the amortization of intangible assets related to our rail and

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coal contracts resulting from the DMG Acquisition. There was no such amortization in 2011. The remaining decrease of approximately $46 million is due to the following:

- Energy revenue decreased by $39 million due to lower market prices and more outage hours, both of which led to lower volumes produced.
- Cost of sales increased by $23 million due to the amortization of intangibles related to the rail and coal contracts recorded as a result of the DMG Acquisition of $25 million which was partially offset by a $2 million decrease in cost of sales due to lower volumes generated.

The above net decrease was partially offset by a $9 million increase in mark-to-market revenue due to a net change in mark-to-market losses of $4 million in the third quarter 2011 compared to mark-to-market revenue of $5 million in the third quarter 2012.

Gas Segment. Spark-spreads were generally higher in the third quarter 2012 compared to the third quarter 2011 resulting in higher generation volumes period over period.

The following table provides summary financial data regarding our Gas segment results of operations for the three months ended September 30, 2012 and 2011, respectively:

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	Three Months Ended September 30, 2012	2011	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$195	$185	$10	5 %
Capacity	61	56	5	9 %
Tolls	40	61	(21)	(34)%
RMR	1	3	(2)	(67)%
Natural gas	38	39	(1)	(3)%
Financial transactions:				
Mark-to-market income	53	15	38	253 %
Financial settlements	(70)	(62)	(8)	(13)%
Option premiums	1	(10)	11	110 %
Total financial transactions	(16)	(57)	41	72 %
Other (1)	(2)	11	(13)	(118)%
Total revenues	317	298	19	6 %
Cost of sales	(190)	(188)	(2)	(1)%
Gross margin	$127	$110	$17	15 %
Million Megawatt Hours Generated (2)	6.2	4.4	1.8	41 %
Average Capacity Factor for Combined Cycle Facilities (3)	61 %	44 %		
Average Quoted On-Peak Market Power Prices ($/MWh) (4):		—		
Commonwealth Edison (NI Hub)	$40	$48	$(8)	(17)%
PJM West	$45	$58	$(13)	(22)%
North of Path 15 (NP 15)	$37	$40	$(3)	(8)%
New York—Zone A	$41	$47	$(6)	(13)%
Mass Hub	$45	$56	$(11)	(20)%
Average On-Peak Market Spark Spreads ($/MWh) (5):	—	—		
Commonwealth Edison (NI Hub)	$20	$19	$1	5 %
PJM West	$24	$28	$(4)	(14)%
North of Path 15 (NP 15)	$13	$7	$6	86 %
New York—Zone A	$18	$14	$4	29 %
Mass Hub	$24	$23	$1	4 %
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.87	$4.13	$(1.26)	(31)%

(1) Other includes ancillary services and other miscellaneous items.
(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility for the three months ended September 30, 2012 and 2011, respectively.
(3) Reflects actual production as a percentage of available capacity.
(4) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.
(5) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas at a daily cash market price and does not reflect spark spreads available to us.
(6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Gross margin for Gas increased by $17 million from $110 million for the three months ended September 30, 2011, to $127 million for the three months ended September 30, 2012. This increase is driven by the following:

- Energy revenue and the corresponding cost of sales increased by $10 million and $2 million, respectively, for a net increase in energy margin of $8 million. Energy revenue and cost of sales increased due to higher volumes generated.

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Volumes were up due to higher spark spreads at Moss Landing, Independence, and Kendall in the third quarter 2012 compared to the third quarter 2011. The increases to both energy revenue and cost of sales caused by higher generation volumes were offset by lower power and gas pricing across all regions.

- Mark-to-market revenue increased by $38 million due to a net change in mark-to-market revenue of $15 million in the third quarter 2011 to mark-to-market revenue of $53 million in the third quarter 2012. The increase in mark-to-market revenue was primarily driven by the roll-off of liability positions.
- An overall change in premium revenue of $11 million due to $10 million in net premiums paid in 2011 compared to $1 million in net premiums received in 2012.

The above increases were partially offset by the following decreases:

- Tolling revenue decreased by $21 million primarily due to the cancellation of the Morro Bay tolling agreement in the second quarter 2012. Please read Note 14—Commitments and Contingencies— SCE Termination.
- Settlement revenue decreased by $8 million primarily due to an increase in settlement expense associated with gas positions executed in prior periods.
- Other revenue decreased by $13 million primarily due to the timing of the termination of certain contractual arrangements related to our Gas assets in the West. Please read Note 14—Commitments and Contingencies— SCE Termination.

DNE Segment. During the period, dark spreads at Danskammer were compressed by lower Zone G prices and increased coal prices.

The following table provides summary financial data regarding our DNE segment results of operations for the three months ended September 30, 2012 and 2011, respectively:

	Three Months Ended September 30,			
	2012	2011	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$26	$37	$(11)	(30)%
Capacity	7	5	2	40%
Financial transactions:				
Mark-to-market loss	—	(24)	24	100%
Financial settlements	1	15	(14)	(93)%
Option premiums	—	2	(2)	(100)%
Financial transactions	1	(7)	8	114%
Other (1)	—	2	(2)	(100)%
Total revenues	34	37	(3)	(8)%
Cost of sales	(20)	(30)	10	33%
Gross margin	$14	$7	$7	100%
Million Megawatt Hours Generated	0.4	0.5	(0.1)	(20)%
In Market Availability for Coal Fired Facilities (2)	83%	97%		
Average Capacity Factor—Coal	22%	37%		
Average Capacity Factor—Gas	8%	7%		
Average Quoted On-Peak Market Power Prices ($/MWh) (3):	—	—		
New York—Zone G	$50	$63	$(13)	(21)%
Average Market Spark Spreads ($/MWh) (4):	—	—		
Fuel Oil	$(138)	$(119)	$(19)	(16)%

(1) Other includes ancillary services and other miscellaneous items.

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(2) Reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched.
(3) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.
(4) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator or an 11.0 MMBtu/MWh heat rate fuel oil-fired generator selling power at day-ahead prices and buying delivered natural gas or fuel oil at a daily cash market price and does not reflect spark spreads available to us.

Gross margin for DNE increased by $7 million from $7 million for the three months ended September 30, 2011, to $14 million for the three months ended September 30, 2012. This increase is driven by the following:

- A decrease in mark-to-market losses of $24 million. We had mark-to-market losses of $24 million in the third quarter 2011 compared to no mark-to-market activity in the third quarter 2012. In 2011, a majority of the financial instruments associated with DNE were terminated and there was only minimal activity in 2012.

The above increase was partially offset by the following:

- Energy revenue and the corresponding cost of sales decreased by $11 million and $10 million, respectively, for a net decrease in energy margin of $1 million. Energy margin decreased due to lower power prices and lower generation. The decrease in generation is due to fewer economic opportunities to dispatch during the third quarter 2012 compared to the third quarter 2011.
- Settlement revenue decreased by $14 million due to a reduction in the use of financial instruments to hedge DNE during 2012. In 2011, a majority of the derivative instruments used to hedge DNE were terminated. During the third quarter 2012, there was only minimal use of financial instruments associated with DNE resulting in a reduction of settlement revenue.

