

DYNEGY INC.
Form 10-Q
August 01, 2013
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2013

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

Delaware

I.R.S. Employer

Identification No.

20-5653152

601 Travis, Suite 1400

Houston, Texas

(Address of principal executive offices)

(713) 507-6400

(Registrant's telephone number, including area code)

77002

(Zip 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.

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Large accelerated filer

Non-accelerated filer

(Do not check if a smaller reporting company)

Accelerated filer

Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes
" No

Table of Contents

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 class of common stock, as of the latest practicable date: Common stock, \$0.01 par value per share, 100,030,967 shares outstanding as of July 26, 2013.

Table of Contents

TABLE OF CONTENTS

	Page
PART I. FINANCIAL INFORMATION	
Item 1. FINANCIAL STATEMENTS:	
Condensed Consolidated Balance Sheets: As of June 30, 2013 and December 31, 2012	<u>1</u>
Condensed Consolidated Statements of Operations: For the three and six months ended June 30, 2013 (Successor) and 2012 (Predecessor)	<u>3</u>
Condensed Consolidated Statements of Comprehensive Income (Loss): For the three and six months ended June 30, 2013 (Successor) and 2012 (Predecessor)	<u>4</u>
Condensed Consolidated Statements of Cash Flows: For the six months ended June 30, 2013 (Successor) and 2012 (Predecessor)	<u>5</u>
Notes to Condensed Consolidated Financial Statements	<u>6</u>
Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	<u>34</u>
Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	<u>71</u>
Item 4. CONTROLS AND PROCEDURES	<u>72</u>
PART II. OTHER INFORMATION	
Item 1. LEGAL PROCEEDINGS	<u>73</u>
Item 1A. RISK FACTORS	<u>73</u>
Item 6. EXHIBITS	<u>74</u>
Signature	<u>75</u>

Table of Contents

DEFINITIONS

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

AEM	Ameren Energy Marketing Company
AER	Ameren Energy Resources Company, LLC
AERG	Ameren Energy Resources Generating Company
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTA	Best Technology Available
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CARB	California Air Resources Board
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	U.S. Commodity Futures Trading Commission
CPUC	California Public Utility Commission
CSAPR	Cross-State Air Pollution Rule
DCIH	Dynegy Coal Investments Holdings, LLC
DH	Dynegy Holdings, LLC (formerly known as Dynegy Holdings Inc.)
DMG	Dynegy Midwest Generation, LLC
DMSLP	Dynegy Midstream Services L.P.
DPC	Dynegy Power, LLC
DYPM	Dynegy Power Marketing, LLC
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
ELG	Effluent Limitation Guidelines
EMA	Energy Management Agency Services Agreement
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
IBEW	International Brotherhood of Electrical Workers
IMA	In-market Asset Availability
IPCB	Illinois Pollution Control Board
IPH	Illinois Power Holdings, LLC
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LC	Letter of Credit
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
MW	Megawatts
MWh	Megawatt Hour
NM	Not Meaningful
NPDES	National Pollutant Discharge Elimination System

Table of Contents

NSPS	New Source Performance Standard
NYISO	New York Independent System Operator
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PRIDE	Producing Results through Innovation by Dynegy Employees
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
SO ₂	Sulfur Dioxide
SPDES	State Pollutant Discharge Elimination System
VaR	Value at Risk
VLGC	Very Large Gas Carrier

Item 1—FINANCIAL STATEMENTS

DYNEGY INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited) (in millions, except share data)

	June 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	\$461	\$ 348
Restricted cash	—	98
Accounts receivable	106	108
Accounts receivable, affiliates	—	1
Inventory	76	101
Assets from risk-management activities	8	13
Assets from risk-management activities, affiliates	—	4
Broker margin account	36	40
Intangible assets	175	271
Prepayments and other current assets	51	59
Total Current Assets	913	1,043
Property, Plant and Equipment	3,122	3,064
Accumulated depreciation	(116) (42
Property, Plant and Equipment, Net	3,006	3,022
Other Assets		
Restricted cash	—	237
Assets from risk-management activities	3	—
Intangible assets	31	71
Deferred income taxes	95	95
Other long-term assets	105	67
Total Assets	\$4,153	\$ 4,535

See the notes to condensed consolidated financial statements.

Table of Contents

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

	June 30, 2013	December 31, 2012
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	\$87	\$112
Accounts payable, affiliates	1	1
Accrued interest	6	—
Deferred income taxes	95	95
Accrued liabilities and other current liabilities	79	85
Liabilities from risk-management activities	42	25
Current portion of long-term debt	7	29
Total Current Liabilities	317	347
Long-term debt	1,289	1,386
Other Liabilities		
Liabilities from risk-management activities	39	42
Other long-term liabilities	292	257
Total Liabilities	\$1,937	\$2,032
Commitments and Contingencies (Note 13)		
Stockholders' Equity		
Common Stock, \$0.01 par value, 420,000,000 shares authorized at June 30, 2013 and December 31, 2012; 100,029,507 shares and 99,999,196 shares issued and outstanding at June 30, 2013 and December 31, 2012, respectively	1	1
Additional paid-in capital	2,605	2,598
Accumulated other comprehensive income, net of tax	4	11
Accumulated deficit	(394) (107)
Total Stockholders' Equity	\$2,216	\$2,503
Total Liabilities and Stockholders' Equity	\$4,153	\$4,535

See the notes to condensed consolidated financial statements.

Table of Contents

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

	Successor		Predecessor	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Revenues	\$301	\$619	\$270	\$538
Cost of sales	(253)	(537)	(170)	(350)
Gross margin, exclusive of depreciation shown separately below	48	82	100	188
Operating and maintenance expense, exclusive of depreciation shown separately below	(85)	(156)	(48)	(82)
Depreciation expense	(49)	(103)	(43)	(65)
Gain on sale of assets, net	1	2	—	—
General and administrative expense	(25)	(47)	(17)	(37)
Acquisition and integration costs	(1)	(4)	—	—
Operating income (loss)	(111)	(226)	(8)	4
Bankruptcy reorganization items, net	(2)	(3)	(23)	129
Interest expense	(16)	(45)	(41)	(72)
Loss on extinguishment of debt	(12)	(11)	—	—
Impairment of Undertaking receivable, affiliate	—	—	—	(832)
Other income and expense, net	(9)	(7)	7	31
Loss from continuing operations before income taxes	(150)	(292)	(65)	(740)
Income tax benefit (Note 15)	—	—	1	7
Loss from continuing operations	(150)	(292)	(64)	(733)
Income (loss) from discontinued operations, net of tax (Note 5)	5	5	(5)	(418)
Net loss	\$(145)	\$(287)	\$(69)	\$(1,151)
Loss Per Share (Note 17):				
Basic loss per share:				
Loss from continuing operations	\$(1.50)	\$(2.92)	N/A	N/A
Income from discontinued operations	0.05	0.05	N/A	N/A
Basic loss per share	\$(1.45)	\$(2.87)	N/A	N/A
Diluted loss per share:				
Loss from continuing operations	\$(1.50)	\$(2.92)	N/A	N/A
Income from discontinued operations	0.05	0.05	N/A	N/A
Diluted loss per share	\$(1.45)	\$(2.87)	N/A	N/A
Basic shares outstanding	100	100	N/A	N/A
Diluted shares outstanding	100	100	N/A	N/A

See the notes to condensed consolidated financial statements.

Table of Contents

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

	Successor		Predecessor	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Net loss	\$ (145)	\$ (287)	\$ (69)	\$ (1,151)
Amortization of unrecognized prior service cost and actuarial loss	—	—	—	(1)
Reclassification of curtailment gain included in net loss, net of tax	(7)	(7)	—	—
Other comprehensive loss, net of tax	\$ (7)	\$ (7)	\$ —	\$ (1)
Total comprehensive loss	\$ (152)	\$ (294)	\$ (69)	\$ (1,152)

See the notes to condensed consolidated financial statements.

Table of Contents

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

	Successor Six Months Ended June 30, 2013	Predecessor Six Months Ended June 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	\$(287)	\$(1,151)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation expense	103	65
Loss on extinguishment of debt	11	—
Non-cash interest expense (benefit)	(3)	4
Amortization of intangibles	127	31
Bankruptcy reorganization items, net	—	247
Impairment of Undertaking receivable, affiliate	—	832
Risk-management activities	34	(49)
Risk-management activities, affiliate	—	(1)
Gain on sale of assets, net	(2)	—
Deferred income taxes	—	(7)
Change in value of common stock warrants	9	—
Other	5	4
Changes in working capital:		
Accounts receivable	3	(14)
Inventory	25	1
Broker margin account	(10)	(12)
Prepayments and other current assets	7	(73)
Accounts payable and accrued liabilities	(21)	34
Affiliate transactions	(1)	6
Changes in non-current assets	(5)	(10)
Changes in non-current liabilities	(5)	(14)
Net cash used in operating activities	\$(10)	\$(107)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(55)	(37)
Proceeds from asset sales, net	3	—
Decrease in restricted cash	335	134
DMG acquisition	—	256
Payments received for Undertaking, receivable affiliate	—	16
Other investing	—	3
Net cash provided by investing activities	\$283	\$372
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	1,753	—
Repayments of borrowings, including debt extinguishment costs	(1,913)	(7)
Net cash used in financing activities	\$(160)	\$(7)
Net increase in cash and cash equivalents	113	258
Cash and cash equivalents, beginning of period	348	398
Cash and cash equivalents, end of period	\$461	\$656

See the notes to condensed consolidated financial statements.

5

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

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. The year-end condensed consolidated balance sheet data was derived from audited consolidated financial statements but does not include all disclosures required by GAAP. The unaudited condensed consolidated financial statements contained in this report include all material adjustments of a normal recurring nature that, in the opinion of management, are necessary for a fair presentation of the results for the interim periods. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2012, filed with the SEC on March 14, 2013, which we refer to as our “Form 10-K.” Unless the context indicates otherwise, throughout this report, the terms “Dynegy,” “the Company,” “we,” “us,” “our,” and “ours” are used to refer to Dynegy Inc. and its direct and indirect subsidiaries.

Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as two segments in our consolidated financial statements: (i) the Coal segment (“Coal”) and (ii) the Gas segment (“Gas”). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and depreciation expense. Please read Note 18—Segment Information for further discussion.

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.

The Coal segment includes Dynegy Midwest Generation, LLC (“DMG”), which owns, directly and indirectly, substantially all of our coal-fired power generation facilities. On September 1, 2011, DH sold 100 percent of the outstanding membership interests of Dynegy Coal Holdco, LLC (“Coal Holdco”) to Legacy Dynegy (as defined below), (the “DMG Transfer”). On June 5, 2012, DH reacquired Coal Holdco (including its subsidiary, DMG) from Legacy Dynegy (the “DMG Acquisition”). Therefore, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012. Please read Note 3—Acquisitions—DMG Acquisition for further discussion.

On September 10, 2012, the Bankruptcy Court (as defined and discussed below in Note 4—Chapter 11 Cases) entered an order confirming the Joint Chapter 11 Plan of Reorganization (the “Plan”), and on October 1, 2012, (the “Plan Effective Date”), we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. As a result of the application of fresh-start accounting as of the Plan Effective Date, the financial statements on or prior to October 1, 2012 are not comparable with the financial statements after October 1, 2012. References to “Successor” refer to the Company after October 1, 2012, after giving effect to the application of fresh-start accounting. References to “Predecessor” refer to the Company on or prior to October 1, 2012. Additionally, on the Plan Effective Date, the DNE Debtor Entities (as defined and discussed below in Note 4—Chapter 11 Cases) did not emerge from bankruptcy; therefore, we deconsolidated our investment in these entities as of October 1, 2012 and began accounting for our investment using the cost method. Accordingly, any activity related to our Roseton and Danskammer operations is presented in discontinued operations for all periods presented.

Merger. On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy, with Dynegy continuing as the surviving legal entity (the “Merger”). Immediately prior to the Merger, Legacy Dynegy had no substantive operations as our power generation facilities were operated through subsidiaries of DH. Further, as a result of the DH Chapter 11 Cases (as defined in Note 4—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. 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.

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 prior to the Merger; therefore, no earnings (loss) per share is presented on our unaudited condensed consolidated statement of operations for the three and six months ended June 30, 2012.

Fresh-Start Accounting. On the Plan Effective Date, we applied “fresh-start accounting.” Fresh-start accounting required us to allocate the reorganization value to our assets and liabilities in a manner similar to that which is required using

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

the acquisition method of accounting for a business combination. The financial statements of the Predecessor include the impact of the Plan provisions and the application of fresh-start accounting. As such, our financial information for the Successor is presented on a basis different from, and is therefore not comparable to, our financial information for the Predecessor for the period ended and as of October 1, 2012 or for prior periods. For further information, please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K.

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.

Accounting Principles Adopted During the Current Period

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. In February 2013, the FASB issued Accounting Standards Update (“ASU”) 2013-02—Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This new guidance requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present significant amounts reclassified out of other comprehensive income by the respective line items of net income if the amount is reclassified in its entirety. ASU 2013-02 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. Please read Note 8—Accumulated Other Comprehensive Income (Loss) for further discussion.

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. The FASB added clarification to this guidance in ASU 2013-01—Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. This new guidance 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. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Accounting Principles Not Yet Adopted

Presentation of Unrecognized Tax Benefits. In July 2013, the FASB issued ASU 2013-11—Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. The provisions of the rule require an unrecognized tax benefit to be presented as a reduction to a deferred tax asset in the financial statements for an NOL carryforward, a similar tax loss, or a tax credit carryforward except in circumstances when the carryforward or tax loss is not available at the reporting date under the tax laws of the applicable jurisdiction to settle any additional income taxes or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purposes. When those circumstances exist, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The new financial statement presentation provisions relating to this update are prospective and effective for interim and annual periods beginning after December 15, 2013, with early adoption permitted. We are currently assessing the future impact of this update, but we do not anticipate a material impact on our financial condition, results of operations or cash flows.

Note 3—Acquisitions

AER Transaction Agreement

On March 14, 2013, Illinois Power Holdings, LLC (“IPH”), an indirect wholly-owned subsidiary of Dynegy, entered into a definitive agreement (the “AER Transaction Agreement”) with Ameren Corporation (“Ameren”) pursuant to which IPH will, subject to the terms and conditions in the AER Transaction Agreement, acquire from Ameren 100 percent of the equity interests of Ameren Energy Resources Company, LLC (“AER”) (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) for no cash consideration (the “AER Acquisition”). AER and its subsidiaries consist of a majority

7

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

of Ameren's merchant generation and its wholesale and retail marketing business. Pursuant to the AER Transaction Agreement, IPH will indirectly acquire AER's subsidiaries, including (i) Ameren Energy Generating Company ("Genco"), (ii) Ameren Energy Resources Generating Company ("AERG") and (iii) Ameren Energy Marketing Company ("AEM"). Dynegy Inc. has provided a limited guaranty of certain obligations of IPH up to \$25 million (the "Limited Guaranty") as described below.

The transaction does not include AER's gas-fired power generation facilities: Elgin, Gibson City and Grand Tower (the "Put Assets"). Prior to signing the AER Transaction Agreement, AERG, Genco and Ameren Energy Medina Valley Cogen L.L.C. ("Medina Valley"), an affiliate of AER that IPH will not be acquiring in the transaction, entered into an amendment to a put option agreement (the "Put Option Agreement") whereby the Put Assets will be sold by Genco, subject to approval by FERC, to Medina Valley for a minimum of \$133 million (the "Put Transaction"). New appraisals will be obtained for the Put Assets prior to closing, and if the average value of the appraisals exceeds \$133 million, any excess amount will be remitted to Genco. Further, in the event Ameren sells the Put Assets within two years of closing, Ameren will pay to Genco any after-tax proceeds in excess of \$133 million, or the higher appraised value, if applicable. The minimum amount of \$133 million is based on an average of three appraisals obtained in October 2012. The amount may increase as a result of new appraisals, but cannot be reduced.

In connection with the transaction, Ameren will retain certain historical obligations of AER and its subsidiaries, including certain historical environmental and tax liabilities. Genco's approximately \$825 million of notes will remain outstanding as an obligation of Genco. The debt bears interest at rates from 6.30 percent to 7.95 percent and matures between 2018 and 2032.

In connection with the transaction, Ameren is required at closing to ensure that a minimum of \$85 million of cash, plus approximately \$8 million for the proceeds of certain real estate sales, is available at AER and its subsidiaries of which \$70 million will be held at Genco plus the proceeds of the Put Transaction described above.

The AER Transaction Agreement includes customary representations, warranties and covenants by the parties. The closing of the transaction is expected to occur during the fourth quarter of 2013 and is subject to certain conditions, including (i) consummation of the Put Transaction under the Put Option Agreement; (ii) approval of FERC under Section 203 of the Federal Power Act, as amended ("FERC Approval"); (iii) approval of certain license transfers by the Federal Communications Commission; (iv) approval by the Illinois Pollution Control Board (the "IPCB") of the transfer to IPH of AER's air variance; (v) no injunction or other orders preventing the consummation of the transactions under the AER Transaction Agreement; (vi) the continuing accuracy of each party's representations and warranties; and (vii) the satisfaction of other conditions. On June 6, 2013, the IPCB rejected, on procedural grounds, AER's and IPH's motion to transfer the air variance, which granted AER a temporary exemption for the coal plants of its subsidiaries from certain air pollution limitations under the Illinois' Multi-Pollutant Standard. The IPCB indicated that IPH may file its own request for variance relief. IPH and AER are pursuing such relief, and on July 22, 2013 IPH and certain co-petitioners filed their request for variance relief.

Each party has agreed to indemnify the other for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions. The AER Transaction Agreement contains certain termination rights for both IPH and Ameren, including if the closing does not occur within 12 months following the date of the AER Transaction Agreement (subject to extension to 13 months in certain circumstances, if necessary, in order to obtain FERC approval).

