UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

AMENDMENT NO. 1

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

For the quarterly period ended June 30, 2004

¨ **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: 1-15659

DYNEGY INC.

(Exact name of registrant as specified in its charter)

Illinois	**74-2928353**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1000 Louisiana, Suite 5800

Houston, Texas 77002

(Address of principal executive offices)

(Zip Code)

(713) 507-6400

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes x No ¨

Number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Class A common stock, no par value per share, 282,639,247 shares outstanding as of July 30, 2004; Class B common stock, no par value per share, 96,891,014 shares outstanding as of July 30, 2004.

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DYNEGY INC.

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DYNEGY INC. FORM 10-Q/A

INTRODUCTORY NOTE

Dynegy Inc. is filing this Amendment No. 1 on Form 10-Q/A (Amendment No. 1) to reflect the effect of the following items on our historical unaudited condensed consolidated financial statements and related information, as reported in our Quarterly Report on Form 10-Q for the period ended June 30, 2004, which was originally filed on August 4, 2004 (the Original Filing):

An increase of $139 million to the $242 million goodwill impairment charge originally recorded in the fourth quarter 2003, and a previously unrecorded after-tax asset impairment charge of $120 million in the fourth quarter 2003, each associated with the sale of Illinois Power, as well as a $6 million after-tax increase to the $15 million loss on the sale of Illinois Power recorded in the first half of 2004, and

A $154 million decrease to our deferred income tax liability at December 31, 2003 resulting from our tax basis balance sheet review.

The aforementioned items are discussed in more detail in the Explanatory Note to the accompanying unaudited condensed consolidated financial statements beginning on page 9. Revised financial information for the periods presented reflecting these restatements was previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2003, which was most recently amended by Amendment No. 2 thereto filed with the SEC on January 18, 2005 (the Form 10-K/A). The restated financial and other information included in this Amendment No. 1

should be read together with the Form 10-K/A. The following Items of the Original Filing are amended by this Amendment No. 1:

Item 1. **Condensed Consolidated Financial Statements**

Item 2. **Management s Discussion and Analysis of Financial Condition and Results of Operations**

Item 4. **Controls and Procedures**

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Item 6. Exhibits and Reports on Form 8-K

Unaffected items have not been repeated in this Amendment No. 1.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 1, INCLUDING THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED SEPTEMBER 30, 2004 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE AUGUST 4, 2004, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

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DEFINITIONS

As used in this Form 10-Q/A, the abbreviations listed below have the following meanings:

ARO	Asset retirement obligation
Bbtu/d	Billions of British thermal units per day
Cal ISO	The California Independent System Operator
Cal PX	The California Power Exchange
CDWR	California Department of Water Resources
CFTC	Commodity Futures Trading Commission
CPUC	California Public Utilities Commission
CRM	Our customer risk management business segment
CUSA	Chevron U.S.A. Inc., a wholly owned subsidiary of ChevronTexaco
$/Bbl	Dollars per barrel
$/Gal	Dollars per gallon
DGC	Dynegy Global Communications
DHI	Dynegy Holdings Inc., our primary financing subsidiary
DMG	Dynegy Midwest Generation, Inc.
DMS	Dynegy Midstream Services
DPM	Dynegy Power Marketing Inc.
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, Inc.
ERISA	The Employee Retirement Income Security Act of 1974, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Form 10-K	Our Annual Report on Form 10-K for the year ended December 31, 2003, filed on February 27, 2004, as amended by Amendment No. 1 on Form 10-K/A filed on July 20, 2004
Form 10-K/A	Amendment No. 2 to our Annual Report on Form 10-K for the year ended December 31, 2003, filed on January 18, 2005
Form 10-Q/A	Amendment No. 1 to our Form 10-Q for the quarter ended June 30, 2004
GAAP	Accounting principles generally accepted in the United States of America
GEN	Our power generation business segment
ICC	Illinois Commerce Commission
KWH	Kilowatt hours
kW-yr	Kilowatts per year
LNG	Liquefied natural gas
MBbls/d	Thousands of barrels per day
MMBtu	Millions of British thermal units
MMCFD	Million cubic feet per day
MW	Megawatt
MWh	Megawatt hour
NGL	Our natural gas liquids business segment
NOV	Notice of Violation
NSPS	New Source Performance Standard
Original Filing	Our Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed on August 4, 2004
PGA	Purchase Gas Adjustment
PPO	Power Purchase Option
PSD	Prevention of Significant Deterioration
REG	Our regulated energy delivery business segment
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SPE	Special Purpose Entity
VaR	Value at Risk

VIE	Variable Interest Entity

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DYNEGY INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited) (in millions, except share data)

See Explanatory Note

	June 30, 2004	December 31, 2003
		(Restated)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 795	$ 477
Restricted cash		19
Accounts receivable, net of allowance for doubtful accounts of $161 and $184, respectively	758	1,010
Accounts receivable, affiliates	18	25
Inventory	218	279
Assets from risk-management activities	887	818
Prepayments and other current assets	448	402
Assets held for sale (Note 2)	309	
Total Current Assets	3,433	3,030
Property, Plant and Equipment	7,736	9,867
Accumulated depreciation	(1,549)	(1,664)
Property, Plant and Equipment, Net	6,187	8,203
Other Assets		
Unconsolidated investments	626	612
Assets from risk-management activities	671	629
Goodwill	15	15
Other long-term assets	216	472
Assets held for sale (Note 2)	2,183	
Total Assets	$ 13,331	$ 12,961
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 591	$ 665
Accounts payable, affiliates	77	74
Accrued liabilities and other current liabilities	534	668
Liabilities from risk-management activities	944	838
Notes payable and current portion of long-term debt	81	245
Current portion of long-term debt to affiliates		86
Liabilities held for sale (Note 2)	407	
Total Current Liabilities	2,634	2,576
Long-term debt	4,239	5,124
Long-term debt to affiliates	407	769
Long-Term Debt	4,646	5,893

Other Liabilities		
Liabilities from risk-management activities	762	746
Deferred income taxes	515	524
Other long-term liabilities	383	743
Liabilities held for sale (Note 2)	1,879	
Total Liabilities	10,819	10,482
Minority Interest	120	121
Commitments and Contingencies (Note 9)		
Redeemable Preferred Securities, redemption value of $411 at June 30, 2004 and December 31, 2003, respectively	411	411
Stockholders Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at June 30, 2004 and December 31, 2003; 284,113,963 and 280,350,169 shares issued and outstanding at June 30, 2004 and December 31, 2003, respectively	2,856	2,848
Class B Common Stock, no par value, 360,000,000 shares authorized at June 30, 2004 and December 31, 2003; 96,891,014 shares issued and outstanding at June 30, 2004 and December 31, 2003	1,006	1,006
Additional paid-in capital	46	41
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive loss, net of tax	(66)	(20)
Accumulated deficit	(1,785)	(1,852)
Treasury stock, at cost, 1,679,183 shares at June 30, 2004 and December 31, 2003	(68)	(68)
Total Stockholders Equity	1,981	1,947
Total Liabilities and Stockholders Equity	$ 13,331	$ 12,961

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited) (in millions, except per share data)

See Explanatory Note

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(Restated)		(Restated)	
Revenues	$ 1,440	$ 1,067	$ 3,097	$ 2,946
Cost of sales, exclusive of depreciation shown separately below	(1,098)	(1,215)	(2,476)	(2,727)
Depreciation and amortization expense	(82)	(116)	(170)	(231)
Impairment and other charges	(64)		(80)	7
Gain on sale of assets, net	36	14	38	15
General and administrative expenses	(99)	(124)	(168)	(197)
Operating income (loss)	133	(374)	241	(187)
Earnings from unconsolidated investments	52	38	92	91
Interest expense	(145)	(109)	(277)	(219)
Other income and expense, net	(6)	3	7	11
Minority interest income (expense)	(8)	(8)	(10)	9
Accumulated distributions associated with trust preferred securities		(4)		(8)
Income (loss) from continuing operations before income taxes	26	(454)	53	(303)
Income tax benefit (Note 12)	1	168	30	112
Income (loss) from continuing operations (Note 8)	27	(286)	83	(191)
Loss from discontinued operations, net of taxes (Notes 2 and 12)	(19)	(4)	(5)	(7)
Income (loss) before cumulative effect of change in accounting principles	8	(290)	78	(198)
Cumulative effect of change in accounting principles, net of taxes (Note 1)				55
Net income (loss)	8	(290)	78	(143)
Less: preferred stock dividends	6	82	11	165
Net income (loss) applicable to common stockholders	$ 2	$ (372)	$ 67	$ (308)
Earnings (Loss) Per Share (Note 8):				
Basic earnings (loss) per share:				
Earnings (loss) from continuing operations	$ 0.06	$ (0.99)	$ 0.19	$ (0.96)
Loss from discontinued operations	(0.05)	(0.01)	(0.02)	(0.02)
Cumulative effect of change in accounting principles				0.15

Basic earnings (loss) per share	$ 0.01	$ (1.00)	$ 0.17	$ (0.83)
Diluted earnings (loss) per share:				
Earnings (loss) from continuing operations	$ 0.05	$ (0.99)	$ 0.17	$ (0.96)
Loss from discontinued operations	(0.05)	(0.01)	(0.01)	(0.02)
Cumulative effect of change in accounting principles				0.15
Diluted earnings (loss) per share	$ 0.00	$ (1.00)	$ 0.16	$ (0.83)
Basic shares outstanding	378	373	377	372
Diluted shares outstanding	435	375	503	374

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (in millions)

See Explanatory Note

	Six Months Ended June 30,	
	2004	**2003**
	(Restated)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 78	$ (143)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation and amortization	196	258
Impairment and other charges	80	
Earnings from unconsolidated investments, net of cash distributions	(19)	(22)
Risk-management activities	(44)	290
Gain on sale of assets, net	(38)	(39)
Deferred income taxes	(4)	(122)
Cumulative effect of change in accounting principles (Note 1)		(55)
Liability associated with gas transportation contracts (Note 2)	(148)	
Other	5	49
Changes in working capital:		
Accounts receivable	84	1,615
Inventory	12	102
Prepayments and other assets	(100)	546
Accounts payable and accrued liabilities	(49)	(2,014)
Changes in non-current assets and liabilities, net	8	(25)
Net cash provided by operating activities	61	440
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(151)	(189)
Proceeds from asset sales, net	81	33
Net cash used in investing activities	(70)	(156)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from long-term borrowings	581	301
Repayments of long-term borrowings	(193)	(425)
Net cash flow from commercial paper and revolving lines of credit		(128)
Proceeds from issuance of capital stock	5	6
Dividends and other distributions, net	(11)	
Other financing, net	(12)	(1)
Net cash provided by (used in) financing activities	370	(247)

Effect of exchange rate changes on cash	(1)	7
Net increase in cash and cash equivalents	360	44
Cash and cash equivalents, beginning of period	477	757
Less: Illinois Power cash classified as held for sale at end of period (Note 2)	(42)	
Cash and cash equivalents, end of period	$ 795	$ 801

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited) (in millions)

See Explanatory Note

	Three Months Ended June 30,	
	2004	2003
	(Restated)	
Net income (loss)	$ 8	$ (290)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains arising during period, net	5	33
Reclassification of mark-to-market losses (gains) to earnings, net	9	(2)
Changes in cash flow hedging activities, net (net of tax expense of $8 and $18, respectively)	14	31
Foreign currency translation adjustments		(3)
Other comprehensive income, net of tax	14	28
Comprehensive income (loss)	$ 22	$ (262)

	Six Months Ended June 30,	
	2004	2003
	(Restated)	
Net income (loss)	$ 78	$ (143)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains (losses) arising during period, net	(53)	45
Reclassification of mark-to-market losses (gains) to earnings, net	20	(21)
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $20 and ($14), respectively)	(33)	24
Foreign currency translation adjustments	(15)	21
Minimum pension liability (net of tax expense of $1 and zero, respectively)	2	
Other comprehensive income (loss), net of tax	(46)	45
Comprehensive income (loss)	$ 32	$ (98)

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

PLEASE NOTE THAT THESE FINANCIAL STATEMENTS AND THE NOTES THERETO DO NOT REFLECT EVENTS OCCURRING AFTER AUGUST 4, 2004 (THE DATE OF THE ORIGINAL FILING). FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE AUGUST 4, 2004, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

EXPLANATORY NOTE

This Amendment No. 1 to our Quarterly Report on Form 10-Q for the period ended June 30, 2004 includes restatements related to our audited consolidated financial statements as of December 31, 2003 and our unaudited condensed consolidated financial statements for the periods ended June 30, 2004 and 2003. On January 18, 2005, we filed Amendment No. 2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2003. The Form 10-K/A also included restated financial information for the period ended June 30, 2003. The restatements relate to increased and additional impairments associated with the sale of Illinois Power and our deferred income tax accounts. Specifically, the restatements are as follows:

Impairment of Illinois Power. As more fully discussed in Note 10 Goodwill beginning on page F-38 of our Form 10-K/A, during 2003, the value of goodwill associated with Illinois Power was determined to be impaired, resulting in our recognizing a charge of $242 million. During 2004, while preparing to record the Illinois Power sale, we identified a deferred tax asset that was excluded from our 2003 impairment analysis. Our exclusion of this asset understated the net book value of the assets and, as a result, understated the impairment that had been recorded in 2003. The impact of the error resulted in an after-tax understatement of goodwill impairment of $139 million and an after-tax understatement of asset impairments of $120 million. As such, we were required to recognize an additional after-tax charge of $259 million ($0.61 per diluted share) in the fourth quarter 2003. In addition, we were required to recognize additional after-tax charges of $4 million ($0.01 per diluted share) and $2 million ($0.00 per diluted share) in the three months ended March 31 and June 30, 2004, respectively, due to changes in the value of the deferred tax asset. This correction had no impact on previously reported net cash provided by (used in) operating activities, investing activities or financing activities. The financial information in this report has been revised to reflect the impact of this correction.

The table below summarizes the effects of the correction on our previously reported net income:

	Three Months Ended June 30, 2004	Six Months Ended June 30, 2004

	(in millions)	
Impairment and other charges as previously reported	$ (44)	$ (54)
Adjustment	(20)	(26)
Impairment and other charges as restated	$ (64)	$ (80)
Income tax benefit (expense) as previously reported	$ (17)	$ 10
Adjustment	18	20
Income tax benefit (expense) as restated	$ 1	$ 30
Net income as previously reported	$ 10	$ 84
Adjustment	(2)	(6)
Net income as restated	$ 8	$ 78

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Deferred Income Tax Accounts. As discussed in the Form 10-K/A, and as previously disclosed in the Original Filing, we undertook an evaluation of our tax accounting and reconciliation controls and processes, including a tax basis balance sheet review, which we have recently completed. Through this initiative, we have determined that adjustments related to our deferred income tax accounts in periods prior to 2004 are required. These adjustments primarily related to errors associated with accounting for acquisitions, incorrect classification of goodwill impairments as permanent differences for purposes of calculating the tax provision and other items. As a result of those errors, adjustments were also made to goodwill and other long-term liabilities accounts.

This restatement has no effect on our previously reported net income or net cash provided by (used in) operating activities, investing activities or financing activities for the three and six months ended June 30, 2004 or 2003.

Balance Sheet Summary. The table below summarizes the effects of both items discussed above on our December 31, 2003 and June 30, 2004 balance sheets:

	June 30, 2004	December 31, 2003
	(in millions)	
Property, Plant and Equipment, Net		
As previously reported	$ 6,187	$ 8,396
Impairment of Illinois Power		(193)
As restated	$ 6,187	$ 8,203
Goodwill		
As previously reported	$ 15	$ 154
Impairment of Illinois Power		(139)
As restated	$ 15	$ 15
Non-current assets held for sale		
As previously reported	$ 2,541	$
Impairment of Illinois Power	(358)	
As restated	$ 2,183	$
Total Assets		

As previously reported	$ 13,689	$ 13,293
Impairment of Illinois Power	(358)	(332)
As restated	$ 13,331	$ 12,961
Deferred income taxes		
As previously reported	$ 411	$ 751
Impairment of Illinois Power	265	(73)
Deferred income tax accounts	(161)	(154)
As restated	$ 515	$ 524
Other long-term liabilities		
As previously reported	$ 383	$ 750
Deferred income tax accounts		(7)
As restated	$ 383	$ 743
Total Liabilities		
As previously reported	$ 11,073	$ 10,716
Impairment of Illinois Power	(93)	(73)
Deferred income tax accounts	(161)	(161)
As restated	$ 10,819	$ 10,482
Stockholders Equity		
As previously reported	$ 2,085	$ 2,045
Impairment of Illinois Power	(265)	(259)
Deferred income tax accounts	161	161
As restated	$ 1,981	$ 1,947

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Note 1 Accounting Policies

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 balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. These interim financial statements should be read together with the restated consolidated financial statements and notes thereto included in our Form 10-K/A, which includes restated financial statements reflecting the adjustments described in the Explanatory Note above.

The unaudited condensed consolidated financial statements contained in this report include all material adjustments that, in the opinion of management, are necessary for a fair presentation of the results for the interim periods. The results of operations for the interim periods presented in this Form 10-Q/A are not necessarily indicative of the results to be expected for the full year or any other interim period, however, 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. The preparation of the unaudited condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect our reported financial position and results of operations. These estimates and assumptions also impact the nature and extent of disclosure, if any, of our contingent liabilities. We review significant estimates affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Judgments and estimates are based on our beliefs and assumptions derived from information available at the time such estimates are made. Adjustments made with respect to the use of these estimates often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates are primarily used in (1) developing fair value assumptions, including estimates of future cash flows and discount rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets, (4) assessing future tax exposure and the realization of tax assets, (5) determining amounts to accrue for contingencies and (6) estimating various factors used to value our pension assets. Actual results could differ materially from any such estimates.

We have reclassified certain amounts reported in this Form 10-Q/A from prior periods to conform to the 2004 financial statement presentation. These reclassifications had no impact on reported net income (loss).

Accounting Principles Adopted

EITF Issue 02-03. In October 2002, the EITF rescinded EITF Issue 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, which previously required use of mark-to-market accounting for our energy trading contracts. While the rescission of EITF Issue 98-10 reduced the number of contracts accounted for on a mark-to-market basis, it did not eliminate mark-to-market accounting. All derivative contracts that either do not qualify, or are not designated, as hedges or as normal purchases or sales, as defined by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, continue to be marked-to-market in accordance with SFAS No. 133. Any earnings or losses previously recognized under EITF Issue 98-10 that would not have been recognized under SFAS No. 133 were reversed in 2003 in connection with our adoption of EITF Issue 02-03.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

The cumulative effect of this change in accounting principle resulted in after-tax earnings of $21 million in the first quarter 2003 and comprised the following items no longer required to be recorded using mark-to-market accounting (in millions):

Removal of net risk-management assets representing the value of natural gas storage contracts	$ (176)
Removal of other net risk-management assets	(24)
Removal of net risk-management liabilities representing the value of power tolling arrangements	103
Net change in risk-management assets and liabilities	(97)
Addition of inventory previously included in risk-management assets (1)	130
Pre-tax gain recorded from change in accounting principle	33
Income tax provision	(12)
After-tax gain recorded in the unaudited condensed consolidated statements of operations	$ 21

(1) A substantial portion of this natural gas inventory was sold during the three months ended March 31, 2003, with the remainder being sold in the second quarter 2003.

SFAS No. 143. In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. We adopted SFAS No. 143, which provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets, effective January 1, 2003. Under SFAS No. 143, an ARO is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset by an amount equal to the ARO. In each subsequent period, the liability is accreted towards the ultimate obligation amount and the capitalized ARO costs are depreciated over the useful life of the related asset.

As part of the transition adjustment in adopting SFAS No. 143, existing environmental liabilities in the amount of $73 million were reversed in the first quarter 2003. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the ARO and was recorded upon adoption of SFAS No. 143. Since the previously accrued liabilities exceeded the fair value of the future retirement obligations, the impact of adopting SFAS No. 143 was an increase in earnings, net of tax, of $34 million in the first quarter 2003, which is included in cumulative effect of change in accounting principles in the unaudited condensed consolidated statements of operations. In addition to these liabilities, we also have potential retirement obligations for dismantlement of power generation facilities, power transmission assets, a fractionation facility and natural gas storage facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded in accordance with SFAS No. 143 at the time we are able to estimate any new AROs.

At January 1, 2004, our ARO liabilities were $30 million for our GEN segment, $10 million for our NGL segment and $1 million for our REG segment. These retirement obligations related to activities such as ash pond and landfill capping, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. During the three and six-month periods ended June 30, 2004, accretion expense recognized as our ARO liabilities accreted toward their ultimate redemption values totaled approximately $1 million and $2 million, respectively. There were no additional AROs recorded or settled, nor were there any revisions to estimated cash flows associated with existing AROs, during the three - and six-month periods ended June 30, 2004. At June 30, 2004, our aggregate ARO liability was $43 million.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

SFAS No. 148. In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation, and provides alternative methods of transition (prospective, modified prospective or retroactive) for entities that voluntarily change to the fair value-based method of accounting for stock-based employee compensation in a fiscal year beginning before December 16, 2003. SFAS No. 148 requires prominent disclosure about the effects on reported net income of an entity s accounting policy decisions with respect to stock-based employee compensation. We transitioned to a fair value-based method of accounting for stock-based compensation in the first quarter 2003 and are using the prospective method of transition as described under SFAS No. 148.

Under the prospective method of transition, all stock options granted after January 1, 2003 are accounted for on a fair value basis. We will incur compensation expense over the vesting period of the options in an amount equal to the fair value of the options. Options granted prior to January 1, 2003 continue to be accounted for using the intrinsic value method. Accordingly, for options granted prior to January 1, 2003, compensation expense is not reflected for employee stock options unless they were granted at an exercise price lower than market value on the grant date. We have granted in-the-money options in the past and have recognized compensation expense over the applicable vesting periods. No in-the-money stock options have been granted since 1999.

Had compensation cost for all stock options granted prior to 2003 been determined on a fair value basis consistent with SFAS No. 123, our net income (loss) and basic and diluted earnings (loss) per share amounts would have approximated the following pro forma amounts for the three and six-month periods ended June 30, 2004 and 2003, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
	(in millions, except per share data)			
Net income (loss) as reported	$ 8	$ (290)	$ 78	$ (143)
Add: Stock-based employee compensation expense included in reported net income (loss), net of related tax effects	1		2	1
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7)	(14)	(16)	(27)
Pro forma net income (loss)	$ 2	$ (304)	$ 64	$ (169)
Earnings (loss) per share:				

Basic as reported	$ 0.01	$ (1.00)	$ 0.17	$ (0.83)
Basic pro forma	$ (0.01)	$ (1.03)	$ 0.14	$ (0.90)
Diluted as reported	$ 0.00	$ (1.00)	$ 0.16	$ (0.83)
Diluted pro forma	$ (0.00)	$ (1.03)	$ 0.14	$ (0.90)

FIN No. 46R. In the fourth quarter 2003, we adopted the initial provisions of FIN No. 46R, Consolidation of Variable Interest Entities An Interpretation of ARB No. 51. FIN No. 46R was effective on December 31, 2003 for entities considered SPEs. We adopted the remaining provisions of FIN No. 46R on March 31, 2004. These provisions require that we review the structure of non-SPE legal entities in which we have an investment and other legal entities with whom we transact to determine whether such entities are VIEs, as defined by FIN No. 46R. With respect to each of the VIEs we identified, we assessed whether we are the

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primary beneficiary, as defined by FIN No. 46R. We concluded that we were not the primary beneficiary of any of these entities and, therefore, the adoption did not have an impact on our unaudited condensed consolidated financial statements.