Consolidated Summary Financial Information — Nine Months Ended September 30, 2012

The following table provides summary financial data regarding our consolidated results of operations for the nine months ended September 30, 2012 and 2011, respectively:

	Nine Months Ended September 30,			
	2012	2011	Change	% Change
	(dollars in millions)			
Revenues	$1,042	$1,298	$(256)	(20)%
Cost of sales	(697)	(781)	84	11%
Gross margin, exclusive of depreciation shown separately below	345	517	(172)	(33)%
Operating and maintenance expense, exclusive of depreciation shown separately below	(196)	(303)	107	35%
Depreciation and amortization expense	(110)	(261)	151	58%
Impairment and other charges	—	(6)	6	100%
General and administrative expenses	(66)	(87)	21	24%
Operating loss	(27)	(140)	113	81%
Interest expense	(121)	(283)	162	57%
Debt extinguishment costs	—	(21)	21	100%
Bankruptcy reorganization charges	(252)	—	(252)	(100)%
Impairment of Undertaking receivable, affiliate	(832)	—	(832)	(100)%
Other income and expense, net	31	11	20	182%
	(1,201)	(433)	(768)	(177)%

Loss from continuing operations before income taxes				
Income tax benefit	9	109	(100)	(92)%
Net loss	$(1,192)	$(324)	$(868)	(268)%

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The following tables provide summary financial data regarding our operating income (loss) by segment for the nine months ended September 30, 2012 and 2011, respectively:

	Nine Months Ended September 30, 2012				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$166	$815	$61	$—	$1,042
Cost of sales	(161)	(501)	(35)	—	(697)
Gross margin, exclusive of depreciation shown separately below	5	314	26	—	345
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(55)	(95)	(46)	—	(196)
Depreciation and amortization expense	(13)	(91)	—	(6)	(110)
General and administrative expense	(12)	(44)	(3)	(7)	(66)
Operating income (loss)	$(75)	$84	$(23)	$(13)	$(27)

	Nine Months Ended September 30, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$460	$743	$95	$—	$1,298
Cost of sales	(237)	(481)	(63)	—	(781)
Gross margin, exclusive of depreciation shown separately below	223	262	32	—	517
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(105)	(111)	(86)	(1)	(303)
Depreciation and amortization expense	(156)	(100)	—	(5)	(261)
Impairment and other charges	—	—	(2)	(4)	(6)
General and administrative expense	(27)	(42)	(9)	(9)	(87)
Operating income (loss)	$(65)	$9	$(65)	$(19)	$(140)

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the nine months ended September 30, 2012:

	Nine Months Ended September 30, 2012				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss					$(1,192)
Income tax benefit					(9)
Impairment of Undertaking receivable, affiliate					832
Bankruptcy reorganization charges					252
Interest expense					121
Other items, net					(31)
Operating income (loss)	$(75)	$84	$(23)	$(13)	$(27)
Impairment of Undertaking receivable, affiliate	—	—	—	(832)	(832)
Bankruptcy reorganization charges	—	—	(589)	337	(252)
Depreciation and amortization expense	13	91	—	6	110
Other items, net	5	2	—	24	31
EBITDA	(57)	177	(612)	(478)	(970)
Impairment of Undertaking receivable, affiliate	—	—	—	832	832
Bankruptcy reorganization charges	—	—	589	(337)	252
Interest income on Undertaking receivable	—	—	—	(24)	(24)
Restructuring costs and other expense	(3)	2	—	6	5
Mark-to-market (income) loss, net	13	(106)	1	—	(92)
Amortization of intangible assets (1)	49	29	—	—	78
Premium adjustment	—	1	—	—	1
SCE termination	—	(21)	—	—	(21)
Other	5	2	—	—	7
Adjusted EBITDA	7	84	(22)	(1)	68
Adjusted EBITDA from Legacy Dynegy (2)	7	—	—	2	9
Enterprise-wide Adjusted EBITDA	$14	$84	$(22)	$1	$77

(1) In connection with the DMG Acquisition, we recorded intangible assets and liabilities related to rail transportation and coal contracts, respectively. The amount in the Gas segment is related to the intangible assets related to the Sithe acquisition.

(2) Our 2012 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the nine months ended September 30, 2012. Additionally, effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from January 1, 2012 through June 5, 2012. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the nine months ended September 30, 2012 and the Coal segment for the period from January 1, 2012 through June 5, 2012 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating income (loss):

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	Nine Months Ended September 30, 2012				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Operating income (loss)	$(2,715)	$—	$—	$1,683	$(1,032)
Depreciation and amortization expense	78	—	—	—	78
Bankruptcy reorganization charges	—	—	—	(8)	(8)
Loss from unconsolidated investment	—	—	—	(1)	(1)
EBITDA	(2,637)	—	—	1,674	(963)
Loss (gain) on Coal Holdco Transfer	2,652	—	—	(1,711)	941
Bankruptcy reorganization charges	—	—	—	8	8
Restructuring costs and other expense	—	—	—	30	30
Mark-to-market income, net	(8)	—	—	—	(8)
Loss from unconsolidated investment	—	—	—	1	1
Adjusted EBITDA from Legacy Dynegy	$7	$—	$—	$2	$9

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the nine months ended September 30, 2011:

	Nine Months Ended September 30, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss					$(324)
Income tax benefit					(109)
Interest expense and debt extinguishment costs					304
Other items, net					(11)
Operating income (loss)	$(65)	$9	$(65)	$(19)	$(140)
Other items, net	2	1	—	8	11
Depreciation and amortization expense	156	100	—	5	261
EBITDA	93	110	(65)	(6)	132
Merger agreement termination fee, restructuring costs and other expenses	(1)	12	(2)	6	15
Impairment and other charges	—	—	2	—	2
Mark-to-market loss, net	76	13	47	5	141
Adjusted EBITDA	$168	$135	$(18)	$5	$290
Adjusted EBITDA from Legacy Dynegy (1)	7	—	—	(2)	5
Enterprise-wide Adjusted EBITDA	$175	$135	$(18)	$3	$295

(1) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the nine months ended September 30, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from September 1, 2011 through September 30, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the nine months ended September 30, 2011 and the Coal segment for the period from September 1, 2011 through September 30, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating loss:

	Nine Months Ended September 30, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Operating loss	$(8)	$—	$—	$(2)	$(10)
Depreciation and amortization expense	13	—	—	—	13
Other items, net	(2)	—	—	(5)	(7)
EBITDA	3	—	—	(7)	(4)
Restructuring costs and other expenses	5	—	—	5	10
Mark-to-market income, net	(1)	—	—	—	(1)
Adjusted EBITDA from Legacy Dynegy	$7	$—	$—	$(2)	$5

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Discussion of Consolidated Results of Operations

Revenues. Revenues decreased by $256 million from $1,298 million for the nine months ended September 30, 2011 to $1,042 million for the nine months ended September 30, 2012. Of this decrease, $235 million is due to including the Coal results for four months in 2012 compared to eight months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The remaining decrease is primarily due to lower market prices, less revenue from premiums and the financial settlement of derivative instruments, as further described below.