The AER Transaction Agreement provides for the payment of a termination fee by each party under specific circumstances. In certain circumstances, including failure to receive FERC Approval, IPH must pay a termination fee of \$25 million to Ameren.

Concurrently with the execution of the AER Transaction Agreement, Dynegy Inc. entered into the Limited Guaranty, capped at \$25 million in favor of Ameren, pursuant to which we will guarantee payout by IPH of any required termination fee and, for a period of two years after the closing (subject to certain exceptions), up to \$25 million with respect to IPH's indemnification obligations and certain reimbursement obligations under the AER Transaction

Agreement.

DMG Acquisition

On June 5, 2012, pursuant to a settlement agreement entered into with certain of DH's creditors, 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.

8

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

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 Legacy Dynegy in the DH Chapter 11 Cases. 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.

Pro Forma Results. The unaudited pro forma financial results for the six months ended June 30, 2012 show the effect of the DMG Acquisition as if the acquisition had occurred as of January 1, 2012.

(amounts in millions)	Predecessor Six Months Ended June 30, 2012	
Revenues	\$768	
Income from continuing operations	\$10	
Loss from discontinued operations	\$(418))
Net loss	\$(408))

Note 4—Chapter 11 Cases

On November 7, 2011, DH and four of its wholly-owned subsidiaries, Dynegy Northeast Generation, Inc. (“DNE”), 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 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”). 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.

On the Plan Effective Date, we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. DNE, Hudson, Danskammer and Roseton (the “DNE Debtor Entities”) remain in Chapter 11 bankruptcy. As a result, we deconsolidated the DNE Debtor Entities on the Plan Effective Date and began accounting for our investment using the cost method. Accordingly, any activity related to our Roseton and Danskammer operations is reported in discontinued operations for all periods presented. Please read Note 5—Discontinued Operations for further discussion.

As of June 30, 2013 and December 31, 2012, we had approximately \$1 million in net payables and less than \$1 million in net receivables, respectively, from the DNE Debtor Entities related to the Service Agreements included in our unaudited condensed consolidated balance sheets. We account for our investment in the DNE Debtor Entities using the cost method and have a carrying amount of zero. Our maximum exposure to loss related to our investment in the DNE Debtor Entities is limited to our net receivables as we have no obligation to provide funding to the DNE Debtor Entities on an ongoing basis.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

For the three and six months ended and as of June 30, 2013, we do not have any subsidiaries under Chapter 11 protection included in our unaudited condensed consolidated financial statements. The condensed combined financial statements of the Debtor Entities included in our results for the three and six months ended June 30, 2012 are set forth below:

Condensed Combined Statement of Operations of the Debtor Entities

(amounts in millions)	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Revenues	\$—	\$—
Cost of sales	—	—
Operating expenses	—	—
General and administrative expenses	(2) (4
Operating loss	(2) (4
Bankruptcy reorganization items, net	(23) 129
Equity losses	(1,310) (1,327
Impairment of Undertaking receivable, affiliate	—	(832
Other income and expense, net	1,270	1,294
Income tax benefit	1	7
Loss from continuing operations	(64) (733
Loss from discontinued operations	(5) (418
Net loss	\$(69) \$(1,151

Condensed Combined Statement of Cash Flows of the Debtor Entities

(amounts in millions) Six Months Ended
June 30, 2012

Net cash provided by:	
Operating activities	\$ 20
Investing activities	—
Financing activities	—
Net increase in cash and cash equivalents	20
Cash and cash equivalents, beginning of period	33
Cash and cash equivalents, end of period	\$ 53

Basis of Presentation. The condensed combined financial statements only include the financial statements of the DH Debtor Entities. Transactions among the DH Debtor Entities are eliminated in the condensed combined financial statements.

Interest Expense. The DH Debtor Entities discontinued recording interest on unsecured liabilities subject to compromise (“LSTC”) effective November 8, 2011. Contractual interest on LSTC not reflected in the condensed combined financial statements was approximately \$70 million and \$141 million for the three and six months ended June 30, 2012, respectively.

Bankruptcy Reorganization Items, net. Bankruptcy reorganization items, net 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 items, net, 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.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

The following table lists the significant items within this category for the three and six months ended June 30, 2012:

(amounts in millions)	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Adjustments of estimated allowable claims:		
DNE Leases (1)	\$—	\$(395)
Subordinated notes (2)	—	161
Write-off of note payable, affiliate (3)	—	10
Other	—	(4)
Total adjustments for estimated allowable claims	—	(228)
Change in value of Administrative Claim (4)	(9)	(9)
Professional fees (5)	(14)	(33)
Total Bankruptcy reorganization items, net	(23)	(270)
Bankruptcy reorganization items, net included in discontinued operations	—	399
Total Bankruptcy reorganization items, net in continuing operations	\$(23)	\$129

Amount represents adjustments to our estimate of the probable allowed claim associated with the DNE leases as a (1) result of entering into the Settlement Agreement. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion.

The estimated allowable claims related to the Subordinated Capital Income Securities were adjusted in the second (2) quarter 2012 based on the terms of the Settlement Agreement, as amended. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion.

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

(4) The Administrative Claim was issued on the effective date of the Settlement Agreement. Please read Note 3—Acquisitions—DMG Acquisition for further discussion.

(5) Professional fees relate primarily to the fees of attorneys and consultants working directly on the Chapter 11 Cases. Note 5—Discontinued Operations

Discontinued Operations

The DNE Debtor Entities remain in Chapter 11 bankruptcy and continue to operate their businesses as “debtors-in-possession.” As a result, Dynegy deconsolidated the DNE Debtor Entities, effective October 1, 2012. The Bankruptcy Court has approved agreements to sell the Danskammer and Roseton facilities for a combined cash purchase price of \$23 million and the assumption of certain liabilities (the “Facilities Sale Transactions”). On January 23, 2013, the Bankruptcy Court approved the DNE Disclosure Statement. On March 12, 2013, the Bankruptcy Court approved the Plan of Liquidation for the DNE Debtor Entities. On April 30, 2013, we completed the sale of the Roseton facility. The Bankruptcy Court ordered the purchaser of the Danskammer facility to close the transaction by July 31, 2013. The purchaser did not close and Danskammer has terminated its obligations under the purchase agreement. The debtors are actively marketing the Danskammer assets. Should the debtors be unable to find a purchaser for the assets, the debtors will evaluate all alternatives for the Danskammer assets including liquidation of the remaining assets or conversion of the Danskammer Chapter 11 Case to Chapter 7 liquidation under the Bankruptcy Code. In such event, the proceeds from the Roseton Facility Sale Transaction will be distributed pursuant to the Plan of Liquidation, including any modification thereto.

Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting and Note 6—Dispositions and Discontinued Operations in our Form 10-K for further discussion. Any activity related to DNE is reported as discontinued operations for all periods presented.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Summary. The amounts in the table below reflect the operating results of the businesses reported as discontinued operations for the three and six months ended June 30, 2013 and 2012, respectively:

(amounts in millions)	Successor		Predecessor	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Revenues	\$(2)	\$(2)	\$20	\$27
Income (loss) from operations before taxes	\$5	\$5	\$(5)	\$(418)
Income (loss) from operations after taxes	\$5	\$5	\$(5)	\$(418)

Note 6—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 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 and purchase fuel through a combination of spot market sales and near-term contractual arrangements (generally over a rolling one- to three-year time frame). Our commodity risk management goal is to protect cash flow in the near-term while keeping the ability to capture value longer-term.

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our unaudited 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 sale.” 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. Interest rate contracts are entered into for purposes of reducing our exposure to interest rate fluctuations on our variable rate debt. Common stock warrants were issued in connection with our emergence from bankruptcy and allow the holder to purchase, on a one-to-one basis, one common share of Dynegy common stock at \$40/share. We elect not to designate any of our derivatives as accounting hedges. As of June 30, 2013, our commodity derivatives were comprised of both purchases and sales of commodities. As of June 30, 2013, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type (dollars in millions)	Hedge Designation	Quantity	Unit of Measure	Fair Value (1)
Commodity contracts:				
Electricity derivatives (2)	Not designated	(25)	MWh	\$(19)
Natural gas derivatives (2)	Not designated	156	MMBtu	\$(32)
Heat rate derivatives	Not designated	(1)/6	MWh/MMBtu	\$1
Emissions derivatives	Not designated	2	Metric Ton	\$—

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Interest rate contracts:

Interest rate swaps	Not designated	796	Dollars	\$(42)
Interest rate caps (3)	Not designated	1,400	Dollars	\$—)
Common stock warrants	Not designated	16	Warrants	\$(29)

12

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting, as discussed below.

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

(3) The interest rate caps were terminated in July 2013.

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, “Margin”). In addition to these 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 (“Collateral”), letters of credit and first liens. We elect to offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement, where the right of offset exists. We also offset Margin and Collateral paid to or received from all counterparties against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, the consolidated balance sheet presents derivative assets and liabilities, as well as cash paid to or received from all counterparties against those positions, on a net basis.

The following tables present the fair value and balance sheet classification of derivatives in the unaudited condensed consolidated balance sheet as of June 30, 2013 and the consolidated balance sheet as of December 31, 2012 segregated by type of contract segregated by assets and liabilities.

Contract Type	Balance Sheet Location	June 30, 2013			
		Gross Fair Value (1)	Contract Netting	Gross amounts offset in the balance sheet Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	\$83	\$(72)	\$—	\$11
Total derivative assets		\$83	\$(72)	\$—	\$11
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	\$(133)	\$72	\$22	\$(39)
Interest rate contracts	Liabilities from risk management activities	(42)	—	—	(42)
Common stock warrants	Other long-term liabilities	(29)	—	—	(29)
Total derivative liabilities		\$(204)	\$72	\$22	\$(110)
Total derivatives		\$(121)	\$—	\$22	\$(99)

(1) As of June 30, 2013, there were no gross amounts available to be offset that were not offset in our unaudited condensed consolidated balance sheet.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Contract Type	Balance Sheet Location	December 31, 2012			
		Gross Fair Value (1)	Contract Netting	Gross amounts offset in the balance sheet Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	\$61	\$(48)	\$—	\$13
Commodity contracts, affiliates	Assets from risk management activities, affiliates	4	—	—	4
Total derivative assets		\$65	\$(48)	\$—	\$17
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	\$(77)	\$48	\$8	\$(21)
Interest rate contracts	Liabilities from risk management activities	(46)	—	—	(46)
Common stock warrants	Other long-term liabilities	(20)	—	—	(20)
Total derivative liabilities		\$(143)	\$48	\$8	\$(87)
Total derivatives		\$(78)	\$—	\$8	\$(70)

(1) As of December 31, 2012, there were no gross amounts available to be offset that were not offset in our consolidated balance sheet.

The following table summarizes our cash collateral posted as of June 30, 2013 and December 31, 2012, along with the location on the balance sheet and the amount applied against our short-term risk management liabilities.

Location on balance sheet	June 30, 2013		December 31, 2012	
	Collateral posted	Amount applied against short-term risk management liabilities	Collateral posted	Amount applied against short-term risk management liabilities
(amounts in millions)				
Broker margin	\$58	\$22	\$44	\$4
Prepayments and other current assets	\$5	\$—	\$17	\$4

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 six months ended June 30, 2013 and 2012.

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 June 30, 2013 and 2012, our Revenues

include unrealized mark-to-market losses related to our commodity derivatives of \$1 million and \$2 million, respectively. For the six months ended June 30, 2013 and 2012, our Revenues include unrealized mark-to-market gains related to our commodity derivatives of \$37 million and \$70 million, respectively. For the three months ended June 30, 2013 and 2012, our Interest expense includes unrealized mark-to-market gains related to our interest rate derivatives of \$4 million and losses of \$10 million, respectively. For the six months ended June 30, 2013 and 2012, our Interest expense includes unrealized mark-to-market gains related to our interest rate derivatives of \$4 million and losses of \$13 million, respectively.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

The realized and unrealized impact of derivative financial instruments on our unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2013 and 2012 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 and interest payments are made.

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Successor		Predecessor	
		Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
(amounts in millions)					
Commodity contracts	Revenues	\$(16)	\$(50)	\$(32)	\$(24)
Commodity contracts, affiliates	Revenues	\$—	\$(2)	\$—	\$(6)
Interest rate contracts	Interest expense	\$3	\$3	\$(14)	\$(11)
Common stock warrants	Other income (expense), net	\$(9)	\$(9)	\$—	\$—

Note 7—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. 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.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2013 and December 31, 2012 and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid. 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.

(amounts in millions)	Fair Value as of June 30, 2013			
	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	\$—	\$52	\$9	\$61
Natural gas derivatives	—	20	—	20
Heat rate derivatives	—	—	1	1
Emissions derivatives	—	1	—	1
Total assets from commodity risk management activities	\$—	\$73	\$10	\$83
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	\$—	\$(68)	\$(12)	\$(80)
Natural gas derivatives	—	(52)	—	(52)
Emissions derivatives	—	(1)	—	(1)

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Total liabilities from commodity risk management activities	—	(121) (12) (133)
Liabilities from interest rate contracts	—	(42) —	(42)
Liabilities from outstanding common stock warrants	(29) —	—	(29)
Total liabilities	\$(29) \$(163) \$(12) \$(204)

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

(amounts in millions)	Fair Value as of December 31, 2012			Total
	Level 1	Level 2	Level 3	
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	\$—	\$37	\$11	\$48
Natural gas derivatives	—	14	—	14
Heat rate derivatives	—	—	3	3
Total assets from commodity risk management activities	\$—	\$51	\$14	\$65
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	\$—	\$(50)	\$(6)	\$(56)
Natural gas derivatives	—	(20)	—	(20)
Heat rate derivatives	—	—	(1)	(1)
Total liabilities from commodity risk management activities	—	(70)	(7)	(77)
Liabilities from interest rate contracts	—	(46)	—	(46)
Liabilities from outstanding common stock warrants	(20)	—	—	(20)
Total liabilities	\$(20)	\$(116)	\$(7)	\$(143)

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

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

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, forward congestion power price spreads and illiquid power location pricing basis to liquid locations. These estimates are generally independent of each other. Volatility curves and power price spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price or volatility of the spread on a long/short position in isolation would result in a higher/lower fair value measurement. The significant unobservable inputs used in the valuation of Dynegy's contracts classified as Level 3 as of June 30, 2013 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Inputs	Significant Unobservable Inputs Range
(dollars in millions)						
Electricity derivatives:						
Forward contracts—power (1)	(1)	Million MWh	\$(1)	Basis spread + liquid location	Basis spread (per MWh)	\$6.26-\$8.00
Capacity purchases	500	MW month	\$(2)	Most recent auction price	Forward price	\$3.75-\$4.15
Off-peak power options	(397)	Thousand MWh	\$—	Option models	Power price volatility	19%-34%
FTRs	4	Million MWh	\$—	Historical congestion	Forward price (per MWh)	\$3.14-\$7.65
Heat rate derivatives	(1)	Million MWh	\$1	Option models	Gas/power price correlation	77%-84%
	6	Million MMBtu			Power price volatility	19%-36%

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

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

(amounts in millions)	Successor Three Months Ended June 30, 2013		
	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at March 31, 2013	\$—	\$3	\$3
Total gains (losses) included in earnings	—	(2)	(2)
Settlements (1)	(3)	—	(3)
Balance at June 30, 2013	\$(3)	\$1	\$(2)
Unrealized gains (losses) relating to instruments held as of June 30, 2013	\$—	\$(2)	\$(2)

(amounts in millions)	Successor Six Months Ended June 30, 2013		
	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at December 31, 2012	\$5	\$2	\$7

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Total gains (losses) included in earnings	—	(1) (1)
Settlements (1)	(8) —	(8)
Balance at June 30, 2013	\$(3) \$1	\$(2)
Unrealized gains (losses) relating to instruments held as of June 30, 2013	\$—	\$(1) \$(1)

17

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

(amounts in millions)	Predecessor				Total
	Three Months Ended June 30, 2012				
	Electricity Derivatives	Heat Rate Derivatives	Administrative Claim	Interest Rate Swaps (1)	
Balance at March 31, 2012	\$22	\$(11)	\$ —	\$ (9)	\$2
Total gains (losses) included in earnings, net of affiliates	(18)	1	(9)	(9)	(35)
Settlements, net of affiliates (2)	—	2	—	—	2
Issuance of Administrative Claim	—	—	(64)	—	(64)
DMG Acquisition	4	—	—	(7)	(3)
Balance at June 30, 2012	\$8	\$(8)	\$(73)	\$(25)	\$(98)
Unrealized gains (losses) relating to instruments (net of affiliates) held as of June 30, 2012	\$7	\$1	\$(9)	\$(17)	\$(18)

(amounts in millions)	Predecessor				Total
	Six Months Ended June 30, 2012				
	Electricity Derivatives	Heat Rate Derivatives	Administrative Claim	Interest Rate Swaps (1)	
Balance at December 31, 2011	\$20	\$(17)	\$ —	\$(6)	\$(3)
Total gains (losses) included in earnings, net of affiliates	(16)	3	(9)	(17)	(39)
Settlements, net of affiliates (2)	—	6	—	—	6
Issuance of Administrative Claim	—	—	(64)	—	(64)
DMG Acquisition	4	—	—	(2)	2
Balance at June 30, 2012	\$8	\$(8)	\$(73)	\$(25)	\$(98)
Unrealized gains (losses) relating to instruments (net of affiliates) held as of June 30, 2012	\$10	\$1	\$(9)	\$(17)	\$(15)

The interest rate contracts classified within Level 3 in the predecessor period include an implied credit fee that (1) impacted the day one value of the instruments. We revalued the credit fee in connection with the application of fresh-start accounting. As a result, these instruments are classified within Level 2 in the successor period.

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

Gains and losses (realized and unrealized) for Level 3 recurring items are included in Revenues and Interest expense on the unaudited condensed consolidated statements of operations for commodity derivatives and interest rate swaps, 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 six months ended June 30, 2013 and 2012. Nonfinancial Assets and Liabilities. Nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

We did not have any nonfinancial assets or liabilities measured at fair value on a non-recurring basis during the three and six months ended June 30, 2013.