FIN No. 46R requires additional disclosures for entities which meet the definition of a VIE in which we hold a significant variable interest but are not the primary beneficiary. We own or have owned 50% equity interests in various generation facilities in Illinois, California, Georgia, Texas and Michigan, which are accounted for using equity method accounting and are included in Unconsolidated investments in our unaudited condensed consolidated balance sheets. We acquired or began involvement with these equity interests in 1997 and 1999. Total net generating capacity for these generating facilities ranges from 62 MW to 1,156 MW. As a result of various contractual arrangements into which these entities have entered, we have concluded that they are VIEs. As we do not absorb a majority of the expected losses or receive a majority of the expected residual returns, we are not considered the primary beneficiary of these entities. Our equity investment balance in the facilities totaled $490 million at June 30, 2004, and one of our affiliates has a loan outstanding to one of these entities, which totaled $10 million at June 30, 2004.

FIN No. 46R also requires additional disclosure for entities where we are unable to obtain, after exhaustive efforts, financial information to determine (1) if the entity is a VIE and (2) if we are deemed to be the primary beneficiary of the entity. We identified one potential VIE for which we were unable to obtain adequate financial information. As required to be disclosed by FIN No. 46R, following is a description of the agreements with this potential VIE. In July 2001, we entered into several agreements, including a power tolling agreement, a financial derivative instrument, an energy management agreement and a natural gas supply agreement, with Sithe Independence Power Partners, L.P., which owns and operates a 955 MW combined cycle natural gas generation facility in Oswego, New York. These agreements are in effect through 2014. Our future obligations under these agreements are approximately $789 million, which includes the fixed capacity payments for our physical tolling contract and fixed payments related to the financial derivative instrument. We recorded expense of $9 million and $141 million under the tolling agreement and financial derivative instrument during the three months ended June 30, 2004 and 2003, respectively, and $10 million and $143 million during the six months ended June 30, 2004 and 2003, respectively.

Cumulative Effect of Change in Accounting Principles

We adopted SFAS No. 143 and provisions of EITF Issue 02-03 in the first quarter 2003. Please see above for a discussion of the impact of adopting these standards.

Note 2 Dispositions, Contract Terminations and Discontinued Operations

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page 9.

Dispositions and Contract Terminations

Pending Sale of Illinois Power. In February 2004, we entered into a purchase agreement to sell all of the outstanding common and preferred shares of Illinois Power Company, which currently comprises our REG segment, owned by Illinova Corporation, our indirect wholly owned subsidiary and the direct parent company of Illinois Power, and our 20% interest in the Joppa power generation facility, to Ameren for $2.3 billion. The sale is scheduled to be completed by the end of 2004, subject to closing conditions. In July 2004, the FERC approved this sale and our two-year power purchase agreement under which Illinois Power will purchase from us up to 2,800 MWs of capacity and 11.5 million MWh of energy at fixed prices beginning in January 2005. We are

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awaiting additional approvals from the ICC and the SEC. We also agreed to sell 300 MWs of capacity in 2005 and 150 MWs of capacity in 2006 to Illinois Power at a fixed price with an option to purchase energy at market-based prices.

In the first quarter 2004, Illinois Power met the held for sale classification requirements of SFAS No. 144. As of June 30, 2004, Illinois Power continued to meet the held for sale requirements and is classified as such on our unaudited condensed consolidated balance sheet. The major classes of current and long-term assets and liabilities classified as Assets held for sale or Liabilities held for sale at June 30, 2004 are as follows (in millions):

Current Assets:	
Cash	$ 42
Accounts receivable	175
Inventory	44
Other	48
Total Current Assets	$ 309
Long-Term Assets:	
Property, plant and equipment, net	$ 1,894
Regulatory assets	181
Other	108
Total Long-Term Assets	$ 2,183
Current Liabilities:	
Accounts payable	$ 44
Current portion of long-term debt, including $78 million due to affiliates	220
Other	143
Total Current Liabilities	$ 407
Long-Term Liabilities:	
Long-term debt, including $301 million due to affiliates	$ 1,668
Other	211
Total Long-Term Liabilities	$ 1,879

Additionally, $11 million included in Redeemable preferred securities and $34 million of Accumulated other comprehensive loss at June 30, 2004 relate to Illinois Power and will not be included in our unaudited condensed consolidated balance sheets subsequent to the sale.

SFAS No. 144 also requires that long-lived assets not be depreciated or amortized while they are classified as held for sale. As such, we discontinued depreciation and amortization of Illinois Power s property, plant and equipment and regulatory assets, effective February 1, 2004. Depreciation and amortization expense related to Illinois Power totaled $30 million and $60 million in the three- and six-month periods ended June 30, 2003, respectively. In addition, SFAS No. 144 requires a loss to be recognized by the amount Assets held for sale less Liabilities held for sale are in excess of fair value less costs to sell. Accordingly, for the three- and six-month periods ended June 30, 2004, we recorded pre-tax losses on the sale of $48 million and $69 million, respectively.

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The first quarter charge, which was primarily associated with the expected transaction costs, is reflected in Gain on sale of assets, net and Impairment and other charges on the unaudited condensed consolidated statements of operations. The second quarter charge, an impairment of assets, is reflected in Impairment and other charges on the unaudited condensed consolidated statements of operations.

Pursuant to SFAS No. 144, we are not reporting the results of Illinois Power s operations as a discontinued operation. If we were to account for Illinois Power as a discontinued operation, its results of operations would be condensed into Income (loss) from discontinued operations, net of taxes, on our unaudited condensed consolidated statements of operations, and prior periods would be required to be restated to conform to this presentation. To qualify for discontinued operations classification, SFAS No. 144 and subsequent interpretations, specifically EITF Issue 03-13, Applying the Conditions in Paragraph 42 of FAS 144 in Determining Whether to Report Discontinued Operations, require that the seller have no significant continuing involvement with the business being sold. As noted above, we have contracted to sell capacity and energy to Illinois Power for two years subsequent to the sale. Consequently, because we will have significant continuing involvement with Illinois Power, we will continue to report the historical results of Illinois Power s operations in continuing operations. Earnings from power sales to Illinois Power derived from periods following the closing of the transaction will continue to be reported in the GEN segment in continuing operations.

Changes in Assets held for sale less Liabilities held for sale in future quarters, prior to the closing of the transaction, may result in additional losses. In accordance with SFAS No. 142, such losses would first be recorded as a reduction to goodwill in our REG segment. The amount of such losses depends on various factors including timing of the closing of the transaction, capital expenditures prior to closing and other matters. Given the nature of these factors, we currently are unable to predict with certainty the additional loss we may realize.

We expect to record a pre-tax gain of approximately $75 million upon closing of the transaction related to the sale of our 20% interest in the Joppa power generation facility. Our interest in the Joppa power generation facility is included in our unaudited condensed consolidated balance sheets in Unconsolidated investments and totaled $24 million at June 30, 2004.

Hackberry LNG Project. During the first quarter 2003, we entered into an agreement to sell our ownership interest in Hackberry LNG Terminal LLC, the entity we formed in connection with our proposed LNG terminal/gasification project in Hackberry, Louisiana, to Sempra LNG Corp., a subsidiary of San Diego-based Sempra Energy. The transaction closed in April 2003, after which we received contingent payments in 2003 based upon project development milestones. In March 2004, we sold our remaining financial interest in this project, which interest included rights to receive future contingent payments under the 2003 agreement, for $17 million and recognized a pre-tax gain of $17 million on the sale. This gain is included in Gain on sale of assets, net on our unaudited condensed consolidated statements of operations.

Indian Basin. In April 2004, we sold our 16% interest in the Indian Basin Gas Processing Plant for approximately $48 million. In the second quarter 2004, we recognized a pre-tax gain on the sale of approximately $36 million. This gain is included in Gain on sales of assets, net on our unaudited condensed consolidated statements of operations.

PESA. In April 2004, we sold our interest in the Plantas Eolicas, S.A. de R.L. 20 MW wind-powered electric generation facility located in Costa Rica for approximately $11 million. We recognized a pre-tax loss of approximately $1 million on the sale. This loss is included in Gain on sale of assets, net on our unaudited condensed consolidated statements of operations.

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Gas Transportation Contracts. In June 2004, we agreed to exit four long-term natural gas transportation contracts whose purpose was to secure firm pipeline capacity through 2014 in support of our former third-party marketing and trading business. In exchange for exiting these obligations, we paid $20 million in June 2004 and will pay an additional $42 million in the first quarter 2005. This future payment obligation was recorded at its fair value of $40 million and will be accreted to $42 million over the period July 1, 2004 through March 31, 2005. Additionally, we reversed an aggregate liability of $148 million associated with the transportation contracts that was originally established in 2001 and recognized a pre-tax gain of $88 million related to these transactions. This gain is included in Revenues on our unaudited condensed consolidated statements of operations and is included in the results of our CRM segment. This agreement will eliminate our obligation to make approximately $295 million in aggregate fixed capacity payments from April 2005 through 2014.

Discontinued Operations

As part of our restructuring plan, we sold or liquidated some of our operations during 2003, including substantial portions of our communications business and our U.K. CRM business, which have been accounted for as discontinued operations under SFAS No. 144. The following table summarizes information related to our discontinued operations:

	U.K. CRM	DGC	Global Liquids	Total
		(in millions)		
Three Months Ended June 30, 2004				
Income from operations before taxes	$ 1	$	$	$ 1
Loss from operations after taxes	(19)			(19)
Three Months Ended June 30, 2003				
Revenue	$	$ 1	$	$ 1
Income (loss) from operations before taxes	4	(10)	(1)	(7)
Income (loss) from operations after taxes	1	(6)	(1)	(6)
Gain on sale before taxes		4		4
Gain on sale after taxes		2		2

	U.K. CRM	DGC	Global Liquids	Total
		(in millions)		
Six Months Ended June 30, 2004				
Income from operations before taxes	$ 18	$ 3	$	$ 21
Income (loss) from operations after taxes	(7)	2		(5)

Six Months Ended June 30, 2003				
Revenue	$ 21	$ 5	$	$ 26
Loss from operations before taxes	(11)	(29)	(1)	(41)
Loss from operations after taxes	(9)	(18)	(1)	(28)
Gain on sale before taxes		25		25
Gain on sale after taxes		21		21

In the first quarter 2004, we recognized $17 million of pre-tax income related to translation gains on foreign currency in the U.K. Please see Note 4 Risk Management Activities and Accumulated Other Comprehensive Loss Net investment hedges in foreign operations for further discussion. Also in the first quarter 2004, we

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recognized $3 million of pre-tax income associated with DGC s receipt of $3 million from a third party in settlement of a prior contractual claim. In the second quarter 2004, we recognized a tax expense of $20 million related to charges resulting from the conclusion of prior year tax audits. Please see Note 12 Income Taxes for further discussion. Please also see Note 8 Earnings (Loss) Per Share for a discussion of an error in our second quarter 2004 earnings news release, which was subsequently identified and corrected in this Form 10-Q, relating to the reclassification of a $13 million income tax benefit between continuing and discontinued operations.

Note 3 Restructuring Charges

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page 9.

In the three and six months ended June 30, 2004, we recorded pre-tax charges relating to our interest in Illinois Power totaling $48 million and $69 million, respectively. For further discussion, please read Note 2 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Pending Sale of Illinois Power. In addition, in the three months ended June 30, 2004, we recorded a $5 million pre-tax charge related to the impairment of one of our midstream assets.

In October 2002, we announced a restructuring plan designed to improve operational efficiencies and performance across our lines of business. The following is a schedule of 2004 activity for the liabilities recorded in connection with this restructuring:

	Severance	Cancellation Fees and Operating Leases	Total
		(in millions)	
Balance at December 31, 2003	$ 23	$ 30	$ 53
2004 adjustments to liability	17	5	22
Cash payments	(36)	(6)	(42)
Balance at June 30, 2004	$ 4	$ 29	$ 33

The adjustment to the accrued liability during 2004 primarily reflects increases in the severance accrual due to changes in our estimate of the probable loss associated with the severance claims of our former chief executive officer and our former president. Cash payments during 2004 reflect payments made to our former chief executive officer and our former president. Please see Note 9 Commitments and Contingencies Severance Arbitrations for further discussion regarding the status of these claims and settlement payments.

Note 4 Risk Management Activities and Accumulated Other Comprehensive Loss

The nature of our business necessarily involves market and financial risks. We enter into financial instrument contracts in an attempt to mitigate or eliminate these various risks. These risks and our strategy for mitigating them are more fully described in Note 5 Risk Management Activities and Financial Instruments beginning on page F-29 of our Form 10-K/A.

Cash flow hedges. We enter into financial derivative instruments that qualify as cash flow hedges. Instruments related to our power generation and natural gas liquids businesses are entered into for purposes of hedging future fuel requirements and sales commitments and locking in future margin. Interest rate swaps are used to convert the floating interest-rate component of some obligations to fixed rates.

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During the three and six months ended June 30, 2004 and 2003, there was no material ineffectiveness from changes in fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows. During the three and six months ended June 30, 2004 and 2003, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring.

The balance in cash flow hedging activities, net at June 30, 2004 is expected to be reclassified to future earnings, contemporaneously with the related purchases of fuel, sales of electricity or natural gas liquids and payments of interest, as applicable to each type of hedge. Of this amount, after-tax losses of approximately $25 million are currently estimated to be reclassified into earnings over the 12-month period ending June 30, 2005. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market conditions and other factors.

Fair value hedges. We also enter into derivative instruments that qualify as fair value hedges. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into variable-rate debt. During the three and six months ended June 30, 2004 and 2003, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During the three and six months ended June 30, 2004 and 2003, no amounts were recognized in relation to firm commitments that no longer qualified as fair value hedges.

In July 2004, we entered into interest rate swaps with a notional value of $500 million. These swaps were designated as fair value hedges and effectively convert a portion of our non-prepayable fixed-rate debt into variable-rate debt.

Net investment hedges in foreign operations. We have investments in foreign subsidiaries, the net assets of which are exposed to currency exchange-rate volatility. In the past, we used derivative financial instruments, including foreign exchange forward contracts and cross-currency interest rate swaps, to hedge this exposure. As of June 30, 2004, we had no net investment hedges in place.

During the first quarter 2003, our efforts to exit the U.K. CRM business and the European communications business were substantially completed. As required by SFAS No. 52, Foreign Currency Translation, a significant portion of unrealized gains and losses resulting from translation and financial instruments utilized to hedge currency exposures previously recorded in stockholders equity were recognized in income, resulting in an after-tax loss of approximately $16 million in the six months ended June 30, 2003. During the first quarter 2004, we repatriated a majority of our cash from the U.K., resulting in the substantial liquidation of our investment in the U.K. As such, we recognized approximately $17 million of pre-tax translation gains in income that arose since April 1, 2003 and had accumulated in stockholders equity.

Accumulated other comprehensive loss. Accumulated other comprehensive loss, net of tax, is included in stockholders equity on the unaudited condensed consolidated balance sheets as follows:

	June 30, 2004	December 31, 2003
	(in millions)	
Cash flow hedging activities, net	$ (23)	$ 10
Foreign currency translation adjustment	12	27
Minimum pension liability	(55)	(57)
Accumulated other comprehensive loss, net of tax	$ (66)	$ (20)

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Note 5 Unconsolidated Investments

A summary of our unconsolidated investments is as follows:

	June 30, 2004	December 31, 2003
	(in millions)	
Equity affiliates:		
GEN investments	$ 539	$ 518
NGL investments	80	82
Total equity affiliates	619	600
Other affiliates, at cost	7	12
Total unconsolidated investments	$ 626	$ 612

Summarized aggregate financial information for unconsolidated equity investments and our equity share thereof was:

	Six Months Ended June 30,			
	2004		2003	
	Total	Equity Share	Total	Equity Share
	(in millions)			
Revenues	$ 1,025	$ 459	$ 1,552	$ 634
Operating income	235	112	270	118
Net income	214	104	215	94

Earnings from unconsolidated investments of $92 million for the six months ended June 30, 2004 include the $104 million above, offset by an $8 million impairment of our Michigan Power equity investment discussed below and $4 million of amortization of the difference between the cost of our unconsolidated investments and our underlying equity in their net assets. Earnings from unconsolidated investments of $91 million for the six months ended June 30, 2003 consist of the $94 million above, offset by $3 million in asset impairments.

During the first quarter 2004, we sold our interest in our power generating facility located in Jamaica. Net proceeds associated with the sale were approximately $5.5 million, and we did not recognize a gain or loss on the sale.

In July 2004, we sold our unconsolidated investments in the Oyster Creek and Michigan Power generating facilities for aggregate net cash proceeds of approximately $104 million. We expect to recognize a gain of approximately $15 million in the third quarter 2004 related to our sale of Oyster Creek. In the three- and six-month periods ended June 30, 2004, we recorded impairments on our investment in Michigan Power totaling $1 million and $8 million, respectively, to adjust our book value to the selling price. Thus, we do not expect to recognize a gain or loss on its sale in the third quarter 2004.

In July 2004, we entered into agreements to sell our unconsolidated investments in the Commonwealth and Hartwell generating facilities. Closing of each of these transactions, targeted for the fourth quarter 2004, is subject to regulatory and other approvals. Under the terms of these agreements, we do not expect to recognize a material gain or loss on these sales.

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Note 6 Debt

Revolvers. During the three- and six-month periods ended June 30, 2004, we reduced an aggregate of approximately $37 million and $17 million, respectively, of letters of credit under our revolving credit facilities, resulting in a total of $171 million utilized at June 30, 2004. As of June 30, 2004, there were no borrowings outstanding under our $700 million revolving credit facility. During the period from June 30, 2004 through July 30, 2004, we increased our outstanding letters of credit under this facility by $6 million.

Effective May 28, 2004, DHI entered into a $1.3 billion credit facility consisting of:

- a $700 million secured revolving credit facility that matures on May 28, 2007; and

- a $600 million secured term loan that matures on May 28, 2010, subject to an earlier maturity in specified circumstances.

The credit facility replaced DHI s $1.1 billion revolving credit facility, which was scheduled to mature in February 2005.

The revolving credit facility provides funding for general corporate purposes. The revolving credit facility is also available for the issuance of letters of credit. Borrowings under the revolving credit facility will bear interest, at DHI s option, at (i) a base rate plus 3.00% per annum or (ii) LIBOR plus 4.00% per annum. A letter of credit fee is payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.00% of such undrawn amount. We also incur additional fees for issuing letters of credit. An unused commitment fee of 0.50% will be payable on the unused portion of the revolving credit facility.

Of the $600 million in proceeds from the term loan drawn at closing, a portion has been used to post cash collateral in lieu of letters of credit, while approximately $19 million was used to pay upfront fees incurred in connection with the new facility. These fees have been capitalized and are being amortized over the term of the credit facility. Additionally, approximately $150 million is required to be used to pre-pay indebtedness and other amounts owed in connection with the ABG Gas Supply financing. We are currently in discussions with the participants in that financing to pre-pay the indebtedness and other obligations. If we do not reach agreement, we will seek a waiver of, or an amendment to, this requirement under the credit facility. The remaining proceeds, subject to specified restrictions in the credit facility, are available for general corporate purposes. Borrowings under the term loan will bear interest, at DHI s option, at (i) a base rate plus 3.00% per annum or (ii) LIBOR plus 4.00% per annum.

The credit facility contains mandatory prepayment events associated with specified asset sales and recovery events (i.e., certain payments in respect of insurance claims or condemnation proceedings). DHI must offer to repay the term loan or permanently reduce the revolving credit facility with 100% of the net cash proceeds of all asset sales or any proceeds from recovery events, excluding (i) proceeds from sales of designated assets, including Illinois Power and the minority generation investments currently targeted for sale; (ii) up to $100 million of net cash proceeds from other asset sales as designated by DHI; and (iii) up to $900 million of proceeds from asset sales and recovery events that are reinvested in the business, subject to specified restrictions. Sales of assets over a specified threshold require written confirmation from both Standard & Poor s Ratings Service and Moody s Investors Service that the credit ratings of the new credit facility will not be lowered as a result. Further, any sale of our Baldwin facility or all or substantially all of our DMS assets would require the written consent of a majority of the lenders under the new credit facility.

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The credit facility provides for no amortization of principal amounts outstanding prior to the maturity dates except (i) upon the occurrence of a mandatory prepayment event and (ii) term loan amortization of 1% per annum.

The new credit facility is secured by substantially the same collateral as the $1.1 billion facility it replaces, including a first priority interest in substantially all our assets and the assets of our subsidiaries, excluding Illinois Power and its subsidiaries, and on substantially all of the equity of our subsidiaries, excluding Illinois Power and its subsidiaries, in each case to the extent permitted by other applicable agreements. We and substantially all of our subsidiaries, excluding Illinois Power and its subsidiaries, also guarantee the new facility.

The credit facility contains affirmative and negative covenants, including negative covenants relating to the following which restrict DHI and its subsidiaries but do not restrict us: liens; investments; indebtedness; dispositions; restricted payments; burdensome agreements; amendments to organizational documents; prepayments of indebtedness; and swap contracts. The credit facility also contains the financial and capital expenditure-related covenants described below.

The credit facility generally prohibits DHI and its subsidiaries, subject to specified exceptions, from incurring additional debt. Notwithstanding this restriction, DHI may issue, to the extent permitted by the more restrictive covenants with respect to secured debt in the indenture governing the DHI second priority senior secured notes, (i) up to $700 million of additional second lien or junior secured debt or unsecured debt, provided such additional debt matures at least six months after the term loan, and (ii) permitted refinancing indebtedness.

The credit facility generally prohibits DHI and its subsidiaries from pre-paying, redeeming or repurchasing its outstanding debt or preferred stock. Notwithstanding this restriction, DHI may repurchase or redeem its remaining 2005 and 2006 senior notes, the ABG Gas Supply facility and the Riverside facility. DHI also may repurchase or redeem its senior unsecured notes maturing in 2007 and thereafter and its second priority senior secured notes, subject to specified conditions.

We and our subsidiaries, excluding Illinois Power and its subsidiaries, are also prohibited from (i) permitting our Secured Debt/EBITDA Ratio (as defined in the credit facility) on and after September 30, 2004 to exceed specified ratios; (ii) permitting our liquidity to be less than $200 million for a period of more than ten consecutive business days; or (iii) making capital expenditures during each four fiscal quarter period in excess of a designated amount, subject to specified exceptions.

The terms and conditions of the new credit facility are described in more detail in the definitive agreements governing the credit facility, which are filed and/or incorporated by reference as exhibits to this Form 10-Q/A.

Repayments. In the first half of 2004, we repaid the $95 million aggregate principal amount of Illinova s 7.125% Senior Notes due 2004. We also made principal repayments of $39 million related to the ABG Gas Supply financing, $43 million related to Illinois Power s transitional funding trust notes and $16 million in mandatory pre-payments on the ChevronTexaco junior notes.

In July and August 2004, we made an aggregate of approximately $75 million in payments on the ChevronTexaco junior notes, including $25 million in mandatory pre-payments from proceeds of our Oyster Creek and Michigan Power sales.

Tilton Capital Lease. In September 1999, Illinois Power entered into an operating lease on four gas turbines located in Tilton, Illinois and a separate land lease at the Tilton site. This facility consists of peaking units totaling 176 MWs of capacity. Illinois Power sublet the turbines to DMG in October 1999.

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In September 2003, we delivered notice of our intent to exercise our option in order for DMG to purchase the turbines upon the expiration of the operating lease in September 2004. Based on our intent to purchase, GAAP required that we reflect the asset and the associated debt on our balance sheets.

In July 2004, Illinois Power terminated its lease arrangement, and DMG purchased the turbines for $81 million. This action resulted in a reduction of debt of $78 million.

Note 7 Related Party Transactions

We engage in transactions with ChevronTexaco Corporation and its affiliates, including purchases and sales of natural gas and natural gas liquids, which we believe are executed on terms that are fair and reasonable. Please see Note 13 Related Party Transactions Transactions with ChevronTexaco beginning on page F-48 of our Form 10-K/A for further discussion.