Cost of Sales. Cost of sales decreased by $84 million from $781 million for the nine months ended September 30, 2011 to $697 million for the nine months ended September 30, 2012. Of this decrease, $109 million is due to including the Coal results for four months in 2012 compared to eight months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The decrease from the DMG Transfer and subsequent DMG Acquisition was partially offset by the amortization of intangibles related to our coal and rail contracts recorded in conjunction with the DMG Acquisition.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense decreased by $107 million from $303 million for the nine months ended September 30, 2011 to $196 million for the nine months ended September 30, 2012. Of this decrease, $49 million is due to including the Coal results for four months in 2012 compared to eight months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The remaining decreases are primarily due to a $40 million reduction in lease expense associated with the rejection of the leases of the Roseton and Danskammer power generation facilities and $15 million lower outage costs in 2012.

Depreciation and Amortization Expense. Depreciation expense decreased by $151 million from $261 million for the nine months ended September 30, 2011 to $110 million for the nine months ended September 30, 2012. Of this decrease, $113 million is due to including the Coal results for four months in 2012 compared to eight months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The remaining decrease is primarily due to a $16 million reduction in our asset retirement obligations associated with the South Bay facility in 2012 that is reflected as a reduction in depreciation and amortization expense because South Bay is fully depreciated and a $31 million reduction due to a lower basis in the Coal assets as a result of the DMG Acquisition, offset by $9 million related to various additions and early retirements.

General and Administrative Expenses. General and administrative expenses decreased $21 million from $87 million for the nine months ended September 30, 2011 to $66 million for the nine months ended September 30, 2012. Of this decrease, $7 million is due to including the Coal results for four months in 2012 compared to eight months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The remaining decrease is primarily the result of lower professional services, lease expense and salaries and benefits.

Bankruptcy Reorganization Charges. Bankruptcy reorganization charges for the nine months ended September 30, 2012 were approximately $252 million. These charges consist of charges of approximately $395 million related to increases in the estimated allowable claims related to the Roseton and Danskammer facilities leases partially offset by reductions of approximately $161 million and $5 million in the estimated allowable claims related to the subordinated debt and other items, respectively. The change in the estimated allowable claims related to the Roseton and Danskammer facilities leases and the subordinated debt are a result of the Settlement Agreement. Additionally, there is approximately $40 million included in the Chapter 11 Cases charges for expenses incurred related to our advisors, offset by $17 million related to the change in the value of the Administrative Claim. There were no such charges during the nine months ended September 30, 2011. Please read Note 3—Chapter 11 Cases for further discussion.

Interest Expense. Interest expense decreased by $162 million from $283 million for the nine months ended September 30, 2011 to $121 million for the nine months ended September 30, 2012. The decrease was primarily driven by the absence of interest expense related to our unsecured notes and debentures in the nine months ended September 30, 2012 as a result of the DH Chapter 11 Cases and the repayment of our prior credit agreement. These decreases were partially offset by interest related to the DPC and DMG Credit Agreements which have higher borrowing rates than our prior credit agreement.

Debt Extinguishment Costs. Debt extinguishment costs totaled $21 million for the nine months ended September 30, 2011 and were incurred in connection with the termination of the Sithe senior debt. There were no such charges during the nine months ended September 30, 2012.

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Impairment of Undertaking Receivable. As a result of entering into the Settlement Agreement, the Undertaking receivable was impaired to $418 million as of March 31, 2012, resulting in a charge of approximately $832 million. The carrying value of the Undertaking was adjusted to the value received in the DMG Acquisition plus interest payments received subsequent to March 31, 2012. There were no such charges during the three months ended September 30, 2011.

Other Income and Expense, Net. Other income and expense, net increased by $20 million from $11 million for the nine months ended September 30, 2011 to $31 million for the nine months ended September 30, 2012. The increase is primarily due to interest income on the Undertaking receivable, affiliate during 2012. The Undertaking was executed on September 1, 2011, impaired as of March 31, 2012 and settled on June 5, 2012; therefore, there is only one month of interest income related to the Undertaking during the nine months ended September 30, 2011 compared to three months of interest income related to the Undertaking during the nine months ended September 30, 2012.

Income Tax Benefit. We reported an income tax benefit of $9 million for the nine months ended September 30, 2012, compared to an income tax benefit of $109 million for the nine months ended September 30, 2011. The effective tax rate in 2012 was 1 percent, compared to 25 percent in 2011.

For the nine months ended September 30, 2012, the difference between the effective rate of 1 percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of September 30, 2012, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

For the nine months ended September 30, 2011, the difference between the effective rates of 25 percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax asset partially offset by the impact of state taxes which included a benefit of $9 million related to an increase in state NOLs due to the acceptance of amended returns, partially offset by an expense of $3 million related to an increase in the Illinois statutory rate.

Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA decreased by $218 million from $295 million for the nine months ended September 30, 2011 to $77 million for the nine months ended September 30, 2012. The decrease is primarily due to lower overall market and capacity prices in 2012 compared to 2011; lower tolling revenue in 2012 due to the cancellation of the Morro Bay toll; settlement of legacy option positions; and lower premiums received in 2012. Offsetting the decrease from lower pricing and tolls is lower operating expense due to lease expense associated with the DNE lease no longer being accrued, lower general and administrative expense due to reductions in head count and a change in methodology associated with amortization expense. Enterprise-wide Adjusted EBITDA for 2011 includes amortization expense related to the Sithe acquisition while it was excluded in 2012.

Discussion of Segment Results of Operations

Coal Segment. Both on-peak and off-peak power prices were lower in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 while generation volumes decreased period over period. As discussed above, as a result of the DMG Acquisition, 2012 results only include the results of the Coal segment for the period of June 6, 2012 through September 30, 2012. Additionally, as a result of the DMG Transfer, 2011 results only include the results of the Coal segment for the period from January 1, 2011 through August 31, 2011. The following table provides summary financial data regarding our Coal segment results of operations for the nine months ended September 30, 2012 and 2011, respectively:

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	Nine Months Ended September 30, 2012	2011	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$184	$512	$(328)	(64)%
Capacity	4	8	(4)	(50)%
Financial transactions:	—	—	—	—
Mark-to-market loss	(14)	(76)	62	82%
Financial settlements	(10)	6	(16)	(267)%
Option premiums	3	14	(11)	(79)%
Total Financial transactions	(21)	(56)	35	63%
Other (1)	(1)	(4)	3	75%
Total revenues	166	460	(294)	(64)%
Cost of sales	(161)	(237)	76	32%
Gross margin	$5	$223	$(218)	(98)%
Million Megawatt Hours Generated (2)	6.6	15.6	(9.0)	(58)%
In Market Availability for Coal Fired Facilities (3)	93%	92%		
Average Quoted On-Peak Market Power Prices ($/MWh) (4):	—	—		
Indiana (Indy Hub) (5)	$40	$45	$(5)	(11)%

(1) Other includes ancillary services and other miscellaneous items.