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.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

The carrying values of financial assets and liabilities (cash, accounts receivable, restricted cash and accounts payable) not presented in the table below approximate fair values due to the short-term maturities of these instruments. Unless otherwise noted, the fair value of debt as reflected in the table has been calculated based on the average of certain available broker quotes as of June 30, 2013 and December 31, 2012, respectively.

(amounts in millions)	June 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Interest rate derivatives not designated as accounting hedges (1)	\$(42)	\$(42)	\$(46)	\$(46)
Commodity-based derivative contracts not designated as accounting hedges (1)	\$(50)	\$(50)	\$(12)	\$(12)
DPC Credit Agreement, due 2016 (2)	\$—	\$—	\$(880)	\$(874)
DMG Credit Agreement, due 2016 (3)	\$—	\$—	\$(535)	\$(537)
Tranche B-2 Term Loan, due 2020 (4)	\$(796)	\$(794)	\$—	\$—
5.875% Senior Notes, due 2023 (5)	\$(500)	\$(458)	\$—	\$—
Common stock warrants	\$(29)	\$(29)	\$(20)	\$(20)

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

Carrying amount includes an unamortized premium of \$43 million at December 31, 2012. The fair value of the (2)DPC Credit Agreement is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

Carrying amount includes an unamortized premium of \$18 million as of December 31, 2012. The fair value of the (3)DMG Credit Agreement is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

Carrying amount includes an unamortized discount of \$4 million as of June 30, 2013. The fair value of the Tranche (4)B-2 Term Loan is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

The fair value of the Senior Notes is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt (5) for further discussion.

Note 8—Accumulated Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive income (loss), net of tax, by component, associated with pension and other post-employment benefit plans, for the six months ended June 30, 2013 and 2012 are as follows:

(amounts in millions)	Successor	Predecessor
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Beginning of period	\$11	\$1
Current period other comprehensive income:		
Other comprehensive income before reclassifications	—	(1)
Amounts reclassified from accumulated other comprehensive income (loss) (1)	(7)	—
Net current period other comprehensive loss	(7)	(1)
DMG Acquisition	—	(25)
End of period	\$4	\$(25)

(1) Amounts reclassified from accumulated other comprehensive income (loss) relate to the DNE pension curtailment gain and are recorded in Income (loss) from discontinued operations, net of tax on our unaudited condensed

consolidated statements of operations. See Note 16—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 9—Inventory

A summary of our inventories is as follows:

(amounts in millions)	June 30, 2013	December 31, 2012
Materials and supplies	\$44	\$46
Coal	23	52
Fuel oil	3	3
Emissions allowances	6	—
Total	\$76	\$101

Note 10—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:

(amounts in millions)	Successor Six Months Ended June 30, 2013	Predecessor Six Months Ended June 30, 2012
Beginning of period	\$83	\$50
Accretion expense	2	1
Revision of previous estimate (1)	36	(16)
DMG Acquisition (2)	—	53
Deconsolidation of DNE	—	(11)
Expenditures	(1)	—
End of period	\$120	\$77

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

The increase in our AROs for the Successor period primarily relates to revised estimates based on observed trends (1) in Illinois related to ash pond closures and groundwater monitoring. The reduction in our AROs for the Predecessor period relates to revised cost estimates related to the demolition of our South Bay facility.

As a result of the DMG Transfer on September 1, 2011, the AROs related to our Coal segment were transferred (2) from DH to Legacy Dynegy and subsequently, as a result of the DMG Acquisition, the AROs were transferred back to DH on June 5, 2012.

Note 11—Intangible Assets and Liabilities

A summary of changes in our intangible assets and liabilities is as follows:

(amounts in millions)	Gas Revenue Contracts	Coal Contracts	Gas Transport	Total
Balance at December 31, 2012	\$ 202	\$ 115	\$(22)	\$ 295
Amortization	(67)	(64)	4	(127)
Balance at June 30, 2013 (1)	\$ 135	\$ 51	\$(18)	\$ 168

The total amount of \$168 million consists of \$175 million in short-term Intangible assets, \$31 million in long-term (1) Intangible assets, \$16 million in Accrued liabilities and other current liabilities, and \$22 million in Other long-term liabilities on our unaudited condensed consolidated balance sheet.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Note 12—Debt

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

(amounts in millions)	June 30, 2013	December 31, 2012
DPC Credit Agreement, due 2016 (1)	\$ —	\$ 837
DMG Credit Agreement, due 2016 (1)	—	517
Tranche B-2 Term Loan, due 2020 (2)	800	—
Revolving Facility (2)	—	—
5.875% Senior Notes, due 2023 (3)	500	—
	1,300	1,354
Unamortized (discount) premium on debt, net	(4) 61
	1,296	1,415
Less: Amounts due within one year, including unamortized (discount) premium on debt, net of (\$1 million and \$15 million, respectively	7	29
Total Long-term debt	\$ 1,289	\$ 1,386

(1) Please read Note 18—Debt—DPC and DMG Credit Agreements in our Form 10-K for further discussion.

(2) On April 23, 2013, we entered into the Credit Agreement. Please read Credit Agreement below for further discussion.

(3) On May 20, 2013, we issued the Senior Notes. Please read Senior Notes below for further discussion.

Credit Agreement

On April 23, 2013, Dynegy (the “Borrower”) entered into a \$1.775 billion credit agreement that consists of (i) a \$500 million seven-year senior secured term loan B facility (the “Tranche B-1 Term Loan”), (ii) an \$800 million seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan” and, together with the Tranche B-1 Term Loan, the “Term Facilities”) and (iii) a \$475 million five-year senior secured revolving credit facility (the “Revolving Facility,” and collectively with the Term Facilities, the “Credit Agreement”). The Term Facilities were offered to investors below par with an original issue discount of 99.5. The Term Facilities bear interest at LIBOR plus 3.00 percent per annum with a one percent floor. The Term Facilities mature April 23, 2020 and will amortize in equal quarterly installments in aggregate annual amounts equal to 1.00 percent of the original principal amount with the balance payable on the maturity date. The Revolving Facility bears interest, initially, at LIBOR plus 2.75 percent per annum, with steps down based on a Senior Secured Leverage Ratio (as defined in the Credit Agreement) and matures April 23, 2018. The Revolving Facility has a commitment fee of 0.50 percent on the unutilized portion of the facility, with steps down based on a Senior Secured Leverage Ratio. The commitment fees are due and payable quarterly in arrears.

At June 30, 2013, we had outstanding letters of credit of approximately \$190 million, which reduces the amount available under the Revolving Facility.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

All obligations of the Borrower under the Credit Agreement are unconditionally guaranteed on a senior basis by certain existing and subsequently acquired or organized direct and indirect material domestic restricted subsidiaries of the Borrower on a joint and several basis (the “Guarantors”). The obligations under the Credit Agreement and certain of our hedging obligations are secured by a perfected first-priority lien on and security interests in substantially all of the present and future assets of the Borrower and each Guarantor (collectively, the “Collateral”). The Collateral excludes certain assets, including, following the consummation of the AER Acquisition, AER and its subsidiaries and their direct and indirect holding companies.

The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a senior secured leverage ratio calculated on a rolling four quarters basis. Under the Credit Agreement, if Dynegy has utilized 25 percent or more of its Revolving Facility, Dynegy must be in compliance with the following ratios for the respective periods:

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

(1) For purposes of calculating Net Debt, we may only apply a maximum of \$150 million in cash to our outstanding secured debt.

Borrowings under the Credit Agreement, together with a portion of our cash on hand, were used to repay in full and terminate commitments under: (i) the DPC Credit Agreement and DMG Credit Agreement, (ii) the DPC Revolving Credit Agreement, (iii) the DPC Letter of Credit Reimbursement and Collateral Agreement, (iv) the DMG Letter of Credit Reimbursement and Collateral Agreement, (v) the Dynegy Letter of Credit Reimbursement and Collateral Agreement and (vi) the Dynegy CS Letter of Credit Agreement. As a result of repaying and terminating these credit agreements, all of the restricted cash on hand was released. None of the borrowings under the Credit Agreement were classified as restricted cash. In connection with the refinancing, the bankruptcy remoteness provisions of certain of our subsidiaries and the related ring-fenced structure at our Coal and Gas segments were removed.

Senior Notes

On May 20, 2013, Dynegy and its current and future wholly-owned domestic subsidiaries (the “Subsidiary Guarantors”) entered into an indenture (the “Indenture”) pursuant to which Dynegy issued \$500 million in aggregate principal amount of unsecured senior notes (the “Senior Notes”) at par. The Senior Notes bear interest at a rate of 5.875 percent per annum. The Senior Notes mature on June 1, 2023.

The Indenture limits, among other things, Dynegy’s ability or any of its Subsidiary Guarantors to (i) create liens upon any principal property to secure debt for borrowed money and (ii) consolidate, merge or sell all or substantially all of their assets. In the event of a Change of Control (as defined in the Indenture), Dynegy will be required to make an offer to each holder of Senior Notes to repurchase all or any part of that holder’s Senior Notes at a repurchase price in cash equal to 101 percent of the aggregate principal amount of the Senior Notes repurchased plus accrued interest. If an event of default arises from certain bankruptcy or insolvency events, all outstanding Senior Notes will become due and payable immediately without further action or notice. In addition, under the Indenture, the Senior Notes may be declared due and payable immediately by the trustee, or the holders of at least 25 percent in aggregate principal amount of the Senior Notes then outstanding, if other events of default occur, subject to certain qualifications and applicable grace periods, and are continuing under the Indenture.

Borrowings under the Senior Notes were used to repay in full and terminate commitments under the Tranche B-1 Term Loan.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Loss on Extinguishment of Debt

In connection with the termination of the DPC and DMG credit agreements, the DPC Revolving Credit Agreement and the Term Loan B-1, we recorded net charges of approximately \$11 million, which is included in Loss on extinguishment of debt on our condensed consolidated statement of operations and consists of (i) a prepayment penalty of approximately \$59 million, (ii) \$2 million accelerated amortization of the discount on the Term Loan B-1, (iii) \$6 million for the accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) \$56 million in non-cash gains for the accelerated amortization of the remaining premium related to the DPC and DMG Credit Agreements.

Interest Rate Swaps

Prior to executing the Credit Agreement and the issuance of the Senior Notes, we had interest rate swaps outstanding with notional amounts aggregating \$1.1 billion at an average fixed rate of 2.2 percent. These swaps were scheduled to terminate in August 2016, which coincided with the termination of our previous DPC and DMG Credit Agreements. Subsequent to executing the Credit Agreement and issuing the Senior Notes, we amended the interest rate swaps to more closely match the terms of our existing floating rate debt. The new swaps have an aggregate notional amount of approximately \$796 million at an average fixed rate of 3.15 percent with a floor of one percent. Settlements on these swaps commence in the third quarter 2013 and run through the second quarter 2020. In lieu of paying the breakage fees related to terminating the old swaps and issuing the new swaps, the costs were incorporated into the terms of the new swaps. As a result, any cash flows related to the settlement of the new swaps will be reflected as a financing activity in our consolidated statement of cash flows.

DPC Revolving Credit Agreement

DPC, as borrower, and certain of its subsidiaries entered into a revolving credit agreement (the "DPC Revolving Credit Agreement"), dated January 16, 2013 (the "Closing Date"). Borrowings under the DPC Revolving Credit Agreement were available for ongoing working capital requirements and general corporate purposes of DPC and its subsidiaries. The DPC Revolving Credit Agreement created a 364-day senior secured revolving credit facility with commitments in principal amount of \$150 million (the "DPC Revolving Credit Facility"), which was available on the closing date. DPC was required to pay a commitment fee at a rate of 0.50 percent per year on the average daily unused amount of the commitment under the DPC Revolving Credit Facility. There were no borrowings on the DPC Revolving Credit Agreement.

On April 23, 2013, we entered into the Credit Agreement, at which time the DPC Revolving Credit Agreement was terminated.

Restricted Cash

As a result of repaying and terminating these credit agreements, we no longer have any restricted cash. The following table depicts our restricted cash as of December 31, 2012:

(amounts in millions)	December 31, 2012
DPC LC facilities (1)	\$220
DPC Collateral Posting Account (2)	63
DMG LC facility (3)	14
DMG Collateral Posting Account (2)	8
Corporate LC facilities (1)	27
Other (4)	3
Total restricted cash	\$335

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

Amounts were restricted and used for future collateral posting requirements or released per the terms of the (2) applicable credit agreement. As a result of terminating these credit agreements, all of our restricted cash was released.

- (3) Includes cash posted to support the letter of credit reimbursement and collateral agreements under the DMG LC facility. Please read “Letter of Credit Facilities” in our Form 10-K for further discussion.
- (4) Includes cash posted to support a letter of credit and collateral for the corporate card program.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Note 13—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.

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 alleged 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. On April 4, 2013, the parties settled the matter for an immaterial amount.

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 continue to 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. On June 4, 2013, the District Court dismissed the appeal. On July 3, 2013, the lead plaintiff filed a notice of appeal with the United States Court of Appeals for the Second Circuit. On July 19, 2013, the defendants filed a substantive motion to dismiss the plaintiffs' remaining claims.

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 we

individually, and in conjunction with other energy companies, engaged in an illegal scheme to inflate natural gas prices in four states by providing false information to natural gas index publications. In July 2011, the court granted defendants' motions for summary judgment, thereby dismissing all of plaintiffs' claims. Plaintiffs appealed the decision to the Ninth Circuit Court of Appeals which reversed the summary judgment on April 10, 2013. We anticipate filing a writ of certiorari with the United States Supreme Court seeking review of the Ninth Circuit's decision.

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

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

PPE \$17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award in the District Court of Dallas County, Texas. In March 2010, the Dallas District Court vacated the award, finding that one of the arbitrators had exhibited evident partiality. PPE appealed that decision to the Fifth District Court of Appeals in Dallas, Texas. Coincident with the appeal, IGC filed a claim against PPE seeking recovery of the \$17 million plus interest. In September 2010, the Dallas District Court ordered PPE to deposit the \$17 million principal in an interest-bearing escrow account jointly owned by IGC and PPE. On August 20, 2012, the Dallas Court of Appeals reversed the Dallas District Court and reinstated the award. IGC and the other respondents filed a petition for review with the Texas Supreme Court on December 5, 2012. As a result of the uncertainty surrounding the outcome of PPE's appeal, we did not assign any value to this potential receivable in fresh-start accounting.

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. On October 1, 2012, 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. On November 29, 2012, FERC issued a letter order approving the settlement agreement. There is a 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 June 30, 2013.

Dam Safety Assessment Reports. In March 2013, the EPA issued final dam safety assessment reports of the surface impoundments at our Baldwin and Hennepin facilities. The reports rate the impoundments at each facility as "poor," meaning that a deficiency is recognized for a required loading condition in accordance with applicable dam safety criteria. A poor rating also applies when further critical studies are needed to identify any potential dam safety deficiencies. The reports include recommendations for further studies, repairs, and changes in operational and maintenance practices. In July 2013, in response to the final report concerning Hennepin, we notified the EPA of our intent to close the Hennepin west ash pond system. The preliminary estimated cost for closure of the west ash pond system, including post-closure monitoring, is approximately \$5 million. As a result of these changes, we increased our ARO by approximately \$2 million during the second quarter 2013. We plan on performing the other recommended further studies and actions at Baldwin and Hennepin, some of which are dependent on necessary permits being obtained. The nature and scope of repairs that ultimately may be needed, if any, cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

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 but the Illinois EPA has not required further investigation. 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.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

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 \$11 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 associated estimated closure cost would add an additional \$2 million to the above estimate.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, we have initiated a six month geotechnical study at Vermilion and have begun a twelve month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. 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 individual NPDES (or SPDES) permits on a case-by-case basis.

The environmental groups that participate in our NPDES permit proceedings generally argue that only closed cycle cooling meets the BTA requirement. The issuance and renewal of the NPDES permit for one of our power generation facilities (Moss Landing) was challenged on this basis. 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.

Other future NPDES 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 SO₂ and mercury air emissions) at Havana. The permit remains in effect during the appeal. The petitioners subsequently filed a separate petition with the Illinois Pollution Control Board to reopen the Havana NPDES permit to include limitations on the affected wastewater discharges. We dispute the allegations in both proceedings and will defend the permit vigorously. The outcome of these proceedings is uncertain at this time.

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,

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

filed an appeal of the remand order in the D.C. Circuit. On December 18, 2012, the D.C. Circuit issued an order denying the appeal of the generator group and affirming FERC's orders on remand.

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. The CPUC Commissioners were scheduled to vote on a draft resolution that rejected the arguments in our protest and approved PG&E's proposed station power charges, including retroactive implementation of such charges, on October 15, 2012. However, the draft resolution was withdrawn from the Commission's calendar and has not yet been rescheduled for a vote. We believe we have established an appropriate accrual.

SCE Termination. In May 2012, Southern California Edison ("SCE") notified Dynegy Morro Bay, LLC and Dynegy Moss Landing, LLC 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 are vigorously pursuing all remedies and amounts due to us under these contracts.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. In June 2013, we amended our maintenance agreements. The term of the agreements will be determined by the maintenance cycles of the respective facility. We currently estimate these agreements will be in effect for a period of 15 or more years. Either party can terminate the agreements based on certain events as specified in the contracts. As of June 30, 2013, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately \$143 million and \$209 million in the event all contracts are terminated by us or the counterparty, respectively.

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, 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.