Series C Convertible Preferred Stock. As discussed in Note 15 Redeemable Preferred Securities Series C Convertible Preferred Stock beginning on page F-53 of our Form 10-K/A in August 2003, we issued 8 million shares of our Series C convertible preferred stock due 2033 to CUSA. We accrue dividends on our Series C convertible preferred stock at a rate of 5.5% per annum. We made the first semi-annual dividend payment of $11 million on February 11, 2004. In July 2004, we declared a dividend of $11 million on our Series C convertible preferred stock to be paid on or before August 11, 2004.

Note 8 Earnings (Loss) Per Share

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page 9.

Basic earnings (loss) per share represents the amount of earnings (losses) for the period available to each share of common stock outstanding during the period. Diluted earnings (loss) per share represents the amount of earnings (losses) for the period available to each share of 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.

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The reconciliation of basic earnings (loss) per share from continuing operations to diluted earnings (loss) per share from continuing operations is shown in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in millions, except per share amounts)			
Income (loss) from continuing operations (4)	$ 27	$ (286)	$ 83	$ (191)
Convertible preferred stock dividends	(6)	(82)	(11)	(165)
Income (loss) from continuing operations for basic earnings (loss) per share	21	(368)	72	(356)
Effect of dilutive securities:				
Interest on convertible subordinated debentures	2		3	
Dividends on Series C convertible preferred stock (1)(4)			11	
Income (loss) from continuing operations for diluted earnings per share	$ 23	$ (368)	$ 86	$ (356)
Basic weighted-average shares	378	373	377	372
Effect of dilutive securities:				
Stock options	2	2	2	2
Convertible subordinated debentures	55		55	
Series C convertible preferred stock (1)(4)			69	
Diluted weighted-average shares (2)	435	375	503	374
Earnings (loss) per share from continuing operations				
Basic (4)	$ 0.06	$ (0.99)	$ 0.19	$ (0.96)
Diluted (3)(4)	$ 0.05	$ (0.99)	$ 0.17	$ (0.96)

(1) The diluted shares for the three months ended June 30, 2004 do not include the effect of the preferential conversion to Class B common stock of the Series C convertible preferred stock held by a ChevronTexaco subsidiary, as such inclusion would be anti-dilutive.

(2) The diluted shares in 2003 do not include the effect of the preferential conversion to Class B common stock of the Series B Mandatorily Convertible Redeemable Preferred Stock previously held by a ChevronTexaco subsidiary, as such inclusion would be anti-dilutive.

(3) When an entity has a net loss from continuing operations, SFAS No. 128, Earnings per Share, prohibits the inclusion of potential shares of common stock in the computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to

calculate both basic and diluted loss per share for the three and six months ended June 30, 2003.

(4) In our second quarter 2004 earnings news release furnished with our Form 8-K filed on July 28, 2004, we reported diluted earnings per share from continuing operations of $0.09 and $0.21 for the three- and six-month periods ended June 30, 2004, respectively. Additionally, we reported diluted shares outstanding of 504 million for the three-month period ended June 30, 2004. The difference between those amounts and the amounts reported herein resulted from an error related to the classification of an income tax benefit between continuing operations and discontinued operations that was identified subsequent to the furnishing of our second quarter 2004 earnings news release. As a result, the amounts reported herein reflect the reclassification of a $13 million income tax benefit from continuing operations to discontinued operations.

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Although net income for the three- and six-month periods ended June 30, 2004 and diluted earnings per share for the six-month period ended June 30, 2004 were not impacted by this reclassification, diluted earnings per share for the three-month period ended June 30, 2004 was reduced from $0.02 to $0.01. This decrease is caused by the reduced loss from discontinued operations as a result of the reclassification, which under GAAP reduces the anti-dilutive effect of discontinued operations.

Note 9 Commitments and Contingencies

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS NOTE 9, WHICH WAS PRESENTED IN OUR SECOND QUARTER 2004 FORM 10-Q ORIGINALLY FILED WITH THE SEC ON AUGUST 4, 2004 IN ORDER TO REFLECT THE MATERIAL CHANGES IN OR UPDATES TO OUR MATERIAL LEGAL PROCEEDINGS SINCE THE ORIGINAL FILING OF OUR 2003 FORM 10-K, DOES NOT REFLECT EVENTS OCCURRING AFTER AUGUST 4, 2004. FOR A DESCRIPTION OF THESE EVENTS, INCLUDING MATERIAL CHANGES IN, OR UPDATES TO, OUR MATERIAL LEGAL PROCEEDINGS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE AUGUST 4, 2004, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

Set forth below is a description of our material legal proceedings. In addition to the matters described below, we are party to legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect our financial condition, results of operations or cash flows.

We record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable under SFAS No. 5, Accounting for Contingencies. During the first six months of 2004, we recorded pre-tax legal and settlement charges of $54 million, including cash payments made in the period in excess of our then-existing accruals. The charges recorded relate to contingencies for which, during the period, either the amount of loss became probable and reasonably estimable or our previous loss estimates were adjusted.

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Please read Note 2 Accounting Policies Other Contingencies beginning on page F-15 of our Form 10-K/A for further discussion of our reserve policies. Environmental reserves do not reflect management s assessment of the insurance coverage that may be applicable to the matters at issue, whereas litigation reserves do reflect such potential coverage. We cannot make any assurances that the amount of any reserves or potential insurance coverage will be sufficient to cover the cash obligations we might incur as a result of litigation or regulatory proceedings, payment of which could be material.

With respect to some of the items listed below, management has determined that a loss is not probable or that any such loss, to the extent probable, is not reasonably estimable. In some cases, management is not able to predict with any degree of certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed each of these matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success. Management s judgment may, as a result of facts arising prior to resolution of these matters or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

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Summary of Recent Developments. As described in greater detail below, the following significant developments involving our material legal proceedings occurred since the original filing of our first quarter 2004 Form 10-Q:

We completed final documentation regarding the previously announced agreement on a comprehensive settlement of numerous contested FERC claims relating to western electric energy market transactions that occurred between January 2000 and June 2001. As part of the settlement, West Coast Power will forego its right to collect past due receivables and interest from the Cal ISO and the Cal PX related to the settlement period and pay $22.5 million in exchange for the dismissal of claims against Dynegy and West Coast Power related to the settlement period. The settlement has received CPUC approval but remains subject to approval by the FERC.

We were ordered by an arbitral panel s binding decision to pay our former president approximately $10.4 million, plus attorneys fees, costs and interest, with respect to his severance claims, and we paid our former chief executive officer $22 million to settle severance claims against us arising under his employment agreement.

We paid the plaintiffs in the Trans-Elect litigation less than $3 million to settle their claims with respect to our termination of the October 2002 asset purchase and sale agreement.

The above summary of recent developments is qualified in its entirety by, and should be read in conjunction with, the following description of our significant legal proceedings.

Shareholder Litigation. We are defending a class action lawsuit filed on behalf of purchasers of our publicly traded securities from January 2000 to July 2002 seeking unspecified compensatory damages and other relief. The lawsuit principally asserts that we and certain of our current and former officers and directors violated the federal securities laws in connection with our disclosures, including accounting disclosures, regarding Project Alpha (a structured natural gas transaction entered into by us in April 2001), round-trip trading, the submission of false trade reports to publications that calculate natural gas index prices, the alleged manipulation of the California power market and the restatement of our financial statements for 1999-2001. The Regents of the University of California are lead plaintiff and Lerach Coughlin Stoia & Robbins, LLP is class counsel. The plaintiff filed an amended complaint in January 2004 and, in March 2004, we filed motions to dismiss. Briefing on our motions was completed in June 2004 and we are awaiting a ruling from the court. An adverse result in this litigation could have a material adverse effect on our financial condition, results of operations and cash flows. Reserves have been provided in connection with this litigation.

In addition, we are a nominal defendant in several derivative lawsuits brought by shareholders on Dynegy s behalf against certain of our former officers and current and former directors whose claims are similar to those described above. These lawsuits have been consolidated into two groups one pending in federal court and the other pending in state court. Our motion to dismiss the federal derivative claim is currently pending and is set for hearing in August 2004. We do not expect to incur any material liability with respect to these claims.

ERISA/401(k) Litigation. We are defending a purported class action complaint filed in federal district court on behalf of participants holding Dynegy common stock in the Dynegy 401(k) Savings Plan during the period from April 1999 to January 2003. This complaint alleges violations of ERISA in connection with our 401(k) Savings Plan, including claims that our Board and certain of our former and current officers, past and present members of our Benefit Plans Committee, former employees who served on a predecessor committee to our Benefit Plans Committee, and Vanguard Fiduciary Trust Company and CG Trust Company (trustees of the trust

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that held Plan assets for portions of the class period) breached their fiduciary duties to the Plan s participants and beneficiaries in connection with the Plan s investment in Dynegy common stock in particular with respect to our financial statements, Project Alpha, round-trip trades and gas price index reporting. The lawsuit seeks unspecified damages for the losses to the Plan, as well as attorney s fees and other costs. In July 2003, we filed a motion to dismiss this action. The judge entered an order on our motion in March 2004, dismissing several of the plaintiff s claims and all of the defendants except Dynegy and the members of our Benefit Plans Committee from January 2002 to January 2003, the substantially reduced class period established by the order. Discovery is proceeding. In May 2004, in response to the plaintiff s request, the judge ordered the parties to engage in mediation. The parties first entered mediation in June 2004, although no settlement has been reached.

We are analyzing these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or to estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Baldwin Station Litigation. Illinois Power and DMG are the subject of an NOV from the EPA and a complaint filed by the EPA and the Department of Justice in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations. Similar notices and complaints were filed against other owners of coal-fired power plants in what we refer to as the Utility Enforcement Initiative. Both the NOV and the complaint allege that certain equipment repairs, replacements and maintenance activities at our three Baldwin Station generating units constituted major modifications under the PSD regulations, the NSPS regulations and applicable Illinois regulations, and that we failed to obtain required operating permits under applicable Illinois regulations. When activities which are not otherwise exempt result in an increase in annual emissions that exceeds the amount deemed significant under the PSD regulations, those activities are considered major modifications. When activities meeting this definition occur, the Clean Air Act and related regulations generally subject those activities to PSD review and permit requirements and require that the generating facilities where the activities occur meet more stringent emissions standards, which may entail the installation of potentially costly pollution control equipment.

We have significantly reduced emissions of sulphur dioxide and nitrogen oxides at the Baldwin Station since the 1999 complaint by converting it from high to low sulfur coal and installing selective catalytic reduction equipment. However, the EPA may seek to require the installation of the best available control technology, or the equivalent, at the Baldwin Station, which we estimate could require us to incur capital expenditures of up to $410 million. The EPA also has the authority to seek penalties for the alleged violations at the rate of up to $27,500 per day for each violation.

In February 2003, the Court granted our motion for partial summary judgment based on the five-year statute of limitations. As a result, the EPA is not permitted to seek any monetary civil penalties for claims related to construction without a permit under the PSD regulations. The Court s ruling also precludes monetary civil penalties for a portion of the claims under the NSPS regulations and the applicable Illinois regulations. We believe that we have meritorious defenses against the remaining claims and vigorously defended against them at trial. The trial to resolve claims of liability began in June 2003 and closing arguments occurred in September 2003. Shortly after closing arguments, several interveners were granted the right to file briefs in support of arguments they believe the United States ceased to pursue. These interventions and delays in post-trial briefing have postponed the issuance of the liability order, and we cannot predict with certainty when a decision will be rendered.

Reserves have been provided in an aggregate amount we consider reasonable for potential penalties

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that could be imposed if the Court finds us liable and the EPA prosecutes successfully the remaining claims for penalties.

In August 2003, two significant decisions were handed down in other cases that are part of the Utility Enforcement Initiative. The court in *United States v. Ohio Edison* applied the EPA s narrow interpretation of the routine maintenance, repair and replacement exclusion, which defines it with respect to what is routine for the specific unit where the projects occurred, while the court in *United States v. Duke Energy Company* rejected the EPA s narrow interpretation, holding that the exclusion should be defined relative to what is routine for the particular industry. The *Duke* court also held that the hours and conditions of a unit s operations must be held constant when measuring emissions increases. Under this rationale, an increase in maximum hourly emissions is required before activities would be considered major modifications. We are unable to predict the significance of these cases to our Baldwin Station litigation as they are pending in other jurisdictions and are not binding authority.

None of our other facilities are covered in the complaint and NOV, but the EPA previously requested information, which we provided, concerning activities at our Vermilion, Wood River, Hennepin, Danskammer and Roseton plants. Although the EPA could eventually commence enforcement actions based on activities at these plants, we are unable to assess the likelihood of any such additional EPA enforcement actions.

California Market Litigation. We and numerous other power generators and marketers are the subject of numerous lawsuits arising from our participation in the western power markets during the California energy crisis. Eight of these lawsuits, which primarily allege manipulation of the California wholesale power markets and seek unspecified treble damages, were consolidated before a single federal judge. That judge dismissed two of the cases in the first quarter 2003 on the grounds of FERC preemption and the filed rate doctrine. In June 2004, the Ninth Circuit Court of Appeals affirmed the dismissal of one of these cases, and we are awaiting a ruling on the other case. Regarding the remaining six consolidated cases, we are awaiting a ruling from the Ninth Circuit, which we expect to occur prior to the end of 2004, on our appeal of a prior decision to remand those cases to state court.

In addition to the eight consolidated lawsuits discussed above, nine other putative class actions and/or representative actions were filed in state and federal court on behalf of business and residential electricity consumers against us and numerous other power generators and marketers between April and October 2002. The complaints allege unfair, unlawful and deceptive practices in violation of the California Unfair Business Practices Act and seek an injunction, restitution and unspecified damages. While some of the allegations in these lawsuits are similar to the allegations in the eight lawsuits described above, these lawsuits include additional allegations relating to, among other things, the validity of the contracts between these power generators and the CDWR. The court dismissed eight of these nine actions, although the plaintiffs have appealed and we are awaiting a hearing on their appeal. The ninth case was remanded to state court, where a newly added defendant filed a motion in February 2004 to remove the case back to federal court. Once a decision is made on this motion, we intend to file a motion to dismiss this case.

In December 2002, two additional actions were filed with similar allegations on behalf of residents of Washington and Oregon. In May 2003, the plaintiffs voluntarily dismissed these actions and refiled them in California Superior Court as a class action complaint. The complaint, which was brought on behalf of consumers and businesses in Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana that purchased energy from the California market, alleges violations of the Cartwright Act and unfair business practices. We

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have removed the action from state court and consolidated it with existing actions pending before the United States District Court for the Northern District of California. The hearing on plaintiffs appeal to remand to state court occurred in February 2004. The judge stayed his ruling on the appeal pending the Ninth Circuit s ruling on the six consolidated cases referenced above. Most recently, the Montana Attorney General has filed a case alleging similar antitrust and market manipulation claims, although we have not been served with this lawsuit.

In May 2004, Wah Chang, a division of TDY Industries, Inc., filed suit in Oregon federal court against several energy companies, including Dynegy Power Marketing, Inc., seeking more than $30 million in compensatory damages resulting from alleged manipulation of the California wholesale power markets.

In June 2004, the City of Tacoma public utility filed a lawsuit in Washington federal court against a number of energy companies, including us, alleging it paid inflated prices for electricity due to the defendants manipulation of the California wholesale power markets. The plaintiff has agreed to put the matter on hold pending the Ninth Circuit s ruling on the second of two cases dismissed in the first quarter 2003 on the grounds of FERC preemption and the filed rate doctrine, as discussed above.

In July 2004, the County of Santa Clara and the County and City of San Francisco filed two separate actions in California state court against us and several other defendants alleging that the defendants violated California s anti-trust and deceptive business practices statutes by manipulating the California wholesale power markets through, among other things, providing false information to gas index publications and engaging in multiple transactions in a short period of time to artificially inflate gas prices. We intend to file our answer in August 2004.

We believe that we have meritorious defenses to these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or estimate the range of possible loss, if any, that we might incur in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

FERC and Related Regulatory Investigations Requests for Refunds. In July 2001, the FERC initiated a hearing to establish refunds to electricity customers, or offsets against amounts owed to electricity suppliers, during the period of October 2000 through June 2001. In particular, the FERC established a methodology to calculate mitigated market clearing prices in the Cal ISO and the Cal PX markets. In December 2002, an administrative law judge issued his recommendations regarding the appropriate level of refunds or offsets. Those recommendations, however, do not fully reflect proposed refund or offset amounts for individual companies. In October 2003, the FERC issued two orders addressing various applications for rehearing, including ours, relating to its previous refund orders. The orders addressed numerous requests by the parties, the most significant of which was the refusal to change the gas pricing methodology and a requirement that the Cal ISO and Cal PX recalculate the refund liability of market participants. The gas price methodology approved by the FERC in March 2003 replaces the gas prices used in the computation, thus reducing the mitigated market clearing price for power and increasing calculated refunds, subject to a provision that provides full recoverability of actual gas costs paid by the generators to unaffiliated third parties. No final refund calculation is expected prior to August 2004. West Coast Power recorded a reserve in the fourth quarter 2003 relating to its estimated refund exposure.

In June 2003, the FERC issued an order to show cause why the activities of certain participants in the California power markets from January 2000 to June 2001, including Dynegy, did not constitute gaming and/or

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anomalous market behavior as defined in the Cal ISO and Cal PX tariffs. In January 2004, Dynegy and the FERC staff submitted a stipulation and settlement agreement to the presiding administrative law judge to settle the issues raised in the June 2003 show cause order, which settlement was approved by the judge in June 2004 but remains subject to final FERC approval. This settlement, which provides that West Coast Power will pay approximately $3 million, following final FERC approval, into a fund established at the U.S. Treasury for the benefit of California and Western electricity consumers, will be incorporated into the broader settlement described below.

In April 2004, Dynegy and West Coast Power announced an agreement to settle FERC claims relating to western energy market transactions that occurred from January 2000 through June 2004, including those described above. The parties to this settlement other than Dynegy and West Coast Power include the FERC, Pacific Gas and Electric Company, Southern California Edison, San Diego Gas & Electric Company, the CDWR, the California Electricity Oversight Board and the California Attorney General. Other market participants may opt into this settlement and share in the distribution of the settlement proceeds. As part of the settlement agreement, West Coast Power will (i) forego its right to collect past-due receivables and interest from the Cal ISO and the Cal PX related to the settlement period, (ii) forego natural gas cost recovery claims against the California settling parties related to the settlement period, and (iii) place into escrow accounts a total of $22.5 million, which includes the above-referenced $3 million settlement with the FERC staff, for subsequent distribution to various California energy purchasers. In exchange, the other settling parties will forego (i) all claims relating to refunds or other monetary damages for sales of electricity during the settlement period, and (ii) claims alleging receipt of unjust or unreasonable rates for the sale of electricity during the settlement period.

Although the parties completed definitive documentation for the settlement in June 2004 and the CPUC granted its approval, the settlement remains subject to approval by the FERC, which is expected in the third quarter 2004. Reserves have been provided for the settlement.

The settlement will not apply to the ongoing civil litigation related to the California energy markets described above in which Dynegy and West Coast Power are defendants. The settlement also will not apply to the pending appeal by the CPUC and the California Electricity Oversight Board of the FERC s prior decision to affirm the validity of the West Coast Power-CDWR contract. We are currently awaiting a ruling on this appeal and related filings and cannot predict their outcome.

West Coast Power. Through our interest in West Coast Power, we have credit exposure for transactions to the Cal ISO and Cal PX, which rely on cash payments from California utilities to in turn pay their bills. West Coast Power currently sells directly to the CDWR pursuant to a long-term sales agreement.

At June 30, 2004, our portion of the receivables owed to West Coast Power by the Cal ISO and Cal PX approximated $205 million. Management periodically assesses our exposure through West Coast Power, relative to our California receivables and establishes and maintains reserves under SFAS 5. Our share of the total reserve taken by West Coast Power at June 30, 2004 was approximately $194 million.

The above-described settlement, if approved, will resolve the claims and disputes which initially gave rise to these reserves at West Coast Power.

Enron Trade Credit Litigation. Shortly before their bankruptcy filing in the fourth quarter 2001, we determined that Enron Corp. and its affiliates had net exposure to us, including certain liquidated damages and

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other amounts relating to the termination of commercial transactions among the parties, of approximately $84 million. This exposure was calculated by setting off approximately $230 million owed from Dynegy entities to Enron entities against approximately $314 million owed from Enron entities to Dynegy entities. The master netting agreement between Enron and us and the valuation of the commercial transactions covered by the agreement, which valuation is based principally on the parties assessment of market prices for such period, remain subject to dispute by Enron. We are engaged in an ongoing process with Enron to reconcile the differences between our respective valuations of the transactions and accounts receivable. As a result of ongoing refinement of the values of past transactions, we reduced the $84 million amount that we originally believed we are owed by Enron to approximately $41 million, including the liabilities under the gas transportation agreement related to the Sithe Independence power tolling arrangement. This change in value had no impact on our results, as the net receivable was fully reserved in the fourth quarter 2001. As required by the master netting agreement, we instituted arbitration proceedings against those Enron parties not in bankruptcy in 2002 and filed a motion with the Bankruptcy Court requesting that we be allowed to proceed to arbitration against those Enron parties that are in bankruptcy. The Enron parties opposed our request and filed an adversary proceeding against us, alleging that the master netting agreement should not be enforced and that the Enron companies should recover approximately $230 million from us. We have disputed such allegations and are vigorously defending our position regarding the setoff rights contained in the master netting agreement, although the Bankruptcy Court has yet to rule on the enforceability of the master netting agreement.

In November 2003, we gave notice of our intent to pursue arbitration against Enron Canada Corp. as a non-bankrupt party to the master netting agreement. In response, Enron Canada Corp. filed a lawsuit in Canadian District Court to recover the amounts that it claims to be owed by our Canadian subsidiary under the master netting agreement, contingent upon a Bankruptcy Court ruling on the enforceability of the master netting agreement. In December 2003, Enron filed an application with the Bankruptcy Court for an injunction to prohibit this arbitration; the Bankruptcy Court ruled that the automatic stay of the bankruptcy applied to our request to pursue arbitration against Enron Canada Corp. under the master netting agreement. Consequently, we are currently prohibited from enforcing the master netting agreement by arbitration. In March 2004, we appealed the enforcement of the automatic stay and requested permission from the appellate court to proceed with arbitration against Enron Canada Corp. We also filed a motion with the Bankruptcy Court requesting a trial to determine the enforceability of the master netting agreement under the U.S. Bankruptcy Code. We are currently awaiting rulings on the appeal and the motion.

If the setoff rights are modified or disallowed, either by agreement or otherwise, the amount available for our entities to set off against sums that might be due Enron entities could be reduced materially. In fact, we could be required to pay to Enron the full amount that it claims to be owed, while we would be an unsecured creditor of Enron to the extent of our claim. We cannot predict with certainty whether we will incur any liability in connection with these disputes. However, given the size of the claims at issue, an adverse result could have a material adverse effect on our financial condition, results of operations and cash flows.

Trans-Elect Litigation. In October 2003, Trans-Elect, Inc. and Illinois Electric Transmission Company, LLC filed suit against Illinois Power Company in the Northern District of Illinois requesting specific performance and estoppel, and claiming damages as a result of breach of contract and lost profits. These causes of action allegedly arise from Illinois Power s termination of an asset purchase and sale agreement entered into by the parties in October 2002. Under the terms of the agreement, Illinois Power agreed to sell its transmission assets to Trans-Elect if, on or before July 7, 2003, the agreement received the required FERC, ICC, SEC and Hart-Scott Rodino approvals. As of July 7, 2003, the agreement had not been approved by, among other entities,

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the FERC and, as a result, Illinois Power terminated the agreement in accordance with its terms on July 8, 2003. Trans-Elect claims that Illinois Power breached the agreement by failing to use its best efforts to obtain the required approvals and/or to negotiate an alternate agreement that could be approved.

In May 2004, we entered into an agreement with the plaintiffs to settle all of their claims relating to this lawsuit. Under this settlement, we paid the plaintiffs less than $3 million and recorded an expense for an equivalent amount in the second quarter 2004.

Severance Arbitrations. Our former CEO, Chuck Watson, former President, Steve Bergstrom, and former CFO, Rob Doty, each filed for arbitration pursuant to the terms of their employment/severance agreements. These former officers made arbitration claims seeking payments of up to approximately $28.7 million, $10.4 million and $3.4 million, respectively.

The arbitration relating to Mr. Bergstrom s severance agreement was tried before a panel of three arbitrators in March 2004. Following the panel s decisions with respect to Mr. Bergstrom s severance claim awarding him approximately $10.4 million in damages in April 2004 and attorneys fees, costs and interest in May 2004, we paid the judgment in full. Shortly after the panel s decisions in the Bergstrom matter, we entered into mediation and reached an agreement with Mr. Watson to settle his severance claims. Pursuant to the terms of the settlement agreement, we paid Mr. Watson $22 million in exchange for a full release of his claims. We recorded an expense in the second quarter 2004 in the amount of the difference between this settlement amount and our severance accrual for this matter. Please read Note 3 Restructuring Charges for further discussion regarding the accrual relating to Mr. Watson.

The arbitration with respect to Mr. Doty is currently scheduled to commence in November 2004. Mr. Doty s agreement is subject to interpretation and we maintain that the amount owed is substantially lower than the amount sought. We recorded a severance accrual we consider reasonable relating to this proceeding.

Farnsworth Litigation. In August 2002, Bradley Farnsworth filed a lawsuit against us in state court claiming breach of contract and that he was demoted and ultimately fired from the position of Controller for refusing to participate in illegal activities. Specifically, Mr. Farnsworth alleges, in the words of his amended complaint, that certain of our former executive officers requested that he shave or reduce for accounting purposes the forward price curves associated with the natural gas business in the United Kingdom for the period of October 1, 2000 through March 31, 2001, in order to indicate a reduction in our mark-to-market losses. Mr. Farnsworth, who seeks unspecified actual and exemplary damages and other compensation, also alleges that he is entitled to a termination payment under his employment agreement equal to 2.99 times the greater of his average base salary and incentive compensation for the highest three calendar years preceding termination or his base salary and target bonus amount for the year of termination (currently estimated at a range of approximately $700,000 to $1,200,000). In March 2004, the judge dismissed Mr. Farnsworth s claim that he was asked to shave forward price curves. Trial on the claim concerning his employment agreement has been rescheduled for October 2004. We are vigorously defending this claim. Although reserves have been provided with respect to this litigation, we do not believe that any liability we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

Apache Litigation. In May 2002, Apache Corporation filed suit in state court against Versado, as purchaser and processor of Apache s gas, and DMS, as operator of the Versado assets in New Mexico, seeking more than $9 million in damages. The plaintiff s petition, as amended, alleges (i) excessive field losses of natural gas from

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wells owned by the plaintiff, (ii) that Versado engaged in sham transactions with affiliates, resulting in Versado not receiving fair market value when it sells gas and liquids, and (iii) that the formula for calculating the amount Versado receives from its buyers of gas and liquids is flawed since it is based on gas price indexes that these same affiliates are alleged to have manipulated by providing false price information to the index publisher. At trial, the plaintiff s claim with respect to the alleged sham transactions and index manipulation, among others, were severed by the court and abated for a future trial, and the jury found in favor of the plaintiff on the remaining lost gas claim, awarding approximately $1.6 million in damages. In May 2004, our motion to set aside this judgment was granted by the court and the jury s award to the plaintiff was vacated. The plaintiff has indicated an intent to appeal the court s decision. We do not believe that any liability we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

Gas Index Pricing Litigation. We are defending the following suits claiming damages resulting from the alleged manipulation of gas index publications and prices by us and others: *Sierra Pacific Resources and Nevada Power Company v. El Paso Corp. et al.*; *Bustamante v. The McGraw Hill Companies et al.*; *In re Natural Gas Commodity Litigation*; *Texas-Ohio Energy Inc. et al. v. Centerpoint Energy et al*; *People of the State of Montana et al. v. Williams Energy Marketing et al*; *Benscheidt v. AEP Energy Services et al.* In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications, thereby manipulating the price. All of the complaints rely heavily on the FERC and CFTC investigations into and report concerning index-reporting manipulation in the energy industry. The plaintiffs generally seek unspecified actual and punitive damages relating to costs they claim to have incurred as a result of the alleged conduct. These cases are in varying procedural stages, although we have not been served in the *Montana* case.

We are analyzing all of these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or to estimate the damages, if any, that might be incurred in connection with these lawsuits. We do not believe that any liability that we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

Atlantigas Corp. Litigation. In November 2003, Atlantigas Corporation filed suit in Maryland against us and several other defendants alleging certain conspiracies between natural gas shippers and storage facilities. The complaint alleges that the interstate pipelines provided preferential storage and transportation services to their own unregulated marketing affiliate in return for percentages of the profits reaped by the marketing affiliate and that such conduct violated applicable FERC regulations and the federal antitrust laws and constituted common law tortious interference with contractual and business relations. In addition, we are alleged to have conspired with the other defendants to receive preferential natural gas storage and transportation services at off-tariff prices. The complaint seeks unspecified compensatory and punitive damages. Defendants are currently challenging plaintiff on the threshold issues of standing, statute of limitations and jurisdiction. These issues were fully briefed in February 2004 and a hearing date has been requested but not scheduled. We are analyzing these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or to estimate the damages, if any, that we might incur in connection with this lawsuit.

Stumpf Litigation. We and two former subsidiaries are defendants in a lawsuit filed in New York by Stumpf AG and two of its affiliates stemming from the shutdown of our Vienna telecommunications office in the spring of 2001. The plaintiffs are seeking $29 million in compensatory and unspecified punitive damages, alleging breach of contract, tortious interference and alter ego-based claims primarily relating to the termination of real

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

property leases to which our former Austrian subsidiary was a party. These claims are based on similar lawsuits filed in Austria against our former Austrian subsidiary, which was sold to a third party in January 2003. This former subsidiary is in liquidation and, recently, one of its liquidators admitted, for purposes of the liquidation, the plaintiffs claims in the amount of $30 million. Although this lawsuit was initially stayed pending the Austrian insolvency proceeding, the stay was recently lifted and we filed our answer in May 2004. The parties are actively engaged in discovery.

We intend to oppose these claims vigorously and believe we have meritorious defenses. Although it is not possible to predict with certainty whether we will incur any liability in connection with these lawsuits, we do not believe that any liability we might incur as a result of these lawsuits would have a material adverse effect on our financial condition, results of operations or cash flows. Reserves have been provided in connection with this litigation.

Alleged Marketing Contract Defaults. We have posted collateral to support a portion of our obligations in our CRM business, including our obligations under one of our power tolling arrangements. While we worked with various counterparties to provide mutually acceptable collateral or other adequate assurance under these contracts, we have not reached agreement with Sithe Independence and Sterlington/Quachita Power LLC regarding a mutually acceptable amount of collateral in support of our obligations under our power tolling arrangements with either of these two parties. Although we are current on all contract payments to these counterparties, we previously received a notice of default from each such party with regard to collateral. Despite receiving these notices, all parties are continuing to perform and we have fulfilled our economic commitments under these contracts. Our average annual capacity payments under these two arrangements approximate $75 million and $63 million, respectively, and the contracts extend through 2014 and 2012, respectively, with a five-year extension option for Sterlington. If these two parties were successfully to pursue claims that we defaulted on these contracts, they could declare a termination of their respective contracts, which generally provide for termination payments based on the agreed mark-to-market value of the contracts. Because of the effects of changes in commodity prices on the mark-to-market value of these contracts, as well as the likelihood that we would differ with our counterparties as to the estimated value of these contracts, we cannot predict with any degree of certainty the amounts of termination payments that could be required under these two contracts. Disputes relating to these two contracts, if resolved against us, could materially adversely affect our financial condition, results of operations and cash flows.

U.S. Attorney Investigations. The U.S. Attorney s office in Houston is continuing its investigation of our actions relating to Project Alpha and our gas trade reporting practices. We have produced documents and witnesses for interviews in connection with this investigation. Seven of our natural gas traders were terminated in the fourth quarter 2002 for violating our Code of Business Conduct after an ongoing internal investigation conducted by our Audit and Compliance Committee in collaboration with independent counsel discovered that inaccurate information regarding natural gas trades had been reported to various energy industry publications. In January 2003, one of our former natural gas traders was indicted in Houston on three counts of knowingly causing the transmission of false trade reports used to calculate the index price of natural gas and four counts of wire fraud. In August 2003, however, several of these counts were dismissed as unconstitutional. Upon request by the U.S. Attorney s office for reconsideration of this ruling, the judge reinstated the dismissed counts. The case was originally set for trial in January 2004; however, both the U.S. Attorney s office and the defense have appealed the court s rulings regarding the dismissed and reinstated charges. The appeals are pending and a new trial date has not been set.

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(Unaudited and Restated)

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In June 2003, three former Dynegy employees were indicted on charges of conspiracy, securities fraud and mail and wire fraud related to the Project Alpha transaction. Subsequently, two of these former employees plead guilty to conspiracy to commit securities fraud and are scheduled to be sentenced in August 2004. Trial on the indictment against the third employee was held in November 2003. The defendant was convicted on all charges and, in March 2004, sentenced to a term of approximately 24 years in federal prison.

We are cooperating fully with the U.S. Attorney s office in its continuing investigation of these matters and cannot predict the ultimate outcome of these investigations.

Additionally, the United States Attorney s office in the Northern District of California has issued a Grand Jury subpoena requesting information related to our activities in the California energy markets in November 2002. We have been, and intend to continue, cooperating fully with the U.S. Attorney s office in its investigation of these matters, including production of substantial documents responsive to the subpoena and other requests for information. We cannot predict the ultimate outcome of this investigation.

Department of Labor Investigation. In August 2002, the U.S. Department of Labor commenced an official investigation pursuant to Section 504 of ERISA with respect to the benefit plans we maintain and our ERISA affiliates. We have cooperated with the Department of Labor throughout this investigation, which remains ongoing. As of this date, the investigation has focused on a review of plan documentation, plan reporting and disclosure, plan recordkeeping, plan investments and investment options, plan fiduciaries and third-party service providers, plan contributions and other operational aspects of the plans. We have not yet received the Department of Labor s definitive findings resulting from its investigation.

Note 10 Regulatory Issues

We are subject to regulation by various federal, state, local and foreign agencies, including extensive rules and regulations governing transportation, transmission and sale of energy commodities as well as the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these regulations requires general and administrative, capital and operating expenditures including those related to monitoring, pollution control equipment, emission fees and permitting at various operating facilities and remediation obligations. In addition, the United States Congress has before it a number of bills that could impact regulations or impose new regulations applicable to us and our subsidiaries. We cannot predict the outcome of these bills or other regulatory developments or the effects that they might have on our business.

Danskammer Water Permit. As previously disclosed, the state-issued water discharge permit associated with our Danskammer facility expired in 1992. However, under New York State law, each permit remains in effect and allows for continued operation under the terms of the original permit, provided that a timely and sufficient application requesting renewal has been filed as required. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer water discharge permit expired because of alleged deficiencies in the renewal application process. The Court has recently indicated that it intends to rule on whether the permit expired because of these deficiencies. In the event the Court determines that our renewal application expired due to deficiencies or otherwise, we intend to appeal the Court s decision and seek a stay pending resolution of the appeal. If, under these circumstances, a stay were not granted, or if our appeal were ultimately unsuccessful, we may be required to curtail operations at our Danskammer facility pending resolution of the appeal and/or receipt of final approval of the renewal of our water discharge permit. We cannot predict with any certainty the outcome of these

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

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proceedings; however, an adverse outcome, particularly a requirement that we curtail operations at our Danskammer facility for any period of time, could have a material adverse effect on our financial condition, results of operations and cash flows.

FERC Market-Based Rate Authority. Market-based rate authority allows the sale of power at negotiated rates through the bilateral market or within an organized energy market. In April 2004, the FERC issued an order concerning the ability of companies to sell electricity at market-based rates. In this order, the FERC adopted two new tests for assessing generation market power. If an applicant for market-based rate authority is found to possess generation market power under these tests and is unsuccessful in challenging that finding, the applicant may either propose mitigation measures or adopt cost-based rates. If the FERC finds that the proposed mitigation measures fail to eliminate the ability to exercise market power, the applicant s market-based rate authority will be revoked and the applicant will be subject to cost-based default rates, or other cost-based rates proposed by the applicant and approved by the FERC. The FERC issued a follow up order in May 2004, which (i) addressed the implementation process for pending and new market-based rate applications and (ii) established a timeline for entities with FERC market-based rate authority to provide the FERC with their market power assessment. Despite challenges from numerous industry participants, in July 2004 the FERC upheld the April 2004 order. These orders require entities that were previously granted market-based rate authority by the FERC, including several Dynegy entities with applications pending since February 2002, to resubmit their market power applications in accordance with the new directive by February 5, 2005. Although we cannot predict with any certainty whether these applications will be approved or the loss of revenues which would result from the imposition of cost-based rates, an adverse outcome with respect to these applications, and the resulting requirement that we charge cost-based rates, could have a material adverse effect on our financial condition, results of operations and cash flows.

Illinois Power Gas Rate Case. In June 2004, Illinois Power filed with the ICC seeking authority to raise its natural gas delivery rates by approximately $40 million annually, or about $5.85 per month for the average residential gas customer. As part of the regulatory process, which can be expected to take up to eleven months, the ICC will decide the amount of increase, if any, to provide recovery of costs from our customers. Upon approval, the new rates will go into effect in spring 2005, after the expected close of the sale of Illinois Power to Ameren.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Note 11 Employee Compensation, Savings and Pension Plans

We have various defined benefit pension plans and post-retirement benefit plans, which are more fully described in Note 20 Employee Compensation, Savings and Pension Plans beginning on page F-74 of our Form 10-K/A.

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

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
	2004	2003	2004	2003
	(in millions)			
Service cost benefits earned during period	$ 6	$ 5	$ 1	$ 1
Interest cost on projected benefit obligation	10	10	3	3
Expected return on plan assets	(12)	(13)	(1)	(1)
Recognized net actuarial loss	4	2	1	1
Total net periodic benefit cost	$ 8	$ 4	$ 4	$ 4

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
	2004	2003	2004	2003
	(in millions)			
Service cost benefits earned during period	$ 12	$ 10	$ 2	$ 2
Interest cost on projected benefit obligation	20	20	6	6
Expected return on plan assets	(24)	(26)	(3)	(3)
Recognized net actuarial loss	8	4	3	3

Total net periodic benefit cost	$ 16	$ 8	$ 8	$ 8

Contributions. In Note 20 Employee Compensation, Savings and Pension Plans Contributions beginning on page F-79 of our Form 10-K/A, we reported that we expected to contribute approximately $13 million to our pension and other postretirement benefit plans in 2004. Due to the Pension Funding Equity Act of 2004, we are no longer required to make estimated quarterly contributions in 2004. However, under the terms of our agreement to sell Illinois Power to Ameren, we will be required to accelerate approximately $15 million to $20 million of future cash funding requirements at closing, which we expect will occur before the end of 2004.

Note 12 Income Taxes

Capital Loss Valuation Allowance. As a result of the asset sales discussed in Note 2 Dispositions, Contract Terminations and Discontinued Operations, as well as other transactions forecasted to occur during the remainder of 2004, we reduced the valuation allowance related to our significant capital loss carryforward by $8 million and $47 million in the three and six months ended June 30, 2004, respectively. This capital loss carryforward primarily related to our third quarter 2002 sale of Northern Natural Gas Company. This benefit is reflected in Income tax benefit (expense) on our unaudited condensed consolidated statements of operations.

Prior Year Tax Audits. In the second quarter 2004, we recognized an expense of $17 million associated with the conclusion of prior year federal tax audits. A charge of $20 million related to our discontinued U.K.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

CRM business is included in Loss from discontinued operations on our unaudited condensed consolidated statements of operations. An offsetting benefit of $3 million is reflected in Income tax benefit (expense) on our unaudited condensed consolidated statements of operations.

Please read Note 8 Earnings (Loss) Per Share for a discussion of an error in our second quarter 2004 earnings news release, which was subsequently identified and corrected in the Original Filing, relating to the classification of a $13 million income tax benefit between continuing operations and discontinued operations.

Note 13 Segment Information

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page 9.

We report our operations in the following segments: GEN, NGL, REG and CRM. All direct general and administrative expenses and other income (expense) items incurred by us on behalf of our subsidiaries are charged to the applicable subsidiary as incurred.

Pursuant to EITF Issue 02-03, all gains and losses on third-party energy-trading contracts in the CRM segment, whether realized or unrealized, are presented net in the unaudited condensed consolidated statements of operations. For the purpose of the segment data presented below, intersegment transactions between CRM and our other segments are presented net in CRM intersegment revenues but are presented gross in the intersegment revenues of our other segments, as the activities of our other segments are not subject to the net presentation requirements contained in EITF Issue 02-03. If transactions between CRM and our other segments result in a net intersegment purchase by CRM, the net intersegment purchases and sales are presented as negative revenues in CRM intersegment revenues. In addition, intersegment hedging activities are presented net pursuant to SFAS No. 133.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Reportable segment information for the three- and six-month periods ended June 30, 2004 and 2003 is presented below:

Dynegy s Segment Data for the Quarter Ended June 30, 2004

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 54	$ 689	$ 317	$ 404	$	$ 1,464
Other		1		(25)		(24)
	54	690	317	379		1,440
Intersegment revenues	361	76	7	(195)	(249)	
Total revenues	$ 415	$ 766	$ 324	$ 184	$ (249)	$ 1,440
Depreciation and amortization	$ (47)	$ (25)	$	$	$ (10)	$ (82)
Operating income (loss)	$ 35	$ 75	$ 22	$ 90	$ (89)	$ 133
Earnings from unconsolidated investments	50	2				52
Other items, net		(5)		(1)	(8)	(14)
Interest expense						(145)
Income from continuing operations before taxes						26
Income tax benefit						1
Income from continuing operations						27
Loss from discontinued operations, net of taxes						(19)
Net income						$ 8
Identifiable assets:						
Domestic	$ 6,362	$ 1,670	$ 4,867	$ 2,353	$ (2,199)	$ 13,053
Other	35	4		209	30	278
Total	$ 6,397	$ 1,674	$ 4,867	$ 2,562	$ (2,169)	$ 13,331

Unconsolidated investments	$ 546	$ 80	$	$	$	$ 626
Capital expenditures	$ (44)	$ (18)	$ (33)	$	$ (3)	$ (98)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Dynegy s Segment Data for the Quarter Ended June 30, 2003

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 104	$ 620	$ 321	$ 26	$	$ 1,071
Other				(4)		(4)
	104	620	321	22		1,067
Intersegment revenues	244	61	7	(254)	(58)	
Total revenues	$ 348	$ 681	$ 328	$ (232)	$ (58)	$ 1,067
Depreciation and amortization	$ (49)	$ (20)	$ (30)	$	$ (17)	$ (116)
Operating income (loss)	$ 16	$ 39	$ 35	$ (360)	$ (104)	$ (374)
Earnings (losses) from unconsolidated investments	45	2		(9)		38
Other items, net		(5)		(3)	(1)	(9)
Interest expense						(109)
Loss from continuing operations before taxes						(454)
Income tax benefit						168
Loss from continuing operations						(286)
Loss from discontinued operations, net of taxes						(4)
Net loss						$ (290)
Identifiable assets:						
Domestic	$ 6,545	$ 1,774	$ 5,304	$ 3,447	$ (2,409)	$ 14,661
Other				524		524
Total	$ 6,545	$ 1,774	$ 5,304	$ 3,971	$ (2,409)	$ 15,185
Unconsolidated investments	$ 589	$ 95	$	$ 2	$	$ 686
Capital expenditures	$ (56)	$ (13)	$ (36)	$	$	$ (105)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Dynegy s Segment Data for the Six Months Ended June 30, 2004

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 100	$ 1,520	$ 769	$ 774	$	$ 3,163
Other	2	1		(69)		(66)
	102	1,521	769	705		3,097
Intersegment revenues	754	146	12	(543)	(369)	
Total revenues	$ 856	$ 1,667	$ 781	$ 162	$ (369)	$ 3,097
Depreciation and amortization	$ (95)	$ (45)	$ (10)	$	$ (20)	$ (170)
Operating income (loss)	$ 88	$ 142	$ 76	$ 77	$ (142)	$ 241
Earnings from unconsolidated investments	88	4				92
Other items, net		(9)	1	2	3	(3)
Interest expense						(277)
Income from continuing operations before taxes						53
Income tax benefit						30
Income from continuing operations						83
Loss from discontinued operations, net of taxes						(5)
Net income						$ 78
Identifiable assets:						
Domestic	$ 6,362	$ 1,670	$ 4,867	$ 2,353	$ (2,199)	$ 13,053
Other	35	4		209	30	278
Total	$ 6,397	$ 1,674	$ 4,867	$ 2,562	$ (2,169)	$ 13,331
Unconsolidated investments	$ 546	$ 80	$	$	$	$ 626
Capital expenditures	$ (58)	$ (27)	$ (61)	$	$ (5)	$ (151)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

Dynegy s Segment Data for the Six Months Ended June 30, 2003

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 221	$ 1,598	$ 776	$ 346	$	$ 2,941
Other				5		5
	221	1,598	776	351		2,946
Intersegment revenues	530	134	15	(491)	(188)	
Total revenues	$ 751	$ 1,732	$ 791	$ (140)	$ (188)	$ 2,946
Depreciation and amortization	$ (91)	$ (40)	$ (60)	$ (1)	$ (39)	$ (231)
Operating income (loss)	$ 99	$ 90	$ 94	$ (322)	$ (148)	$ (187)
Earnings from unconsolidated investments	84	5		2		91
Other items, net	3	(10)		23	(4)	12
Interest expense						(219)
Loss from continuing operations before taxes						(303)
Income tax benefit						112
Loss from continuing operations						(191)
Loss from discontinued operations, net of taxes						(7)
Cumulative effect of change in accounting principles, net of taxes						55
Net loss						$ (143)
Identifiable assets:						
Domestic	$ 6,545	$ 1,774	$ 5,304	$ 3,447	$ (2,409)	$ 14,661
Other				524		524
Total	$ 6,545	$ 1,774	$ 5,304	$ 3,971	$ (2,409)	$ 15,185
Unconsolidated investments	$ 589	$ 95	$	$ 2	$	$ 686

Capital expenditures	$	(93)	$	(25)	$	(68)	$		$	(3)	$	(189)

Note 14 Subsequent Events

In July 2004, we announced agreements to sell our 50% interests in the Commonwealth and Hartwell power generating facilities. These sales are targeted to close in the fourth quarter 2004, subject to receipt of required regulatory, lender and other approvals. Also in July 2004, we sold our unconsolidated investments in the Oyster Creek and Michigan Power generating facilities. Please read Note 5 Unconsolidated Investments for further discussion.

In July and August 2004, we made aggregate payments of approximately $75 million on our ChevronTexaco junior notes, including approximately $25 million in mandatory pre-payments from proceeds of the Oyster Creek and Michigan Power sales. Please read Note 6 Debt for further discussion.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited and Restated)

For the Interim Periods Ended June 30, 2004 and 2003

In July 2004, Illinois Power terminated its lease arrangement and DMG purchased four gas turbines located in Tilton, Illinois for $81 million. Please read Note 6 Debt for further discussion.

In July 2004, we entered into interest rate swaps with a notional value of $500 million. Please read Note 4 Risk Management Activities and Accumulated Other Comprehensive Loss Fair Value Hedges for further discussion.

In July 2004, the FERC approved the sale of Illinois Power to Ameren. Please read Note 2 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Pending Sale of Illinois Power for further discussion.

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DYNEGY INC.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

For the Interim Periods Ended June 30, 2004 and 2003

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. As discussed in the Introductory Note to this Amendment No. 1, the financial information contained in this Form 10-Q/A has been revised to reflect the restatement items described in the Explanatory Note to the accompanying unaudited condensed consolidated financial statements. We have also amended our 2003 Annual Report on Form 10-K, most recently with Amendment No. 2 thereto filed with the SEC on January 18, 2005. The restatements to the financial statements contained in the Form 10-K and related information are further described in the Form 10-K/A, and this Amendment No. 1 should be read together with the Form 10-K/A. The following discussion contains forward-looking statements. Please read Factors Affecting Future Results of Operations and Uncertainty of Forward-looking Statements below for a discussion of the limitations inherent in these statements.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 1, INCLUDING THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED SEPTEMBER 30, 2004 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE AUGUST 4, 2004, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

GENERAL

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily in three areas of the energy industry: power generation, natural gas liquids and regulated energy delivery. As described below, however, our regulated energy business is the subject of a pending sales agreement with Ameren Corp. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. We also separately report the results of our customer risk management business, which primarily consists of our four remaining power tolling arrangements and related gas transportation contracts, as well as legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization, but because of their nature, these items are not reported as a separate segment.

Since the filing of our first quarter 2004 Form 10-Q in May 2004, we have continued our efforts to restructure our company to align more closely our asset base with our business strategy. Significant developments during this period include the following:

- In May 2004, we replaced our $1.1 billion credit facility scheduled to mature in February 2005 with a new $1.3 billion credit facility. This new facility, which is described in more detail in Liquidity and Capital Resources Debt Obligations, is comprised of a revolving credit facility and a term loan, which are scheduled to mature in May 2007 and May 2010, respectively.

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In June 2004, we reached agreements to exit four long-term natural gas transportation agreements. We paid $20 million in June and are required to pay another $42 million in the first quarter 2005 under these agreements, in exchange for which we will discharge our obligations to make fixed capacity payments from April 2005 through 2014 aggregating $295 million. Please read Results of Operations Operating Income (Loss) CRM for a discussion of the $88 million pre-tax gain we realized in the second quarter 2004 in connection with the exit from these agreements.

In July 2004, we completed the sales of our 50% ownership interests in each of the 424 MW Oyster Creek generating facility and the 123 MW Michigan Power generating facility. We received approximately $104 million in aggregate net cash proceeds from these transactions.

In July 2004, we entered into agreements to sell our 50% ownership in each of the 310 MW Hartwell generating facility and the 310 MW Commonwealth generating facility. We expect to close these transactions, which are subject to regulatory and bank approvals and other closing conditions, in the fourth quarter 2004.

Additionally, we are continuing to work through the regulatory approval process regarding the pending sale of Illinois Power to Ameren. In July 2004, the FERC approved this transaction, including the proposed power purchase agreements among the parties. Although significant approvals remain, including required approvals from the ICC and the SEC, we believe that the transaction remains on track to close before the end of the year.

Operationally, our performance during the second quarter 2004 reflected our continued sensitivity to commodity prices, particularly in our unregulated energy businesses. In our GEN business, total volumes increased 7% from the second quarter 2003 to the second quarter 2004, excluding those volumes relating to ownership interests in non-core assets that have been sold or are in the process of being sold. This increase, together with increased power prices, positively impacted our GEN business, more than offsetting an increase in fuel and transportation costs. In our NGL business, our restructured gas processing contract portfolio benefited from higher natural gas prices, yielding higher field processing plant profits upstream. Downstream, our marketing results increased, primarily due to rising natural gas liquids prices quarter over quarter, market volatility and the termination of a contract which allowed us to recognize gains on sales of natural gas liquids. Please read Results of Operations for further discussion of the comparative results of our reportable business segments.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we provide updates related to our liquidity and capital requirements and our internal and external liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures, regulatory and legal settlements and working capital needs. Examples of working capital needs include purchases of commodities, particularly natural gas, coal and natural gas liquids, facility maintenance costs (including required environmental expenditures) and other costs such as payroll. Our liquidity and capital resources are primarily derived from cash flows from operations, cash on hand, borrowings under our financing agreements, asset sale proceeds and proceeds from capital market transactions.

Debt Obligations

We have a substantial amount of indebtedness, which results in significant debt service obligations. Accordingly, over the near and longer term, we expect to devote a considerable portion of our liquidity and capital resources to debt service requirements. Please read Results of Operations Interest Expense below for further discussion of our debt service obligations.

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With respect to our debt maturities, we continued our efforts to extend our maturity profile in the second quarter 2004 through, among other things, the restructuring of our primary credit facility. Specifically, in May 2004, DHI entered into a $1.3 billion credit facility consisting of:

- a $700 million secured revolving credit facility that matures on May 28, 2007; and
- a $600 million secured term loan that matures on May 28, 2010, subject to an earlier maturity in specified circumstances.

The credit facility replaces DHI s $1.1 billion revolving credit facility, which was scheduled to mature in February 2005.

The revolving credit facility provides funding for general corporate purposes and was undrawn at closing. The revolving facility is also available for the issuance of letters of credit. Borrowings under the revolving credit facility will bear interest, at DHI s option, at (i) a base rate plus 3.00% per annum or (ii) LIBOR plus 4.00% per annum. A letter of credit fee will be payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.00% of such undrawn amount. We also incur additional fees for issuing letters of credit. An unused commitment fee of 0.50% will be payable on the unused portion of the revolving facility.

Of the $600 million in proceeds from the term loan drawn at closing, approximately $19 million was used to pay fees and expenses incurred in connection with the closing of the new credit facility. We also used a portion of these proceeds to replace letters of credit and to otherwise satisfy collateral obligations to avoid incurring the letter of credit fees imposed on letters of credit under the revolving credit facility. We intend to use approximately $150 million of these proceeds to pre-pay indebtedness and other amounts owed in connection with the ABG Gas Supply financing, as required by the new credit facility. We are currently in discussions with the participants in that financing to pre-pay the indebtedness and other obligations. If we do not reach agreement, we will seek a waiver of, or an amendment to, this requirement under the credit facility. The remaining proceeds, subject to specified restrictions in the credit facility, are available for general corporate purposes. Please read Cash on Hand below for further discussion. Borrowings under the term loan will bear interest, at DHI s option, at (i) a base rate plus 3.00% per annum or (ii) LIBOR plus 4.00% per annum. Please read Note 6 Debt for further discussion of our new credit facility.

Other transactions impacting the change in our debt maturities in the second quarter 2004 include the following:

- $20 million in amortizing payments on the ABG Gas Supply financing;
- $15 million in mandatory pre-payments on the ChevronTexaco junior notes; and
- $21 million in amortizing payments on Illinois Power s transitional funding trust notes.

As a result of our efforts, our aggregate maturities for long-term debt as of June 30, 2004 were as follows:

Period	Total	Illinois Power (1)	Total Less Illinois Power (1)

		(in millions)	
2004	$ 150(2)	$ 107(2)	$ 43
2005	264	156	108
2006	136	86	50
2007	276	86	190
2008	317	86	231
Thereafter	5,472	1,367	4,105

(1) If the Ameren transaction closes as expected before the end of 2004, Ameren will assume Illinois Power s then outstanding indebtedness. Please read Note 6 Debt for further discussion of our outstanding debt.

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(2) Our maturities for the 2004 period have been reduced by approximately $15 million in cash collected from customers and funded, since the issuance of the Transitional Funding Trust Notes in December 1998, to the Illinois Power Special Purpose Trust, as described in Note 12 Debt Illinois Power Transitional Funding Trust Notes on page F-46 of our Form 10-K/A. This cash will be refunded to us after the Transitional Funding Trust Notes are paid in full in 2008.

Although not reflected in the table above, we have reduced our debt maturities by approximately $170 million since June 30, 2004, primarily through the following transactions:

$81 million in payments relating to the termination of the Tilton capital lease, which is further described in Note 6 Debt Tilton Capital Lease;

$75 million in pre-payments on the ChevronTexaco junior notes, including approximately $25 million in mandatory pre-payments from proceeds of the Oyster Creek and Michigan Power sales; and

approximately $14 million in amortizing payments on the ABG Gas Supply financing and Illinois Power s transitional funding trust notes.

We have incurred significant debt service obligations in the course of extending our debt maturities. Please read Note 4 Risk Management Activities and Accumulated Other Comprehensive Loss Fair Value Hedges for a discussion of the derivative instruments we use to hedge the interest rates associated with these obligations, including those entered into in July 2004. We also are subject to covenants in the related transaction agreements that are substantially more restrictive than those typically found in financing agreements of borrowers with investment grade credit ratings, including covenants limiting our ability to incur additional debt and sell certain assets. We are currently in compliance with these restrictive covenants, but our future financial condition and results of operations could be materially adversely affected by our ability to comply with these restrictive covenants in the future.

Collateral Postings

We continue to 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 financing condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our consolidated collateral postings to third parties by operating division and by type at July 30, 2004, June 30, 2004 and December 31, 2003:

	July 30, 2004	June 30, 2004	December 31, 2003
		(in millions)	
By Operating Division:			
GEN	$ 198	$ 185	$ 136
CRM	174	184	121
NGL	162	169	179
REG	28	27	38
Other	9	10	8

Total	$ 571	$ 575	$ 482
By Type:			
Cash	$ 394	$ 404	$ 294
Letters of Credit	177	171	188
Total	$ 571	$ 575	$ 482

The increase in collateral postings since December 31, 2003, relates primarily to the following:

- $62 million of additional collateral posted in support of our GEN segment primarily as a result of increased commodity prices, particularly the price of natural gas, as well as increased coal purchases and collateral posted in connection with new electric capacity sales transactions; and

- $53 million of additional collateral posted in support of our CRM segment primarily as a result of (i) increased commodity prices, particularly the price of natural gas, (ii) $22.5 million of collateral posted in connection with an existing natural gas transaction and (iii) various amounts of collateral posted primarily to support fuel purchases relating to the Sithe power tolling arrangement and a legacy gas transaction in our Canadian CRM business; the Sithe-related purchases generally have been required because we decided, in connection with our efforts to seek a settlement or termination of the Sithe power tolling arrangement, not to renew a prior long-term contract for such fuel purchases.

In addition to the increase in the total amount of collateral posted, we have also increased the proportion of cash used to satisfy counterparty collateral demands. As of December 31, 2003, approximately 61% of the aggregate collateral posted (or approximately $294 million) consisted of cash, compared to approximately 70% cash collateral (or approximately $404 million) as of June 30, 2004 and 69% cash collateral (or approximately $394 million) as of July 30, 2004. This increase is the result of our ongoing efforts to post cash collateral in lieu of letters of credit, to the extent economical, to avoid paying the 4.00% per annum letter of credit fee payable under our revolving credit facility.

Going forward, we expect counterparties 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. Although these factors, as well as timing of contract settlements and the level of new capacity sales agreements or forward hedging transactions during the remainder of 2004, will impact our aggregate collateral obligations, we believe that, assuming current natural gas price levels, these obligations will be between $500-$525 million at year end 2004. We also believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for at least the remainder of 2004. Over the longer term, we expect to achieve incremental reductions associated with the completion of our exit from the CRM business. Please see Results of Operations Outlook CRM Outlook below for a discussion of the expected collateral roll-off from this business.

Disclosure of Contractual Obligations and Contingent Financial Commitments

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

Our contractual obligations and contingent financial commitments have changed since December 31, 2003, with respect to which information is included in our Form 10-K/A. In February 2004, we terminated our conditional purchase obligation related to 14 gas-fired turbines as part of a comprehensive settlement agreement with the manufacturer. No cash, other than $11 million previously paid to the manufacturer as a deposit, was provided as consideration for the termination. Therefore, our conditional purchase obligations of $766 million as reported on page 11 of our Form 10-K/A have been reduced by approximately $5 million in 2004, $144 million in 2005, $193 million in 2006, $113 million in 2007 and $24 million in 2008.

In June 2004, we reached agreements to exit four natural gas transportation agreements. We paid $20 million in June 2004 and are required to pay another $42 million in the first quarter 2005 under these agreements, in exchange for which we will discharge our obligations to make fixed capacity payments aggregating $295

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million from April 2005 through 2014. As a result, our capacity payments of $2,852 million as reported on page 11 of our Form 10-K/A have been reduced by approximately $22 million in 2005, $31 million in each of the years ended 2006 through 2008, and $180 million thereafter. Please read Results of Operations Operating Income (Loss) CRM for a discussion of the $88 million pre-tax gain we recorded in the second quarter 2004 in connection with these agreements.

Please also read Note 6 Debt and Liquidity and Capital Resources Debt Obligations for a discussion of changes in our long-term debt obligations. There have been no other material changes to our contractual obligations and contingent financial commitments since December 31, 2003.

Dividends on Preferred and Common Stock

Dividend payments on our common stock are at the discretion of our Board of Directors. We did not declare or pay a dividend for the first half of 2004 and do not foresee a declaration of dividends in the near term, particularly given our financial condition and the dividend restrictions contained in our financing agreements. We have, however, continued to make the required dividend payments on our outstanding trust preferred securities.

We accrue dividends on our Series C preferred stock at a rate of 5.5% per annum. These dividends are payable in February and August of each year, but we may defer payments for up to 10 consecutive semi-annual periods. In July 2004, we declared a dividend of $11 million on the Series C preferred stock, to be paid on or before August 11, 2004.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations, cash on hand and available capacity under our new $700 million revolving credit facility, which is scheduled to mature in May 2007.

Cash Flows from Operations. We had operating cash flows of $61 million for the six months ended June 30, 2004. This consisted of $551 million in operating cash flows from our GEN, NGL and REG segments, reflecting positive earnings for the period partially offset by reductions in working capital from increased cash collateral postings, partially offset by $490 million of cash outflows relating to our CRM business and corporate-level expenses. Please read Results of Operations Operating Income and Cash Flow Disclosures for further discussion of factors impacting our operating cash flows for the periods presented.

Much of our restructuring work has extended our significant debt maturities to 2008 and beyond, positioning us to benefit from the expected long-term recovery in the U.S. power markets. Our future financial condition and results of operations will be materially adversely affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant price deterioration in the upstream portion of our NGL business. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Form 10-K for a discussion of our views on supply and demand in the regions where our power generation business operates. Please also read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 16 of our Form 10-K/A for a discussion of our expectations regarding the financial impact of the expected recovery.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs, including costs for fuel and maintenance, and to renew or replace our CDWR power purchase agreement. With respect to costs, in January 2004 we entered into a new rail transportation contract that we anticipate will reduce the fees associated with fuel procurement at our coal-fired generation facilities in the Midwest; however, in the first quarter 2004, these fee reductions were substantially offset by increased coal prices and higher costs associated with the purchase of emission credits. Our ability to achieve

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fuel-related and other targeted cost savings from our previously disclosed value creation project, a company-wide initiative focused on identifying opportunities to improve our operational efficiencies, in the face of industry-wide increases in labor and benefits costs, together with changes in commodity prices, will impact our future operating cash flows. Please read Results of Operations Outlook GEN Outlook for further discussion.

In addition, our CDWR power purchase agreement expires by its terms on December 31, 2004. Our share of West Coast Power s earnings during the six months ended June 30, 2004 totaled $82 million, approximately 70% of which was derived from the CDWR agreement. We are actively pursuing a renewal or replacement of this agreement; however, we cannot guarantee that an agreement can be reached on the same or similar terms, if at all. If we are unable to renew or replace this agreement, we will seek to sell the associated energy and capacity through other long-term arrangements or into the open market, where our operating cash flows would be dependent on then prevailing market prices and the market for capacity in California. Because we expect that the generating facilities supporting the CDWR contract would be significantly less profitable as merchant facilities, we may consider other alternatives if we are unable to enter into a renewal or replacement agreement, including shutting down one or more units if we no longer consider them commercially viable. Please read Results of Operations Outlook GEN Outlook for further discussion of the CDWR agreement and the anticipated impairments relating to its scheduled expiration.

Cash on Hand. At July 30, 2004 and June 30, 2004, we had cash on hand of $712 million and $837 million, respectively, as compared to $477 million at the end of 2003. This substantial increase in cash on hand from the end of 2003 is primarily attributable to the remaining proceeds from our $600 million secured term loan that have yet to be deployed. We are currently exploring possible uses of a portion of this cash. These possible uses include (i) redemption or repurchase of outstanding debt securities and (ii) settlement of pending litigation or one or more power tolling arrangements, if the opportunity is available to do so on terms we consider economically justifiable. We are also required to use a portion of this cash on hand to repay amounts outstanding in connection with the ABG Gas Supply financing. Please read Liquidity and Capital Resources Debt Obligations for further discussion. We expect to use additional amounts of this cash on hand for operations and capital expenditures. Based on current expectations, we estimate that we will have approximately $550 million in cash on hand at year end. Unforeseen events, such as legal judgments, regulatory requirements or matters impacting our operations, could negatively impact our cash position.

Revolver Capacity. In May 2004, DHI entered into a new $1.3 billion credit facility, consisting of a $600 million term loan and a $700 million revolving credit facility. This $700 million revolving credit facility, which is scheduled to mature in May 2007, is our primary credit facility. We currently have no drawn amounts under this facility, although as of July 30, 2004, we had $177 million in letters of credit issued under the facility. Our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important to our liquidity and financial condition, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements or to realize the asset sale proceeds we anticipate during 2004. Please read Note 6 Debt for further discussion of our new credit facility.

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Current Liquidity. The following table summarizes our consolidated credit capacity and liquidity position at July 30, 2004, June 30, 2004 and December 31, 2003:

	July 30, 2004	June 30, 2004	December 31, 2003
		(in millions)	
Total Revolver Capacity	$ 700(1)	$ 700(1)	$ 1,100
Outstanding Letters of Credit Under Revolving Credit Facility	(177)	(171)	(188)
Unused Revolver Capacity	523	529	912
Cash	712(2)(3)	837(2)(3)	477
Total Available Liquidity	$ 1,235(4)	$ 1,366(4)	$ 1,389

(1) Please read Note 6 Debt for a discussion of our new credit facility.
(2) The July 30, 2004 and June 30, 2004 amounts include approximately $44 million of cash that remains in Canada and the U.K. that is associated primarily with contingent liabilities relating to our former Canadian and U.K. marketing and trading operations.
(3) The reduction in cash from June 30, 2004 to July 30, 2004 primarily results from approximately $150 million in payments on debt obligations, as further described above under Liquidity and Capital Resources Debt Obligations, together with cash outflows from operations, which more than offset the $104 million in proceeds from the sales of the Oyster Creek and Michigan Power generating facilities.
(4) Includes approximately $17 million and $42 million, respectively, of liquidity at Illinois Power. Please read Item 1. Business Regulation beginning on page 21 of our Form 10-K for a discussion of ICC regulations that restrict our ability to receive cash dividends from Illinois Power.

External Liquidity Sources

Our primary external liquidity sources are proceeds from asset sales and other types of capital-raising transactions, including potential equity issuances.

Asset Sale Proceeds. Based on our current estimates, we expect that our operating cash flows will be insufficient to satisfy our capital expenditures, debt maturities, interest expenses and operating commitments for the foreseeable future. Accordingly, the receipt of proceeds from asset sales that we are currently pursuing will significantly impact our near-term financial condition.

In February 2004, we entered into an agreement to sell Illinois Power and our 20% interest in the Joppa power generation facility to Ameren for $2.3 billion. Upon closing of the transaction, which is subject to regulatory approvals and other closing conditions, we would receive approximately $400 million in cash, subject to working capital adjustments, and Ameren would deposit $100 million in escrow, subject to full release to us on December 31, 2010 or earlier upon the occurrence of specified events. Please read Note 23 Subsequent Events beginning on page F-86 of our Form 10-K/A for further discussion of this transaction. We expect this transaction will close before the end of 2004.

In an effort to maximize our return on investment and to further clarify our business strategy, we are pursuing or considering sales of other assets that we do not consider core to our operations. These assets primarily include our ownership interests in certain non-strategic domestic and international power generation facilities, which domestic facilities are detailed in Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Form 10-K, as well as our minority ownership interests in one or more upstream or downstream NGL facilities. Since the end of the first quarter 2004, we have sold or entered into definitive agreements to sell the following assets:

In April 2004, we sold our interest in the Indian Basin Gas Processing Plant for approximately $48 million in net cash proceeds.

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Also in April 2004, we sold our interest in a 20 MW wind-powered electric power generation facility located in Costa Rica for approximately $9 million in net cash proceeds.

In July 2004, we completed the sales of our 50% ownership interests in each of the 424 MW Oyster Creek generating facility and the 123 MW Michigan Power generating facility. We received approximately $104 million in aggregate net cash proceeds from these transactions.

In July 2004, we entered into agreements to sell our 50% ownership in each of the 310 MW Hartwell generating facility and the 310 MW Commonwealth generating facility. We expect to close these transactions, which are subject to regulatory and bank approvals and other closing conditions, in the fourth quarter 2004.

Generally, the aggregate projected loss of earnings in 2004 associated with these assets is not considered material and is expected to be more than offset by net gains on sale in 2004. However, beginning in 2005, the lost earnings from these assets will no longer be offset by gains on sale.

Our desire or ability to effect these or any other non-core asset sales is subject to a number of factors, many of which are beyond our control, including the market for the assets and investments not yet subject to a sale agreement, the receipt of any regulatory and other approvals that may be required and the willingness of lenders and other counterparties to consent to a proposed transaction. Accordingly, we cannot guarantee that the pending sales or any other sales will be consummated or that the expected proceeds will be received. In addition, if the sales are consummated, we are required to use a portion of the proceeds in accordance with the restrictive covenants contained in the indenture governing the junior notes. Please read Note 12 Debt Junior Unsecured Subordinated Notes beginning on page F-47 of our Form 10-K/A for a discussion of the mandatory prepayment provisions of the junior notes indenture.

We discuss and evaluate merger and acquisition activities as part of our ongoing business strategy. In the power generation industry, in particular, we believe that consolidation is likely to occur within the next several years. We further believe that our efficient and scalable operations platform, together with our multi-fuel capabilities and multi-region presence, position us to benefit from opportunities that might arise in connection with any consolidation transactions. However, as indicated above, our desire or ability to participate in any such transactions is subject to a number of factors beyond our control. As such, we cannot guarantee that any such transactions will occur, nor can we predict with any degree of certainty the impact of any such transactions on our financial condition or results of operations.

Capital-Raising Transactions. As part of our ongoing efforts to develop a capital structure that is more closely aligned with the cash-generating potential of our asset-based businesses, each of which is subject to cyclical changes in commodity prices, we are continuing to explore additional capital-raising transactions both in the near- and long-term. The timing of any capital-raising transaction may be impacted by unforeseen events, such as legal judgments or regulatory requirements, as well as strategic decisions relating to litigation settlements or contract terminations (including settlement of one or more of our remaining power tolling arrangements), which would necessitate additional capital in the near-term.

These transactions may include capital markets transactions. Our ability to issue public securities is enhanced by our effective shelf registration statement, under which we have approximately $430 million in remaining availability. However, the receptiveness of the capital markets to a public offering cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Any issuance of equity likely would have other effects as well, including shareholder dilution. Further, our ability to issue debt securities is limited by our financing agreements, including our new credit facility. Please read Note 6 Debt Revolvers for further discussion.

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Conclusion

For the foreseeable future, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be insufficient to satisfy our capital expenditures, debt maturities, interest expenses and operating commitments. However, we believe that our cash on hand, together with proceeds from anticipated asset sales and capacity under our new $700 million revolving credit facility, will be sufficient to discharge these obligations for at least the next twelve months.

Our liquidity position and financial condition will be materially affected by a number of factors, including our ability to consummate non-core asset sales, particularly the Illinois Power sale to Ameren, and, over the longer term, to generate cash flows from our asset-based energy businesses in relation to our substantial debt and commercial obligations, including increased interest expense, the fixed payment obligations associated with our CRM business and counterparty collateral requirements. The sale of Illinois Power would provide significant cash proceeds to repay outstanding debt and advance our business strategy of focusing on our unregulated energy businesses.

Our ability to generate operating cash flows from our asset-based energy businesses will be impacted by a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for power and natural gas, and the success of our ongoing efforts to manage operating costs and capital expenditures. Over the longer term we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of our restructuring work has extended our significant debt maturities to 2008 and beyond, positioning us to benefit from earnings and growth opportunities associated with an expected recovery in the U.S. power markets. Additionally, our natural gas liquids business is currently operating in a highly favorable pricing environment. Our future financial condition and results of operations will be materially adversely affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant, prolonged pricing deterioration in the NGL segment.

Additionally, our longer term liquidity position and financial condition will be impacted by our desire and ability to generate proceeds through capital markets transactions. We have significant long-term fixed payment obligations relating to the tolling arrangements that remain in our CRM business, in addition to potential payment obligations relating to our securities litigation and other legal and regulatory matters. Our ability to continue to satisfy these obligations, through settlement or otherwise, will be impacted by our access to the capital markets and the cash flow generating ability of our asset-based businesses. This is particularly important with respect to our long-term tolling arrangements, which we expect will continue to reduce our operating cash flows absent an early termination or settlement. We expect that our liquidity position will trend downward as these obligations are satisfied or extinguished.

Please read Uncertainty of Forward-Looking Statements and Information for additional factors that could impact our future operating results and financial condition.

FACTORS AFFECTING FUTURE RESULTS OF OPERATIONS

In Management s Discussion and Analysis of Financial Condition and Results of Operations Overview beginning on page 4 of our Form 10-K/A, we detailed the primary factors that have impacted, and are expected to continue to impact, the earnings and cash flows from our business segments and other operations. Our results of operations during the remainder of 2004 and beyond may be significantly affected by any or all of these factors, including the following factors in particular:

Changes in commodity prices, including the relationships between prices for power and natural gas or other power generating fuels, commonly referred to as the spark spread, and the frac spread, which represents the relative difference in value between natural gas liquids and natural gas on a Btu basis;

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Our ability to control our capital expenditures, which primarily are limited to maintenance, safety, environmental and reliability projects, and other costs through disciplined management and safe, efficient operations;

The impact of reduced market liquidity and counterparty collateral demands on our ability to sell our energy products through forward sales or similar transactions;

Our ability to address the substantial long-term payment obligations associated with our four remaining power tolling arrangements, the restructuring or termination of one or more of which likely would require a significant cash payment; and

The impact of increased interest expense primarily attributable to our recent restructuring and refinancing transactions and our non-investment grade credit ratings.

Please read Uncertainty of Forward-Looking Statements and Information for additional factors that could impact our future operating results.

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three- and six-month periods ended June 30, 2004 and 2003. We have also included our business outlook for each segment.

We report our operations in the following segments: GEN, NGL, REG and CRM. Other reported results include corporate overhead and our discontinued communications business. All direct general and administrative expenses and other income (expense) items incurred by us on behalf of our subsidiaries are charged to the applicable subsidiary as incurred.

Three Months Ended June 30, 2004 and 2003

The following tables provide summary financial data regarding our consolidated and segmented results of operations for the three months ended June 30, 2004 and 2003, respectively. This financial data has been restated to reflect the impact of the items described in the Explanatory Note to the unaudited condensed consolidated financial statements. The restatements relate to increased and additional impairments associated with the sale of Illinois Power and our deferred income tax accounts. Please read this Explanatory Note for further discussion of these restatement items.

Quarter Ended June 30, 2004

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(in millions)		

Operating income (loss)	$ 35	$ 75	$ 22	$ 90	$ (89)	$ 133
Earnings from unconsolidated investments	50	2				52
Other items, net		(5)		(1)	(8)	(14)
Interest expense						(145)
Income from continuing operations before taxes						26
Income tax benefit						1
Income from continuing operations						27
Loss from discontinued operations, net of taxes						(19)
Net income						$ 8

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Quarter Ended June 30, 2003

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(in millions)		
Operating income (loss)	$ 16	$ 39	$ 35	$ (360)	$ (104)	$ (374)
Earnings (losses) from unconsolidated investments	45	2		(9)		38
Other items, net		(5)		(3)	(1)	(9)
Interest expense						(109)
Loss from continuing operations before taxes						(454)
Income tax benefit						168
Loss from continuing operations						(286)
Loss from discontinued operations, net of taxes						(4)
Net loss						$ (290)

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The following table provides summary segmented operating statistics for the three months ended June 30, 2004 and 2003, respectively.

	Quarter Ended June 30,	
	2004	2003
Power Generation		
Million megawatt hours generated gross	9.0	8.7
Million megawatt hours generated net	8.6	8.3
Average natural gas price Henry Hub ($/MMbtu) (1)	$ 6.09	$ 5.63
Average on-peak market power prices ($/MW hour)		
Cinergy	$ 45	$ 33
Commonwealth Edison	$ 44	$ 33
Southern	$ 52	$ 40
New York Zone G	$ 63	$ 58
ERCOT	$ 54	$ 55
SP-15	$ 55	$ 51
Natural Gas Liquids		
Gross NGL production (MBbls/d):		
Field plants	56.1	60.0
Straddle plants	23.6	26.4
Total gross NGL production	79.7	86.4
Natural gas (residue) sales (Bbtu/d)	181.9	167.0
Natural gas inlet volumes (MMCFD):		
Field plants	529.9	581.4
Straddle plants	785.1	1,199.4
Total natural gas inlet volumes	1,315.0	1,780.8
Fractionation volumes (MBbls/d)	213.1	188.2
Natural gas liquids sold (MBbls/d)	252.3	275.6
Average commodity prices:		
Crude oil WTI ($/Bbl)	$ 38.51	$ 29.31
Natural gas Henry Hub ($/MMbtu) (2)	$ 6.00	$ 5.40
Natural gas liquids ($/Gal)	$ 0.64	$ 0.51
Fractionation spread ($/MMBtu) daily	$ 1.15	$ 0.46
Regulated Energy Delivery		
Electric sales in KWH (millions)		
Residential	1,135	998
Commercial	1,118	1,052
Industrial	1,371	1,648
Transportation of customer-owned electricity	803	601
Other	90	88
Total electric sales	4,517	4,387

Gas sales in Therms (millions)		
Residential	34	35
Commercial	16	16
Industrial	10	18
Transportation of customer-owned gas	56	57
Total gas delivered	116	126
Cooling degree days actual (3)	373	198
Cooling degree days 10-year rolling average	373	364
Heating degree days actual (4)	388	469
Heating degree days 10-year rolling average	453	431

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(1) Calculated as the average of the daily gas prices for the period.
(2) Calculated as the average of the first of the month prices for the period.
(3) A Cooling Degree Day (CDD) represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in our service area. The CDDs for a period of time are computed by adding the CDDs for each day during the period.
(4) A Heating Degree Day (HDD) represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in our service area. The HDDs for a period of time are computed by adding the HDDs for each day during the period.

The following tables summarize significant items on a pre-tax basis, with the exception of the 2004 tax item, affecting net income (loss) for the periods presented.

	Quarter Ended June 30, 2004					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Discontinued operations	$	$	$	$ 1	$	$ 1
Legal and settlement charges		2	1		(42)	(39)
Illinois Power asset impairment			(48)			(48)
Acceleration of financing costs					(14)	(14)
Taxes					(9)	(9)
Gas transportation contracts				88		88
Gain on sale of Indian Basin		36				36
Total	$	$ 38	$ (47)	$ 89	$ (65)	$ 15

	Quarter Ended June 30, 2003					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Discontinued operations	$	$ (1)	$	$ 4	$ (6)	$ (3)
Southern Power settlement				(133)		(133)
Sithe power tolling contract				(132)		(132)
Legal charges					(50)	(50)
Kroger settlement				(30)		(30)
Gain on sale of Hackberry LNG		10		2		12
Total	$	$ 9	$	$ (289)	$ (56)	$ (336)

Operating Income (Loss)

Operating income (loss) was $133 million for the quarter ended June 30, 2004, compared to $(374) million for the quarter ended June 30, 2003.

GEN. Operating income for the GEN segment was $35 million for the quarter ended June 30, 2004, compared to $16 million for the quarter ended June 30, 2003.

The Midwest region was the primary driver of the above increase in operating income, as the region s results increased $22 million quarter over quarter. The Midwest region benefited by $22 million from higher power prices, with average on peak prices up 33% compared with the second quarter 2003. However, because a substantial portion of our production in this region is under contract or hedged, we were unable to realize the full benefit of the unexpected but significant increases in market prices. Volumes of 4.8 MWh for the second quarter 2004 were slightly higher than the 4.7 MWh for the second quarter 2003, contributing an additional $1 million. Operating expense decreased by $2 million from $40 million for the second quarter of 2003 to $38 million for the second quarter 2004.

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Results for the Northeast region decreased $10 million, from $7 million for the quarter ended June 30, 2003 to a loss of $3 million for the quarter ended June 30, 2004. Results declined $8 million primarily as a result of higher fuel and fuel transportation costs quarter over quarter. Additionally, results were reduced by a $2 million increase in operating expense, as well as a $2 million decrease in contracted revenues under a transitional power purchase agreement. These factors were partly mitigated by an increase in volumes. Aggregate volumes increased from 1.1 MWh for the quarter ended June 30, 2003 to 1.4 MWh for the quarter ended June 30, 2004, primarily as a result of Roseton s duel fuel capability and the cost advantage of burning fuel oil rather than natural gas. This increase in volume contributed an additional $3 million to results.

Results in the Southeast region decreased by $6 million in the second quarter 2004 compared with second quarter 2003, as a result of the loss of capacity revenues related to a contract that expired at the end of 2003.

Our other regions and businesses benefited approximately $5 million from higher power prices quarter over quarter.

GEN s reported operating income for the 2004 and 2003 periods includes approximately zero and $6 million, respectively, of mark-to-market losses related to derivative contracts that did not meet the criteria for hedge accounting under SFAS No. 133 and, therefore, were accounted for on a mark-to-market basis.

NGL. Operating income for the NGL segment was $75 million for the quarter ended June 30, 2004, compared to $39 million for the quarter ended June 30, 2003. Operating income for the second quarter 2004 included a $36 million gain associated with the sale of our financial interest in Indian Basin, offset by increased depreciation expense of $6 million due to an adjustment to accumulated depreciation and an asset impairment of $5 million; operating income for the second quarter 2003 included a $10 million gain on the sale of our ownership interest in the Hackberry LNG project. Please read Note 2 Dispositions, Contract Terminations and Discontinued Operations for further discussion. Also, please read Item 1. Business Segment Discussion Natural Gas Liquids beginning on page 7 of our Form 10-K for a detailed description of the NGL segment, including its contract portfolio.

The NGL segment s profitability was higher in all areas as compared to 2003, with NGL marketing, gas processing and marketing assets all producing strong results.

Gathering and processing benefited from 11% higher absolute commodity prices for natural gas and 25% higher absolute commodity prices for natural gas liquids compared to the same quarter in 2003. Frac spreads increased year over year but continued to be lower than required to support liquids extraction under keep whole processing contracts. At our field plants, our improved contract portfolio quarter over quarter reflected our successful 2003 efforts to reform two major keep whole contracts to percentage of proceeds contracts. This contract portfolio of nearly 98% percentage of proceeds, percentage of liquids and fee-based contracts benefited from higher prices in the second quarter 2004 contributing to a 9% increase in processing plant margins. Gross and net natural gas liquids production declined and natural gas net to our account increased as compared to the second quarter 2003 due to the difference in settlement terms between the two types of contracts and lower natural gas inlet and NGL production volumes resulting from the sale of our interest in Indian Basin in April 2004.

As a result of our percentage of proceeds and percentage of liquids contracts, we take ownership of natural gas and natural gas liquids as payment for our services. We have established a comprehensive hedging strategy and related control procedures to manage price risk on these equity volumes. We limit the volume considered for hedging and forward selling to Dynegy-owned volumes received at our field processing facilities that must operate for the gas to meet natural gas pipeline quality specifications. The portion of equity natural gas and natural gas liquids that we hedge is monitored closely against our field processing plant operations to ensure we hedge no more than the volume we own. We seek to mitigate correlation risk by hedging each natural gas liquid product against our physical production of that product.

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Processing margins at our straddle plants were 7% lower and liquids volumes produced in the second quarter 2004 were 11% lower than in the second quarter 2003. Frac spreads increased quarter over quarter to $1.15, up from $0.46. Even at this higher frac spread, it is still not profitable to recover liquids at these high natural gas prices in most cases. Straddle plant results declined slightly due to lower inlet volumes at our plants resulting from uncertainty in the interstate pipeline market related to the enforcement of pipeline quality specifications in 2004 compared to 2003.

In our downstream business, volumes available for fractionation increased 12% to 213.1 MBbls/d in the second quarter 2004 versus 188.2 MBbls/d in the second quarter 2003. Volumes increased at our Mont Belvieu fractionator as a result of a new fractionation contract and increased ethane recovery in Rocky Mountain gas processing plants feeding into our facility.

In our wholesale marketing operations, results were materially the same quarter over quarter.

Marketing results quarter over quarter increased significantly to approximately $14 million, compared to the results of approximately $3 million for the 2003 period. In the second quarter 2004, we terminated an inactive natural gas liquids sales contract which allowed us to recognize a $6 million gain on sales of natural gas liquids at current market prices previously held outside our normal inventory at historic below-current market prices. Marketing results were also favorably impacted by volatile and rising liquids prices during the period, offset partially by the recognition of well measurement losses. Marketing volumes continue to be impacted negatively due to reduced overall market liquidity.

Wholesale marketing and marketing combined volumes declined from approximately 275.6 MBbls/d in the second quarter 2003 to approximately 252.3 MBbls/d in the second quarter 2004 due to cooler weather and our decision to curtail low margin sales and reduce inventory risk. This volumetric decline had minimal impact on our operating income.

In June 2004, we tested certain of our assets for impairment based on the identification of triggering events as defined by SFAS No. 144. After testing, we recorded a pre-tax impairment of $5 million for the Puckett gas treating plant and gathering system due to rapidly depleting reserves associated with that facility. We concluded that no impairment was necessary for any of our other facilities as estimated undiscounted cash flows exceeded facility book values.

REG. Operating income for the REG segment was $22 million for the quarter ended June 30, 2004, compared to $35 million for the quarter ended June 30, 2003. Operating income for the quarter ended June 30, 2004 includes a $48 million charge for the impairment of assets associated with this segment. Additionally, we stopped depreciating our Illinois Power assets on February 1, 2004, as they are classified as held for sale, which resulted in a benefit to operating income of $30 million compared to the quarter ended June 30, 2003.

Operationally, this segment was impacted by average weather in the second quarter 2004 as compared to cooler than average weather in 2003, which resulted in increased residential and commercial electric sales volumes in 2004. Residential and commercial gas sales were relatively flat. Industrial electric sales were negatively affected by customers choosing alternate energy providers. Such switching is typically based on price and service reliability. Lower overall operating costs were partially offset by higher employee pension costs.

CRM. Operating income for the CRM segment was $90 million for the quarter ended June 30, 2004, compared to a loss of $360 million for the quarter ended June 30, 2003. In June 2004, we reached agreements to exit four natural gas transportation contracts, which we originally entered into to secure firm pipeline capacity in support of our third-party marketing and trading business. In exchange for exiting these obligations, we paid $20 million in June 2004 and will pay an additional $42 million in the first quarter 2005. These payments eliminate approximately $295 million in aggregate fixed capacity payments from April 2005 through 2014. In connection with the exit from these contracts, we reversed an aggregate liability of $148 million, resulting in a net pre-tax gain of $88 million. This segment s results for the second quarter 2004 also reflect the impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold. In addition, results for the second quarter 2004 include $10 million in gains associated with the mark-to-market value of certain legacy gas contracts which had previously been accounted for on an accrual basis. Results for the second quarter 2003 include a $133 million charge associated with the settlement of power tolling arrangements with Southern Power, $132 million in mark-to-market losses on contracts associated with our Sithe Independence power tolling arrangement and a $30 million charge associated with the settlement of power supply agreements with Kroger. Additionally, 2003 results include losses associated with fixed payments on power tolling arrangements in excess of realized margins on power generated and sold pursuant to these agreements.

Other. Other operating loss was $89 million for the quarter ended June 30, 2004, compared to $104 million for the quarter ended June 30, 2003. Operating loss for the quarter ended June 30, 2004 includes increased legal and settlement charges of $42 million. The increased legal charges resulted from additional activities during the quarter that affected management s assessment of the probable and estimable loss associated with the applicable proceedings. Please read Note 3 Restructuring Charges for a discussion of the settlement charges. Operating loss for the second quarter 2003 includes increased legal charges of $50 million.

Earnings from Unconsolidated Investments.

Our earnings from unconsolidated investments were approximately $52 million for the quarter ended June 30, 2004, compared to $38 million for the quarter ended June 30, 2003.

GEN. GEN s earnings from unconsolidated investments were approximately $50 million for the quarter ended June 30, 2004, compared to $45 million for the quarter ended June 30, 2003. Earnings from our West Coast Power investment are the primary driver of results for each of these periods. West Coast Power provided equity earnings of approximately $47 million for the quarter ended June 30, 2004, compared to $36 million for the quarter ended June 30, 2003. Earnings at West Coast Power were higher quarter over quarter due to higher realized margins resulting from hedges put in place in connection with the execution of the CDWR contract. Please read Item 1. Business Segment Discussion Power Generation West region Western Electricity Coordinating Council (WECC) beginning on page 6 of our Form 10-K for further discussion of West Coast Power s CDWR contract.

NGL. NGL s earnings from unconsolidated investments were approximately $2 million for each of the quarters ended June 30, 2004 and 2003.

CRM. CRM s losses from unconsolidated investments were zero for the quarter ended June 30, 2004, compared to $9 million for the quarter ended June 30, 2003. As of December 31, 2003, CRM had no material unconsolidated investments. As such, 2004 and future results are expected to be de minimis. The earnings in 2003 primarily related to our Nicor Energy joint venture, the operations of which were sold in the first half of 2003.

Interest Expense

Interest expense totaled $145 million for the quarter ended June 30, 2004, compared to $109 million for the quarter ended June 30, 2003. The significant increase in 2004, as compared to 2003, is primarily attributable to higher average interest rates on borrowings related to the new securities issued in connection with our August and October 2003 debt refinancings. In addition, interest expense in 2004 includes $14 million associated with deferred financing costs relating to our former credit facility, which were expensed upon the execution of our new $1.3 billion credit facility.

Other Items, Net

Other items, net consists of other income and expense items, net, minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $(14) million for the

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quarter ended June 30, 2004, compared to $(9) million for the quarter ended June 30, 2003. The decrease in 2004, as compared to 2003, is due to mark-to-market losses recognized in the second quarter 2004 associated with interest rate swaps partially offset by a reduction in accumulated distributions associated with trust preferred securities.

Income Tax Benefit

We reported an income tax benefit during the quarter ended June 30, 2004 of $1 million. The 2004 effective tax rate was 37%, compared to 37% in 2003. The 2004 effective rate includes an $8 million benefit related to the release of reserves upon the conclusion of prior year tax audits and a $3 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with anticipated gains on asset sales. Please read Note 12 Income Taxes for further discussion. Excluding these items from the 2004 calculation would result in an effective tax rate of 38%. In general, differences between these effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Discontinued Operations

Discontinued operations includes our global liquids business in the NGL segment, our U.K. natural gas storage assets and our U.K. CRM business in the CRM segment and our communications business in Other and Eliminations. The largest contributor to the pre-tax gain of $1 million ($19 million loss after-tax) for the quarter ended June 30, 2004 is the U.K. CRM business, primarily due to $20 million in tax expenses related to the conclusion of prior year tax audits. Please read Note 12 Income Taxes for further discussion. The largest contributor to the pre-tax loss of $3 million ($4 million after-tax) for the quarter ended June 30, 2003 is the pre-tax loss from operations of our communications business, offset by a pre-tax gain from our U.K. CRM operations.

Preferred Stock Dividends

The $6 million preferred stock dividend recognized in the second quarter 2004 is related to our Series C preferred stock, which accumulates dividends at an annual rate of 5.5%. The 2003 dividend of $82 million related to the Series B preferred stock that included an implied dividend of $660 million, which was amortized over a two-year period. Please read Note 15 Redeemable Preferred Securities beginning on page F-53 of our Form 10-K/A for a description of the August 2003 exchange of the Series B preferred stock for, among other things, the Series C preferred stock, and the impact on the associated dividends.

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Six Months Ended June 30, 2004 and 2003

The following tables provide summary financial data regarding our consolidated and segmented results of operations for the six-month periods ended June 30, 2004 and 2003, respectively. This financial data has been restated to reflect the impact of the items described in the Explanatory Note to the unaudited condensed consolidated financial statements. The restatements relate to increased and additional impairments associated with the sale of Illinois Power and our deferred income tax accounts. Please read this Explanatory Note for further discussion of these restatement items.

Six Months Ended June 30, 2004

	GEN	NGL	REG	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 88	$ 142	$ 76	$ 77	$ (142)	$ 241
Earnings from unconsolidated investments	88	4				92
Other items, net		(9)	1	2	3	(3)
Interest expense						(277)
Income from continuing operations before taxes						53
Income tax benefit						30
Income from continuing operations						83
Loss from discontinued operations, net of taxes						(5)
Net income						$ 78

Six Months Ended June 30, 2003

	GEN	NGL	REG	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 99	$ 90	$ 94	$ (322)	$ (148)	$ (187)
Earnings from unconsolidated investments	84	5		2		91
Other items, net	3	(10)		23	(4)	12
Interest expense						(219)
Loss from continuing operations before taxes						(303)
Income tax benefit						112
Loss from continuing operations						(191)
Loss from discontinued operations, net of taxes						(7)
Cumulative effect of change in accounting principles, net of taxes						55

Net loss	$ (143)

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The following table provides summary segmented operating statistics for the six months ended June 30, 2004 and 2003, respectively.

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
Power Generation		
Million megawatt hours generated gross	19.6	18.6
Million megawatt hours generated net	18.7	17.7
Average natural gas price Henry Hub ($/MMbtu) (1)	$ 5.86	$ 6.00
Average on-peak market power prices ($/MW hour)		
Cinergy	$ 43	$ 42
Commonwealth Edison	$ 42	$ 40
Southern	$ 47	$ 44
New York Zone G	$ 63	$ 67
ERCOT	$ 49	$ 56
SP-15	$ 52	$ 53
Natural Gas Liquids		
Gross NGL production (MBbls/d):		
Field plants	57.0	58.1
Straddle plants	23.8	26.6
Total gross NGL production	80.8	84.7
Natural gas (residue) sales (Bbtu/d)	182.4	171.3
Natural gas inlet volumes (MMCFD):		
Field plants	551.3	574.6
Straddle plants	826.7	1,296.3
Total natural gas inlet volumes	1,378.0	1,870.9
Fractionation volumes (MBbls/d)	199.0	181.9
Natural gas liquids sold (MBbls/d)	276.9	319.7
Average commodity prices:		
Crude oil WTI ($/Bbl)	$ 36.64	$ 31.86
Natural gas Henry Hub ($/MMbtu) (2)	$ 5.84	$ 6.00
Natural gas liquids ($/Gal)	$ 0.63	$ 0.56
Fractionation spread ($/MMBtu) daily	$ 1.27	$ 0.42
Regulated Energy Delivery		
Electric sales in KWH (millions)		
Residential	2,590	2,431
Commercial	2,172	2,110
Industrial	2,691	3,053
Transportation of customer-owned electricity	1,432	1,150
Other	188	187
Total electric sales	9,073	8,931
Gas sales in Therms (millions)		
Residential	194	220
Commercial	74	88

Industrial	29	41
Transportation of customer-owned gas	125	122
Total gas delivered	422	471
Cooling degree days actual (3)	373	198
Cooling degree days 10-year rolling average	374	364
Heating degree days actual (4)	3,096	3,404
Heating degree days 10-year rolling average	3,131	3,018

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(1) Calculated as the average of the daily gas prices for the period.
(2) Calculated as the average of the first of the month prices for the period.
(3) A Cooling Degree Day (CDD) represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in our service area. The CDDs for a period of time are computed by adding the CDDs for each day during the period.
(4) A Heating Degree Day (HDD) represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in our service area. The HDDs for a period of time are computed by adding the HDDs for each day during the period.

The following tables summarize significant items on a pre-tax basis, with the exception of the 2004 tax item, affecting net income (loss) for the periods presented.

	Six Months Ended June 30, 2004					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Discontinued operations	$	$	$	$ 18	$ 3	$ 21
Legal and settlement charges	2	2	(1)		(57)	(54)
Illinois Power asset impairment			(54)			(54)
Loss on anticipated sale of Illinois Power			(15)			(15)
Acceleration of financing costs					(14)	(14)
Gas transportation contracts				88		88
Gain on sale of Indian Basin		36				36
Gain on sale of Hackberry LNG		17				17
Taxes					30	30
Total	$ 2	$ 55	$ (70)	$ 106	$ (38)	$ 55

	Six Months Ended June 30, 2003					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Discontinued operations	$	$ (1)	$	$ (11)	$ (4)	$ (16)
Southern Power settlement				(133)		(133)
Kroger settlement				(30)		(30)
Sithe power tolling contract				(132)		(132)
Legal charges					(50)	(50)
Gain on sale of Hackberry LNG		10		2		12
Cumulative effect of change in accounting principles	47		(3)	43		87
Total	$ 47	$ 9	$ (3)	$ (261)	$ (54)	$ (262)

Operating Income (Loss)

Operating income (loss) was $241 million for the six months ended June 30, 2004, compared to ($187) million for the six months ended June 30, 2003.

GEN. Operating income for the GEN segment was $88 million for the six months ended June 30, 2004, compared to $99 million for the six months ended June 30, 2003.

In the Midwest region, results increased $9 million period over period. Volumes were up slightly, from 10.2 MWh for the six months ended June 30, 2003 to 10.3 MWh for the six months ended June 30, 2004, contributing $2 million. Additionally, average on peak power prices were up 5%, contributing an additional $12 million for the first half of 2004 compared with the same period in 2003. However, increased volumes and pricing were partially offset by an increase in operating expenses for the Midwest of approximately $5 million, primarily as a result of the timing of maintenance expenditures.

Results for the Northeast region were down $4 million, from $21 million for the six months ended June 30, 2003 to $17 million for the six months ended June 30, 2004. This decrease was driven primarily by a $13 million decrease resulting from lower average prices during the first half of 2004. Further, revenues for the first six months of 2004 under a transitional power purchase agreement were $6 million less than they were in the same period in 2003. Results were also reduced by a $3 million increase in operating expense, primarily resulting from the timing of maintenance expenditures. However, the effects of pricing and operating expense were largely offset by the benefit of increased volumes. For the first half of 2004, generated volumes were 3.7 MWh, up 48% from the same period in 2003, primarily as a result of Roseton s dual fuel capability and the cost advantage of burning fuel oil rather than natural gas. This increase in volume contributed an additional $19 million.

The decrease in operating income in the first six months of 2004 also reflects the loss of approximately $11 million of capacity revenues in the Southeast region related to a contract that expired at the end of 2003.

GEN s reported operating income for the 2004 and 2003 periods includes approximately $4 million and $8 million, respectively, of mark-to-market income related to derivative contracts that did not meet the criteria for hedge accounting under SFAS No. 133 and, therefore, were accounted for on a mark-to-market basis.

In March 2004, we tested our CoGen Lyondell facility for an impairment based on the identification of a triggering event as defined by SFAS No. 144. After performing the test, we concluded that no impairment was necessary as the estimated undiscounted cash flows exceeded the book value of the facility.

NGL. Operating income for the NGL segment was $142 million for the six months ended June 30, 2004, compared to $90 million for the six months ended June 30, 2003. Operating income for the six months ended June 30, 2004 included pre-tax gains of $17 million and $36 million, respectively, from our Hackberry LNG and Indian Basin sales, offset by increased depreciation expense of $6 million due to an adjustment to accumulated depreciation and an asset impairment of $5 million; operating income for the six months ended June 30, 2003 included a $10 million gain on the sale of our ownership interest in the Hackberry LNG facility and a $3 million gain associated with the expiration of an environmental guarantee. Please read Note 2 Dispositions, Contract Terminations and Discontinued Operations for further discussion. Also, please read Item 1. Business Segment Discussion Natural Gas Liquids beginning on page 7 of our Form 10-K for a detailed description of the NGL segment, including its contract portfolio.

The NGL segment s profitability was higher in all areas as compared to 2003, with NGL marketing, gas processing and marketing assets all producing strong results.

Gathering and processing experienced 3% lower absolute commodity prices for natural gas and 12.5% higher absolute commodity prices for natural gas liquids compared to the same period in 2003. Frac spreads increased year over year but continued to be lower than required to support liquids extraction under keep whole processing contracts. At our field plants, our improved contract portfolio period over period reflected our successful 2003 efforts to reform two major keep whole contracts to percentage of proceeds contracts. This contract portfolio of nearly 98% percentage of proceeds, percentage of liquids and fee-based contracts benefited from the higher natural gas liquid prices in the first half of 2004 contributing to a 12% increase in processing plant margins. Gross and net natural gas liquids production declined and natural gas net to our account increased as compared to 2003 due to the difference in settlement terms between the two types of contracts and lower natural gas inlet and NGL production volumes due to the sale of our interest in Indian Basin effective April 1, 2004.

As a result of our percentage of proceeds and percentage of liquids contracts, we take ownership of natural gas and natural gas liquids as payment for our services. We have established a comprehensive hedging strategy and related control procedures to manage price risk on these equity volumes. We limit the volume considered for hedging and forward selling to Dynegy-owned volumes received at our field processing facilities that must operate for the gas to meet natural gas pipeline quality specifications. The portion of equity natural gas and natural gas liquids that we hedge is monitored closely against our field processing plant operations to ensure we hedge no more than the volume we own. We seek to mitigate correlation risk by hedging each natural gas liquid product against our physical production of that product.

Processing margins at our straddle plants were 26% lower and liquids volumes produced in the first half of 2004 were 13% lower than in the 2003 period. Frac spreads in the first six months of 2004 increased to $1.27, up from $0.42 in the same period during 2003. Even at this higher frac spread, it is still not profitable to recover liquids at these high natural gas prices in most cases. Straddle plant results declined due to lower inlet volumes at our plants resulting from uncertainty in the interstate pipeline market related to enforcement of pipeline quality specifications in 2004 compared to 2003.

In our downstream business, volumes available for fractionation increased 9% to 199.0 MBbls/d in the first half of 2004 versus 181.9 MBbls/d in the same period in 2003. Volumes increased at our Mont Belvieu fractionator as a result of a new fractionation contract and increased ethane recovery in Rocky Mountain gas processing plants feeding into our facility, and at our Lake Charles fractionator primarily due to the return to operations of a third party gas processing plant.

In our wholesale marketing operations, results were materially the same period over period.

Marketing results for the first six months of 2004 increased to approximately $18 million, compared to the results for the same period in 2003 of approximately $15 million. In the second quarter 2004, we terminated an inactive natural gas liquids sales contract which allowed us to recognize a $6 million gain on sales of natural gas liquids at current market prices previously held outside our normal inventory at historic below-current market prices. This increase was partially offset by recognition of well measurement losses in early 2004.

Marketing volumes continue to be impacted negatively by reduced overall market liquidity. Combined volumes for our wholesale marketing and marketing businesses declined from approximately 319.7 MBbls/d in the first half of 2003 to approximately 276.9 MBbls/d in the first half of 2004 due to our decision to curtail low margin sales and reduce inventory risk. This volumetric decline had little impact on our operating income.

In June 2004, we tested certain of our assets for impairment based on the identification of triggering events as defined by SFAS No. 144. After testing, we recorded a pre-tax impairment of $5 million for our Puckett gas treating plant and gathering system due to rapidly depleting reserves associated with that facility. We concluded that no impairment was necessary for any of the other facilities as estimated undiscounted cash flows exceeded facility book values.

REG. Operating income for the REG segment was $76 million for the six months ended June 30, 2004, compared to $94 million for the six months ended June 30, 2003. The 2004 period includes a $15 million charge related to the anticipated sale of Illinois Power and a $54 million charge for the impairment of assets associated with this segment. We also stopped depreciating our Illinois Power assets on February 1, 2004, as they are classified as held for sale, which resulted in a benefit to operating income of $50 million compared to the six months ended June 30, 2003.

Operationally, this segment was positively impacted in 2004 as compared to 2003 by warmer spring weather, which resulted in increased residential and commercial electric sales volumes. Residential and commercial gas sales were negatively impacted by warmer than normal winter weather compared to 2003. Industrial electric sales were negatively affected by customers choosing alternate energy providers. Operating expenses in 2004 were negatively impacted by higher employee pension costs and costs associated with personal injury and other damage claims.

CRM. Operating income for the CRM segment was $77 million for the six months ended June 30, 2004, compared to a loss of $322 million for the six months ended June 30, 2003. In June 2004, we reached agreements to exit four natural gas transportation contracts, which we originally entered into to secure firm pipeline capacity in support of our third-party marketing and trading business. In exchange for exiting these obligations, we paid $20 million in June 2004 and will pay $42 million in the first quarter 2005. These payments eliminate approximately $295 million in aggregate fixed capacity payments from April 2005 through 2014. In connection with the exit from these contracts, we reversed an aggregate liability of $148 million, resulting in a net pre-tax gain of $88 million. This segment s results for the first half of 2004 also reflect the impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold. In addition, the results for the second quarter 2004 include $10 million in gains associated with the mark-to-market value of certain legacy gas contracts which had previously been accounted for on an accrual basis. Results for the first six months of 2003 include a $133 million charge associated with the settlement of power tolling arrangements with Southern Power, $132 million in mark-to-market losses on contracts associated with our Sithe Independence power tolling arrangement and a $30 million charge associated with the settlement of power supply agreements with Kroger. Additionally, 2003 results include gains in value of our remaining marketing and trading portfolio.

Other. Other operating loss was $142 million for the six months ended June 30, 2004, compared to $148 million for the six months ended June 30, 2003. Results for 2004 include approximately $57 million of expenses related to increased legal and settlement charges. The increased legal charges resulted from additional activities during the quarter that affected management s assessment of the probable and estimable loss associated with the applicable proceedings. Please read Note 3 Restructuring Charges for a discussion of the settlement charges. This increase was partially offset by lower compensation costs in the 2004 period. Operating loss for 2003 includes increased legal charges of $50 million.

Earnings from Unconsolidated Investments

Our earnings from unconsolidated investments were approximately $92 million for the six months ended June 30, 2004, compared to $91 million for the six months ended June 30, 2003.

GEN. GEN s earnings from unconsolidated investments were approximately $88 million for the six months ended June 30, 2004, compared to $84 million for the six months ended June 30, 2003. Earnings from our West Coast Power investment are the primary driver of results for each of these periods. Please read Item 1. Business Segment Discussion Power Generation West region Western Electricity Coordinating Council (WECC) beginning on page 6 of our Form 10-K for further discussion of West Coast Power s CDWR contract. West Coast Power provided equity earnings of approximately $82 million for the six months ended June 30, 2004, compared to $65 million for the six months ended June 30, 2003. Earnings at West Coast Power were higher quarter over quarter due to higher realized margins resulting from hedges put in place in connection with the execution of the CDWR contract. Please read Note 9 Commitments and Contingencies Summary of Material Legal Proceedings Western Long-Term Contract Complaints for further discussion of the legal challenges to the CDWR contract.

As described above under Liquidity and Capital Resources External Liquidity Sources Asset Sale Proceeds, in January 2004, we sold our 17.55% interest in a 74 MW power generating facility located in Jamaica for $5.5 million in net aggregate proceeds. We did not recognize a gain or loss on the sale. In July 2004, we completed the sale of our 50% interest in the 424 MW Oyster Creek generating facility for approximately $79 million of net cash proceeds. This sale will result in a gain of approximately $15 million in the third quarter 2004. Also in July 2004, we sold our 50% interest in the 123 MW Michigan Power generating facility for net cash proceeds of approximately $25 million. In the six months ended June 30, 2004, we recorded impairments of approximately $8 million related to the anticipated sale of Michigan Power which offset our share of Michigan Power s earnings for the quarter. The net loss related to Michigan Power recorded in the six months ended June 30, 2004 was $2.3 million. In July 2004, we reached an agreement to sell our 50% interests in the Commonwealth and Hartwell generating facilities. The transactions, which are scheduled to close in the fourth quarter 2004 and are subject to regulatory, lender and other approvals, are not expected to result in material gains

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or losses on sale. Please read Note 5 Unconsolidated Investments for further discussion of our accounting relating to these pending sales. We are continuing to pursue opportunities to sell our interests in other domestic and international projects, none of which are considered core to our GEN business.

NGL. NGL s earnings from unconsolidated investments were approximately $4 million for the six months ended June 30, 2004, compared to $5 million for the six months ended June 30, 2003. Lower fractionation fees at our Gulf Coast Fractionator investment in 2004 contributed to this decline in earnings.

CRM. CRM s earnings from unconsolidated investments were zero for the six months ended June 30, 2004, compared to $2 million for the six months ended June 30, 2003. As of December 31, 2003, CRM had no material unconsolidated investments. As such, 2004 and future results are expected to be *de minimis*. The earnings in 2003 primarily related to our Nicor Energy joint venture, the operations of which were sold in the first half of 2003.

Interest Expense

Interest expense totaled $277 million for the six months ended June 30, 2004, compared to $219 million for the six months ended June 30, 2003. The significant increase in 2004, as compared to 2003, is primarily attributable to higher average interest rates on borrowings related to the new securities issued in connection with our August and October 2003 debt refinancings. In addition, interest expense in 2004 includes $14 million associated with deferred financing costs relating to our former credit facility, which were expensed upon the execution of our new $1.3 billion credit facility.

Other Items, Net

Other items, net consists of other income and expense items, net; minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $(3) million for the six months ended June 30, 2004, compared to $12 million for the six months ended June 30, 2003. The decrease in 2004, as compared to 2003, is primarily due to lower minority interest income.

Income Tax Benefit

We reported an income tax benefit during the six months ended June 30, 2004 of $30 million. The 2004 effective tax rate was (13)%, compared to 37% in 2003. The 2004 tax benefit includes a $47 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with anticipated gains on asset sales and a $3 million benefit related to the release of reserves upon the conclusion of prior year tax audits. Please read Note 12 Income Taxes for further discussion. Excluding these items from the 2004 calculation would result in an effective tax rate of 38%. In general, differences between these effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Discontinued Operations

Discontinued operations includes our global liquids business in the NGL segment, our U.K. natural gas storage assets and our U.K. CRM business in the CRM segment and our communications business in Other and Eliminations. The largest contributor to the pre-tax gain of $21 million ($5 million after-tax loss) for the six months ended June 30, 2004 is the U.K. CRM business, primarily due to $20 million in tax expenses related to the conclusion of prior year tax audits offset by translation gains recognized on the repatriation of cash from the U.K. Please read Note 12 Income Taxes for further discussion. The largest contributor to the pre-tax loss of $16 million ($7 million after-tax) for the six months ended June 30, 2003 is the pre-tax loss associated with the wind-down of our U.K. CRM operations.

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Cumulative Effect of Change in Accounting Principles

EITF Issue 02-03 s rescission of EITF Issue 98-10 effective January 1, 2003 is reflected as a cumulative effect of a change in accounting principle. The net impact was a pre-tax benefit of $33 million ($21 million after-tax), of which a benefit of $43 million was recognized in our CRM segment and a charge of $10 million was recognized in our GEN segment. We also adopted SFAS No. 143 effective January 1, 2003 and recognized a pre-tax benefit of $54 million ($34 million after-tax) associated with its implementation. The $54 million benefit was split between our GEN ($57 million) and REG ($(3) million) segments.

Please read Note 1 Accounting Policies for further discussion of our adoption of new accounting policies.

Preferred Stock Dividends

The $11 million preferred stock dividend recognized in the first half of 2004 is related to our Series C convertible preferred stock, which accumulates dividends at an annual rate of 5.5%. The 2003 dividend of $165 million related to the Series B preferred stock that included an implied dividend of $660 million, which was amortized over a two-year period. Please read Note 15 Redeemable Preferred Securities beginning on page F-53 of our Form 10-K/A for a description of the August 2003 exchange of the Series B preferred stock for, among other things, the Series C preferred stock, and the impact on the associated dividends.

Outlook

The following summarizes our business outlook for our four reportable segments.

GEN Outlook. This segment s future financial results will continue to reflect a sensitivity to commodity prices and weather conditions. We will continue our efforts to manage price risk through the optimization of fuel procurement and the marketing of power generated from our assets, including through forward sales and related transactions. Our sensitivity to commodity prices and our ability to manage this sensitivity is subject to a number of factors, including general market liquidity, particularly in forward years, our ability to provide necessary collateral support and the willingness of counterparties to transact business with us given our non-investment grade credit ratings. Additionally, because we seek to manage price risk through forward sales and related transactions, at times we may be unable to capture opportunities presented by rising prices.

The operation of our generation facilities is highly dependent on our ability to procure coal as a fuel. Power generators in the Midwest and the Northeast are experiencing significant pressures on available coal supplies that are either transportation or supply related. Our long-term supply and transportation agreements for our Midwest fleet mitigate most of these near-term concerns. In the Northeast, our coal supply and transportation arrangements are more short-term in nature. Accordingly, we have been accumulating coal inventories to the extent we have considered it economically justifiable and believe that our coal inventory levels in the Northeast as well as the Midwest are sufficient to operate our assets in these regions.

As discussed in Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Form 10-K, we enter into sales of capacity from our generation assets, which provide a revenue stream independent of energy sales. In late 2003 and continuing into 2004, we have seen increases in the market for capacity-related products from our peaking and intermediate generation facilities.

At the beginning of 2004, a substantial portion of our 2004 operating margin was under contract or hedged. The primary contracts included the CDWR contract held by West Coast Power and the Illinois Power power purchase agreement. Our future results of operations will be significantly impacted by our ability to extend or renew these agreements. West Coast Power, whose equity earnings are primarily derived from the CDWR contract, has been our largest contributor in terms of earnings from unconsolidated investments. If we are unable to enter into a new contract for the operation of our West Coast Power assets, earnings from the investment will be substantially reduced. This will result in a need to evaluate all strategic alternatives for our West Coast Power assets, including the option of taking certain assets out of service. Regardless of our ability to extend or enter into a new contract, the scheduled expiration of the CDWR contract in December 2004 will negatively impact the fair value of our investment in West Coast Power. As the value of the CDWR contract is realized through 2004, the fair value of our investment in West Coast Power will decline and, accordingly, we anticipate that the remaining value of the investment will be less than its book value. As a result, we will evaluate our investment quarterly and anticipate such reviews will necessitate an impairment of our investment of approximately $70 million to $80 million during the remainder of 2004. Please read Note 9 Commitments and Contingencies Summary of Material Legal Proceedings Western Long-Term Contract Complaints for further discussion of the legal challenges to the CDWR contract. Please also read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations for a discussion of our efforts to seek a renewal or replacement of the CDWR contract.

The current power purchase agreement between DMG and Illinois Power will terminate on December 31, 2004. In connection with the sale of Illinois Power to Ameren, DPM has agreed, conditioned on the closing of the sale, to enter into a two-year power purchase agreement with Ameren with expected volumes comparable to our current agreement. Under the terms of this new agreement, provided it is implemented as expected, we have agreed to provide Illinois Power with up to 2,800 MWs of capacity at $48.00 per kW-yr and up to 11.5 million MWh of energy each year at a fixed price of $30 per MWh. Under this arrangement, we would no longer be the provider of last resort for Illinois Power, which exposed us to volume and price uncertainties under the current contract. However, the structure of the new arrangement differs from the current power purchase agreement with Illinois Power. Under the current agreement, we receive contract revenues based on a higher fixed capacity payment and lower variable energy payments. Accordingly, GEN s operating income under the new agreement would be impacted more significantly by deviations from expected energy purchases by Illinois Power. We expect that any reduction in operating income under this new agreement would be mitigated by our no longer serving as the provider of last resort.

In the event the sale of Illinois Power to Ameren does not close before the end of 2004, DPM and Illinois Power will enter into an interim power purchase agreement that would take effect if the pending sale is not completed by December 31, 2004. This interim power purchase agreement was approved by the FERC in July 2004 and would remain in effect only until the earlier of the closing of the pending sale or December 31, 2006, which latter date coincides with the expiration of the retail electric rate freeze in the State of Illinois. The interim power purchase agreement, which would provide for capacity and energy to serve Illinois Power s customers through 2006 if the pending sale is not consummated, contains terms and conditions, including pricing terms, substantially similar to those contained in the Ameren power purchase agreement.

We recently sold our 50% interests in the 424 MW Oyster Creek generating facility and the 123 MW Michigan Power generating facility. In addition, we recently executed agreements to sell our 50% interests in the 310 MW Commonwealth natural gas fired peaking facility and the 310 MW Hartwell generating facility. Our investments in these four facilities, together with our investment in the Jamaica facility previously sold, contributed approximately $21 million in earnings to our full year 2003 results, exclusive of any impairment charges. Please read Note 5 Unconsolidated Investments GEN Investments for further discussion of these investments. Additionally, the pending transaction with Ameren includes the sale of our 20% interest in the Joppa generating facility, which contributed approximately $3.3 million in earnings from unconsolidated investments in our full year 2003 results. Our ability to consummate these pending sales on the terms and within the timeframes we anticipate is subject to several factors, many of which are beyond our control, including the willingness of lenders and other counterparties to consent to a proposed transaction.

NGL Outlook. The outlook for our NGL segment has remained the same from the first quarter 2004. Financial results will continue to reflect sensitivity to natural gas and natural gas liquids prices, and we expect that the pricing environment for the rest of 2004 will continue to be strong. Our upstream contract settlements under percentage of proceeds and percentage of liquids contracts will continue to benefit from these relatively high prices; our hybrid contracts, which are sensitive to frac spread, will generally revert from percentage of liquids settlements to fee settlements. Natural gas liquids production from both our own and third-party natural gas processing plants that are exposed to frac spread will continue to be reduced as frac spreads remain lower than that required to justify economical extraction of natural gas liquids in today s natural gas price environment.

The impact of these lower processing volumes is an ongoing reduction of natural gas liquids supply to our and third parties fractionation, storage and distribution infrastructure, similar to 2003. Accordingly, aggressive competition exists between fractionators for available volumes, causing a reduction in fees paid for fractionation services.

Straddle plant gas processing in the Gulf of Mexico will continue to be negatively impacted by uncertainty surrounding the determination of gas quality specifications for liquefiable hydrocarbons. Over the past several years extraction economics have been generally poor, causing pipeline companies to become increasingly concerned about heavy hydrocarbons that have been left in the natural gas entering their systems instead of being extracted. These heavy hydrocarbons cause pipeline operational and safety concerns. As a result, many have used emergency powers (operational flow orders or critical notices) to force producers to extract heavy hydrocarbons by processing their gas. While industry stakeholders respond to recent FERC decisions directing pipeline companies to address this issue in their tariff, there is a significant lack of clarity around when and where processing is required. The result is a patchwork of pipeline policies and practices, leaving producers and processors without clearly defined ground rules. As a result, contracting gas and planning straddle plant operations are difficult. Resolution of the issue is currently being pursued through the Natural Gas Council, FERC and other affected stakeholders.

Drilling rig rates for natural gas throughout our core processing areas in New Mexico, West Texas, North Texas and offshore Louisiana continue to increase, consistent with natural gas prices that have averaged $5 $6/MMBtu. Continued exploration and production at these levels will benefit our upstream business by providing additional volumes for gathering and processing. If natural gas prices were to decline in the future, resulting in reduced drilling activities, this segment s results could be adversely affected.

While we have not experienced significant turnover in customer contracts as a result of our non-investment grade credit ratings, we have been required to provide collateral or other adequate assurance of our obligations in connection with many of our commercial relationships. On occasion, we have been unable to satisfy efficiently a potential new customer s concerns about our credit ratings. We expect similar collateral requirements until such time as our credit ratings measurably improve. Our ability to hedge future natural gas liquids production during 2004 will again be limited by reduced market liquidity and our obligation to post collateral.

We intend to continue our aggressive North Texas gathering system expansion, where additional compression and plant debottlenecking are expected to add volumes to our expanded Chico gas processing plant. We also intend to continue to review our asset portfolio to maximize return on investment. We have identified and sold a few assets that are not strategic to our core operations, including our interests in Hackberry LNG and Indian Basin. We may pursue sales of other assets if the price is sufficient to mitigate the anticipated impact on future earnings. Please see Liquidity and Capital Resources External Liquidity Sources Asset Sale Proceeds for further discussion.

REG Outlook. Future results of operations for the REG segment may be affected, either positively or negatively, by regulatory actions (with respect to rates or otherwise), general economic conditions, weather and customers choosing to utilize competitive alternate service providers. Also, the effects of the REG segment on our consolidated results of operations will be significantly impacted by our ability to consummate the pending sale of Illinois Power to Ameren. Additionally, we may record incremental impairments in this segment approximating $40 million to $50 million during the remainder of 2004. The amount of such impairments depends on various factors, including the timing of the closing of the transaction, capital expenditures prior to closing and other matters.

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In June 2004, Illinois Power filed with the ICC seeking authority to raise its natural gas delivery rates by approximately $40 million annually, or about $5.85 per month, for the average residential gas customer. The requested increase will allow Illinois Power to recover investments in its natural gas delivery system which include upgrades in gas storage facilities and transmission lines, installation of more than 600 miles of new transmission and distribution lines, and increases in computer and telecommunications capabilities. The requested increase applies only to base rates and does not affect the cost of gas itself, which typically accounts for about two-thirds of customers total gas bills and is recovered via the PGA process. As part of the regulatory process, which can be expected to take up to eleven months, the ICC will decide the amount of increase, if any, to provide recovery of costs from Illinois Power customers. If approved by the ICC, the new rates will go into effect in spring 2005, after the expected close of the sale of Illinois Power to Ameren.

With no alternate suppliers certified by the ICC to provide residential electric service pursuant to the Customer Choice Law, Illinois Power does not expect to experience any residential customer switching in 2004. In the second quarter 2004, less than 1% and 35.7% of our commercial and industrial loads, respectively, were served by other energy providers. We anticipate that by the end of 2004, approximately 38% of our industrial load will have been served by alternate energy providers. We anticipate that incremental switching to alternate energy providers by our commercial customers will be minimal. Actual switching will be influenced in part by market based energy prices, plus any delivery charges, relative to bundled and PPO offerings, that Illinois Power is required to provide.

Beyond 2004, this segment s results will be impacted by changes in costs for capacity and energy to serve its load. Please read Outlook GEN Outlook above for a discussion of the capacity and energy arrangements being pursued relative to the closing of the pending sale to Ameren. Any capacity and energy needs not met by this agreement would be secured from either existing agreements, through a competitive purchasing process or, in limited circumstances, through open market purchases.

CRM Outlook. Our CRM business future results of operations will be significantly impacted by our ability to complete our exit from this business. Although we were successful in reaching agreements to exit four of our natural gas transportation agreements this quarter, the CRM segment remains comprised primarily of four power tolling arrangements, as well as gas transportation agreements and legacy power and gas trading positions. Although our Gregory tolling arrangement expires by its terms in July 2005, our other three tolling arrangements extend through 2012 to 2017. We are exploring opportunities to assign or renegotiate the terms of some of these arrangements, but we cannot guarantee that we will be successful. If we do not renegotiate or terminate these remaining arrangements, they will continue to negatively impact our near- and long-term earnings and cash flows based on the current pricing environment. Any renegotiation or termination of these long-term contracts would likely result in significant cash payments and a charge to earnings in the applicable period. For a discussion of our annual and long-term obligations under these arrangements, please read Disclosure of Contractual Obligations and Contingent Financial Commitments and Item 1. Business Segment Discussion Customer Risk Management beginning on page 18 of our Form 10-K.

The earnings of the CRM segment may also be significantly impacted, either positively or negatively, by mark-to-market changes in the value of a derivative contract associated with the Sithe Independence tolling agreement as power and gas prices change.

As of July 30, 2004, we have posted approximately $174 million of collateral associated with this business. Approximately $15 million of this balance relates to our tolling arrangements. The remaining $159 million is related to our ABG Gas Supply financing contract and our legacy gas and power trading positions, which collateral will be substantially eliminated by 2007.

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Cash Flow Disclosures

The following table presents operating cash flows by reportable segment and includes cash flows from our discontinued operations, which are disclosed on a net basis in loss from discontinued operations, net of tax, in the condensed consolidated statements of operations:

	GEN	NGL	REG	CRM	Other & Eliminations	Consolidated
				(in millions)		
For the six-months ended June 30, 2004	$ 200	$ 170	$ 181	$ (182)	$ (308)	$ 61
For the six-months ended June 30, 2003	$ 141	$ 38	$ 87	$ 372	$ (198)	$ 440

Operating Cash Flow. Our net cash provided by operating activities totaled $61 million for the six months ended June 30, 2004. During the period, our GEN, NGL and REG segments provided positive cash flow from operations. GEN provided cash flow from operations of $200 million due primarily to positive earnings for the period, partially offset by increased cash collateral posted in lieu of letters of credit; NGL provided cash flow from operations of $170 million due primarily to positive earnings and seasonality of the wholesale business for the period; and REG provided cash flow from operations of $181 million due primarily to positive earnings for the period and the withdrawals of gas in storage. Our CRM segment used approximately $182 million in cash due primarily to fixed payments associated with the power tolling arrangements and related gas transportation agreements, increased cash collateral posted in lieu of letters of credit and our exit from four long-term natural gas transportation contracts. Other and eliminations includes a use of approximately $308 million in cash due primarily to interest payments to service debt, settlement payments and general and administrative expenses.

Our net cash provided by operating activities totaled $440 million for the six months ended June 30, 2003. Cash provided in 2003 primarily relates to collateral returns, settlements of risk management assets and sales of natural gas in storage from our CRM business, a $110 million income tax refund reflected in Other and the operational performances of our GEN, NGL and REG segments. Our GEN segment provided cash flows of $141million largely due to strong commodity prices. Similarly, our NGL segment contributed cash flows from operations of $38 million due to increasing commodity prices, which benefited our upstream and marketing businesses, offset by higher prepayments. Our REG segment contributed operating cash flows of $87 million, primarily from normal operating conditions and withdrawals of gas from storage. General and administrative costs and continued extinguishment of liabilities during our exit from our communications business partially offset these positive operational cash flows during the six months ended June 30, 2003.

Capital Expenditures and Investing Activities. Net cash used in investing activities during the six months ended June 30, 2004 totaled $70 million. Capital spending of $151 million was comprised primarily of $58 million, $27 million and $61 million in the GEN, NGL and REG segments, respectively. The capital spending for our GEN segment related primarily to maintenance capital projects. Capital spending in our NGL segment related primarily to maintenance capital projects and wellconnects, as well as approximately $5 million on a gathering system expansion. Capital spending in our REG segment related primarily to projects intended to maintain system reliability and new business services. Proceeds from asset sales included primarily $17 million in proceeds from the sale of our remaining financial interest in the Hackberry LNG project, $48 million from the sale of Indian Basin, $9 million from the sale of PESA and approximately $5.5 million from the sale of our interest in a power generating facility located in Jamaica.

Net cash used in investing activities during the six months ended June 30, 2003 totaled $156 million. Capital spending of $189 million was comprised principally of $93 million, $25 million and $68 million in our GEN, NGL and REG segments, respectively, representing primarily improvements to our existing asset base. The capital spending for our GEN segment included approximately $31 million spent on the construction of Rolling Hills, with respect to which commercial operation began in June 2003. Proceeds from asset sales included primarily $20 million from the sale of SouthStar and $20 million from the sale of our ownership interest in the Hackberry LNG project, offset by $10 million in cash outflows associated with the sale of our European communications business.

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Financing Activities. Net cash provided by financing activities during the six months ended June 30, 2004 totaled $370 million. The cash provided was due primarily to proceeds from a new $600 million secured term loan, net of issuance costs of $19 million, which was offset partially by repayments of long-term debt. Repayments of long-term debt totaled $193 million for the six months ended June 30, 2004 and consisted of the following: (1) payments of $95 million on a maturing series of Illinova senior notes; (2) payments of $43 million on Illinois Power s transitional funding trust notes; (3) payments of $39 million under our ABG Gas Supply financing; and (4) payments of $16 million on the ChevronTexaco junior notes. Net cash provided by financing activities was also offset by a semi-annual dividend payment of $11 million on our Series C preferred stock.

Net cash used in financing activities during the six months ended June 30, 2003 totaled $247 million. During the six months ended June 30, 2003, we repaid $128 million, net, under our revolving credit facilities. Long-term debt proceeds, net of issuance costs, for the six months ended June 30, 2003 consisted of $142 million from the delayed issuance of $150 million in Illinois Power 11.5% Mortgage Bonds due 2010 and $159 million from the Term A Loan drawn in connection with the April 2, 2003 credit facility restructuring. Repayments of long-term debt totaled $425 million for the six months ended June 30, 2003 and consisted of the following: (1) payments of $200 million under the Renaissance and Rolling Hills interim financing; (2) payments of $100 million on Illinois Power s term loan; (3) payments of $43 million on Illinois Power s transitional funding trust notes; (4) payments of $41 million under the Black Thunder secured financing; (5) payments of $36 million under our ABG Gas Supply financing; and (6) purchase of $5 million of Illinova senior notes on the open market.

RISK-MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk-management data on the unaudited condensed consolidated balance sheets, statements of operations and statements of cash flows:

	As of and for the Six Months Ended June 30, 2004 (in millions)	
Balance Sheet Risk-Management Accounts		
Fair value of portfolio at January 1, 2004	$	(137)
Risk-management gains recognized through the income statement in the period, net		27
Cash paid related to risk-management contracts settled in the period, net		47
Changes in fair value as a result of a change in valuation technique (1)		
Non-cash adjustments and other (2)		(85)
Fair value of portfolio at June 30, 2004	$	(148)
Income Statement Reconciliation		
Risk-management gains recognized through the income statement in the period, net	$	27
Physical business recognized through the income statement in the period, net (3)		45
Non-cash adjustments and other		(5)
Net recognized operating income	$	67
Cash Flow Statement		
Cash paid related to risk-management contracts settled in the period, net	$	(47)
Estimated cash received related to physical business settled in the period, net (3)		45
Timing and other, net (4)		25

Cash received during the period	$	23
Risk-Management cash flow adjustment for the six months ended June 30, 2004 (5)	$	(44)

(1) Our modeling methodology has been consistently applied.
(2) This amount primarily consists of changes in value associated with cash flow hedges on forward power sales.

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(3) This amount includes the $88 million gain recognized by our exit from four gas transportation contracts offset by capacity payments on our power tolling arrangements.
(4) This amount consists primarily of cash received in connection with the settlement of cash flow hedges.
(5) This amount is calculated as Cash received during the period less Net recognized operating income.

The net risk management liability of $148 million is the aggregate of the following line items on the 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 tables depict the mark-to-market value and cash flow components of our net risk-management assets and liabilities at June 30, 2004 and December 31, 2003:

Mark-to-Market Value of Net Risk-Management Assets (1)

	Total	2004(2)	2005	2006	2007	2008	Thereafter
				(in millions)			
June 30, 2004	$ (102)	$ (5)	$ (8)	$ (12)	$ (40)	$ (15)	$ (22)
December 31, 2003	(144)	(22)	(17)	(25)	(39)	(12)	(29)
Increase (decrease)	$ 42	$ 17	$ 9	$ 13	$ (1)	$ (3)	$ 7

(1) The table reflects the fair value of our risk-management asset position, which considers time value, credit, price and other reserves necessary to determine fair value. These amounts exclude the fair value associated with certain derivative instruments designated as hedges. The net risk-management liabilities at June 30, 2004 of $148 million on the unaudited condensed consolidated balance sheets include the $102 million herein as well as hedging instruments. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.
(2) Amounts represent July 1 to December 31, 2004 values in the June 30, 2004 row and January 1 to December 31, 2004 values in the December 31, 2003 row.

Cash Flow Components of Net Risk-Management Assets

	Six Months Ended June 30, 2004	Six Months Ended December 31, 2004	Total 2004	2005	2006	2007	2008	Thereafter
				(in millions)				
June 30, 2004 (1)	$ (14)	$ (3)	$ (17)	$ (7)	$ (11)	$ (44)	$ (17)	$ (28)
December 31, 2003			(17)	(14)	(24)	(43)	(15)	(39)
Increase (Decrease)			$	$ 7	$ 13	$ (1)	$ (2)	$ 11

(1) The cash flow values for 2004 reflect realized cash flows for the six months ended June 30, 2004 and anticipated undiscounted cash inflows and outflows by contract based on the tenor of individual contract position for the remaining periods. These anticipated undiscounted cash flows have not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges.

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The following table provides an assessment of net contract values by year as of June 30, 2004, based on our valuation methodology:

Net Fair Value of Risk-Management Portfolio

	Total	2004	2005	2006	2007	2008	Thereafter
				(in millions)			
Market Quotations (1)	$ (58)	$ (5)	$ (8)	$ (12)	$ (28)	$ (5)	$
Prices Based on Models	(44)				(12)	(10)	(22)
Total	$ (102)	$ (5)	$ (8)	$ (12)	$ (40)	$ (15)	$ (22)

(1) Prices obtained from actively traded, liquid markets for commodities other than natural gas positions. All natural gas positions for all periods are contained in this line based on available market quotations.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-Q/A 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, e other words of similar meaning. In particular, these include, but are not limited to, statements relating to the following:

- projected operating or financial results, include anticipated cash flows from operations and asset sale proceeds for 2004;
- expectations regarding capital expenditures, interest expense and other payments;
- our ability to execute the cost-savings measures we have identified;
- our beliefs and assumptions relating to our liquidity position, including our ability to satisfy or refinance our significant debt maturities and other obligations before or as they come due;
- our ability to access the capital markets as and when needed;
- our ability to address our substantial leverage;

- our ability to compete effectively for market share with industry participants;

- beliefs about the outcome of legal and administrative proceedings, including matters involving the western power and natural gas markets, shareholder claims and environmental and master netting agreement matters, as well as the investigations primarily relating to Project Alpha and our past trading practices;

- our ability to consummate the disposition of specified non-strategic assets on the terms and in the timeframes anticipated, particularly the agreed upon sale of Illinois Power to Ameren; and

- our ability to complete our exit from the CRM business and the costs associated with this exit.

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 including, among others:

- the timing and extent of changes in weather and commodity prices, including the relationships between prices for power and natural gas or other power generating fuels, commonly referred to as the spark spread, and the frac spread;

the effects of competition in our asset-based business lines;

the effects of the proposed sale of specified non-strategic assets, particularly the agreed upon sale of Illinois Power to Ameren;

our ability to renew or replace West Coast Power s CDWR power purchase agreement;

the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions, and our ability to engage in capital-raising transactions;

our financial condition, including our ability to satisfy our significant debt maturities and debt service obligations;

our ability to realize our significant deferred tax assets, including loss carryforwards;

the effectiveness of our risk-management policies and procedures and the ability of our counterparties to satisfy their financial commitments;

the liquidity and competitiveness of wholesale trading markets for energy commodities, particularly natural gas, electricity and natural gas liquids;

operational factors affecting the start up or ongoing commercial operations of our power generation, natural gas and natural gas liquids and regulated energy delivery facilities, including catastrophic weather-related damage, regulatory approvals, permit issues, unscheduled blackouts, outages or repairs, unanticipated changes in fuel costs or availability of fuel emission credits, the unavailability of gas transportation and the unavailability of electric transmission service or workforce issues;

increased interest expense and the other effects of our 2003 restructuring and refinancing transactions, including the security arrangements and restrictive covenants contained in the related financing agreements;

counterparties collateral demands and other factors affecting our liquidity position and financial condition;

our ability to operate our businesses efficiently, manage capital expenditures and costs (including general and administrative expenses) tightly and generate earnings and cash flow from our asset-based businesses in relation to our substantial debt and other obligations;

the direct or indirect effects on our business of any further downgrades in our credit ratings (or actions we may take in response to changing credit ratings criteria), including refusal by counterparties to enter into transactions with us and our inability to obtain credit or capital in amounts or on terms that are considered favorable;

the costs and other effects of legal and administrative proceedings, settlements, investigations and claims, including legal proceedings related to the western power and natural gas markets, shareholder claims, claims arising out of the CRM business and environmental liabilities that may not be covered by indemnity or insurance, as well as the FERC, U.S. Attorney and other similar investigations primarily surrounding Project Alpha and our past trading practices;

the effects of our ongoing efforts to improve our internal control structure, particularly with respect to those matters discussed under Item 4 Controls and Procedures, and to achieve compliance with Section 404 of Sarbanes-Oxley within the prescribed period;

other North American regulatory or legislative developments that affect the regulation of the electric utility industry, the demand and pricing for energy generally, increase in the environmental compliance cost for our facilities or that impose liabilities on the owners of such facilities; and

general political conditions and developments in the United States and in foreign countries whose affairs affect our asset-based businesses including any extended period of war or conflict.

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In addition, there may be other factors that could cause our actual results to be materially different from the results referenced in the forward-looking statements, some of which are included elsewhere in this Form 10-Q/A. Many of these factors will be important in determining our actual future results. Consequently, no forward-looking statement can be guaranteed. Our actual future results may vary materially from those expressed or implied in any forward-looking statements.

All forward-looking statements contained in this Form 10-Q/A are qualified in their entirety by this cautionary statement. Forward-looking statements speak only as of the date they are made, and we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this Form 10-Q/A, except as otherwise required by applicable law.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 to the unaudited condensed consolidated financial statements for a discussion of recently issued accounting pronouncements affecting us. Specifically, we adopted certain provisions of FIN No. 46R on March 31, 2004.

CRITICAL ACCOUNTING POLICIES

Please read Critical Accounting Policies beginning on page 40 of our Form 10-K/A for a complete description of our critical accounting policies, with respect to which there have been no material changes since the filing of our Form 10-K.

Item 4 CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. Effective as of the end of the second quarter 2004, 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 Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified by the SEC. This evaluation also considered the work completed as of the end of the second quarter 2004 relating to our efforts to achieve compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which is further described below. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective at the reasonable assurance level and designed to ensure that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the requisite time periods. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of our internal controls performed during the second quarter 2004 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

During the second and third quarter 2004, we identified deficiencies in our internal controls over financial reporting, including matters relating to system access and system implementation controls, segregation of duties and documentation of controls and procedures and their effective operation and monitoring. We have also identified deficiencies in our tax accounting and tax reconciliation controls and processes that make this an area of particular focus. These deficiencies contributed to an error in our second quarter 2004 earnings news release relating to the classification of a $13 million income tax benefit between continuing operations and discontinued

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operations. For further discussion of this error, which was identified after the issuance of our second quarter 2004 earnings news release and was corrected in the Original Filing, please read Note 8 Earnings (Loss) per Share. Additionally, in the third quarter 2004, we determined that adjustments related to our deferred income tax accounts in periods prior to 2004 were required. We identified these deficiencies and promptly brought them to the attention of our audit and compliance committee and independent auditors. Accordingly, in this Form 10-Q/A, we have restated our unaudited condensed consolidated financial statements. For further information, please see the Explanatory Note beginning on page 9. We believe we have addressed these tax deficiencies, by taking the following steps to improve our internal controls around our tax accounting and tax reconciliation controls and processes:

- Increased the levels of review in the preparation of the quarterly and annual tax provision;
- Formalized processes, procedures and documentation standards; and
- Restructured our Tax Department to ensure segregation of duties regarding preparation and review of the quarterly and annual tax provision.

Beginning with the year ending December 31, 2004, Section 404 of the Sarbanes-Oxley Act of 2002 requires us to provide an annual internal controls report of management. This report must contain (i) a statement of management s responsibility for establishing and maintaining adequate internal controls over financial reporting for our company, (ii) a statement identifying the framework used by management to conduct the required evaluation of the effectiveness of our internal controls over financial reporting, (iii) management s assessment of the effectiveness of our internal controls over financial reporting as of the end of our most recent fiscal year, including a statement as to whether or not our internal controls over financial reporting are effective, and (iv) a statement that our independent auditors have issued an attestation report on management s assessment of our internal controls over financial reporting. Additionally, Section 404 requires that our independent auditors attest to and report on management s assessment of our internal controls over financial reporting. In seeking to achieve compliance with Section 404 within the prescribed period, management formed a steering committee to oversee our efforts to comply with Section 404, engaged outside consultants and adopted and implemented a detailed project work plan to assess the adequacy of our internal controls over financial reporting, remediate any control weaknesses that may be identified, validate through testing that controls are functioning as documented and implement a continuous reporting and improvement process for internal controls over financial reporting.

Additionally, the Public Company Accounting Oversight Board recently adopted very stringent standards governing management s required evaluation of its internal controls over financial reporting and the independent auditors review of those controls and management s evaluation thereof. These standards will likely result in a significant number of companies, which may include Dynegy, identifying significant deficiencies and/or material weaknesses in their internal controls. Indeed, the items referenced in the preceding paragraphs could preclude our independent auditors from delivering an unqualified opinion on internal controls under Section 404 of Sarbanes-Oxley.

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DYNEGY INC.

PART II. OTHER INFORMATION

Item 6 EXHIBITS AND REPORTS ON FORM 8-K

(a) The following documents are included as exhibits to this Form 10-Q/A:

10.1	Amended and Restated Credit Agreement dated as of May 28, 2004 among Dynegy Holdings Inc., as Borrower, Dynegy Inc., as Parent Guarantor, the Other Guarantors Party Thereto, the Lenders Party Thereto and Various Other Parties Thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2004, File No. 1-15659).
*10.2	Amendment No. 1 to Collateral Trust and Intercreditor Agreement, dated as of May 28, 2004, among Dynegy Holdings Inc., various grantors named therein, JPMorgan Chase Bank, as collateral agent, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee.
+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.

+ Filed herewith.

* Previously filed.

** 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.

(b) Reports on Form 8-K of Dynegy Inc. filed during the second quarter 2004:

1. We filed a Current Report on Form 8-K on April 2, 2004. Item 5 was reported and no financial statements were filed.

2. We filed a Current Report on Form 8-K on April 27, 2004. Items 5 and 7 were reported and no financial statements were filed.

3. We filed a Current Report on Form 8-K on April 28, 2004. Items 7 and 12 were reported and no financial statements were filed.

4. We filed a Current Report on Form 8-K on May 21, 2004. Items 5 and 7 were reported and no financial statements were filed.

5. We filed a Current Report on Form 8-K on June 1, 2004. Items 5 and 7 were reported and no financial statements were filed.

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DYNEGY INC.

SIGNATURES

Pursuant to the requirements 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: January 19, 2005

By: /s/ NICK J. CARUSO

Nick J. Caruso

Executive Vice President and Chief Financial Officer

(Duly Authorized Officer and Principal Financial Officer)

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