(2) Reflects production volumes in million MWh generated during the periods Coal was included in our consolidated results. Generation volumes were 15.2 million MWh and 16.9 million MWh for the full nine months ended September 30, 2012 and 2011, respectively.

(3) Reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched during the periods Coal was included in our consolidated results. In Market Availability for Coal Fired Facilities was 93 percent for the full nine months ended September 30, 2012 and 2011.

(4) Reflects the average of day-ahead quoted prices for the periods Coal was included in our consolidated results and does not necessarily reflect prices we realized. The average of day-ahead quoted prices were $35 and $44 for the full nine months ended September 30, 2012 and 2011, respectively.

(5) The market reference for 2011 was Cinergy (Cin Hub).

Gross margin for Coal decreased by $218 million from $223 million for the nine months ended September 30, 2011, to $5 million for the nine months ended September 30, 2012. Approximately $125 million of this decrease is due to including the Coal results for four months in 2012 compared to eight months in 2011 as a result of the DMG Transfer on September 1, 2011 and subsequent DMG Acquisition on June 5, 2012. The remaining decrease of $93 million is driven primarily by the following:

- Energy revenue decreased by $58 million and the corresponding cost of sales increased by $33 million, for a total decrease in energy margin of $91 million. The decrease in energy revenue is due to lower market prices and more planned outages, both of which led to lower volumes produced. The increase in cost of sales is due to the amortization of intangibles related to our rail and coal contracts recorded in conjunction with the DMG Acquisition.

Gas Segment. Spark-spreads were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 resulting in higher generation volumes period over period.

The following table provides summary financial data regarding our Gas segment results of operations for the nine months ended September 30, 2012 and 2011, respectively:

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	Nine Months Ended September 30, 2012	2011	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$492	$403	$89	22%
Capacity	162	166	(4)	(2)%
Tolls	79	100	(21)	(21)%
RMR	5	5	—	—%
Natural gas	100	134	(34)	(25)%
Financial transactions:				
Mark-to-market income (loss)	117	(16)	133	831%
Financial settlements	(171)	(96)	(75)	(78)%
Option premiums	3	21	(18)	(86)%
Total financial transactions	(51)	(91)	40	44%
Other (1)	28	26	2	8%
Total revenues	815	743	72	10%
Cost of sales	(501)	(481)	(20)	(4)%
Gross margin	$314	$262	$52	20%
Million Megawatt Hours Generated (2)	16.9	9.6	7.3	76%
Average Capacity Factor for Combined Cycle Facilities (3)	57%	33%		
Average Quoted On-Peak Market Power Prices ($/MWh) (4):	—	—		
Commonwealth Edison (NI Hub)	$34	$44	$(10)	(23)%
PJM West	$40	$55	$(15)	(27)%
North of Path 15 (NP 15)	$30	$36	$(6)	(17)%
New York—Zone A	$35	$43	$(8)	(19)%
Mass Hub	$39	$57	$(18)	(32)%
Average Market Spark Spreads ($/MWh) (5):	—	—		
Commonwealth Edison (NI Hub)	$16	$14	$2	14%
PJM West	$20	$21	$(1)	(5)%
North of Path 15 (NP 15)	$8	$3	$5	167%
New York—Zone A	$13	$10	$3	30%
Mass Hub	$18	$19	$(1)	(5)%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.53	$4.21	$(1.68)	(40)%

(1) Other includes ancillary services and other miscellaneous items.

(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility for the three months ended September 30, 2012 and 2011, respectively.

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

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

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

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

Gross margin for Gas increased by $52 million from $262 million for the nine months ended September 30, 2011, to $314 million for the nine months ended September 30, 2012. This increase is driven by the following:

- Energy revenue and the corresponding cost of sales increased by $89 million and $20 million, respectively, for a net increase in energy margin of $69 million. Energy revenue and cost of sales increased due to higher volumes generated.

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Volumes were up due to higher spark spreads at Moss Landing, Independence and Kendall in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. Volumes were also up due to fewer outage hours in the first nine months of 2012 compared to the first nine months of 2011. The increases to both energy revenue and cost of sales caused by higher generation volumes were offset by lower power and gas pricing across all regions.

- Mark-to-market revenue increased by $133 million due to a net change in mark-to-market losses of $16 million in the nine months ended September 30, 2011 to mark-to-market revenue of $117 million in the nine months ended September 30, 2012. The increase in mark-to-market revenue was primarily driven by the roll off of liability positions.

The above increases were partially offset by the following:

- Tolling revenue decreased by $21 million primarily due to the cancellation of the Morro Bay tolling agreement.
- Gas revenue decreased by $34 million due to lower volumes sold and lower gas pricing in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. As we lack gas storage capabilities, all gas purchased must be used in generation or sold back to the market. Higher generation across the gas fleet in the first nine months of 2012 led to less gas available for resale and therefore less gas revenue.
- Settlement revenue decreased by $75 million primarily due to an increase in settlement expense associated with gas positions executed in prior periods.
- Premium revenue decreased by $18 million due to a reduction in the number of options sold.

DNE Segment. During the nine months ended September 30, 2012, dark spreads at Danskammer were compressed by lower Zone G prices and increased coal prices.

The following table provides summary financial data regarding our DNE segment results of operations for the nine months ended September 30, 2012 and 2011, respectively:

	Nine Months Ended September 30,			
	2012	2011	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$44	$89	$(45)	(51)%
Capacity	14	14	—	— %
Financial transactions:				
Mark-to-market loss	(1)	(47)	46	98 %
Financial settlements	1	33	(32)	(97)%
Option premiums	—	2	(2)	(100)%
Total financial transactions	—	(12)	12	100 %
Other (1)	3	4	(1)	(25)%
Total revenues	61	95	(34)	(36)%
Cost of sales	(35)	(63)	28	44 %
Gross margin	$26	$32	$(6)	(19)%
Million Megawatt Hours Generated	0.7	1.1	(0.4)	(36)%
In Market Availability for Coal Fired Facilities (2)	87 %	97 %		
Average Capacity Factor—Coal	12 %	34 %		
Average Capacity Factor—Gas	4 %	4 %		
Average Quoted On-Peak Market Power Prices ($/MWh) (3):	—	—		
New York—Zone G	$43	$61	$(18)	(30)%
Average Market Spark Spreads ($/MWh) (4):				

Fuel Oil	$(150)	$(116)	$(34)	(29)%

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(1) Other includes ancillary services and other miscellaneous items.
(2) Reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched.
(3) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.
(4) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator or an 11.0 MMBtu/MWh heat rate fuel oil-fired generator selling power at day-ahead prices and buying delivered natural gas or fuel oil at a daily cash market price and does not reflect spark spreads available to us.