Indemnifications

We entered into indemnifications regarding environmental, tax, employee and other representations when completing asset sales such as, but not limited to, Calcasieu and Heard County power generating facilities, the sale of our midstream business ("DMSLP"), the sale of Illinois Power Company and the sale of assets to LS Power. DPC remains the sole entity liable for indemnification claims with respect to Calcasieu and Heard County. DYPM remains liable for indemnification claims with respect to DMSLP. Illinova Corporation remains liable for any indemnification claims resulting from the Illinois Power Company sale. DPC, DMG and DYPM remain jointly and severally liable for any indemnification claims for the LS Power asset sales. As of June 30, 2013, no claims have been made against and we have not recorded a liability for these indemnities.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

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 June 30, 2013, 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 \$52 million under the guarantee. No amount has been accrued related to this guarantee as we consider the likelihood of a default to be remote.

Other Minimum Commitments

We are party to two charter agreements related to VLGCs previously utilized in our former global liquids business. The primary term of one charter is through September 2013 while the primary term of the second charter is through September 2014. Both of these VLGCs have been sub-chartered to a wholly-owned subsidiary of Transammonia Inc. on terms that are identical to the terms of the original charter agreements. The aggregate minimum base commitments of the charter party agreements are approximately \$7 million, \$13 million and \$5 million for the remainder of 2013, 2014 and 2015, respectively. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreements.

Note 14—Related Party Transactions

The following table summarizes the cash received for the three and six months ended June 30, 2013 and 2012 related to various agreements with Dynegy Inc., as discussed below.

(amounts in millions)	Successor		Predecessor	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Service Agreements	\$1	\$2	\$4	\$15
EMA Agreements	—	—	—	1
Total	\$1	\$2	\$4	\$16

The following table summarizes the Accounts receivable, affiliates, and Accounts payable, affiliates, on our unaudited condensed consolidated balance sheets as of June 30, 2013 and December 31, 2012 related to various agreements with Dynegy Inc., as discussed below.

(amounts in millions)	June 30, 2013		December 31, 2012	
	Accounts Receivable, Affiliates	Accounts Payable, Affiliates	Accounts Receivable, Affiliates	Accounts Payable, Affiliates
Service Agreements	\$—	\$1	\$1	\$1
EMA Agreements	—	—	—	—
Total	\$—	\$1	\$1	\$1

Service Agreements. Legacy Dynegy and certain of our subsidiaries (collectively, the “Providers”) provided certain services (the “Services”) to DCIH and certain of its subsidiaries, and certain of our subsidiaries (collectively, the “Recipients”). Additionally, we provide certain services to the DNE Debtor Entities. Service Agreements between Legacy Dynegy and the Recipients govern the terms under which such Services are provided.

As a result of the Merger, transactions between DH and Legacy Dynegy executed under the Service Agreements subsequent to September 30, 2012, are no longer considered related party transactions because they eliminate in consolidation.

On October 1, 2012, Dynegy deconsolidated the DNE Debtor Entities. Please read Note 1—Organization and Operations—Chapter 11 Filing and Emergence from Bankruptcy in our Form 10-K for further discussion. Our unaudited

condensed consolidated statement of operations includes \$1 million and \$3 million of power purchased from our unconsolidated affiliate, which is reflected in Revenues for the three and six months ended June 30, 2013.

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 other subsidiaries, 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 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 other subsidiaries with risk management by entering into one or more risk management transactions, the purpose of which is to set the price or value of 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. 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. Our unaudited condensed consolidated statement of operations includes \$69 million and \$198 million of power purchased from affiliates, which is reflected in Revenues, and \$24 million and \$79 million of coal sold to affiliates, which is reflected in Costs of sales, for the three and six months ended June 30, 2012, respectively. This affiliate activity is presented net of third party activity within Revenue and Cost of sales. Also, please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for derivative balances with affiliates.

DMG Transfer and Undertaking Agreement. During the six months ended June 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 during the three months ended June 30, 2012 as we impaired the value of the Undertaking as of March 31, 2012 and the valuation as of that date considered the interest payments received during the second quarter of 2012. In addition, we received payments of \$48 million from Legacy Dynegy during the three and six months ended June 30, 2012 related to the Undertaking Agreement. The Undertaking Agreement was terminated on June 5, 2012 in connection with the execution of the Settlement Agreement.

Note payable, affiliates. On August 5, 2011, Coal Holdco made a loan to DH of \$10 million with a maturity of three 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.

Note 15—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. Dynegy Inc.’s income taxes included in continuing operations were as follows:

(amounts in millions, except rates)	Successor		Predecessor		
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012	
Income tax benefit	\$—	\$—	\$1	\$7	
Effective tax rate	—	% —	% 2	% 1	%

For the three and six months ended June 30, 2013, our overall effective tax rate on continuing operations of zero percent was different than the statutory tax rate of 35 percent primarily due to a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of June 30, 2013, 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 three months ended June 30, 2012, our overall effective tax rate on continuing operations of two percent was different than the statutory tax rate of 35 percent due primarily to the impact of state taxes.

For the six months ended June 30, 2012, our overall effective tax rate on continuing operations of one percent was different than the statutory tax rate of 35 percent primarily due to a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of June 30, 2012, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Note 16—Pension and Other Post-Employment Benefit Plans

We sponsor and administer defined benefit plans and defined contribution plans for the benefit of our employees and also provide other post 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.

As a result of the DMG Transfer on September 1, 2011, we and our subsidiaries were no longer the primary participant in certain defined benefit pension and other post-employment benefit plans sponsored by Legacy Dynegy; therefore, we began accounting for our participation in these plans as multi-employer plans. The transfer of the plans was recorded as part of the DMG Transfer as a common control transaction.

Additionally, we completed the DMG Acquisition on June 5, 2012, and we were once again the primary participant in certain defined benefit pension and other post-employment benefit plans; therefore, the costs related to these plans were included within net periodic benefit costs only from June 6 to June 30, 2012 for the three and six months ended June 30, 2012 and for the full three and six months ended June 30, 2013.

Components of Net Periodic Benefit Cost. The components of net periodic benefit cost for the three and six months ended June 30, 2013 and 2012 were as follows:

(amounts in millions)	Pension Benefits			
	Successor		Predecessor	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Service cost benefits earned during period	\$2	\$5	\$1	\$1
Interest cost on projected benefit obligation	3	6	1	1
Expected return on plan assets	(4) (9) (1) (1
Curtailment gain (1)	(7) (7) —) —
Total net periodic benefit cost (gain)	\$(6) \$(5) \$1) \$1

(1) The curtailment gain is related to the DNE pension plan and resulted from the Roseton sale and the termination of a majority of the Danskammer employees.

(amounts in millions)	Other Benefits			
	Successor		Predecessor	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Service cost benefits earned during period	\$—	\$1	\$—	\$1
Interest cost on projected benefit obligation	1	1	1	1
Total net periodic benefit cost	\$1	\$2	\$1	\$2

Contributions. We are not required to make contributions to our pension plans and other postretirement benefit plans during 2013; however, during the six months ended June 30, 2013, we made \$6 million in voluntary contributions to our pension plans and no contributions to our other post-retirement benefit plans.

Note 17—Loss Per Share

The reconciliation of basic loss per share from continuing operations to diluted loss per share from continuing operations of our common stock outstanding during the period is shown in the following table. Basic loss per share represents the amount of losses for the period available to each share of our common stock outstanding during the period. Diluted loss per share represents the amount of losses for the period available to each share of our common

stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all dilutive potential common shares outstanding during the period. Please read Note 23—Capital Stock in our Form 10-K for further discussion.

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 during the Predecessor periods; therefore, no loss per share is presented for the three and six months ended June 30, 2012.

(in millions, except per share amounts)	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Loss from continuing operations for basic and diluted loss per share	\$(150) \$(292
Basic weighted-average shares	100	100
Effect of dilutive securities—stock options and restricted stock units	—	—
Diluted weighted-average shares	100	100
Loss per share from continuing operations:		
Basic	\$(1.50) \$(2.92
Diluted (1)	\$(1.50) \$(2.92

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Entities with a net loss from continuing operations are prohibited from including potential common shares in the (1) computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the three and six months ended June 30, 2013.

Note 18—Segment Information

We report the results of our operations in two segments: (i) Coal and (ii) Gas. In connection with our emergence from bankruptcy, we deconsolidated the DNE Debtor Entities and we began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified DNE's operating results as discontinued operations in the consolidated financial statements for all periods presented. Subsequent to our emergence from bankruptcy, management does not consider general and administrative expense when evaluating the performance of our Coal and Gas segments, but instead evaluates general and administrative expense on an enterprise-wide basis. Accordingly, we recast our segments to present general and administrative expense in Other and Eliminations for all periods presented.

On September 1, 2011, we completed the DMG Transfer. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition; therefore, the results of our Coal segment are only included in our consolidated results for the period of June 6 through June 30, 2012 and in subsequent periods. Please read Note 3—Acquisitions—DMG Acquisition for further discussion.

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three and six months ended June 30, 2013 and 2012 is presented below:

Segment Data as of and for the Three Months Ended June 30, 2013

(amounts in millions)	Successor			Total
	Coal	Gas	Other and Eliminations	
Domestic:				
Unaffiliated revenues	114	187	\$—	\$301
Intercompany revenues	1	(1) —	—
Total revenues	\$115	\$186	\$—	\$301
Depreciation expense	(10) (39) —	(49
General and administrative expense	—	—	(25) (25
Operating loss	\$(49) \$(36) \$(26) \$(111
Bankruptcy reorganization items, net	—	—	(2) (2
Interest expense				(16
Loss on extinguishment of debt				(12
Other items, net	—	(1) (8) (9
Loss from continuing operations before income taxes				(150
Income tax benefit				—
Loss from continuing operations				(150
Income from discontinued operations, net of tax				5
Net loss				\$(145
Identifiable assets (domestic)	\$1,214	\$2,378	\$561	\$4,153
Capital expenditures	\$(19) \$(15) \$(1) \$(35

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2013 and 2012

Segment Data as of and for the Three Months Ended June 30, 2012

(amounts in millions)	Predecessor			Total
	Coal	Gas	Other and Eliminations	
Domestic:				
Unaffiliated revenues	\$40	\$230	\$—	\$270
Total revenues	\$40	\$230	\$—	\$270
Depreciation expense	(4) (36) (3) (43
General and administrative expense	—	—	(17) (17
Operating income (loss)	\$(17) \$28	\$(19) \$(8
Bankruptcy reorganization items, net	—	—	(23) (23
Interest expense				(41
Other items, net	5	2	—	7
Loss from continuing operations before income taxes				(65
Income tax benefit				1
Loss from continuing operations				(64
Loss from discontinued operations, net of tax				(5
Net loss				\$(69
Identifiable assets (domestic)	\$1,340	\$5,254	\$205	\$6,799
Capital expenditures	\$(11) \$(12) \$(5) \$(28

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2013 and 2012

Segment Data as of and for the Six Months Ended June 30, 2013

(amounts in millions)	Successor			Total
	Coal	Gas	Other and Eliminations	
Domestic:				
Unaffiliated revenues	201	418	\$—	\$619
Intercompany revenues	1	(1) —	—
Total revenues	\$202	\$417	\$—	\$619
Depreciation expense	(23) (79) (1) (103
General and administrative expense	—	—	(47) (47
Operating loss	\$(129) \$(44) \$(53) \$(226
Bankruptcy reorganization items, net	—	—	(3) (3
Interest expense				(45
Loss on extinguishment of debt				(11
Other items, net	—	—	(7) (7
Loss from continuing operations before income taxes				(292
Income tax benefit				—
Loss from continuing operations				(292
Income from discontinued operations, net of tax				5
Net loss				\$(287
Identifiable assets (domestic)	\$1,214	\$2,378	\$561	\$4,153
Capital expenditures	\$(31) \$(23) \$(1) \$(55

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended June 30, 2013 and 2012

Segment Data as of and for the Six Months Ended June 30, 2012

(amounts in millions)	Predecessor			Total
	Coal	Gas	Other and Eliminations	
Domestic:				
Unaffiliated revenues	\$40	\$498	\$—	\$538
Total revenues	\$40	\$498	\$—	\$538
Depreciation expense	(4) (56) (5) (65
General and administrative expense	—	—	(37) (37
Operating income (loss)	\$(17) \$62	\$(41) \$4
Bankruptcy reorganization items, net	—	—	129	129
Interest expense				(72
Impairment of Undertaking receivable, affiliate	—	—	(832) (832
Other items, net	5	2	24	31
Loss from continuing operations before income taxes				(740
Income tax benefit				7
Loss from continuing operations				(733
Loss from discontinued operations, net of tax				(418
Net loss				\$(1,151
Identifiable assets (domestic)	\$1,340	\$5,254	\$205	\$6,799
Capital expenditures	\$(11) \$(20) \$(6) \$(37

33

DYNEGY INC.

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

For the Interim Periods Ended June 30, 2013 and 2012

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 two separate segments in our unaudited condensed consolidated financial statements: (i) Coal and (ii) Gas. In connection with our emergence from bankruptcy on the Plan Effective Date, we deconsolidated the DNE Debtor Entities, which constituted our previously reported DNE segment, and began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified the results of the previously reported DNE segment as discontinued operations in our consolidated financial statements for all periods presented.

Refinancing of Debt Obligations

During the six months ended June 30, 2013, we refinanced existing indebtedness.

New Credit Agreement. On April 23, 2013, Dynegy entered into \$1.775 billion in new credit facilities including \$1.3 billion in new senior, secured term loans and a \$475 million corporate revolver. The proceeds of the term loans were used, together with cash on hand, to repay the former DMG and DPC credit agreements and fund related transaction costs. Please read Note 12—Debt for further discussion.

Senior Notes. On May 20, 2013, Dynegy and its Subsidiary Guarantors entered into an Indenture pursuant to which Dynegy issued \$500 million in aggregate principal amount of Senior Notes. Borrowings under the Senior Notes were used to repay in full and terminate commitments under a portion of the senior, secured term loans. Please read Note 12—Debt for further discussion.

AER Transaction Agreement

On March 14, 2013, IPH entered into the AER Transaction Agreement, whereby IPH will acquire AER (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) and its subsidiaries. There will be no cash consideration or stock issued as part of the purchase price. Genco's debt will remain outstanding. The transaction is subject to certain closing conditions and the receipt of regulatory approvals. On June 6, 2013, the IPCB rejected, on procedural grounds, AER's and IPH's motion to transfer variance relief from Illinois' Multi-Pollutant Standard. The IPCB indicated that IPH may file a request for variance relief on its own behalf. IPH and AER are pursuing such relief, and on July 22, 2013 IPH and certain co-petitioners filed their request for variance relief. The closing is expected to occur in the fourth quarter 2013. Please read Note 3—Acquisitions—AER Transaction Agreement for further discussion.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of liquidity are cash flows from operations, cash on hand and amounts available under the revolver.

Table of Contents

On April 23, 2013, Dynegy entered into the Credit Agreement, which consists of (i) a \$500 million Tranche B-1 Term Loan, (ii) an \$800 million Tranche B-2 Term Loan and (iii) a \$475 million Revolving Facility. Borrowings under the Credit Agreement, together with a portion of our cash on hand, were used to repay in full and terminate commitments under: (i) the DPC Credit Agreement and DMG Credit Agreement, (ii) the DPC Revolving Credit Agreement, (iii) the DPC Letter of Credit Reimbursement and Collateral Agreement, (iv) the DMG Letter of Credit Reimbursement and Collateral Agreement, (v) the Dynegy Letter of Credit Reimbursement and Collateral Agreement and (vi) the Dynegy CS Letter of Credit Agreement. As a result of repaying these credit agreements, we no longer have any restricted cash.

On May 20, 2013, Dynegy and its Subsidiary Guarantors entered into an Indenture pursuant to which Dynegy issued \$500 million in aggregate principal amount of Senior Notes. Borrowings under the Senior Notes were used to repay in full and terminate commitments under the Tranche B-1 Term Loan (as discussed above). Please read Note 12—Debt for further discussion.

These financings improved our capital structure efficiency and flexibility, increased liquidity and reduced administrative costs.

Current Liquidity. The following tables summarize our liquidity position at July 26, 2013 and June 30, 2013.

(amounts in millions)	July 26, 2013	June 30, 2013
Revolver capacity	\$475	\$475
Less: Outstanding letters of credit	(188) (190
Revolver availability	287	285
Cash and cash equivalents	500	461
Total available liquidity	\$787	\$746

Operating Activities

Historical Operating Cash Flows. Our cash flow used in operations totaled \$10 million for the six months ended June 30, 2013. During the period, we had positive Adjusted EBITDA (as described below in Results of Operations—EBITDA and Adjusted EBITDA) of \$51 million. This was offset by (i) \$44 million in interest payments, (ii) \$7 million in negative changes in working capital, including \$2 million of increased collateral postings to satisfy our counterparty collateral demands and (iv) \$10 million of bankruptcy reorganization, acquisition and integration and other expenses.

Our cash flow used in operations totaled \$107 million for the six months ended June 30, 2012. During the period, we had positive Adjusted EBITDA of \$42 million and \$2 million related to the receipt of a tax refund. This was offset by (i) negative Adjusted EBITDA of \$20 million related to discontinued operations, (ii) \$34 million in interest payments and (iii) \$97 million in negative changes in working capital, including \$84 million of increased collateral postings to satisfy our counterparty collateral demands.

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

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 July 26, 2013, June 30, 2013 and December 31, 2012:

(amounts in millions)	July 26, 2013	June 30, 2013	December 31, 2012
Cash (1)	\$55	\$63	\$64
Letters of credit	188	190	252

Total	\$243	\$253	\$316
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Includes Broker margin account on our unaudited condensed consolidated balance sheets as well as other collateral (1) postings included in Prepayments and other current assets on our unaudited condensed consolidated balance sheets.

As of June 30, 2013 and December 31, 2012, \$22 million and \$8 million of cash posted as collateral was netted

35

Table of Contents

against Liabilities from risk management activities on our unaudited condensed consolidated balance sheets, respectively.