Gross margin for DNE decreased by $6 million from $32 million for the nine months ended September 30, 2011, to $26 million for the nine months ended September 30, 2012. This decrease is driven by the following:

- Energy revenue and the corresponding cost of sales decreased by $45 million and $28 million, respectively, for a net decrease in energy margin of $17 million. Energy margin decreased due to lower power prices and lower generation. The decrease in generation is due to fewer economic opportunities to dispatch during the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011.
- Settlement revenue decreased by $32 million due to a reduction in the use of financial instruments associated with DNE. In 2011, a majority of the derivative instruments used to hedge DNE were terminated. During the nine months ended September 30, 2012, there was only minimal use of financial instruments associated with DNE resulting in a reduction of settlement revenue.

The above decreases were partially offset by the following:

- Mark-to-market revenue increased by $46 million due to a net change in mark-to-market losses of $47 million in the nine months ended September 30, 2011 to $1 million in mark-to-market revenue in the nine months ended September 30, 2012. In 2011, a majority of the financial instruments associated with DNE were terminated and there was only minimal activity in 2012.

Outlook

We are focused on reducing and consolidating non-plant support activities and achieving cost efficiencies at both operating facilities and corporate support functions. Going forward, we have an operating fleet supported by our service contracts, which has resulted in adjusting corporate functions to support the new operational model. As previously discussed, on September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy with Legacy Dynegy continuing as the surviving legal entity of the Merger. We own the Gas and DNE segments and, as of June 5, 2012 (due to the “recapitalization” accounting described in Note 1—Basis of Presentation and Organization) the Coal segment. On October 1, 2012, we consummated our reorganization under Chapter 11 pursuant to the Plan and exited bankruptcy (with the exception of the DNE Entities).

We expect that our future financial results will continue to be sensitive to fuel and commodity prices, especially gas prices and the impact on such prices of shale gas production. Other factors to which our future financial results will remain sensitive include market structure and prices for electric energy, capacity and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, the volatility of fuel and electricity prices, transportation and transmission logistics, weather conditions, the outcome of certain contractual disputes and IMA. Further, there is a trend toward greater environmental regulation of all aspects of our business. As this trend continues, it is likely that we will experience additional costs and limitations.

Coal. The Coal segment consists of six plants, all located in the MISO region, and totaling 3,132 MW. On September 1, 2011, we completed the DMG Transfer. On June 5, 2012, the effective date of the Settlement Agreement, we completed the DMG Acquisition. Therefore, the results of our Coal segment (including DMG) were only included in our consolidated results for the period of June 6, 2012 through September 30, 2012. Please read Note 3—Chapter 11 Cases for further information.

Our Consent Decree requires substantial emission reductions from our Illinois coal-fired power plants and the completion of several supplemental environmental projects in Illinois. On November 3, 2012, Dynegy completed the Baldwin Unit 2 outage marking the completion of the Consent Decree environmental capital compliance requirements. We expect our costs associated with Consent Decree as of September 30, 2012, to be approximately $13 million and $3 million for the remainder of 2012 and 2013, respectively.

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Our remaining expected coal requirements are fully contracted and priced in 2012. Our forecasted coal requirements for 2013 are 90 percent contracted and priced. Our coal transportation requirements are 100 percent contracted and priced through 2013 when our current contracts expire. In August 2012, we executed new coal transportation contracts which take effect when our current contracts expire. These new long-term contracts also cover 100 percent of our coal transportation requirements. We continue to explore various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable and competitive fuel supplies and to mitigate further supply risks for near- and long-term coal supplies.

Our Coal expected generation volumes are volumetrically 77 percent hedged through 2012 and approximately 47 percent hedged for 2013.

The MISO filed proposed Resource Adequacy Enhancements with FERC on July 20, 2011. FERC conditionally approved MISO's proposal on June 11, 2012, leaving much of MISO's proposal in place. The proposed tariff revisions require capacity to be procured on a zonal basis for a full planning year (June 1 - May 31) versus the current monthly requirement, with procurement occurring two months ahead of the planning year. The new construct will be in place for the 2013-2014 Planning Year. While the new construct is an incremental improvement over the status quo, it is unlikely to have an influence on capacity prices in the near future due to excess capacity in the MISO market. In addition, increased market participation by demand response resources offset by potential retirement of marginal MISO coal capacity due to poor economics or expected environmental mandates could also affect MISO capacity and energy market prices in the future.

We currently intend to retire the Oglesby and Stallings peaking facilities, representing 152 MW, by the end of 2012, subject to a reliability assessment by MISO.

Gas. The Gas segment consists of eight plants, geographically diverse in five markets, totaling 6,771 MW. Approximately 50 percent of our power plant capacity in the CAISO market is contracted through 2012 under tolling agreements with load-serving entities and an RMR agreement. A significant portion of the remaining capacity is sold as a resource adequacy product in the CAISO market, and much of our remaining expected production in the CAISO market has been financially hedged.

The CAISO capacity market is bilateral in nature. The load-serving entities are required to procure sufficient resources for their peak load plus a fifteen percent reserve margin. The CAISO footprint currently has a capacity surplus due to a weak economy and increased participation from renewable resources. The CAISO faces challenges to ensure system reliability as well as adequate ancillary services in the future with the mandate to have 33 percent renewable resources by 2020. The combination of bilateral markets, one-off utility procurements, and short-term requirements make this a larger concern than in other markets where multi-year forward requirements and more transparent markets are in place.

In May 2012, SCE notified Morro Bay and Moss Landing that it was terminating certain energy and capacity contracts with those entities. The validity of the purported terminations and subsequent actions by SCE are being disputed by Dynegy. Such terminations will likely impact the timing and amount of cash flows going forward. We are actively seeking other commercial arrangements for the facilities and have been offering output in the day-ahead market administered by the CAISO since May 19, 2012. We will continue to respond to the RFO process of California utilities seeking to procure electric capacity needed to serve their customers. While we have been successful in winning contracts through this RFO process in the past, we believe that a more forward-looking, transparent, market-based solution to securing electric supply would benefit consumers, utilities and independent generators.

The South Bay power generation facility has been permanently retired and is currently in the process of being demolished. We have a contractual obligation to demolish the facility and potentially remediate specific parcels of the property. We currently estimate that our obligation, in excess of the funds in escrow, to be approximately $20 million, exclusive of certain rental payments that will be due the Port of San Diego. Our estimates for the demolition and any potential remediation costs will likely change as the project advances through the next phase of the demolition process. We currently expect the escrow funds to cover costs through at least 2013.

The estimated useful lives of our generation facilities consider environmental regulations currently in place. With respect to Units 6 and 7 at our Moss Landing facility, we are continuing to review the potential impact of the California Water Intake Policy. We are currently depreciating these units through 2024; however, depending on the ultimate impact of the California Water Intake Policy, we may determine that we would be required to install cooling systems that could render operation of the units uneconomical. If such a determination were to be made, we could decide to reduce operations or cease to operate the units as early as December 31, 2017.

In New England, six forward capacity auctions have been held since the ISO-NE transitioned to a forward capacity market in June 2010. Capacity clearing prices have ranged from a high of $4.50 per kW-month for the 2010-2011 market period to a low of $2.95 per kW-month for the 2013-2014 market period. The most recent capacity auction, for 2015-2016, cleared at the floor price of $3.43 per kW-month. The annual auctions continue to clear at the designated floor due to oversupply conditions. Efforts to implement prospective improvements in the forward capacity market design are currently underway, which include migration to a demand curve and/or extension of the auction floor for Forward Capacity Auction #8 and beyond. We anticipate changes will impact the Forward Capacity Auction #8, which is the auction period from June 2017 to May 2018.

In PJM, where the Kendall and Ontelaunee combined-cycle plants are located, eight forward capacity auctions (known as RPM or Reliability Pricing Model) have been held since the transition from a daily capacity market in June 2007. RPM clearing prices have ranged from $0.50 per kW-month (Kendall, PY2012-13) and $1.24 per kW-month (Ontelaunee, PY2007-8) to $5.30 per kW-month (Kendall, PY2010-11) and $6.88 per kW-month (Ontelaunee, PY2013-14). The latest RPM auction was for the 2015-2016 Planning Year, which cleared at $4.14 per kW-month (Kendall) and $5.09 per kW-month (Ontelaunee).

Capacity pricing for the NYISO seems to be recovering from the low point in 2011. The most recent summer and winter auctions have cleared higher than the previous auctions with summer 2012 at $1.25 per kW-month and winter 2012-2013 at $0.82 per kW-month. The next auction for summer 2013 is trading in the bi-lateral market at approximately $2.85 per kW-month. We attribute the rebound in part due to the recent FERC Order on buyer-side mitigation for New York City capacity zone. Approximately 70 percent of the capacity revenue for our Independence facility has been contracted at a favorable premium compared to current market prices through 2014.

Currently, our Gas portfolio is 99 percent hedged volumetrically through 2012 and approximately 53 percent hedged for 2013.

We plan to continue our hedging program for Gas over a rolling 12-36 month period using various forward sale instruments. Beyond 2013, the portfolio is largely open, positioning Gas to benefit from possible future power market pricing improvements.

DNE. DNE is comprised of the Roseton and Danskammer facilities located in Newburgh, New York, with a total capacity of 1,693 MW. A total of 1,570 MW of generation capacity relates to leased units at the two facilities. The DNE Entities remain in Chapter 11 bankruptcy and continue to operate their businesses as “debtors-in-possession.” The DNE Entities, with the cooperation of the PSEG entities, will use commercially reasonable efforts to sell the Facilities with the proceeds of any sale to pay transaction expenses and to be distributed as set forth in the Settlement Agreement and the Plan. November 1, 2012 was the original deadline for bids for the Facilities sale process. This date was extended to November 5, 2012 due to superstorm Sandy, which caused flooding at the Danskammer plant on October 30. Remediation and repair work at the facility are underway, as well as a full assessment on the extent of the damage. We are currently evaluating the bids received. Further, we are in current negotiations with the union regarding its collective bargaining agreement, which is set to expire on November 7, 2012.

Other. Other includes traditional corporate support functions, including those services contemplated in the various service agreements, including the Service Agreements, Energy Management Agreements, Tax Sharing Agreements and Cash Management Agreements, which were entered into in conjunction with the 2011 Prepetition Restructuring.

During 2011, we initiated a new cost and performance improvement initiative, known as PRIDE (“Producing Results through Innovation by Dynegy Employees”), which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. In the nine months ended September 30, 2012, we recognized $14 million in operating margin and cost improvements versus 2011 and $118 million in incremental liquidity from balance sheet improvements due to PRIDE initiatives. For the full year 2012, we are forecasting additional margin and cost improvements of $43 million, and balance sheet improvements of $136 million. We will continue to use the PRIDE initiative to improve our operating performance, cost structure and balance sheet.

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K for the period ended December 31, 2011 for a detailed discussion of our environmental and regulatory matters.

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The Dodd-Frank Act

The CFTC has regulatory oversight authority over the trading of electricity and gas commodities, including financial products and derivatives, under the Commodity Exchange Act. On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), which, among other things, aims to improve transparency and accountability in derivative markets. The Dodd-Frank Act increases the CFTC's regulatory authority on matters related to over-the-counter derivatives, market clearing, position reporting, and capital requirements. On October 12, 2012, certain record-keeping and reporting requirements went into effect for Swap Dealers and Major Swap Participants, as defined by the CFTC. Beginning on October 10, 2012, the CFTC Staff issued various materials, including “No Action” letters, that delayed the effectiveness or otherwise altered many of these requirements. Other swap clearing and reporting requirements are expected to go into effect later this year and in 2013. Though Dynegy does not anticipate becoming a Swap Dealer or Major Swap Participant, we have put systems in place in order to monitor our swap activity and prepare for upcoming non-Swap Dealer/Major Swap Participant reporting requirements. We continue to monitor the CFTC's releases for guidance on these rules and any other clearing and reporting requirements that will be required of our business or impact current operations.

Multi-Pollutant Air Emission Initiatives

Cross-State Air Pollution Rule. In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CSAPR and ordered the EPA to continue administering the CAIR pending the promulgation of a valid replacement. On October 5, 2012, the EPA and others filed petitions for rehearing. We continue to monitor developments regarding the CSAPR and evaluate potential impacts on our operations.

Climate Change

State Regulation of Greenhouse Gases. On September 5, 2012, RGGI held its seventeenth auction, in which approximately 24.5 million allowances were sold at a clearing price of $1.93 per allowance. RGGI's next quarterly auction is scheduled for December 2012. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure some allowances for our affected assets.

Climate Change Litigation. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit issued its decision in Native Village of Kivalina v. ExxonMobil Corp., (following the filing of the DH Chapter 11 Cases, the Kivalina plaintiffs voluntarily dismissed DH with prejudice on February 2, 2012), ruling that the Clean Air Act and EPA actions authorized by the Act have displaced federal common law public nuisance claims concerning domestic GHGs. The court, relying heavily on the Supreme Court's 2011 ruling in AEP v. Connecticut, decided that the displacement of federal common law public nuisance claims regarding GHGs applies equally to actions seeking damages or injunctive relief. The Ninth Circuit declined to address whether the plaintiffs had standing or whether plaintiffs' claims were political questions not subject to the judicial review. The Kivalina plaintiffs have filed a petition for rehearing.

The Clean Water Act

In September 2012, the Illinois EPA issued a renewed NPDES permit for the Havana Power Station. In October 2012, environmental interest groups filed a petition for review with the Illinois Pollution Control Board challenging the permit. The petitioners allege that the permit does not adequately address the discharge of wastewaters associated with newly installed air pollution control equipment (i.e., a spray dryer absorber and activated carbon injection system to reduce SO2 and mercury air emissions) at Havana. We dispute the allegations and will defend the permit vigorously. The permit remains in effect during the appeal. While the outcome of the appeal is uncertain, an adverse result could cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations, and cash flows.