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

Collateral postings decreased from December 31, 2012 to June 30, 2013 primarily due to reductions in collateral supporting our DNE operations, fuel purchases and contractual service agreements. These decreases were partially offset by increases in collateral supporting our hedging program. Collateral postings were relatively flat from June 30, 2013 to July 26, 2013.

The fair value of our derivatives collateralized by first priority liens included liabilities of \$108 million, \$84 million and \$100 million at July 26, 2013, June 30, 2013 and December 31, 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 of such instruments.

Investing Activities

Capital Expenditures. We had capital expenditures of approximately \$55 million and \$37 million during the six months ended June 30, 2013 and 2012, respectively. Our capital spending by reportable segment was as follows:

(amounts in millions)	Successor	Predecessor
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Coal (1)	\$31	\$11
Gas	23	20
Other and eliminations	1	6
Total	\$55	\$37

On June 5, 2012, we completed the DMG Acquisition; therefore, capital expenditures were included only from June 6 to June 30, 2012 for the six months ended June 30, 2012, and for the full six months ended June 30, 2013. (1) For the six months ended June 30, 2012, including the periods that Coal was not included in our consolidated financial statements, Coal capital expenditures were \$53 million.

Other Investing Activities. During the six months ended June 30, 2013, there was a \$335 million cash inflow related to restricted cash balances related to the release of cash collateral associated with the DPC LC and DMG LC facilities. A portion of these proceeds were used to repay in full and terminate commitments under the DMG and DPC Credit Agreements as further discussed below. As a result of repaying these credit agreements, all of our restricted cash was released.

In connection with the DMG Acquisition on June 5, 2012, we acquired \$256 million in cash and received \$16 million related to the Undertaking during the six months ended June 30, 2012. There was a \$134 million cash inflow related to restricted cash balances associated with the DPC LC facilities and DPC Credit Agreement during the six months ended June 30, 2012. During the first quarter of 2012, we requested the release of unused cash collateral related to the DPC LC facilities.

Financing Activities

Historical Cash Flow from Financing Activities. Cash flow used in financing activities totaled \$160 million for the six months ended June 30, 2013 due to \$1,913 million in repayments of borrowings in full on the DMG and DPC credit agreements and the Tranche B-1 Term Loan, including \$59 million in prepayment penalties associated with the early termination of the DMG and DPC credit agreements, offset by \$1,753 million in proceeds from borrowings on the Credit Agreement and Senior Notes, net of financing costs.

Cash flow used in financing activities totaled \$7 million for the six months ended June 30, 2012 due to repayments of borrowings on the former DMG and DPC Credit Agreements.

Financing Trigger Events. Our debt instruments and certain of our other financial obligations include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events connected to the financing include the violation of covenants (including, under certain circumstances, the senior secured leverage ratio

Table of Contents

covenant discussed below), defaults on scheduled principal or interest payments, including any indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions, insolvency events, acceleration of other financial obligations and change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

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

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

For purposes of calculating Net Debt, we may only apply a maximum of \$150 million in cash to our outstanding (1) debt, the outstanding debt used in this calculation is limited to the amounts outstanding under the Tranche B-2 Term Loan.

Please read Note 12—Debt for further discussion.

Credit Ratings

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

	Moody’s	S&P
Dynegy Inc.:		
Corporate Family Rating	B2	B
Senior Secured	B1	BB-
Senior Unsecured	B3	B+

Update of Selected Contractual Obligations

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

The following table updates selected contractual obligations of the Company and its consolidated subsidiaries as of June 30, 2013 from our Form 10-K disclosure for changes that occurred during 2013. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Expiration by Period				
	Total	Remainder of 2013	2014-2015	2016-2017	2018 and Beyond
Long-term debt (including current portion)	\$ 1,300	\$ 4	\$ 16	\$ 16	\$ 1,264
Interest payments on debt	649	39	169	155	286
Contractual service agreements (1)	123	5	62	56	—

Table of Contents

The table above includes projected payments through 2017 assuming the contracts remain in full force and effect; (1) however, we currently estimate these agreements will be in effect for a period of 15 or more years. Our minimum obligation related to these agreements is limited to the termination payments.

Long-Term Debt (Including Current Portion). Long-term debt includes amounts related to the Senior Notes and the Credit Agreement. Please read Note 12—Debt for further discussion.

Interest Payments on Debt. Interest payments on debt represent estimated periodic interest payment obligations associated with the Senior Notes and the Credit Agreement. Amounts do not include the impact of interest rate hedging agreements. Please read Note 12—Debt for further discussion.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. In June 2013, we amended our maintenance agreements. The amendments substantially reduce collateral postings, restructure and reduce maintenance costs, extend the term of the agreements, decrease our risk from a catastrophic turbine failure and include technology upgrades for our equipment. We currently estimate these agreements will be in effect for a period of 15 or more years. The table above includes our current estimate of payments under the contracts through 2017 based on anticipated timing of outages and are subject to change as outage dates move. As of June 30, 2013, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately \$143 million and \$209 million in the event all contracts are terminated by us or the counterparty, respectively. Please read Note 13—Commitments and Contingencies for further discussion.

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.

Table of Contents

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 six months ended June 30, 2013 and 2012. At the end of this section, we have included our business outlook for each segment.

We report the results of our power generation business primarily as two separate segments in our consolidated financial statements: (i) Coal and (ii) Gas. In connection with our emergence from bankruptcy, we deconsolidated the DNE Debtor Entities, which constituted our previously reported DNE segment, and began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified the results of the previously reported DNE segment as discontinued operations in the consolidated financial statements for all periods presented. Subsequent to our emergence from bankruptcy, management does not consider general and administrative expense when evaluating the performance of our Coal and Gas segments, but instead evaluates general and administrative expense on an enterprise-wide basis. Accordingly, we have recast our segments to present general and administrative expense in Other and Eliminations for all periods presented.

We applied fresh-start accounting as of the Plan Effective Date. Fresh-start accounting required us to allocate the reorganization value to our assets and liabilities in a manner similar to the acquisition method of accounting for business combinations. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion.

On September 1, 2011, we completed the DMG Transfer. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition. Therefore, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 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. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit) and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of certain assets, (ii) the impacts of mark-to-market changes on economic hedges related to our generation portfolio, (iii) the impact of impairment charges and certain other costs such as those associated with the acquisition of AER, internal reorganization and bankruptcy proceedings, (iv) amortization of intangible assets and liabilities, (v) income or loss associated with discontinued operations and (vi) income or expense on up front premiums received or paid for financial options in periods other than the strike periods. Enterprise-wide Adjusted EBITDA includes the Adjusted EBITDA for Legacy Dynegy for the periods prior to the Merger.

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, 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).

Table of Contents

Significant Items

Our results of operations are impacted by several significant items. In the discussion below, we have included the variances associated with these significant items in tables with the following descriptions:

DMG Transfer—The amounts in the tables add back the results of our Coal segment for the period of time that our Coal segment was not included in the consolidated results due to the DMG Transfer. For the three months ended June 30, 2012, this amount includes the results of operations related to the Coal segment for the period of April 1 through June 5, 2012. For the six months ended June 30, 2012, this amount includes the results of operations related to the Coal segment for the period of January 1 through June 5, 2012.

DMG Acquisition—The DMG Acquisition was accounted for using the acquisition method. Therefore, the acquired assets and liabilities were recorded at their estimated fair values as of the acquisition date. As a result, our results for the three and six months ended June 30, 2012 include the amortization of intangible assets and liabilities that were established at the acquisition date. In addition, the property, plant and equipment associated with the Coal segment had a significantly lower basis as a result of the purchase price allocation. The intangible assets and liabilities and property, plant and equipment were adjusted in connection with the application of fresh-start accounting. The amounts in the tables below remove the impact of purchase price adjustments included in 2012 results.

Fresh-Start Adjustments—Upon emergence from bankruptcy on the Plan Effective Date, we applied fresh-start accounting which resulted in adjusting our assets and liabilities to their estimated fair values. As a result, our three and six months ended June 30, 2013 results include the amortization of intangible assets and liabilities that did not exist in the three and six months ended June 30, 2012. In addition, our property, plant and equipment had a significantly lower basis in the three and six months ended June 30, 2013 as a result of the fresh-start adjustments. The amounts in the tables below remove the impact of the fresh-start adjustments included in our three and six months ended June 30, 2013 results that have no corresponding amounts in our three and six months ended June 30, 2012 results.

We believe providing a reconciliation of the impact of these significant items provides the basis for a more meaningful comparison of our three and six months ended June 30, 2013 results to our three and six months ended June 30, 2012 results.

Table of Contents

Consolidated Summary Financial Information — Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

The following table provides summary financial data regarding our consolidated results of operations for the three months ended June 30, 2013 and 2012, respectively:

(amounts in millions)	Successor Three Months Ended June 30, 2013	Predecessor Three Months Ended June 30, 2012	Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
Revenues	\$301	\$270	\$ 31	11	%
Cost of sales	(253)	(170)	(83)	(49))%
Gross margin, exclusive of depreciation shown separately below	48	100	(52)	(52))%
Operating and maintenance expense, exclusive of depreciation shown separately below	(85)	(48)	(37)	(77))%
Depreciation expense	(49)	(43)	(6)	(14))%
Gain on sale of assets, net	1	—	1	100	%
General and administrative expense	(25)	(17)	(8)	(47))%
Acquisition and integration costs	(1)	—	(1)	(100))%
Operating loss	(111)	(8)	(103)	(1,288))%
Bankruptcy reorganization items, net	(2)	(23)	21	91	%
Interest expense	(16)	(41)	25	61	%
Loss on extinguishment of debt	(12)	—	(12)	100	%
Other income and expense, net	(9)	7	(16)	(229))%
Loss from continuing operations before income taxes	(150)	(65)	(85)	(131))%
Income tax benefit	—	1	(1)	(100))%
Loss from continuing operations	(150)	(64)	(86)	(134))%
Income (loss) from discontinued operations, net of tax	5	(5)	10	200	%
Net loss	\$(145)	\$(69)	\$ (76)	(110))%

Table of Contents

The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended June 30, 2013 and 2012, respectively:

(amounts in millions)	Successor				
	Three Months Ended June 30, 2013				
	Coal	Gas	Other	Total	
Revenues	\$115	\$186	\$—	\$301	
Cost of sales	(103) (150) —	(253)
Gross margin, exclusive of depreciation shown separately below	12	36	—	48	
Operating and maintenance expense, exclusive of depreciation shown separately below	(52) (33) —	(85)
Depreciation expense	(10) (39) —	(49)
Gain on sale of assets, net	1	—	—	1	
General and administrative expense	—	—	(25) (25)
Acquisition and integration costs (1)	—	—	(1) (1)
Operating loss	\$(49) \$(36) \$(26) \$(111)

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

(amounts in millions)	Predecessor				
	Three Months Ended June 30, 2012				
	Coal	Gas	Other	Total	
Revenues	\$40	\$230	\$—	\$270	
Cost of sales	(39) (131) —	(170)
Gross margin, exclusive of depreciation shown separately below	1	99	—	100	
Operating and maintenance expense, exclusive of depreciation shown separately below	(14) (35) 1	(48)
Depreciation expense	(4) (36) (3) (43)
General and administrative expense	—	—	(17) (17)
Operating income (loss)	\$(17) \$28	\$(19) \$(8)

Table of Contents

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended June 30, 2013:

(amounts in millions)	Successor			Total
	Three Months Ended June 30, 2013			
	Coal	Gas	Other	
Net loss				\$(145)
Income from discontinued operations, net of tax				(5)
Bankruptcy reorganization items, net				2
Loss on extinguishment of debt				12
Interest expense				16
Other items, net				9
Operating loss	\$(49)	\$(36)	\$(26)	\$(111)
Depreciation expense	10	39	—	49
Bankruptcy reorganization items, net	—	—	(2)	(2)
Other items, net	—	(1)	(8)	(9)
EBITDA	(39)	2	(36)	(73)
Bankruptcy reorganization items, net	—	—	2	2
Acquisition and integration costs	—	—	1	1
Mark-to-market (income) loss, net	(18)	19	—	1
Amortization of intangible assets and liabilities (1)	33	31	—	64
Change in fair value of common stock warrants	—	—	9	9
Restructuring costs and other expenses	—	—	3	3
Other	—	1	—	1
Enterprise-wide Adjusted EBITDA	\$(24)	\$53	\$(21)	\$8

In connection with the application of fresh-start accounting on the Plan Effective Date, we recorded intangible (1) assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts. Please read Note 11—Intangible Assets and Liabilities for further discussion.

Table of Contents

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

(amounts in millions)	Predecessor			
	Three Months Ended June 30, 2012			
	Coal	Gas	Other	Total
Net loss				\$(69)
Loss from discontinued operations, net of tax				5
Income tax benefit				(1)
Bankruptcy reorganization items, net				23
Interest expense				41
Other items, net				(7)
Operating income (loss)	\$(17)	\$28	\$(19)	\$(8)
Bankruptcy reorganization items, net	—	—	(23)	(23)
Depreciation expense	4	36	3	43
Other items, net	5	2	—	7
EBITDA from continuing operations	(8)	66	(39)	19
Bankruptcy reorganization items, net	—	—	23	23
Amortization of intangible assets	12	10	—	22
Mark-to-market (income) loss, net	2	(49)	—	(47)
Adjusted EBITDA from continuing operations	\$6	\$27	\$(16)	\$17
Adjusted EBITDA from Legacy Dynegy (1)	(1)	—	(5)	(6)
Enterprise-wide Adjusted EBITDA	\$5	\$27	\$(21)	\$11

Our consolidated results for the three months ended June 30, 2012 reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Additionally, effective September 1, 2011, we completed the DMG Transfer and effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, related to Legacy Dynegy, are not included in our (1) consolidated results for the period of April 1 through June 5, 2012. Additionally, the results of certain items in the Other segment related to Legacy Dynegy are not included in our consolidated results for the three months ended June 30, 2012. However, we have included the Adjusted EBITDA from Legacy Dynegy for this period 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):

(amounts in millions)	Three Months Ended June 30, 2012		
	Coal	Other	Total
Operating income (loss)	\$(2,703)	\$1,667	\$(1,036)
Depreciation expense	28	—	28
Loss from unconsolidated investment	—	(1)	(1)
EBITDA	(2,675)	1,666	(1,009)
Loss (gain) on Coal Holdco Transfer	2,652	(1,711)	941
Restructuring charges	—	39	39
Loss from unconsolidated investment	—	1	1
Mark-to-market loss, net	22	—	22
Adjusted EBITDA from Legacy Dynegy	\$(1)	\$(5)	\$(6)

Table of Contents

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by \$31 million from \$270 million for the three months ended June 30, 2012 to \$301 million for the three months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	
As reported	\$ 301	\$ 270	\$ 31
Plus:			
DMG Transfer	—	53	(53)
Less:			
Fresh-start adjustments	(23)	—	(23)
Total as adjusted	\$ 324	\$ 323	\$ 1

The \$23 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with certain tolling, energy and capacity agreements related to our power generation facilities as a result of applying fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the increase in revenues was \$1 million. The increase in revenues in our Coal segment, driven largely by mark-to-market changes, were partially offset by decreases in our Gas segment. The decrease in revenues in our Gas segment were primarily due to mark-to-market changes and decreases in capacity revenue, partially offset by lower financial settlements. Please read our Discussion of Segment Results of Operations below.

Cost of Sales. Cost of sales increased by \$83 million from \$170 million for the three months ended June 30, 2012 to \$253 million for the three months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	
As reported	\$(253)	\$(170)	\$ (83)
Plus:			
DMG Transfer	—	(46)	46
Less:			
DMG Acquisition		(12)	12
Fresh-start adjustments	(32)	—	(32)
Total as adjusted	\$(221)	\$(204)	\$ (17)

The \$32 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with rail transportation, coal purchase and gas transportation contracts as a result of applying fresh-start accounting on the Plan Effective Date. The \$12 million included in DMG Acquisition relates to the amortization of intangible assets and liabilities associated with our rail transportation and coal purchase contracts. After considering the impact of significant items, the increase in cost of sales was \$17 million. This increase is primarily due to higher gas prices partially offset by lower generation volumes and higher emissions costs due to the new CCA regulations that went into effect in 2013 in the Gas segment. Please read our Discussion of Segment Results of Operations below.

Table of Contents

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense increased by \$37 million from \$48 million for the three months ended June 30, 2012 to \$85 million for the three months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	
As reported	\$ (85)	\$ (48)	\$ (37)
Plus:			
DMG Transfer	—	(30)	30
Total as adjusted	\$ (85)	\$ (78)	\$ (7)

After considering the impact of significant items, the increase in operating and maintenance expense was \$7 million, which is primarily due to higher outage expenses in Coal in the three months ended June 30, 2013 compared to the three months ended June 30, 2012.

Depreciation Expense. Depreciation expense increased by \$6 million from \$43 million for the three months ended June 30, 2012 to \$49 million for the three months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	
As reported	\$ (49)	\$ (43)	\$ (6)
Plus:			
DMG Transfer	—	(28)	28
Less:			
DMG Acquisition	—	12	(12)
Fresh-start adjustments	33	—	33
Total as adjusted	\$ (82)	\$ (83)	\$ 1

The \$33 million included in Fresh-start adjustments relates to a lower basis in our power generation facilities as a result of applying fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the remaining decrease in depreciation expense was primarily related to the timing of various projects being placed into service.

General and Administrative Expense. General and administrative expense increased by \$8 million from \$17 million for the three months ended June 30, 2012 to \$25 million for the three months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	
As reported	\$ (25)	\$ (17)	\$ (8)
Plus:			
DMG Transfer	—	(5)	5
Total as adjusted	\$ (25)	\$ (22)	\$ (3)

After considering the impact of significant items, the increase in general and administrative expense was \$3 million. This increase is primarily the result of the write off of a deferred rent credit in 2012 related to the termination of the lease for our previous corporate headquarters and higher legal costs in 2013.

Table of Contents

Acquisition and Integration Costs. Acquisition and integration costs totaled \$1 million for the three months ended June 30, 2013 and were incurred in connection with our pending acquisition of AER. There were no such costs incurred during the three months ended June 30, 2012. Please read Note 3—Acquisitions for further discussion.

Bankruptcy Reorganization Items, Net. Bankruptcy reorganization items, net decreased by \$21 million from \$23 million for the three months ended June 30, 2012 to \$2 million for the three months ended June 30, 2013. Bankruptcy reorganization items, net for the three months ended June 30, 2013 consisted primarily of professional and advisor fees. Bankruptcy reorganization items, net for the three months ended June 30, 2012 consisted primarily of \$14 million in expenses incurred related to advisors and \$9 million related to the change in the value of the Administrative Claim.

Interest Expense. Interest expense decreased by \$25 million from \$41 million for the three months ended June 30, 2012 to \$16 million for the three months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended June 30, 2013	Predecessor Three Months Ended June 30, 2012	Favorable (Unfavorable) \$ Change
As reported	\$(16)	\$(41)	\$ 25
Plus:			
DMG Transfer	—	(11)	11
Total as adjusted	\$(16)	\$(52)	\$ 36

After considering the impact of significant items, the decrease in interest expense was \$36 million, which primarily related to the early repayment of \$325 million, in aggregate, of the outstanding balances related to the DPC and DMG credit agreements in the fourth quarter 2012 and lower interest rates on the new Credit Agreement than the DPC and DMG credit agreements. Please read Note 18—Debt in our Form 10-K for further discussion.

Loss on Extinguishment of Debt. Loss on extinguishment of debt totaled \$12 million for the three months ended June 30, 2013 and were incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately \$59 million, (ii) \$2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) \$6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) \$55 million in non-cash gains net for the accelerated amortization of the remaining premium related to the DPC and the DMG Credit Agreements. Please read Note 12—Debt for further discussion. There was no similar activity during the three months ended June 30, 2012.

Other Income and Expense, net. Other income and expense, net decreased by \$16 million from income of \$7 million for the three months ended June 30, 2012 to expense of \$9 million for the three months ended June 30, 2013. The decrease was partially due to a \$9 million loss due to a change in the fair value of our common stock warrants for the three months ended June 30, 2013. The remaining decrease is primarily due to a \$5 million distribution received related to our retained profits interest in Plum Point for the three months ended June 30, 2012.

Income Tax Benefit. We reported an income tax benefit of zero for the three months ended June 30, 2013 compared to an income tax benefit from continuing operations of \$1 million for the three months ended June 30, 2012. The effective tax rate for the three months ended June 30, 2013 was zero percent compared to one percent for the three months ended June 30, 2012.

For the three months ended June 30, 2013, the difference between the effective rate of zero percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of June 30, 2013, 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 three months ended June 30, 2012, the difference between the effective rate of two 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 June 30, 2012, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

Income (Loss) from Discontinued Operations, Net of Tax. For the three months ended June 30, 2013 and 2012, our income (loss) from discontinued operations, net of tax primarily related to the DNE operations. During the three months ended June 30, 2013, our income from discontinued operations, net of tax was \$5 million, which consisted of a \$7 million DNE

Table of Contents

pension curtailment gain due to the termination of a majority of the Danskammer employees and closing the Roseton sale, partially offset by a \$2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility. During the three months ended June 30, 2012, our loss from discontinued operations, net of tax was \$5 million, primarily related to operating losses of the DNE Debtor Entities.

Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA decreased by \$3 million from \$11 million for the three months ended June 30, 2012 to \$8 million for the three months ended June 30, 2013. The decrease was primarily due to a decrease in the Coal segment Adjusted EBITDA due to lower realized prices, net of hedges, and higher operating expenses and lower volumes due to planned outages. Offsetting the decrease was an increase in the Gas segment Adjusted EBITDA primarily due to improved hedge results and the absence of legacy put option settlements.

Table of Contents

Discussion of Segment Results of Operations

Coal Segment. The decrease in period over period realized power prices, net of hedges, was driven by a decrease in revenue from financial settlements due to the timing of when positions were executed and subsequent market moves. As a result of the DMG Transfer, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012; however, we have included the results of our Coal segment for the period from April 1 through June 5, 2012, related to Legacy Dynegy, in our combined results for the three months ended June 30, 2012 for comparative purposes.

The following table provides summary financial data regarding our Coal segment results of operations for the three months ended June 30, 2013 and 2012, respectively:

(dollars in millions)	Successor		Predecessor		Legacy Dynegy		Combined		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
	Three Months Ended June 30, 2013	June 6 Through June 30, 2012	June 6 Through June 30, 2012	April 1 Through June 5, 2012	Three Months Ended June 30, 2012	Three Months Ended June 30, 2012	Three Months Ended June 30, 2012	Three Months Ended June 30, 2012			
Operating Revenues											
Energy	\$112	\$42		\$69		\$111		1	1	%	
Mark-to-market income (loss), net	18	(2))	(21))	(23))	41	178	%	
Other (1)	(15))	—	5		5		(20)	(400))%	
Total operating revenues	\$115	\$40		\$53		\$93		\$22	24	%	
Operating Costs											
Cost of sales	(70))	(27))	(46))	(73))	3	4	%
Contract amortization	(33))	(12))	—		(12))	(21)	(175))%
Total operating costs	\$(103))	\$(39))	\$(46))	\$(85))	\$(18)	(21))%
Gross margin	\$12		\$1		\$7		\$8		\$4	50	%
Operating and maintenance expense	(52))	(14))	(30))	(44))	(8)	(18))%
Depreciation expense	(10))	(4))	(28))	(32))	22	69	%
Gain on sale of assets, net	1		—		—		—		1	100	%
Loss on Coal Holdco Transfer	—		—		(2,652))	(2,652))	2,652	100	%
Operating income (loss)	\$(49))	\$(17))	\$(2,703))	\$(2,720))	\$2,671	98	%
Depreciation expense	10		4		28		32		(22)	(69))%
Other items, net	—		5		—		5		(5)	(100))%
EBITDA	\$(39))	\$(8))	\$(2,675))	\$(2,683))	\$2,644	99	%
Mark-to-market (income) loss	(18))	2		22		24		(42)	(175))%
Amortization of intangible assets and liabilities	33		12		—		12		21	175	%
Loss on Coal Holdco Transfer	—		—		2,652		2,652		(2,652)	(100))%
Adjusted EBITDA	\$(24))	\$6		\$(1))	\$5		\$(29)	(580))%
Million Megawatt Hours Generated (2)	4.4		1.7		2.9		4.6		(0.2)	(4))%
In Market Availability for Coal-Fired Facilities (3)	91	%	94	%	92	%	93	%			

Average Quoted On-Peak
Market Power Prices
(\$/MWh) (4):

Indiana (Indy Hub)	\$41.76	\$38.34	\$31.45	\$33.74	\$ 8.02	24	%
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49

Table of Contents

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

Reflects production volumes in million MWh generated during the period that Coal was included in our

(2) consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the three months ended June 30, 2013 and 2012, respectively.

(3) Reflects the percentage of generation available during the period that Coal was included in our consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the three months ended June 30, 2013 and 2012, respectively, when market prices are such that these units could be profitably dispatched.

(4) Reflects the average of day-ahead quoted prices for the period that Coal was included in our consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the three months ended June 30, 2013 and 2012, respectively, and does not necessarily reflect prices we realized.

Operating loss for the three months ended June 30, 2013 was \$49 million compared to \$17 million for the three months ended June 30, 2012. Operating loss on a combined basis for the three months ended June 30, 2012 was \$2,720 million, or \$68 million excluding the loss on the Coal Holdco Transfer. Adjusted EBITDA was a loss of \$24 million during the three months ended June 30, 2013 compared to income of \$5 million during the same period in 2012. The decrease in Adjusted EBITDA for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 resulted from an increase in outages, higher rail expense and a decline in hedge settlements this quarter compared to the same period last year. An increase in outages, primarily at Baldwin and Hennepin, led to lower gross margin and increased operating expenses which reduced Adjusted EBITDA by \$10 million. Rail transportation costs increased \$4 million as a result of the rail contract modification occurring in 2012. Hedge settlement revenues decreased \$19 million compared to the second quarter of 2012 because the company benefited from hedges during the second quarter of 2012 when commodity prices were weak but was a net payer on its hedges during the second quarter of 2013 due to the stronger commodity price environment. These lower hedge settlements were partially offset by a \$6 million increase in physical energy margin attributable to higher power prices which more than offset an increase in transmission congestion.

Table of Contents

Gas Segment. Spark-spreads were generally lower in the three months ended June 30, 2013 compared to the three months ended June 30, 2012, resulting in lower generation volumes period over period. Volumes also decreased due to an increase in outage hours. The following table provides summary financial data regarding our Gas segment results of operations for the three months ended June 30, 2013 and 2012, respectively:

(dollars in millions)	Successor Three Months Ended June 30, 2013	Predecessor Three Months Ended June 30, 2012	Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
Operating Revenues					
Energy	\$ 132	\$ 130	\$ 2	2	%
Capacity	56	65	(9)	(14))%
Mark-to-market income (loss), net	(17)	21	(38)	(181))%
Contract amortization	(33)	(10)	(23)	(230))%
Other (1)	48	24	24	100	%
Total operating revenues	\$ 186	\$ 230	\$ (44)	(19))%
Operating Costs					
Cost of sales	(152)	(132)	(20)	(15))%
Contract amortization	2	1	1	100	%
Total operating costs	\$(150)	\$(131)	\$ (19)	(15))%
Gross margin	\$36	\$99	\$ (63)	(64))%
Operating and maintenance expense	(33)	(35)	2	6	%
Depreciation expense	(39)	(36)	(3)	(8))%
Operating income (loss)	\$(36)	\$28	\$ (64)	(229))%
Depreciation expense	39	36	3	8	%
Other items, net	(1)	2	(3)	(150))%
EBITDA	\$2	\$66	\$ (64)	(97))%
Mark-to-market (income) loss	19	(49)	68	139	%
Amortization of intangible assets and liabilities	31	10	21	210	%
Other	1	—	1	100	%
Adjusted EBITDA	\$53	\$27	\$ 26	96	%
Million Megawatt Hours Generated (2)					
In Market Availability for Combined Cycle Facilities (3)	3.5	4.8	(1.3)	(27))%
Average Capacity Factor for Combined Cycle Facilities (4)	96	%	96	%	
Average Market On-Peak Spark Spreads (\$/MWh) (5)	37	%	50	%	
Average Market Off-Peak Spark Spreads (\$/MWh) (5)	\$ 13.46	\$ 14.87	\$ (1.41)	(9))%
Average natural gas price—Henry Hub (\$/MMBtu) (6)	\$ 1.91	\$ 4.46	\$ (2.55)	(57))%
	\$ 4.01	\$ 2.27	\$ 1.74	77	%

(1) Other includes ancillary services, RMR, tolls, natural gas, financial settlements, option premiums and other miscellaneous items.

(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility for the three months ended June 30, 2013 and 2012, respectively.

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

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

- (5) Reflects the average of our on- and off-peak spark spreads at the following facilities: Commonwealth Edison (NI Hub), PJM West, North of Path 15 (NP 15), New York - Zone A and Mass Hub.
- (6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Table of Contents

Operating loss for the three months ended June 30, 2013 was \$36 million compared to operating income of \$28 million for the three months ended June 30, 2012. Adjusted EBITDA totaled \$53 million during the three months ended June 30, 2013 compared to \$27 million during the same period in 2012. The \$26 million increase in Adjusted EBITDA primarily resulted from a \$59 million improvement due to improved hedge results and the absence of legacy put option settlements and other out of the money gas settlements. These favorable results were partially offset by \$5 million in lower market capacity payments, primarily at the Kendall facility, a \$4 million decrease in tolling payments associated with the early termination of the Morro Bay contract and a \$19 million decrease in physical energy margin before hedges due to lower generation volumes and spark spreads.

Table of Contents

Consolidated Summary Financial Information — Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The following table provides summary financial data regarding our consolidated results of operations for the six months ended June 30, 2013 and 2012, respectively:

(amounts in millions)	Successor	Predecessor	Favorable		Favorable	
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	(Unfavorable) \$ Change	(Unfavorable) % Change		
Revenues	\$619	\$538	\$ 81	15	%	
Cost of sales	(537)	(350)	(187)	(53)	%	
Gross margin, exclusive of depreciation shown separately below	82	188	(106)	(56)	%	
Operating and maintenance expense, exclusive of depreciation shown separately below	(156)	(82)	(74)	(90)	%	
Depreciation expense	(103)	(65)	(38)	(58)	%	
Gain on sale of assets, net	2	—	2	100	%	
General and administrative expense	(47)	(37)	(10)	(27)	%	
Acquisition and integration costs	(4)	—	(4)	(100)	%	
Operating income (loss)	(226)	4	(230)	(5,750)	%	
Bankruptcy reorganization items, net	(3)	129	(132)	(102)	%	
Interest expense	(45)	(72)	27	38	%	
Loss on extinguishment of debt	(11)	—	(11)	(100)	%	
Impairment of Undertaking receivable, affiliate	—	(832)	832	100	%	
Other income and expense, net	(7)	31	(38)	(123)	%	
Loss from continuing operations before income taxes	(292)	(740)	448	61	%	
Income tax benefit	—	7	(7)	(100)	%	
Loss from continuing operations	(292)	(733)	441	60	%	
Income (loss) from discontinued operations, net of tax	5	(418)	423	101	%	
Net loss	\$(287)	\$(1,151)	\$ 864	75	%	

The following tables provide summary financial data regarding our operating income (loss) by segment for the six months ended June 30, 2013 and 2012, respectively:

(amounts in millions)	Successor			
	Six Months Ended June 30, 2013			
	Coal	Gas	Other	Total
Revenues	\$202	\$417	\$—	\$619
Cost of sales	(218)	(319)	—	(537)
Gross margin, exclusive of depreciation shown separately below	(16)	98	—	82
Operating and maintenance expense, exclusive of depreciation shown separately below	(92)	(63)	(1)	(156)
Depreciation expense	(23)	(79)	(1)	(103)
Gain on sale of assets, net	2	—	—	2
General and administrative expense	—	—	(47)	(47)
Acquisition and integration costs (1)	—	—	(4)	(4)
Operating loss	\$(129)	\$(44)	\$(53)	\$(226)

Table of Contents

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

(amounts in millions)	Predecessor			
	Six Months Ended June 30, 2012			
	Coal	Gas	Other	Total
Revenues	\$40	\$498	\$—	\$538
Cost of sales	(39) (311) —	(350
Gross margin, exclusive of depreciation shown separately below	1	187	—	188
Operating and maintenance expense, exclusive of depreciation shown separately below	(14) (69) 1	(82
Depreciation expense	(4) (56) (5) (65
General and administrative expense	—	—	(37) (37
Operating income (loss)	\$(17) \$62	\$ (41) \$4

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the six months ended June 30, 2013:

(amounts in millions)	Successor			
	Six Months Ended June 30, 2013			
	Coal	Gas	Other	Total
Net loss				\$(287
Income from discontinued operations, net of tax				(5
Bankruptcy reorganization items, net				3
Interest expense				45
Loss on extinguishment of debt				11
Other items, net				7
Operating loss	\$(129) \$(44) \$(53) \$(226
Depreciation expense	23	79	1	103
Bankruptcy reorganization items, net	—	—	(3) (3
Other items, net	—	—	(7) (7
EBITDA	(106) 35	(62) (133
Bankruptcy reorganization items, net	—	—	3	3
Acquisition and integration costs	—	—	4	4
Mark-to-market loss, net	22	15	—	37
Amortization of intangible assets and liabilities (1)	64	63	—	127
Change in fair value of common stock warrants	—	—	9	9
Restructuring costs and other expenses	—	—	3	3
Other	—	1	—	1
Enterprise-wide Adjusted EBITDA	\$(20) \$114	\$ (43) \$51

In connection with the application of fresh-start accounting on the Plan Effective Date, we recorded intangible (1) assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts. Please read Note 11—Intangible Assets and Liabilities for further discussion.

Table of Contents

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

(amounts in millions)	Predecessor			Total
	Six Months Ended June 30, 2012			
	Coal	Gas	Other	
Net loss				\$(1,151)
Loss from discontinued operations, net of tax				418
Income tax benefit				(7)
Impairment of Undertaking receivable, affiliate				832
Bankruptcy reorganization items, net				(129)
Interest expense				72
Other items, net				(31)
Operating income (loss)	\$(17)	\$62	\$(41)	\$4
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	129	129
Depreciation expense	4	56	5	65
Other items, net	5	2	24	31
EBITDA from continuing operations	(8)	120	(715)	(603)
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(129)	(129)
Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	5	5
Amortization of intangible assets	12	20	—	32
Mark-to-market (income) loss, net	2	(74)	—	(72)
Premium adjustment	—	1	—	1
Adjusted EBITDA from continuing operations	\$6	\$67	\$(31)	\$42
Adjusted EBITDA from Legacy Dynegy (1)	21	—	(14)	7
Enterprise-wide Adjusted EBITDA	\$27	\$67	\$(45)	\$49

Our consolidated results for the six months ended June 30, 2012 reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Additionally, effective September 1, 2011, we completed the DMG Transfer and effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, related to Legacy Dynegy, were not included in our (1) consolidated results for the period of January 1 through June 5, 2012. Additionally, the results of certain items in the Other segment related to Legacy Dynegy were not included in our consolidated results for the six months ended June 30, 2012. However, we have included the Adjusted EBITDA from Legacy Dynegy for this period in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

Table of Contents

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

(amounts in millions)	Six Months Ended June 30, 2012		
	Coal	Other	Total
Operating income (loss)	\$ (2,701) \$ 1,644	\$ (1,057)
Depreciation expense	78	—	78
Loss from unconsolidated investment	—	(1) (1)
EBITDA	(2,623) 1,643	(980)
Loss (gain) on Coal Holdco Transfer	2,652	(1,711) 941
Restructuring charges	—	53	53
Loss from unconsolidated investment	—	1	1
Mark-to-market income, net	(8) —	(8)
Adjusted EBITDA from Legacy Dynegy	\$ 21	\$ (14) \$ 7

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by \$81 million from \$538 million for the six months ended June 30, 2012 to \$619 million for the six months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	
As reported	\$ 619	\$ 538	\$ 81
Plus:			
DMG Transfer	—	230	(230)
Less:			
Fresh-start adjustments	(46)	—	(46)
Total as adjusted	\$ 665	\$ 768	\$ (103)

The \$46 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with certain tolling, energy and capacity agreements related to our power generation facilities as a result of applying fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the decrease in revenues was \$103 million. This decrease is primarily due to a \$108 million reduction in mark-to-market revenues. This decrease was partially offset by lower settlements on legacy positions in 2013 compared to 2012. Please read our Discussion of Segment Results of Operations below.