Coal Combustion Residuals

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In response, we submitted to the Illinois EPA a proposed compliance commitment agreement for each facility. For Vermilion, we proposed to implement the previously submitted corrective action plans and, for Baldwin, we proposed to perform additional studies of hydrogeologic conditions and apply for a groundwater management zone in preparation for submittal, as necessary, of a corrective action plan. In October 2012, the Illinois EPA notified us that it would not issue proposed compliance commitment agreements for Vermilion and Baldwin and, instead, would consider referral of the matters to the Illinois Office of the Attorney General. At this time we cannot reasonably estimate the costs of resolving these matters, but resolution of these matters may cause us to incur significant costs that could have a material adverse effect on our

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financial condition, results of operations and cash flows. Please read Note 14—Commitments and Contingencies —Other Commitments and Contingencies—Vermilion and Baldwin Groundwater, for further information.

RISK-MANAGEMENT DISCLOSURES

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

	As of and for the Nine Months Ended September 30, 2012 (in millions)
Balance Sheet Risk-Management Accounts (1)	
Fair value of portfolio at December 31, 2011	$(182)
Risk-management losses recognized through the income statement in the period, net	(99)
Cash paid related to risk-management contracts settled in the period, net	178
DMG Acquisition (2)	9
Fair value of portfolio at September 30, 2012	$(94)

(1) Our modeling methodology has been consistently applied.
(2) On June 5, 2012, we completed the DMG Acquisition. Please read Note 5—Merger and Acquisition for further discussion.

The net risk management liability of $94 million is the aggregate of the following line items on our unaudited condensed 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 September 30, 2012, based on our valuation methodology:

Net Fair Value of Risk-Management Portfolio

	Total (in millions)	2012	2013	2014	2015	2016	Thereafter
Market quotations (1) (2)	$(61)	$(51)	$(10)	$—	$—	$—	$—
Prices based on models (2)	(33)	(5)	6	(17)	(13)	(4)	—
Total	$(94)	$(56)	$(4)	$(17)	$(13)	$(4)	$—

(1) Prices obtained from actively traded, liquid markets for commodities.
(2) The market quotations and prices based on models categorization differ from the categories of Level 1, Level 2 and Level 3 used in our fair value disclosures due to the application of the different methodologies. Please read Note 8—Fair Value Measurements for further discussion.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-Q includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements". All statements included or incorporated by reference in this quarterly report, other than statements of historical fact, that address activities, events or developments that we or our management expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements represent our reasonable judgment on 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 includ are not limited to, statements relating to the following:

- our ability to sell the Facilities to one or more third parties as set forth in the Settlement Agreement and the Plan;

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- beliefs and assumptions relating to our liquidity, available borrowing capacity and capital resources generally, including the extent to which such liquidity could be affected by poor economic and financial market conditions or new regulations and any resulting impacts on financial institutions and other current and potential counterparties;
- the anticipated benefits of the overall restructuring activities, our reorganization value and the effects of fresh start accounting;
- limitations on our ability to utilize previously incurred federal net operating losses or alternative minimum tax credits;
- expectations regarding our compliance with the DMG and DPC Credit Agreements, including collateral demands, interest expense and other payments;
- the timing and anticipated benefits of any repayments under the DMG and DPC Credit Agreements;
- the timing and anticipated benefits to be achieved through our company-wide cost savings programs, including our PRIDE initiative;
- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations to which we are, or could become, subject;
- beliefs, assumptions and projections regarding the demand for power, generation volumes and commodity pricing, including natural gas prices and the impact on such prices from shale gas proliferation and the timing of a recovery in natural gas prices, if any;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market, including the anticipation of higher market pricing over the longer term;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- beliefs and assumptions about weather and general economic conditions;
- 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;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the South Bay Facility;
- beliefs and assumptions regarding the outcome of the SCE contract terminations dispute and the impact of such terminations on the timing and amount of future cash flows;
- beliefs about the outcome of legal, administrative, legislative and regulatory matters, including the impact of final rules regarding derivatives to be issued by the CFTC under the Dodd-Frank Act; and
- expectations regarding performance standards and estimates regarding capital and maintenance expenditures.

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 and Item 1A-Risk Factors of this Form 10-Q.

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.

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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. Following is a discussion of the more material of these risks and our relative exposures as of September 30, 2012.

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, Gas and DNE 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 "Value at Risk" in our Form 10-K for a complete description of our valuation methodology. The decrease in the September 30, 2012 VaR was primarily due to decreased forward sales as compared to December 31, 2011.

Daily and Average VaR for Risk-Management Portfolios

	September 30, 2012	December 31, 2011
	(in millions)	
One day VaR—95 percent confidence level	$4	$8
One day VaR—99 percent confidence level	$6	$12
Average VaR for the year-to-date period—95 percent confidence level	$6	$5

Credit Risk. The following table represents our credit exposure at September 30, 2012 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality	Total
	(in millions)		
Type of Business:			
Financial institutions	$2	$—	$2
Utility and power generators	9	—	9
Commercial / industrial / end users	1	4	5
Total	$12	$4	$16

Interest Rate Risk. We are exposed to fluctuating interest rates related to variable rate financial obligations. As of September 30, 2012, all of our third party debt was considered variable rate debt. We use a variety of instruments, including interest rate swaps and caps, to mitigate this interest rate exposure. Our interest rate hedging instruments are recorded at their fair value with changes in fair value recorded in interest expense. The related debt is not recorded at its fair value. Based on a sensitivity analysis of the variable rate financial obligations in our debt portfolio as of September 30, 2012, to the extent LIBOR remains below 1.5 percent, which represents the interest rate floor in DPC and DMG Credit Agreements, each 50 basis point decrease in LIBOR rates will increase interest expense by approximately $6 million over the twelve months ended September 30, 2013, which corresponds to the change in the fair value of the interest rate swaps. We estimate that increases in LIBOR to ranges between 1.5 percent and 2 percent will result in up to $3 million in increased interest expense over the twelve months ended September 30, 2013 as the higher interest expense on the debt would be partially offset the change in the fair value of the interest rate swaps. For these same twelve months, each additional 100 basis point increase in LIBOR above 2 percent would decrease the interest expense recognized over the period by approximately $8 million, as the change in value of the interest rate hedging instruments would more than offset the increase in debt expense for the variable rate debt over the period.

The absolute notional financial contract amounts associated with our interest rate contracts were as follows at September 30, 2012 and December 31, 2011, respectively:

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	September 30, 2012	December 31, 2011
Interest rate risk-management contracts (in millions of U.S. dollars) (1)	$1,100	$788
Fixed interest rate paid (percent)	2.22	2.21
Interest rate risk-management contracts (in millions of U.S. dollars)	$1,400	$900
Interest rate threshold (percent)	2.00	2.00

(1) The $1,100 million interest rate contracts are not effective until the fourth quarter 2013.

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 and our Chief Financial Officer, 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 September 30, 2012.

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 September 30, 2012.

DYNEGY INC.
PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

See Note 14—Commitments and Contingencies—Legal Proceedings to the accompanying unaudited condensed consolidated financial statements for a discussion of the legal proceedings that we believe could be material to us.

Item 1A—RISK FACTORS

Please read Item 1A—Risk Factors, of our Form 10-K, filed September 18, 2012, for factors, risks and uncertainties that may affect future results.