Table of Contents

Cost of Sales. Cost of sales increased by \$187 million from \$350 million for the six months ended June 30, 2012 to \$537 million for the six months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	
As reported	\$ (537)	\$ (350)	\$ (187)
Plus:			
DMG Transfer	—	(132)	132
Less:			
DMG Acquisition	—	(12)	12
Fresh-start adjustments	(64)	—	(64)
Total as adjusted	\$ (473)	\$ (470)	\$ (3)

The \$64 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with rail transportation, coal purchase and gas transportation contracts as a result of applying fresh-start accounting on the Plan Effective Date. The \$12 million included in DMG Acquisition relates to the amortization of intangible assets and liabilities associated with our rail transportation and coal purchase contracts. After considering the impact of significant items, the increase in cost of sales was \$3 million. This increase is primarily due to an increase in natural gas expense due to higher gas prices, offset by lower generation volumes in the Gas segment, as further described in our Discussion of Segment Results of Operations below.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense increased by \$74 million from \$82 million for the six months ended June 30, 2012 to \$156 million for the six months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	
As reported	\$ (156)	\$ (82)	\$ (74)
Plus:			
DMG Transfer	—	(69)	69
Total as adjusted	\$ (156)	\$ (151)	\$ (5)

After considering the impact of significant items, the increase in operating and maintenance expense was \$5 million, which is primarily due to higher outage costs for Coal in the six months ended June 30, 2013 compared to the six months ended June 30, 2012.

Table of Contents

Depreciation Expense. Depreciation expense increased by \$38 million from \$65 million for the six months ended June 30, 2012 to \$103 million for the six months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	
As reported	\$ (103)	\$ (65)	\$ (38)
Plus:			
DMG Transfer	—	(78)	78
Less:			
DMG Acquisition	—	12	(12)
Fresh-start adjustments	65	—	65
Total as adjusted	\$ (168)	\$ (155)	\$ (13)

After considering the impact of significant items the increase in depreciation expense was \$13 million, which is primarily due to a benefit of \$16 million in the first quarter 2012 due to a reduction in our asset retirement obligations associated with the South Bay facility with no similar benefit in 2013, offset by decreases due to timing of various projects being placed into service.

General and Administrative Expense. General and administrative expense increased by \$10 million from \$37 million for the six months ended June 30, 2012 to \$47 million for the six months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	
As reported	\$ (47)	\$ (37)	\$ (10)
Plus:			
DMG Transfer	—	(14)	14
Total as adjusted	\$ (47)	\$ (51)	\$ 4

After considering the impact of significant items, the decrease in general and administrative expense was \$4 million.

This decrease is primarily related to lower legal expenses in the six months ended June 30, 2013 compared to the six months ended June 30, 2012.

Acquisition and Integration Costs. Acquisition and integration costs totaled \$4 million for the six months ended June 30, 2013 and were incurred in connection with our pending acquisition of AER. There were no such costs incurred during the six months ended June 30, 2012. Please read Note 3—Acquisitions for further discussion.

Bankruptcy Reorganization Items, Net. Bankruptcy reorganization items, net decreased by \$132 million from a gain of \$129 million for the six months ended June 30, 2012 to a loss of \$3 million for the six months ended June 30, 2013. The 2013 Bankruptcy reorganization items, net consisted primarily of professional and advisor fees. The 2012 Bankruptcy reorganization items, net consisted primarily of reductions of approximately \$161 million and \$10 million in the estimated allowable claims related to the subordinated debt and other items, respectively, partially offset by \$33 million in expenses incurred related to advisors and \$9 million related to the change in the value of the Administrative Claim.

Table of Contents

Interest Expense. Interest expense decreased by \$27 million from \$72 million for the six months ended June 30, 2012 to \$45 million for the six months ended June 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	
As reported	\$ (45)	\$ (72)	\$ 27
Plus:			
DMG Transfer	—	(24)	24
Less:			
Fresh-start adjustments	8	—	8
Total as adjusted	\$ (53)	\$ (96)	\$ 43

The \$8 million included in Fresh-start adjustments related to amortization of the premium recorded in connection with adjusting our outstanding debt to its fair value in connection with the application of fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the decrease in interest expense was \$43 million, which primarily related to the early repayment of \$325 million, in aggregate, of the outstanding balances related to the DPC and DMG credit agreements in the fourth quarter 2012 and lower interest rates on the new Credit Agreement compared to the DPC and DMG credit agreements. Please read Note 12—Debt included herein and Note 18—Debt—DPC and DMG Credit Agreements in our Form 10-K for further discussion.

Loss on Extinguishment of Debt. Loss on extinguishment of debt totaled \$11 million for the six months ended June 30, 2013 and were incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately \$59 million, (ii) \$2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) \$6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) \$56 million in non-cash gains net for the accelerated amortization of the remaining premium related to the DPC and the DMG Credit Agreements. Please read Note 12—Debt for further discussion. There was no similar activity during the six months ended June 30, 2012.

Impairment of Undertaking Receivable, Affiliate. As a result of entering into the Settlement Agreement, the Undertaking receivable was impaired to approximately \$418 million as of March 31, 2012, resulting in a charge of approximately \$832 million for the six months ended June 30, 2012. The carrying value of the Undertaking was adjusted to the value received in the DMG Acquisition plus interest payments received subsequent to March 31, 2012. The Undertaking was settled upon execution of the Settlement Agreement; therefore, there were no such charges during the six months ended June 30, 2013.

Other Income and Expense, net. Other income and expense, net decreased by \$38 million from income of \$31 million for the six months ended June 30, 2012 to expense of \$7 million for the six months ended June 30, 2013. The decrease was primarily due to interest income on the Undertaking receivable, affiliate during the six months ended June 30, 2012. The Undertaking was executed on September 1, 2011, impaired as of March 31, 2012 and settled on June 5, 2012; therefore, there are three months of interest income related to the Undertaking during the six months ended June 30, 2012. The Undertaking was settled upon execution of the Settlement Agreement; therefore, there is no interest income related to the Undertaking during the six months ended June 30, 2013. Additionally, the decrease was partially due to a \$9 million loss due to a change in the fair value of our common stock warrants for the six months ended June 30, 2013. The remaining decrease is primarily due to a \$5 million distribution received related to our retained profits interest in Plum Point for the six months ended June 30, 2012.

Income Tax Benefit. We reported an income tax benefit of zero for the six months ended June 30, 2013 compared to an income tax benefit from continuing operations of \$7 million for the six months ended June 30, 2012. The effective tax rate in the six months ended June 30, 2013 was zero percent compared to one percent for the six months ended June 30, 2012.

For the six months ended June 30, 2013, the difference between the effective rate of zero percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of June 30, 2013, 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.

Table of Contents

For the six months ended June 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 June 30, 2012, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

Income (Loss) from Discontinued Operations, Net of Tax. For the six months ended June 30, 2013 and 2012, our income (loss) from discontinued operations, net of tax primarily related to the DNE operations. During the six months ended June 30, 2013, our income from discontinued operations, net of tax was \$5 million, primarily related to a \$7 million DNE pension curtailment gain due to the termination of a majority of the Danskammer employees and closing the Roseton sale, offset by a \$2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility. During the six months ended June 30, 2012, our loss from discontinued operations, net of tax was \$418 million, primarily related to Bankruptcy reorganization items, net of \$399 million, which included a \$395 million charge related to the estimated claim for the rejection of the DNE Facilities Lease and \$4 million related to other items.

Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA increased by \$2 million from \$49 million for the six months ended June 30, 2012 to \$51 million for the six months ended June 30, 2013. The increase was primarily due to an increase in the Gas segment Adjusted EBITDA primarily due to improved hedge results and the absence of legacy put option settlements. Offsetting the increase was a decrease in the Coal segment Adjusted EBITDA due to lower realized prices, net of hedges, and higher outages resulting in higher operating expenses and lower gross margin.

Table of Contents

Discussion of Segment Results of Operations

Coal Segment. The decrease in period over period realized power prices, net of hedges, was driven by a decrease in revenue from financial settlements due to the timing of when positions were executed and subsequent market moves. As a result of the DMG Transfer, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012; however, we have included the results of our Coal segment for the period of January 1 through June 5, 2012, related to Legacy Dynegy, in our combined results for the six months ended June 30, 2012 for comparative purposes.

The following table provides summary financial data regarding our Coal segment results of operations for the six months ended June 30, 2013 and 2012, respectively:

(dollars in millions)	Successor	Predecessor	Legacy Dynegy	Combined	Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
	Six Months Ended June 30, 2013	June 6 Through June 30, 2012	January 1 Through June 5, 2012	Six Months Ended June 30, 2012			
Operating Revenues							
Energy	\$230	\$42	\$193	\$235	\$ (5) (2)%
Mark-to-market income (loss), net	(22)	(2)	9	7	(29)	(414))%
Other (1)	(6)	—	28	28	(34)	(121))%
Total operating revenues	\$202	\$40	\$230	\$270	\$ (68) (25)%
Operating Costs							
Cost of sales	(154)	(27)	(132)	(159)	5	3	%
Contract amortization	(64)	(12)	—	(12)	(52)	(433))%
Total operating costs	\$(218)	\$(39)	\$(132)	\$(171)	\$ (47) (27)%
Gross margin	\$(16)	\$1	\$98	\$99	\$ (115) (116)%
Operating and maintenance expense	(92)	(14)	(69)	(83)	(9)	(11))%
Depreciation expense	(23)	(4)	(78)	(82)	59	72	%
Loss on Coal Holdco Transfer	—	—	(2,652)	(2,652)	2,652	100	%
Gain (loss) on sale of assets, net	2	—	—	—	2	100	%
Operating loss	\$(129)	\$(17)	\$(2,701)	\$(2,718)	\$ 2,589	95	%
Depreciation expense	23	4	78	82	(59)	(72))%
Other items, net	—	5	—	5	(5)	(100))%
EBITDA	\$(106)	\$(8)	\$(2,623)	\$(2,631)	\$ 2,525	96	%
Mark-to-market (income) loss, net	22	2	(8)	(6)	28	467	%
Amortization of intangible assets and liabilities	64	12	—	12	52	433	%
Loss on Coal Holdco Transfer	—	—	2,652	2,652	(2,652)	(100))%
Adjusted EBITDA	\$(20)	\$6	\$21	\$27	\$ (47) (174)%
Million Megawatt Hours Generated (2)	9.4	1.7	8.5	10.2	(0.8)	(8))%
	90	% 94	% 93	% 94	%		

In Market Availability for
Coal-Fired Facilities (3)
Average Quoted On-Peak
Market Power Prices
(\$/MWh) (4):
Indiana (Indy Hub)

\$37.96	\$38.34	\$30.41	\$31.74	\$ 6.22	20	%
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61

Table of Contents

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

Reflects production volumes in million MWh generated during the period that Coal was included in our

(2) consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the six months ended June 30, 2013 and 2012, respectively.

Reflects the percentage of generation available during the period that Coal was included in our consolidated results (3) and during the period that Coal was included in Legacy Dynegy's consolidated results during the six months ended June 30, 2013 and 2012, respectively, when market prices are such that these units could be profitably dispatched.

Reflects the average of day-ahead quoted prices for the period that Coal was included in our consolidated results (4) and during the period that Coal was included in Legacy Dynegy's consolidated results during the six months ended June 30, 2013 and 2012, respectively, and does not necessarily reflect prices we realized.

Operating loss for the six months ended June 30, 2013 was \$129 million compared to \$17 million the six months ended June 30, 2012. On a combined basis, operating loss was \$2,718 million, or \$66 million excluding the loss on the Coal Holdco Transfer. Adjusted EBITDA was a loss of \$20 million during the six months ended June 30, 2013 compared to income of \$27 million during the same period in 2012. The decrease in Adjusted EBITDA for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 resulted primarily from an increase in outages, higher rail expense and a decline in hedge settlements this year compared to the same period last year. An increase in outages, primarily at Baldwin and Hennepin, led to lower gross margin and increased operating expenses which reduced Adjusted EBITDA by \$17 million. Rail transportation costs increased \$9 million as a result of the rail contract modification occurring in 2012. Hedge settlement revenues decreased \$33 million compared to the second quarter of 2012 because the company benefited from hedges during the second quarter of 2012 when commodity prices were weak but was a net payer on its hedges during the second quarter of 2013 due to the stronger commodity price environment. The lower hedge settlements were partially offset by a \$15 million increase in physical energy margin attributable to higher power prices.

Table of Contents

Gas Segment. Spark-spreads were generally lower in the six months ended June 30, 2013 compared to the six months ended June 30, 2012, resulting in lower generation volumes period over period. Volumes also decreased due to an increase in outage hours. The following table provides summary financial data regarding our Gas segment results of operations for the six months ended June 30, 2013 and 2012, respectively:

(dollars in millions)	Successor	Predecessor	Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012			
Operating Revenues					
Energy	\$301	\$289	\$ 12	4	%
Capacity	108	123	(15)	(12)%
Mark-to-market income (loss), net	(15) 64	(79)	(123)%
Contract amortization	(67) (21) (46)	(219)%
Other (1)	90	43	47		109%
Total operating revenues	\$417	\$498	\$ (81)	(16)%
Operating Costs					
Cost of sales	(323) (313) (10)	(3)%
Contract amortization	4	2	2		100%
Total operating costs	\$(319) \$(311) \$(8)	(3)%
Gross margin	\$98	\$187	\$(89)	(48)%
Operating and maintenance expense	(63) (69) 6		9%
Depreciation expense	(79) (56) (23)	(41)%
Operating income (loss)	\$(44) \$62	\$(106)	(171)%
Depreciation expense	79	56	23		41%
Other items, net	—	2	(2)	(100)%
EBITDA	\$35	\$120	\$(85)	(71)%
Mark-to-market (income) loss, net	15	(74) 89		120%
Amortization of intangible assets and liabilities	63	20	43		215%
Premium adjustment	—	1	(1)	(100)%
Other	1	—	1		100%
Adjusted EBITDA	\$114	\$67	\$ 47		70%
Million Megawatt Hours Generated (2)	7.8	10.7	(2.9)	(27)%
In Market Availability for Combined Cycle Facilities (3)	97	% 97	%		
Average Capacity Factor for Combined Cycle Facilities (4)	41	% 55	%		
Average Market On-Peak Spark Spreads (\$/MWh) (5)	\$13.30	\$12.61	\$ 0.69		5%
Average Market Off-Peak Spark Spreads (\$/MWh) (5)	\$2.62	\$4.79	\$(2.17)	(45)%
Average natural gas price—Henry Hub (\$/MMBtu) (6)	\$3.75	\$2.36	\$ 1.39		59%

Table of Contents

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- (1) Other includes ancillary services, RMR, tolls, natural gas, financial settlements, option premiums and other miscellaneous items.
 - (2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility for the six months ended June 30, 2013 and 2012, respectively.
 - (3) Reflects the percentage of generation available when market prices are such that these units could be profitably dispatched.
 - (4) Reflects actual production as a percentage of available capacity.
 - (5) Reflects the average of our on- or off-peak spark spreads at the following facilities: Commonwealth Edison (NI Hub), PJM West, North of Path 15 (NP 15), New York - Zone A and Mass Hub.
 - (6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us. Operating loss for the six months ended June 30, 2013 was \$44 million compared to operating income of \$62 million for the six months ended June 30, 2012. Adjusted EBITDA totaled \$114 million during the six months ended June 30, 2013 compared to \$67 million during the same period in 2012. The \$47 million increase in Adjusted EBITDA primarily resulted from a \$73 million improvement due to improved hedge results the absence of legacy put option settlements and other out of the money gas settlements and with lower operating expenses due to outages during 2012. These favorable results were partially offset by \$11 million in lower market capacity payments, primarily at the Kendall facility, and a \$6 million decrease in tolling payments associated with the early termination of the Morro Bay contract.

Outlook

We expect that our future financial results will continue to be impacted by fuel and commodity prices, especially natural gas prices. Other factors to which our future financial results will remain sensitive include market structure and prices for electric energy, capacity and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, the volatility of fuel and electricity prices, transportation and transmission logistics, weather conditions, 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 possible that we will experience additional costs associated with the handling and disposal of coal ash, how water used by our power generation facilities is withdrawn and treated before being discharged or more stringent air emission standards. On March 14, 2013, IPH entered into the AER Transaction Agreement, whereby IPH will acquire AER (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) and its subsidiaries. There is no cash consideration or stock issued as part of the purchase price. Genco's debt will remain outstanding. The transaction is subject to certain closing conditions and the receipt of regulatory approvals. On June 6, 2013, the IPCB rejected, on procedural grounds, AER's and IPH's motion to transfer variance relief from Illinois' Multi-Pollutant Standard. The IPCB indicated that IPH may file a request for variance relief on its own behalf. IPH and AER are pursuing such relief, and on July 22, 2013 IPH and certain co-petitioners filed their request for variance relief. The closing is expected to occur in the fourth quarter 2013. Please read Note 3—Acquisitions—AER Transaction Agreement for further discussion. Coal. The Coal segment consists of four plants, all located in the MISO region, totaling 2,980 MW. The discussion below does not include any potential impacts associated with the pending AER transaction.

As of July 26, 2013, our Coal expected generation volumes are 57 percent hedged volumetrically for 2013 and approximately 34 percent hedged volumetrically for 2014. We plan to continue our hedging program for Coal over a one- to three-year period using various instruments, which includes the sale of natural gas swaps as a cross-commodity correlated hedge for our power revenue. As a result of the offsetting risks of our Coal and Gas segments, we are able to reduce the costs associated with hedging by executing a portion of Coal's hedges with an internal affiliate. The internal hedges are cross-commodity hedges and we intend to expand this in the future. Beyond 2013, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements.

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

economically available. Furthermore, Coal's hedge levels are likely to be lower than the hedge levels in prior years. Currently, our expected coal requirements are 96 percent contracted and priced in 2013. Our forecasted coal requirements for 2014 are 92 percent contracted and 71 percent priced. Our coal transportation requirements are fully

Table of Contents

contracted and priced for the next several years. 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.

The MISO filed proposed Resource Adequacy Enhancements with FERC on July 20, 2011. The FERC conditionally approved MISO's proposal on June 11, 2012, leaving much of MISO's proposal in place. The new tariff provisions replace the monthly construct with a full planning year product (June 1 - May 31) and further recognize zonal deliverability capacity requirements. The first zonal auction was held in March 2013. For the 2013-2014 planning year, capacity cleared at \$1.05 per MW-day for all zones. This low clearing price was likely caused by excess capacity conditions prevailing in MISO for the term of the planning year. In the future, the potential retirement of marginal MISO coal capacity due to poor economics or expected environmental mandates and confirmed future capacity exports from MISO to PJM could also affect MISO capacity and energy pricing.

We have initiated various studies of the MISO transmission grid to identify opportunities to reduce congestion and improve the busbar power prices at our coal fired facilities.

Further, we are in negotiations with the union (IBEW Local 51) regarding its collective bargaining agreement, which expired, following an extension, on July 8, 2013. This agreement covers approximately 400 represented employees at our four Coal plants located in Illinois. Since the expiration of the collective bargaining agreement, the Company and IBEW Local 51 continue to operate under the substantive terms and conditions of the expired agreement. Both parties remain active participants in negotiations to reach a mutually acceptable agreement on a new collective bargaining agreement.

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 2013 under tolling agreements with load-serving entities and a RMR agreement. A significant portion of the remaining capacity is sold as a resource adequacy product in the CAISO market.

The CAISO capacity market is bilateral in nature. The load-serving entities are required to procure sufficient resources for their peak load plus a 15 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. The CAISO and CPUC recently released a joint proposal for a multi-year forward capacity market called the Joint Reliability Framework. This proposal would fill the gap between the Resource Adequacy (one year requirement) and the LTPP (ten year plan) to establish a multi-year forward resource adequacy requirement on LSEs, provide a CAISO administered multi-year forward capacity market, and a market-based backstop mechanism to procure reliability services (both capacity and flexibility). This new capacity auction is called the Reliability Services Auction. CAISO intends to solicit feedback from stakeholders on its proposal.

In May 2012, SCE notified Morro Bay and Moss Landing that it was terminating certain energy and capacity contracts with those entities. We are disputing the validity of the purported terminations and subsequent actions by SCE. 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 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 within the CAISO footprint.

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. The first phase of the demolition is largely complete as the above ground portion of the facility has been demolished and removed. The second phase will consist of the below ground structures. Our estimates for the demolition and any potential remediation costs may change as the project advances through the next phase of the

demolition process. We currently expect the escrowed 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 (a) a final determination of the compliance term and requirements of the California Water Intake Policy, and (b) our ability to secure energy and/or capacity contracts in the future, we could decide to reduce operations or cease to operate the units prior to 2024. Furthermore, we

Table of Contents

continue to evaluate our Morro Bay facility. If we are unable to enter into contracts that make this facility economic to operate, we will likely retire this facility.

In New England, seven 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 2016-2017, cleared at the floor price of \$3.15 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 removal 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, ten 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, 2012-2013 Planning Year) and \$1.24 per kW-month (Ontelaunee, 2007-2008 Planning Year) to \$5.30 per kW-month (Kendall, 2010-2011 Planning Year) and \$6.88 per kW-month (Ontelaunee, 2013-2014 Planning Year). The latest RPM auction was for the 2016-2017 Planning Year, which cleared at \$1.81 per kW-month (Kendall) and \$3.62 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 2013 at \$4.20 per kW-month and winter 2012-2013 at \$0.82 per kW-month for the rest of state market. The winter 2013-2014 capacity market is also showing a considerable rebound from the aforementioned 2012-2013 market, currently valued at \$2.80 per kW-month. We attribute the rebound in part due to the FERC Order on buyer-side mitigation and retirements impacting 2013.

Approximately 70 percent of the capacity revenue for our Independence facility has been contracted at a favorable premium compared to current market prices through October 31, 2014.

Excluding volumes subject to tolling agreements, as of July 26, 2013, our Gas portfolio is 75 percent hedged volumetrically through 2013 and approximately 41 percent hedged volumetrically for 2014. As a result of the offsetting risks of our Gas and Coal segments, we are able to reduce the costs associated with hedging by executing a portion of our natural gas purchases with an internal affiliate. As discussed above, we intend to expand this in the future.

We plan to mitigate the risk of a potential breakdown between plant LMP prices and trading hub prices through participation in FTR markets and busbar basis swaps to the extent they are economically available. Furthermore, Gas hedge levels are likely to be lower than the hedge levels in prior years.

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K and Outlook-Environmental and Regulatory Matters in our Form 10-Q for the period ended March 31, 2013 for a detailed discussion of our environmental and regulatory matters.

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 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 April 10, 2013, certain record-keeping and reporting requirements went into effect for Non-Swap Dealers/Non-Major Swap Participants, as defined by the CFTC. Beginning on April 5, 2013, the CFTC Staff issued various materials, including “No Action” letters, which delayed the effectiveness or otherwise altered many of these requirements. Dynegy has 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.

The Clean Air Act

Cross-State Air Pollution Rule. On August 21, 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 rule. In June 2013, the Supreme Court granted petitions to review the appellate court's decision vacating the CSAPR. We will

Table of Contents

continue to monitor rulemaking, judicial and legislative developments regarding the CSAPR and a possible replacement rule and evaluate any potential impacts on our operations.

The Clean Water Act

Effluent Limitation Guidelines. In spring 2013, the EPA proposed revisions to the Effluent Limitation Guidelines (“ELG”) for steam electric power generation units. The proposed rule would establish new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts, including flue gas desulfurization, fly ash, bottom ash, and flue gas mercury control. The proposed rule identifies four preferred options for regulation of discharges from existing sources, with the options differing in the number of waste streams covered, the size of the units controlled, and the stringency of the controls to be imposed. As proposed, the new ELG requirements would be phased in between 2017 and 2022. The ELG rulemaking includes a public comment period. The EPA is expected to take final action on the proposal by May 22, 2014 and intends to align the ELG rule with its related CCR rule proposed in 2010. The timing and ultimate requirements of the final rule ELG and options available for compliance cannot be predicted with confidence at this time but could have a material adverse effect on our financial condition, results of operations and cash flows.

Cooling Water Intake Structures. On March 28, 2011, the EPA released a proposed rule for cooling water intake structures at existing facilities that would establish national standards for impingement mortality and entrainment. The EPA has secured additional time to finalize standards, under an amended settlement agreement entered in June 2013. The deadline for issuance of EPA's final rule on cooling water intake structures has been extended until November 4, 2013. The scope of requirements, timing for compliance and the compliance methodologies that will ultimately be allowed under the final rule potentially may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Dam Safety Assessment Reports

In March 2013, the EPA issued final dam safety assessment reports of the surface impoundments at our Baldwin and Hennepin facilities. The reports rate the impoundments at each facility as “poor,” meaning that a deficiency is recognized for a required loading condition in accordance with applicable dam safety criteria. A poor rating also applies when further critical studies are needed to identify any potential dam safety deficiencies. The reports include recommendations for further studies, repairs, and changes in operational and maintenance practices. In July 2013, in response to the final report concerning Hennepin, we notified the EPA of our intent to close the Hennepin west ash pond system. The preliminary estimated cost for closure of the west ash pond system, including post-closure monitoring, is approximately \$5 million. As a result of these changes, we increased our ARO by approximately \$2 million during the second quarter 2013. We plan on performing the other recommended further studies and actions at Baldwin and Hennepin, some of which are dependent on necessary permits being obtained. The nature and scope of repairs that ultimately may be needed, if any, cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Coal Combustion Residuals

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 requests by the Illinois EPA. Groundwater monitoring results indicate that the CCR surface impoundments at each site impact onsite groundwater.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, we have initiated a six month geotechnical study at Vermilion and have begun a twelve month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. 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.

In June 2013, the Illinois EPA released a draft rule of general applicability that would establish standards for closure of CCR surface impoundments at power plants. We will continue to monitor developments regarding the draft rule and evaluate potential impacts on our operations.

Climate Change

Federal Regulation of Greenhouse Gases. In June 2013, President Obama announced his Administration's plan to address climate change. In addition to supporting measures such as energy efficiency and renewable energy, the plan directs the EPA to re-propose the GHG NSPS for new electric generating units by September 20, 2013. The plan also directs the EPA

Table of Contents

to propose carbon emission standards for existing electric generating units by June 1, 2014, and to finalize such standards by June 1, 2015. Under the plan, state implementation plans addressing existing electric generating units would be due by June 30, 2016. The nature and scope of carbon emission requirements, if any, that ultimately may be imposed on existing electric generating units cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

State Regulation of Greenhouse Gases. On June 5, 2013, RGGI held its twentieth auction, in which approximately 39 million allowances for the second control period were sold at a clearing price of \$3.21 per allowance. RGGI's next quarterly auction is scheduled for September 4, 2013. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

We estimate the cost of RGGI allowances required to operate our affected facilities during 2013 will be approximately \$6 million.

On May 16, 2013, CARB held its third allowance auction, in which all of the approximate 14.5 million 2013 vintage allowances available for sale were sold at a clearing price of \$14.00 per allowance. In addition, approximately 7.5 million vintage 2016 allowances were sold at the floor price of \$10.71 per allowance.

We have participated in CARB's quarterly allowance auctions and will procure additional allowances as needed in future auctions and secondary markets. CARB's next quarterly allowance action is scheduled for August 16, 2013. We estimate the cost of CARB allowances required to operate our affected facilities during 2013 will be approximately \$24 million.

We expect that the cost of compliance for both RGGI and the California GHG program would be reflected in the power market and the actual impact to gross margin would be largely offset by an increase in revenue.

Climate Change Litigation. There is a risk of litigation from those seeking relief from power generators or to impose liability on sources of GHG emissions, including power generation, for claims of adverse effects due to climate change. Recent court decisions disagree on whether the claims are subject to resolution by the courts and whether the plaintiffs have standing to sue.

On May 20, 2013, the Supreme Court denied the plaintiffs' petition for writ of certiorari 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 22, 2012). The appellate court had ruled that the Clean Air Act and EPA actions authorized by the Act displaced federal common law public nuisance claims concerning domestic GHGs.

In May 2013, the U.S. Court of Appeals for the Fifth Circuit upheld the dismissal of climate change tort claims brought by a group of plaintiffs, ruling that such claims had previously been decided by the court. In October 2009, the court considered the appeal of *Comer v. Murphy Oil* and held that claims related to climate change by property owners along the Mississippi Gulf Coast against energy companies could be resolved by the courts. However, the *Comer v. Murphy Oil* decision was subsequently vacated. In May 2011, the plaintiffs re-filed a substantially similar complaint in the U.S. District Court for the Southern District of Mississippi. In March 2012, the District Court dismissed the complaint on multiple alternative grounds, concluding, among other things, that the plaintiffs lacked standing. The plaintiffs appealed to the Fifth Circuit. On May 14, 2013, the U.S. Court of Appeals for the Fifth Circuit upheld the lower court's dismissal of plaintiffs' climate change tort claims, ruling that plaintiffs' claims had previously been decided in the initial *Comer* case.

RISK-MANAGEMENT DISCLOSURES

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

(amounts in millions)	As of and for the Six Months Ended June 30, 2013
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at December 31, 2012	\$(50)
Risk-management losses recognized through the statement of operations in the period, net	(25)

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Contracts realized or otherwise settled during the period	(9)
Changes in collateral/margin netting	14)
Fair value of portfolio at June 30, 2013	\$(70)

68

Table of Contents

The net risk management liability of \$70 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 June 30, 2013, based on our valuation methodology:

Net Fair Value of Risk-Management Portfolio

(amounts in millions)	Total	2013	2014	2015	2016	2017	Thereafter
Market quotations (1) (2)	\$(92)	\$(57)	\$(13)	\$(14)	\$(9)	\$(3)	\$4
Prices based on models (2)	—	—	—	—	—	—	—
Total (3)	\$(92)	\$(57)	\$(13)	\$(14)	\$(9)	\$(3)	\$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 7—Fair Value Measurements for further discussion.

Excludes \$22 million of margin that has been netted against Risk Management liabilities on our consolidated (3) balance sheet. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-Q includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as “forward-looking statements.” All statements included or incorporated by reference in this quarterly report, other than statements of historical fact, that address activities, events or developments that we 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 include, but are not limited to, statements relating to the following:

- expectations and beliefs related to the AER Acquisition and satisfying closing conditions, including obtaining variance relief from the IPCB;
- anticipated benefits and expected synergies resulting from the AER Acquisition and beliefs associated with the integration of operations;
- our ability to consummate the DNE Debtors Chapter 11 Joint Plan of Liquidation ;
- lack of comparable financial data due to the application of fresh-start accounting;
- 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;
- limitations on our ability to utilize previously incurred federal net operating losses or alternative minimum tax credits;
- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios and other payments;
- the timing and anticipated benefits to be achieved through our company-wide savings improvement programs, including our PRIDE initiative;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;
- assumptions to achieve benefit and fixed cost savings through negotiations with IBEW Local 51;
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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;

69

Table of Contents

beliefs, assumptions and projections regarding the demand for power, generation volumes and commodity pricing, including natural gas prices and the timing of a recovery in natural gas prices, if any;

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 and Vermilion facilities;

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;

ability to mitigate impacts associated with expiring RMR and/or capacity contracts;

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.

Table of Contents

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 June 30, 2013.

Value at Risk (“VaR”). The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk-management portfolio primarily associated with the Coal and Gas segments. The VaR calculation does not include market risks associated with the accrual portion of the risk-management portfolio that is designated as “normal purchase normal sale,” nor does it include expected future production from our generating assets. Please read “VaR” in our Form 10-K for a complete description of our valuation methodology. The decrease in the June 30, 2013 VaR was primarily due to decreased forward sales as compared to December 31, 2012.

Daily and Average VaR for Risk-Management Portfolios

(amounts in millions)	June 30, 2013	December 31, 2012
One day VaR—95 percent confidence level	\$3	\$2
One day VaR—99 percent confidence level	\$5	\$3
Average VaR for the year-to-date period—95 percent confidence level	\$5	\$4

Credit Risk. The following table represents our credit exposure at June 30, 2013 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

(amounts in millions)	Investment Grade Quality	Non-Investment Grade Quality	Total
Type of Business:			
Financial institutions	\$4	\$—	\$4
Utility and power generators	—	—	—
Commercial / industrial / end users	—	—	—
Total	\$4	\$—	\$4

Interest Rate Risk

We are exposed to fluctuating interest rates related to our variable rate financial obligations, which consist of amounts outstanding under our Credit Agreement. We 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. The related debt is not recorded at its fair value. As a result of our outstanding interest rate derivatives, we do not have any significant exposure to changes in LIBOR.

The absolute notional amounts associated with our interest rate contracts were as follows at June 30, 2013 and December 31, 2012, respectively:

	June 30, 2013	December 31, 2012
Interest rate swaps (in millions of U.S. dollars) (1)	\$796	\$1,100
Fixed interest rate paid (percent)	3.15	2.22
Interest rate caps (in millions of U.S. dollars) (2)	\$1,400	\$1,400
Interest rate threshold (percent)	2.00	2.00

(1) The calculation period for \$250 million of the interest rate swaps began June 30, 2013, and the calculation period for the remaining \$546 million is scheduled to begin in the fourth quarter of 2013.

(2) The \$1,400 million interest rate caps were terminated in July 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 June 30, 2013.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the quarter ended June 30, 2013.

DYNEGY INC.

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

See Note 13—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 and Form 10-Q for the quarter ended March 31, 2013 for factors, risks and uncertainties that may affect future results.

73

Item 6—EXHIBITS

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

Exhibit Number	Description
4.1	Indenture, dated May 20, 2013, among Dynegy Inc., the Guarantors and Wilmington Trust, National Association as Trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
4.2	Registration Rights Agreement, dated May 20, 2013, among Dynegy Inc., the Guarantors, Morgan Stanley and Credit Suisse (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
10.1	Purchase Agreement, dated May 15, 2013, among Dynegy Inc., the Guarantors, Morgan Stanley and Credit Suisse (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
10.2	Credit Agreement, dated as of April 23, 2013, among Dynegy Inc., as borrower and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.3	Guarantee and Collateral Agreement, dated as of April 23, 2013 among Dynegy Inc., the subsidiaries of the borrower from time to time party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.4	Collateral Trust and Intercreditor Agreement, dated as of April 23, 2013 among Dynegy, the Subsidiary Guarantors (as defined therein), Credit Suisse AG, Cayman Islands Branch and each person party thereto from time to time (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
**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

** 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: August 1, 2013

By: /s/ CLINT C. FREELAND
Clint C. Freeland
Executive Vice President and Chief Financial Officer

75