Risks Related to Our Accounting Practices

Information contained in our historical financial statements will not be comparable to the information contained in our financial statements after the application of fresh-start accounting.

Following the consummation of the Plan, our financial condition and results of operations from and after the Effective Date will not be comparable to the financial condition or results of operations reflected in our historical financial statements. As a result of our restructuring under Chapter 11 of the Bankruptcy Code, our financial statements will be subject to the fresh start accounting provisions of GAAP. We will apply fresh start accounting, in which assets, liabilities and non-controlling interests will be recorded at their estimated fair value using the acquisition method. Goodwill, if any, will result if the reorganization value of Dynegy exceeds the net total of the fair value of its assets, liabilities and non-controlling interests. Adjustments to the carrying amounts could be material and could affect prospective results of operations as balance sheet items are settled, depreciated, amortized or impaired.

This will make it difficult for stockholders to assess our performance in relation to prior periods. Our Annual Report on Form 10-K for the fiscal year ending December 31, 2012 will reflect the consummation of the Plan and the adoption of fresh start accounting.

Risks Related to Emergence from Bankruptcy Protection

Our actual financial results may vary significantly from the projections filed with the Bankruptcy Court.

In connection with the Plan, we were required to prepare projected financial information to demonstrate to the Bankruptcy Court the feasibility of the Plan and our ability to continue operations upon emergence from bankruptcy (the “Projections”). We filed the Projections with the Bankruptcy Court most recently on July 12, 2012, as Exhibit E to the disclosure statement related to the Plan and approved by the Bankruptcy Court (the “Disclosure Statement”).

While the Projections were presented in the Disclosure Statement with numerical specificity, our management had based the Projections on a variety of estimates and assumptions that may not be realized and are inherently subject to significant business, economic, competitive, industry, regulatory, market and financial uncertainties and contingencies, many of which will be beyond our control. We do not and cannot make any representations as to the accuracy of the Projections or to our ability to achieve the projected results. Some assumptions inevitably will not materialize. Furthermore, events and circumstances occurring subsequent to the date on which the Projections were prepared may differ from any assumed facts and circumstances. Alternatively, any events and circumstances that come to pass may well have been unanticipated, and thus may affect financial results in a materially adverse or materially beneficial manner. The Projections, therefore, may not be relied upon as a guaranty or other assurance of the actual results that will occur.

The Projections were based upon assumptions, qualifications, and explanations developed in January 2012 and were further qualified in July 2012 to note that the Projections were not updated to reflect changes in the market and other subsequent events, including, without limitation, the termination of certain tolling arrangements for certain Gas assets in the West, changes in the price of natural gas, and changed market costs for delivering coal.

Our emergence from bankruptcy will reduce or eliminate our net operating losses and other tax attributes and limit our ability to offset future taxable income with tax losses and credits incurred prior to its emergence from bankruptcy.

The use of our net operating losses ("NOLs") and alternative minimum tax ("AMT") credits has been limited by two "ownership changes" under Section 382 of the Internal Revenue Code (the "Code") - the first occurring in the second quarter 2012 (the "Initial Ownership Change") and the second on the Effective Date of the Plan ("the Emergence Ownership Change"). The limitation resulting from the Initial Ownership Change is substantial and applies to all NOLs and tax AMT credits existing at the time of the Initial Ownership Change. The limitation resulting from the Emergence Ownership Change has not yet been determined and, although this limitation applies to all NOLs and AMT credits existing at the time of the Emergence Ownership Change, this limitation generally only will have an impact on NOLs and AMT credits generated after the Initial Ownership Change because the NOLs and AMT credits generated before the Initial Ownership Change already are subject to the limitations resulting from the Initial Ownership Change. NOLs and AMT credits generated after the Emergence Ownership Change are not subject to the limitations from either of the prior ownership changes. As a result of the discharge of debt of DH in the Chapter 11 Cases, we and our subsidiaries will be required to reduce the amount of their NOLs and AMT credits and potentially other tax attributes existing at the end of our taxable year. All NOLs and AMT credits are available to be reduced, regardless of whether the NOLs and AMT credits are subject to limitations from the ownership changes. All of these reductions in, and limitation on the use of, NOLs and AMT credits could affect our ability to offset future taxable income.

Item 2—UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Upon vesting of restricted stock awarded to employees, shares are withheld to cover the employees' withholding taxes. Information on our purchases of equity securities during the quarter follows:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 1-31	1,266	$0.58	—	N/A
August 1-31	—	$—	—	N/A
September 1-30	—	$—	—	N/A
Total	1,266	$0.58	—	N/A

These were the only purchases of equity securities made by us during the three months ended September 30, 2012. We do not have a stock repurchase program.

Item 6—EXHIBITS

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

Exhibit Number	Description
2.1	Confirmation Order for Dynegy Inc. and Dynegy Holdings, LLC, as entered by the Bankruptcy Court on September 10, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on September 13, 2012, File No. 001-33443).
2.2	Agreement and Plan of Merger between Dynegy Inc. and Dynegy Holdings, LLC, dated September 28, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 2, 2012, File No. 001-33443).
3.1	Third Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
3.2	Fourth Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
4.1	Registration Rights Agreement, dated October 1, 2012, by and among the Company and the investors party thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
10.1	Dynegy Shareholders Trust Declaration between Dynegy Inc. and Wilmington Trust, National Association, as trustee, dated September 28, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 2, 2012, File No. 001-33443).
*10.2	Warrant Agreement, dated October 1, 2012, by and among Dynegy Inc., Computershare Inc. and Computershare Trust Company, N.A., as warrant agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
10.3	2012 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
10.4	Assignment Agreement by and between Dynegy Inc. and Dynegy Operating Company, dated July 5, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. on July 10, 2012, File No. 001-33443).
10.5	Joint Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC and Dynegy Inc. proposed by Dynegy Holdings, LLC and Dynegy Inc., dated July 12, 2012 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on July 13, 2012, File No. 001-33443).
10.6	Disclosure Statement related to the Joint Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC and Dynegy Inc. proposed by Dynegy Holdings, LLC and Dynegy Inc., dated July 12, 2012 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on July 13, 2012, File No. 001-33443).
10.7	First Amendment to the Amended Plan Support Agreement, dated July 31, 2012, among Dynegy Inc., Dynegy Holdings, LLC and certain of its subsidiaries and certain beneficial owners of a portion of Dynegy Holdings, LLC's outstanding senior notes (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K for Dynegy Inc. and Dynegy Holdings, LLC filed on August 1, 2012, File No. 001-33443).

10.8	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443).
10.9	Form of Stock Unit Award Agreement - Officers (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443).

10.10	Form of Stock Unit Award Agreement - Directors (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443).
**10.11	Form of Phantom Stock Unit Award Agreement - MD & Above Version (2012 LTIP Awards)
**10.12	Form of Phantom Stock Unit Award Agreement - MD & Above Version (2012 Replacement Shares)
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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

** Filed herewith.

† 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:	November 7, 2012	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer