UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q/A

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D)

OF THE SECURITIES EXCHANGE ACT OF 1934

For Quarter Ended June 30, 2004

Commission File Number 1-4928

DUKE ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

North Carolina	**56-0205520**
(State or Other Jurisdiction of Incorporation)	**(IRS Employer Identification No.)**

526 South Church Street

Charlotte, NC 28202-1803

(Address of Principal Executive Offices)

(Zip code)

704-594-6200

(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 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 Securities Exchange Act of 1934). Yes x No ¨

Indicate the number of shares outstanding of each of the Issuer s classes of common stock, as of the latest practicable date.

Number of shares of Common Stock, without par value, outstanding as of July 30, 2004 937,782,753

Explanatory Note

This Amendment No. 1 to the Quarterly Report on Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2004 is being filed for the purpose of amending and revising Item 1 of Part I. This Form 10-Q/A is being filed in order to correct data input errors within the Consolidated Statements of Cash Flows. These revisions did not affect net cash provided by operating activities, net cash used in investing activities, net cash used in financing activities or cash and cash equivalents.

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DUKE ENERGY CORPORATION

FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2004

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SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Duke Energy Corporation s reports, filings and other public announcements may contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as may, will, could, project, believe, anticipate, expect, estimate, continue, potential, plan, forecast and other similar words. Those statemen Energy s intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors. Many of those factors are outside Duke Energy s control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. Those factors include:

State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries

The outcomes of litigation and regulatory investigations, proceedings or inquiries

Industrial, commercial and residential growth in Duke Energy s service territories

The weather and other natural phenomena

The timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates

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General economic conditions, including any potential effects arising from terrorist attacks and any consequential hostilities or other hostilities

Changes in environmental and other laws and regulations to which Duke Energy and its subsidiaries are subject or other external factors over which Duke Energy has no control

The results of financing efforts, including Duke Energy s ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy s credit ratings and general economic conditions

Lack of improvement or further declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy s defined benefit pension plans

The level of creditworthiness of counterparties to Duke Energy s transactions

The amount of collateral required to be posted from time to time in Duke Energy s transactions

Growth in opportunities for Duke Energy s business units, including the timing and success of efforts to develop domestic and international power, pipeline, gathering, processing and other infrastructure projects

The performance of electric generation, pipeline and gas processing facilities

The extent of success in connecting natural gas supplies to gathering and processing systems and in connecting and expanding gas and electric markets

The effect of accounting pronouncements issued periodically by accounting standard-setting bodies and

Conditions of the capital markets and equity markets during the periods covered by the forward-looking statements

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements.***

DUKE ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In millions, except per-share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003 (as Revised - see Note 1)	2004	2003 (as Revised - see Note 1)
Operating Revenues				
Non-regulated electric, natural gas, natural gas liquids and other	$ 3,453	$ 3,394	$ 6,909	$ 7,406
Regulated electric	1,272	1,122	2,523	2,401
Regulated natural gas	635	636	1,617	1,515
Total operating revenues	5,360	5,152	11,049	11,322
Operating Expenses				
Natural gas and petroleum products purchased	2,594	2,664	5,626	6,156
Operation, maintenance and other	837	881	1,628	1,555
Fuel used in electric generation and purchased power	607	369	1,171	917
Depreciation and amortization	421	438	857	869
Property and other taxes	125	134	279	274
Total operating expenses	4,584	4,486	9,561	9,771
Gains on Sales of Investments in Commercial and Multi-Family Real Estate	62	9	121	11
(Losses) Gains on Sales of Other Assets, net	(11)	1	(349)	3
Operating Income	827	676	1,260	1,565
Other Income and Expenses				
Equity in earnings of unconsolidated affiliates	43	16	77	50
Gains on sales of equity investments		219		233
Other income and expenses, net	46	60	71	86

Total other income and expenses	89	295	148	369
Interest Expense	337	325	693	651
Minority Interest Expense	41	50	79	100
Earnings From Continuing Operations Before Income Taxes	538	596	636	1,183
Income Tax Expense from Continuing Operations	133	195	166	390
Income From Continuing Operations	405	401	470	793
Discontinued Operations				
Net operating (loss) income, net of tax	(3)	17	4	20
Net gain (loss) on dispositions, net of tax	30	6	269	(2)
Income From Discontinued Operations	27	23	273	18
Income Before Cumulative Effect of Change in Accounting Principle	432	424	743	811
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest				(162)
Net Income	432	424	743	649
Dividends and Premiums on Redemption of Preferred and Preference Stock	3	7	5	10
Earnings Available For Common Stockholders	$ 429	$ 417	$ 738	$ 639
Common Stock Data				
Weighted-average shares outstanding				
Basic	926	902	919	899
Diluted	928	903	921	900
Earnings per share (from continuing operations)				
Basic	$ 0.43	$ 0.44	$ 0.50	$ 0.87
Diluted	$ 0.43	$ 0.44	$ 0.50	$ 0.87
Earnings per share (from discontinued operations)				
Basic	$ 0.03	$ 0.02	$ 0.30	$ 0.02
Diluted	$ 0.03	$ 0.02	$ 0.30	$ 0.02
Earnings per share (before cumulative effect of change in accounting principle)				
Basic	$ 0.46	$ 0.46	$ 0.80	$ 0.89
Diluted	$ 0.46	$ 0.46	$ 0.80	$ 0.89
Earnings per share				
Basic	$ 0.46	$ 0.46	$ 0.80	$ 0.71
Diluted	$ 0.46	$ 0.46	$ 0.80	$ 0.71
Dividends per share	$ 0.550	$ 0.550	$ 0.825	$ 0.825

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)

	June 30, 2004	December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,696	$ 1,160
Receivables (net of allowance for doubtful accounts of $223 at June 30, 2004 and $280 at December 31, 2003)	2,982	2,888
Inventory	837	941
Assets held for sale	113	424
Unrealized gains on mark-to-market and hedging transactions	1,346	1,566
Other	604	694
Total current assets	8,578	7,673
Investments and Other Assets		
Investments in unconsolidated affiliates	1,331	1,398
Nuclear decommissioning trust funds	1,243	925
Goodwill	3,855	3,962
Notes receivable	244	260
Unrealized gains on mark-to-market and hedging transactions	1,632	1,857
Assets held for sale	692	1,444
Investments in residential, commercial and multi-family real estate (net of accumulated depreciation of $28 at June 30, 2004 and $32 at December 31, 2003)	1,228	1,331
Other	840	1,117
Total investments and other assets	11,065	12,294
Property, Plant and Equipment		
Cost	45,530	46,009
Less accumulated depreciation and amortization	12,800	12,139
Net property, plant and equipment	32,730	33,870
Regulatory Assets and Deferred Debits		
Deferred debt expense	317	275
Regulatory assets related to income taxes	1,175	1,152
Other	962	939
Total regulatory assets and deferred debits	2,454	2,366
Total Assets	$ 54,827	$ 56,203

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)

	June 30, 2004	December 31, 2003
LIABILITIES AND COMMON STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 2,112	$ 2,317
Notes payable and commercial paper	437	130
Taxes accrued	398	14
Interest accrued	309	304
Liabilities associated with assets held for sale	44	651
Current maturities of long-term debt	1,535	1,200
Unrealized losses on mark-to-market and hedging transactions	1,147	1,283
Other	1,826	1,799
Total current liabilities	7,808	7,698
Long-term Debt, including debt to affiliates of $258 at June 30, 2004 and $876 at December 31, 2003	19,181	20,622
Deferred Credits and Other Liabilities		
Deferred income taxes	4,315	4,120
Investment tax credit	159	165
Unrealized losses on mark-to-market and hedging transactions	1,415	1,754
Liabilities associated with assets held for sale		737
Other	5,586	5,524
Total deferred credits and other liabilities	11,475	12,300
Commitments and Contingencies		
Minority Interests	1,674	1,701
Preferred and preference stock without sinking fund requirements	134	134
Common Stockholders Equity		
Common stock, no par, 2 billion shares authorized; 938 million and 911 million shares outstanding at June 30, 2004 and December 31, 2003, respectively	10,492	9,519
Retained earnings	4,053	4,060
Accumulated other comprehensive income	10	169
Total common stockholders equity	14,555	13,748
Total Liabilities and Common Stockholders Equity	$ 54,827	$ 56,203

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)

	Six Months Ended June 30,	
	2004	**2003**
		(as Revised - see Note 1)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 743	$ 649
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization (including amortization of nuclear fuel)	943	972
Cumulative effect of change in accounting principle		162
Gains on sales of investments in commercial and multi-family real estate	(121)	(11)
Losses (gains) on sales of equity investments and other assets	64	(239)
Deferred income taxes	76	24
Purchased capacity levelization	100	97
(Increase) decrease in		
Net realized and unrealized mark-to-market and hedging transactions	150	(42)
Receivables	(50)	446
Inventory	104	(72)
Other current assets	171	(196)
Increase (decrease) in		
Accounts payable	(293)	(284)
Taxes accrued	452	487
Other current liabilities	(18)	208
Capital expenditures for residential real estate	(138)	(76)
Cost of residential real estate sold	80	50
Other, assets	(41)	(188)
Other, liabilities	120	(163)
Net cash provided by operating activities	2,342	1,824
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital and investment expenditures, net of refund	(1,318)	(1,413)
Net proceeds from the sales of equity investment and other assets, and sales of and collections on notes receivable	718	1,279
Proceeds from the sales of commercial and multi-family real estate	303	47
Other	(102)	(51)
Net cash used in investing activities	(399)	(138)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the		
Issuance of long-term debt	112	1,707

Issuance of common stock and common stock related to employee benefit plans	947	150
Payments for the redemption of		
Long-term debt	(1,138)	(1,427)
Guaranteed preferred beneficial interests in subordinated notes		(250)
Preferred stock of a subsidiary	(76)	
Notes payable and commercial paper	297	(710)
Distributions to minority interests	(703)	(1,484)
Contributions from minority interests	638	1,467
Dividends paid	(526)	(524)
Other	2	10
Net cash used in financing activities	(447)	(1,061)
Changes in cash and cash equivalents associated with assets held for sale	40	
Net increase in cash and cash equivalents	1,536	625
Cash and cash equivalents at beginning of period	1,160	857
Cash and cash equivalents at end of period	$ 2,696	$ 1,482
Supplemental Disclosures		
Significant non-cash transactions:		
Non-cash proceeds related to sale of Asia-Pacific operations	$ 838	$
Dividends declared but not paid	258	249
Proceeds from remarketing of Equity Units for senior notes	875	

See Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation

Nature of Operations and Basis of Consolidation. Duke Energy Corporation (collectively with its subsidiaries, Duke Energy), is a leading energy company located in the Americas with a real estate subsidiary. The Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Duke Energy and all majority-owned subsidiaries, and those variable interest entities where Duke Energy is the primary beneficiary. The Consolidated Financial Statements also reflect Duke Energy s 12.5% undivided interest in the Catawba Nuclear Station.

These Consolidated Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to fairly present Duke Energy s financial position and results of operations. Amounts reported in the interim Consolidated Statements of Operations are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, the timing of maintenance on electric generating units, changes in mark-to-market valuations, changing commodity prices and other factors. These Consolidated Financial Statements and other information included in this quarterly report should be read in conjunction with the Consolidated Financial Statements and Notes in Duke Energy s Form 10-K/A for the year ended December 31, 2003.

Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, management makes estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management s best available knowledge at the time, actual results could differ.

Income Tax Expense. The effective income tax rate was 25% for the three months and 26% for the six months ended June 30, 2004, compared to 33% in the prior year periods. The decreased rates were due primarily to the reversal of $52 million of state and federal income tax reserves. These reserves were released in the second quarter of 2004 due to the resolution of various income tax positions taken by Duke Energy and changes in estimates.

Reclassifications and Revisions. In 2004, Duke Energy elected to change its business segments to present Crescent as a separate segment. In connection with this change, management determined that revisions were required to reclassify certain financial statement line items related to Crescent s activities. In Duke Energy s Quarterly Report on Form 10-Q for June 30, 2003, the cash outflows related to Crescent s purchases of commercial, residential and multi-family real estate were presented as a component of capital expenditures within cash flows from investing activities. The proceeds from the sales of these properties, as well as proceeds from the sales of legacy land, were shown as part of the reconciliation of net income to net cash flows from operating activities, and thus included in cash flows from operating activities.

Duke Energy has since determined that the cash inflows and outflows from Crescent s purchases and sales of commercial and multi-family properties, as well as the proceeds from the sales of legacy land, should be presented as a component of cash flows from investing activities. All cash inflows and outflows related to Crescent s residential properties should be presented on a net basis within cash flows from operating activities, whereas in past presentations, only the inflows were presented within cash flows from operating activities. As a result of the change, net cash provided by operating activities decreased by $123 million from $1,947 million to $1,824 million and net cash used in investing activities decreased by $123 million from $261 million to $138 million in the June 30, 2003 Consolidated Statement of Cash Flows.

Also in Duke Energy s Quarterly Report on Form 10-Q for June 30, 2003, all proceeds from sales of real estate by Crescent were reported in revenues and the cost basis for all properties sold was included in operation and maintenance expenses in the Consolidated Statements of Operations. Consistent with the change in presentation noted

above for the Consolidated Statements of Cash Flows, Duke Energy has determined that amounts related to the purchases and sales of commercial and multi-family real estate, as well as the sales proceeds and underlying cost of legacy land, should be presented in the Consolidated Statements of Operations as Gains on Sales of Investments in Commercial and Multi-Family Real Estate of $9 million for the three months and $11 million for the six months ended June 30, 2003, rather than presented in revenues, and operation and maintenance expenses. As a result of this change, total operating revenues decreased by $38 million, from $5,190 million to $5,152 million, for the three months and $40 million, from $11,362 million to $11,322 million, for the six months ended June 30, 2003, and total operating expenses decreased by $29 million, from $4,515 million to $4,486 million, for the three months and $29 million, from $9,800 million to $9,771 million, for the six months ended June 30, 2003.

Also included in the reclassified amounts are increases to both Non-Regulated Electric, Natural Gas, Natural Gas Liquids and Other revenues, and to Natural Gas and Petroleum Products Purchased of $223 million for the three months and $459 million for the six months ended June 30, 2003, related to the Field Services segment.

Some prior period amounts have been reclassified to conform to the presentation for the current period.

2. Earnings Per Common Share

Basic earnings per share are computed by dividing earnings available for common stockholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share are computed by dividing earnings available for common stockholders by the diluted weighted-average number of common shares outstanding during the period. Diluted earnings per share reflect the potential dilution that could occur if securities or other agreements to issue common stock which have met market price or other contingencies (such as stock options, equity units, stock-based performance unit awards, convertible debt and phantom stock awards) were exercised or converted into common stock. The following table reconciles the weighted-average shares outstanding to the diluted weighted-average shares outstanding.

Weighted-Average Shares Outstanding (in millions)

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2004	**2003**	**2004**	**2003**
Weighted-average shares outstanding	926	902	919	899
Potential dilution for the period	2	1	2	1
Diluted weighted-average shares outstanding	928	903	921	900

The increase in weighted-average shares outstanding for the three and six-month periods ended June 30, 2004, compared to the same periods in 2003, was due primarily to the issuance of shares in connection with the settlement of the forward purchase contract component of Duke Energy s Equity Units. For further information see Note 5.

Options, restricted stock, performance and phantom stock awards to purchase approximately 26 million shares as of June 30, 2004 and 27 million shares as of June 30, 2003 were not included in potential dilution for the period in the above table because either the option exercise prices were greater than the average market price of the common shares during those periods, or performance measures related to the awards had not yet been met.

Duke Energy s $750 million of Equity Units, which will result in an issuance of approximately 19 million shares, is not included in potential dilution for the period in the above table because their inclusion would be antidilutive.

Additionally, Duke Energy s $770 million convertible debt issuance, which is potentially convertible into approximately 33 million shares, is not included in potential dilution for the period in the above table because the market price and other contingencies for issuance had not been met as of June 30, 2004 and June 30, 2003.

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3. Stock-Based Compensation

Duke Energy accounts for its stock-based compensation arrangements under the intrinsic value recognition and measurement principles of Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees, and Financial Accounting Standards Board (FASB) Interpretation No. 44, Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion No. 25). The following table shows what earnings available for common stockholders, basic earnings per share and diluted earnings per share would have been if Duke Energy had applied the fair value recognition provisions of Statement of Financial Accounting Standards (SFAS) No. 123, Accounting for Stock-Based Compensation, and provisions of SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure (an amendment to FASB Statement No. 123), to all stock-based compensation awards.

Pro Forma Stock-Based Compensation (in millions, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Earnings available for common stockholders, as reported	$ 429	$ 417	$ 738	$ 639
Add: stock-based compensation expense included in reported net income, net of related tax effects	3	3	6	5
Deduct: total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects	(5)	(11)	(12)	(18)
Pro forma earnings available for common stockholders, net of related tax effects	$ 427	$ 409	$ 732	$ 626
Earnings per share				
Basic as reported	$ 0.46	$ 0.46	$ 0.80	$ 0.71
Basic pro forma	$ 0.46	$ 0.45	$ 0.79	$ 0.70
Diluted as reported	$ 0.46	$ 0.46	$ 0.80	$ 0.71
Diluted pro forma	$ 0.46	$ 0.45	$ 0.79	$ 0.70

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4. Inventory

Inventory is recorded at the lower of cost or market value, primarily using the average cost method.

Inventory (in millions)

	June 30, 2004	December 31, 2003
Materials and supplies	$ 443	$ 445
Natural gas and natural gas liquid products held in storage for transmission, processing, and sales commitments	224	299
Coal held for electric generation	87	87
Petroleum products	83	110
Total inventory	$ 837	$ 941

5. Debt and Credit Facilities

In February 2004, Duke Energy remarketed $875 million of senior notes, due in 2006, underlying its Equity Units and reset the interest rate from 5.87% to 4.302%. As this action was contemplated in the original Equity Units issuance, the transaction had no immediate accounting implications. Subsequently, Duke Energy exchanged $475 million of the remarketed senior notes for $200 million of 4.37% senior unsecured notes due in 2009, and $288 million of 5.5% senior unsecured notes due in 2014. In accordance with Emerging Issues Task Force (EITF) Issue No. 96-19, Debtors Accounting for a Modification or Exchange of Debt Instruments, the $475 million of remarketed senior notes issued earlier at 4.302% was extinguished. This exchange transaction resulted in an approximate $11 million loss, which was included in interest expense in the Consolidated Statement of Operations for the first quarter of 2004.

In May 2004, Duke Energy issued 22,449,000 shares of its common stock in the settlement of the forward purchase contract component of its Equity Units issued in March 2001. Duke Energy issued 35,000,000 Equity Units in March 2001 at $25 per unit. Under the terms of the contract, the Equity Unit holders were required to purchase common stock at a settlement rate based on the current market price of Duke Energy s common stock at the time of settlement. The rate was 0.6414 shares of stock per Equity Unit.

In March 2004, Duke Energy redeemed the entire issue of its 7.20% debt due to an affiliate in 2037 for approximately $350 million, in connection with the redemption of its Duke Energy Capital Trust I 7.20% Cumulative Quarterly Income Preferred Securities due 2037. As the securities were redeemed at par, security holders received $25 per each note held, plus accrued and unpaid distributions to the redemption date.

In April 2004, approximately $840 million of debt was retired (as a non-cash financing activity) as part of the sale of the Asia-Pacific operations. This does not include approximately $50 million of Australian debt, which has been placed in trust and fully funded in connection with the closing of the sale transaction and will be repaid in September 2004. This trust is included in the Consolidated Financial Statements as Duke

Energy is the primary beneficiary of the trust and, therefore, is required to consolidate the trust under provisions of FASB Interpretation No. 46 (FIN 46), Consolidation of Variable Interest Entities. The Asia-Pacific debt was classified as Current and Non-Current Liabilities Associated with Assets Held for Sale on the December 31, 2003 Consolidated Balance Sheet. Duke Energy completed the sale of the Asia-Pacific assets, which includes substantially all of Duke Energy s assets in Australia and New Zealand, to Alinta Ltd. on April 23, 2004.

In April 2004, Duke Capital LLC (Duke Capital) purchased $101 million of its outstanding notes in the open market. These purchases included $49 million of Duke Capital 5.50% senior notes due March 1, 2014 and $52 million of Duke Capital 4.37% senior notes due March 1, 2009. The securities were redeemed at the then current market price plus accrued interest.

In May 2004, Duke Energy redeemed its Series C 6.60% senior notes due in 2038, at a $200 million face value. As the securities were redeemed at par, security holders received $25 per each note held, plus accrued interest to the redemption date.

In June 2004, Duke Energy redeemed the entire issue of its 7.20% debt due to an affiliate in 2039 for approximately $250 million, in connection with the redemption of its Duke Energy Capital Trust II 7.20% Trust Preferred Securities. As the securities were redeemed at par, security holders received $25 per preferred security held, plus accrued and unpaid distributions to the redemption date.

In July 2004, Duke Energy announced that on August 31, 2004, it will redeem the entire issue of Duke Capital Financing Trust III 8 3/8% Trust Preferred Securities due August 31, 2029 with a face value of $250 million. As the securities are being redeemed at par, security holders will receive $25 per preferred security held, plus accrued and unpaid distributions to the redemption date. Additionally, Duke Energy plans to remarket $750 million of its 4.32% senior notes, due in 2006, underlying its 8.00% Equity Units on August 11, 2004. Proceeds from the remarketed notes will be held by a collateral agent and used to purchase U.S. Treasury securities to satisfy the forward stock purchase contract component of the Equity Units in November 2004.

Credit Facilities Capacity and Restrictive Debt Covenants. During the six months ended June 30, 2004, credit facilities capacity was reduced by approximately $860 million compared to December 31, 2003, primarily relating to the divested Australian operations. In addition, Duke Energy, Duke Capital, Duke Energy Field Services, LLC (DEFS), Westcoast Energy Inc. and Union Gas Limited renewed and replaced their credit facilities at lower amounts due to reduced need for surplus credit capacity. The credit facilities as of June 30, 2004 are included in the following table. The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the credit facilities.

Duke Energy s credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of June 30, 2004, Duke Energy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the credit agreements contain material adverse change clauses or any covenants based on credit ratings.

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Credit Facilities Summary as of June 30, 2004 (in millions)

	Expiration Date	Credit Facilities Capacity	Amounts Outstanding Commercial Paper	Letters of Credit	Other Borrowings	Total
Duke Energy						
$150 two-year bilateral [a, b]	September 2005					
$500 three-year syndicated [a, b]	June 2007					
Total Duke Energy		$ 650	$ 546	$	$	$ 546
Duke Capital LLC						
$600 364-day syndicated [a, b, c]	June 2005					
$600 three-year syndicated [a, b, c]	June 2007					
Total Duke Capital LLC		1,200		618		618
Westcoast Energy Inc.						
$74 two-year syndicated [b, d]	July 2005					
$149 three-year syndicated [b, e]	June 2007					
Total Westcoast Energy Inc.		223				
Union Gas Limited						
$223 364-day syndicated [f, g]	June 2005	223				
Duke Energy Field Services, LLC						
$250 364-day syndicated [c, h, i]	March 2005	250				
Total [j]		$ 2,546	$ 546	$ 618	$	$ 1,164

[a] Credit facility contains an option allowing borrowing up to the full amount of the facility on the day of expiration for up to one year.
[b] Credit facility contains a covenant requiring that the debt-to-total capitalization ratio not exceed 65%.
[c] Credit facility contains an interest coverage covenant.
[d] Credit facility is denominated in Canadian dollars and was 100 million Canadian dollars as of June 30, 2004.
[e] Credit facility is denominated in Canadian dollars and was 200 million Canadian dollars as of June 30, 2004.
[f] Credit facility contains a covenant requiring that debt-to-total capitalization ratio not exceed 75%. Credit facility is denominated in Canadian dollars and was 300 million Canadian dollars as of June 30, 2004.
[g] Credit facility contains an option at maturity allowing for the conversion of all outstanding loans to a term loan repayable up to one year after maturity date but not exceeding 18 months from the date of first draw.
[h] Credit facility contains an option at maturity allowing for conversion of all outstanding loans to a term loan repayable up to one year after maturity date.
[i] Credit facility contains a covenant requiring that the debt-to-total capitalization ratio not exceed 53%.
[j] Various operating credit facilities and credit facilities that support commodity, foreign exchange, derivative and intra-day transactions are not included in this credit facilities summary.

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6. Employee Benefit Obligations

The following table shows the components of the net periodic pension costs for Duke Energy s U.S. retirement plans and Westcoast Energy Inc. s (Westcoast, a subsidiary of Duke Energy) Canadian retirement plans.

Components of Net Periodic Pension Costs (Income) (in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Duke Energy U.S.				
Service cost	$ 16	$ 18	$ 32	$ 35
Interest cost on projected benefit obligation	40	44	80	88
Expected return on plan assets	(58)	(59)	(116)	(118)
Amortization of prior service cost	(1)	(1)	(1)	(2)
Amortization of net transition asset	(1)	(1)	(2)	(2)
Amortization of loss	4		7	
Curtailment gain			(1)	
Net Periodic pension costs (income)	$	$ 1	$ (1)	$ 1
Westcoast				
Service cost	$ 2	$ 1	$ 4	$ 3
Interest cost on projected benefit obligation	6	6	13	12
Expected return on plan assets	(6)	(6)	(12)	(12)
Amortization of loss	1		1	
Net periodic pension costs	$ 3	$ 1	$ 6	$ 3

Duke Energy s policy is to fund amounts on an actuarial basis to provide sufficient assets to pay benefits to U.S. plan participants. Duke Energy does not have a required contribution to the U.S. plan for 2004.

Duke Energy s policy is to fund the Westcoast defined benefit retirement plans on an actuarial basis and in accordance with Canadian pension standards legislation, in order to accumulate sufficient assets to pay benefits. Duke Energy has contributed $6 million to the Westcoast plans during the six months ended June 30, 2004, and anticipates making total contributions of approximately $27 million in 2004.

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The following table shows the components of the net periodic post-retirement benefit costs for the Duke Energy U.S. and Westcoast plans.

Components of Net Periodic Post-Retirement Benefit Costs (in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Duke Energy U.S.				
Service cost benefit	$ 1	$ 1	$ 3	$ 3
Interest cost on accumulated post-retirement benefit obligation	11	13	24	26
Expected return on plan assets	(5)	(5)	(9)	(11)
Amortization of net transition liability	4	5	8	9
Amortization of loss	2	1	5	2
Net periodic post-retirement benefit costs	$ 13	$ 15	$ 31	$ 29
Westcoast				
Service cost benefit	$ 1	$ 1	$ 1	$ 1
Interest cost on accumulated post-retirement benefit obligation	1	1	2	2
Amortization of loss			1	
Net periodic post-retirement benefit costs	$ 2	$ 2	$ 4	$ 3

In May 2004, the FASB staff issued FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, (the Act). The Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care benefit plans. The FSP provides accounting guidance for the subsidy. Duke Energy adopted and retroactively applied this FSP as of the date of issuance, impacting second quarter results for its U.S. plan. As a result, the accumulated post-retirement benefit obligation decreased by $96 million. The effect on net periodic post-retirement benefit cost was a $4 million decrease for the three months and six months ended June 30, 2004.

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7. Comprehensive Income and Accumulated Other Comprehensive Income

Comprehensive Income. Comprehensive income includes net income and all other non-owner changes in equity.

Total Comprehensive Income (in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net Income	$ 432	$ 424	$ 743	$ 649
Other comprehensive income				
Foreign currency translation adjustments	(241)	240	(284)	404
Net unrealized gains on cash flow hedges [a]	52	241	179	417
Reclassification into earnings from cash flow hedges [b]	(60)	(55)	(54)	(107)
Other comprehensive (loss) income, net of tax	(249)	426	(159)	714
Total Comprehensive Income	$ 183	$ 850	$ 584	$ 1,363

[a] Net unrealized gains on cash flow hedges, net of $14 million and $179 million tax expense for the three months ended 2004 and 2003, respectively, and $66 million and $261 million tax expense for the six months ended 2004 and 2003, respectively

[b] Reclassification into earnings from cash flow hedges, net of $21 million and $57 million tax benefit for the three months ended 2004 and 2003, respectively, and $18 million and $83 million tax benefit for the six months ended 2004 and 2003, respectively

Accumulated Other Comprehensive Income

Components of and Changes in Accumulated Other Comprehensive Income (in millions)

	Foreign Currency Adjustments	Net Gains on Cash Flow Hedges	Minimum Pension Liability Adjustment	Accumulated Other Comprehensive Income (Loss)
Balance as of December 31, 2003	$ 315	$ 298	$ (444)	$ 169
Other comprehensive income changes year-to-date (net of $48 tax expense)	(284)	125		(159)

Balance as of June 30, 2004	$ 31	$ 423	$ (444)	$ 10

8. Acquisitions and Dispositions

Acquisitions. Duke Energy consolidates assets and liabilities from acquisitions as of the purchase date, and includes earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price minus the estimated fair value of the acquired assets and liabilities is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information on contingencies existing at the date of acquisition becomes available within one year after the acquisition, and longer for some income tax items.

In the second quarter of 2004, DEFS acquired gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for a total purchase price of approximately $80 million, consisting of $74 million in cash and the assumption of approximately $6 million of liabilities.

Dispositions. For the six months ended June 30, 2004, the sale of other assets (which excludes assets held for sale as of June 30, 2004 and discontinued operations, both of which are discussed in Note 9, and sales by Crescent which are discussed separately below) resulted in approximately $142 million in proceeds, and

net gains of $6 million recorded in (Losses) Gains on Sales of Other Assets, net on the Consolidated Statements of Operations. Significant sales of other assets in 2004 are detailed by business segment as follows:

Natural Gas Transmission s asset sales totaled $12 million in net proceeds. Those sales resulted in gains of $9 million which were recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Sales included the sale of storage gas related to the Canadian distribution operations in the second quarter of 2004.

Duke Energy North America s (DENA s) asset sales totaled $64 million in net proceeds. Those sales resulted in losses of $13 million which were recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Significant sales included the sale of turbines and surplus equipment in the first and second quarter of 2004, some Duke Energy Trading and Marketing, LLC (DETM) contracts in the first and second quarter of 2004 (DETM held a net liability position in those contracts), and the sale of a 25% undivided interest in DENA s Vermillion facility in the second quarter of 2004. Duke Energy still owns the remaining 75% interest in the Vermillion facility.

Asset sales within Other totaled $62 million in net proceeds. Those sales resulted in gains of $7 million which were recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Significant sales included Duke Energy Royal LLC s interest in six energy service agreements and DukeSolutions Huntington Beach LLC in the first quarter of 2004, and Duke Energy Merchant LLC s (DEM s) 15% ownership interest in Caribbean Nitrogen Company in the first quarter of 2004.

For the six months ended June 30, 2004, Crescent s commercial and multi-family real estate sales resulted in $303 million of proceeds, and $121 million of net gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations. Significant sales included the Potomac yard retail center in the Washington, D.C. area in March 2004, the Alexandria land tract in the Washington, D.C. area in June 2004 and several large legacy land sales closed in the first quarter of 2004.

In May 2004, Duke Energy reached an agreement to sell its 30% equity interest in Compañia de Nitrógeno de Cantarell, S.A. de C.V., a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico for approximately $60 million. Duke Energy recorded a $13 million non-cash charge to Operation, Maintenance and Other expenses on the Consolidated Statement of Operations in the first quarter of 2004 in anticipation of this sale. The sale is expected to close in the third quarter of 2004.

The pro forma results of operations for acquisitions and dispositions do not materially differ from reported results.

9. Assets Held for Sale and Discontinued Operations

Assets Held for Sale. In 2003, Duke Energy decided to exit the merchant power generation business in the southeastern United States. In the first quarter of 2004, as a result of marketing efforts related to DENA s eight plants in the region, Duke Energy classified the assets and associated liabilities as held for sale in the March 31, 2004 Consolidated Balance Sheet and recorded an approximate $360 million pre-tax loss on those assets, which represents the excess of the carrying value over the fair value of the plants, less estimated costs to sell. This loss was included in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. The fair value of the plants was based on the final sales price of $475 million, which Duke Energy announced it had agreed to with KGen Partners LLC (KGen) on May 4, 2004. The sales price consists of $425 million cash and a $50 million note receivable from KGen. The $50 million note receivable bears variable interest at LIBOR (London Interbank Offered Rate) plus 14.25% per annum, compounded quarterly, and is secured by a fourth lien on the assets of KGen s owner, and matures with a balloon payment of principal and interest due no later than 7.5 years after closing date. The agreement includes the sale of all of Duke Energy s merchant generation assets in the southeastern United States. The results of operations related to those assets are not

reported in Discontinued Operations, due to Duke Energy s significant continuing involvement in the future operations of the plants, including a long-term operating agreement for one of the plants and retention of certain guarantees related to those assets.

Also in the first quarter of 2004, Duke Energy recorded a $238 million after-tax gain related to International Energy s Asia Pacific power generation and natural gas transmission businesses. The estimated fair value, less costs to sell was classified as held for sale as of December 31, 2003. The gain recorded in the first quarter of 2004 restores the loss recorded during the fourth quarter of 2003. The December 31, 2003 estimated fair value was based on third-party bids received by International Energy. During the first quarter, Duke Energy determined that it was likely a bid in excess of the originally determined fair value would be accepted.

In April 2004, Duke Energy completed the sale of the Asia-Pacific businesses to Alinta Ltd. for a gross sales price of approximately $1.2 billion. This resulted in recording an additional $40 million after-tax gain in the second quarter. Duke Energy received approximately $390 million of cash proceeds, net of debt repayment of approximately $840 million of debt retired (as a non-cash financing activity) as part of the Asia-Pacific operations. The $840 million does not include approximately $50 million of Australian debt, which has been placed in trust and fully funded in connection with the closing of the sale transaction and will be repaid in September 2004. This trust is included in the Consolidated Financial Statements as Duke Energy is the primary beneficiary of the trust and, therefore, is required to consolidate the trust under provisions of FIN 46. The Asia-Pacific debt had been classified as Current and Non-Current Liabilities Associated with Assets Held for Sale on the December 31, 2003 Consolidated Balance Sheet. All gains related to this transaction and the results of operations for these assets are included in Net Gain (Loss) on Dispositions, net of tax, within Discontinued Operations, in the Consolidated Statements of Operations. See Note 5 for a discussion of the impact of this transaction to consolidated long-term debt.

In the second quarter of 2004, Duke Energy announced an agreement to sell one of DENA s deferred facilities, Moapa, to Nevada Power Company for approximately $182 million in cash, with closing expected during the fourth quarter of 2004 pending regulatory approvals. The Moapa asset was classified as held for sale in the June 30, 2004 Consolidated Balance Sheet. This facility will not be reported in Discontinued Operations as, among other considerations, the facility never entered into operations and has no associated historical operating revenues or costs.

The following table presents the carrying values as of June 30, 2004 and December 31, 2003 of the major classes of Assets Held for Sale and associated liabilities in the Consolidated Balance Sheets. International Energy s European operations, some turbines and related equipment owned by DENA and the merchant finance business conducted by Duke Capital Partners, LLC (DCP) were the material items classified as held for sale at both June 30, 2004 and December 31, 2003. The December 31, 2003 period also included International Energy s Asia-Pacific power generation and natural gas transmission businesses, and the June 30, 2004 period also included DENA s eight plants in the southeastern United States, DENA s Moapa facility, and certain commercial office buildings owned by Crescent in which it expects continuing involvement through a third party leasing and management agreement with the new owners of the buildings.

Summarized Balance Sheet Information for Assets Held for Sale (in millions)

	June 30, 2004	December 31, 2003
Current assets	$ 113	$ 424
Investments and other assets	199	379
Property, plant and equipment, net	493	1,065
Total assets held for sale	$ 805	$ 1,868
Current liabilities	$ 44	$ 651
Long-term debt		514
Deferred credits and other liabilities		223

Total liabilities associated with assets held for sale	$ 44	$ 1,388

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Discontinued Operations. The following table summarizes the operating results classified as Discontinued Operations in the Consolidated Statements of Operations. The three and six-month periods ended June 30, 2004 include the results for International Energy s Asia-Pacific power generation and natural gas transmission businesses and its European operations, the merchant finance business conducted by DCP, and some other assets at Field Services. In addition, the three and six-month periods ended June 30, 2003 contain Duke Energy Hydrocarbons LLC and some Crescent real estate projects that were sold in 2003. For additional information related to the exit of those activities, see the Notes to the Consolidated Financial Statements in Duke Energy s Annual Report on Form 10-K/A for the year ended December 31, 2003.

Discontinued Operations (in millions)

		Operating Income			Net Gain (Loss) on Dispositions		
	Operating Revenues	**Pre-tax Operating Income (Loss)**	**Income Tax Expense (Benefit)**	**Operating Income (Loss), Net of Tax**	**Pre-tax Gain (Loss) on Dispositions**	**Income Tax Expense (Benefit)**	**Gain (Loss) on Dispositions, Net of Tax**
Three Months Ended June 30, 2004							
International Energy	$ 19	$ (1)	$ 2	$ (3)	$ 39	$ 9	$ 30
Field Services							
Crescent and Other	1						
Total consolidated	$ 20	$ (1)	$ 2	$ (3)	$ 39	$ 9	$ 30
Three Months Ended June 30, 2003							
International Energy	$ 196	$ 14	$ (3)	$ 17	$ (1)	$	$ (1)
Field Services	98	3	1	2	19	7	12
Crescent and Other	7	1	3	(2)	(8)	(3)	(5)
Total consolidated	$ 301	$ 18	$ 1	$ 17	$ 10	$ 4	$ 6
Six Months Ended June 30, 2004							
International Energy	$ 82	$ 3	$ 1	$ 2	$ 295	$ 27	$ 268
Field Services	14	1		1	2	1	1
Crescent and Other	1	2	1	1			
Total consolidated	$ 97	$ 6	$ 2	$ 4	$ 297	$ 28	$ 269
Six Months Ended June 30, 2003							
International Energy	$ 408	$ 15	$ (1)	$ 16	$ (1)	$	$ (1)
Field Services	237	7	2	5	19	7	12
Crescent and Other	25	1	2	(1)	(20)	(7)	(13)
Total consolidated	$ 670	$ 23	$ 3	$ 20	$ (2)	$	$ (2)

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10. Business Segments

Duke Energy operates the following business units: Franchised Electric, Natural Gas Transmission, Field Services, DENA, International Energy and Crescent. Duke Energy s chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. The entities under each business unit, have similar economic characteristics, services, production processes, distribution methods and regulatory concerns. All of the business units offer different products and services, are managed separately and are considered reportable segments under SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information.

Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages legacy land holdings primarily in the southeastern and southwestern United States. All other entities previously part of Other Operations and now within Other still remain, primarily: DukeNet Communications LLC, DEM and Duke Energy s 50% equity investment in Duke/Fluor Daniel. Unallocated corporate costs are also recorded in Other in the table below.

Accounting policies for the segments are the same as those described in the Notes to the Consolidated Financial Statements in Duke Energy s Annual Report on Form 10-K/A for December 31, 2003. Management evaluates segment performance primarily based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT).

On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash and cash equivalents are managed centrally by Duke Energy, so the gains and losses on foreign currency remeasurement associated with cash balances, and interest income on those balances, are generally excluded from the segments EBIT.

Transactions between reportable segments are accounted for on the same basis as revenues and expenses in the accompanying Consolidated Financial Statements.

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Business Segment Data (in millions)

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT / Consolidated Earnings from Continuing Operations before Income Taxes
Three Months Ended June 30, 2004				
Franchised Electric	$ 1,222	$ 6	$ 1,228	$ 338
Natural Gas Transmission	635	53	688	311
Field Services	2,353	3	2,356	94
Duke Energy North America	648	24	672	(39)
International Energy	147		147	68
Crescent	101		101	87
Total reportable segments	5,106	86	5,192	859
Other	254	36	290	(26)
Eliminations		(122)	(122)	
Interest expense				(337)
Minority interest expense and other [a]				42
Total consolidated	$ 5,360	$	$ 5,360	$ 538
Three Months Ended June 30, 2003				
Franchised Electric	$ 1,104	$ 6	$ 1,110	$ 316
Natural Gas Transmission	636	56	692	306
Field Services	1,972	76	2,048	53
Duke Energy North America	904	58	962	211
International Energy	169		169	91
Crescent	76		76	21
Total reportable segments	4,861	196	5,057	998
Other	291	71	362	(69)
Eliminations		(267)	(267)	
Interest expense				(325)
Minority interest expense and other [a]				(8)
Total consolidated	$ 5,152	$	$ 5,152	$ 596

[a] Includes interest income, foreign currency remeasurement gains and losses, and additional minority interest expense not allocated to the segment results.

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Business Segment Data (in millions)

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT / Consolidated Earnings from Continuing Operations before Income Taxes
Six Months Ended June 30, 2004				
Franchised Electric	$ 2,488	$ 11	$ 2,499	$ 762
Natural Gas Transmission	1,617	109	1,726	709
Field Services	4,670	61	4,731	186
Duke Energy North America	1,275	53	1,328	(596)
International Energy	301		301	97
Crescent	140		140	147
Total reportable segments	10,491	234	10,725	1,305
Other	558	76	634	(31)
Eliminations		(310)	(310)	
Interest expense				(693)
Minority interest expense and other [a]				55
Total consolidated	$ 11,049	$	$ 11,049	$ 636
Six Months Ended June 30, 2003				
Franchised Electric	$ 2,351	$ 10	$ 2,361	$ 770
Natural Gas Transmission	1,515	145	1,660	729
Field Services	4,054	544	4,598	83
Duke Energy North America	2,212	146	2,358	234
International Energy	341		341	131
Crescent	97		97	21
Total reportable segments	10,570	845	11,415	1,968
Other	752	127	879	(117)
Eliminations		(972)	(972)	
Interest expense				(651)
Minority interest expense and other [a]				(17)
Total consolidated	$ 11,322	$	$ 11,322	$ 1,183

[a] Includes interest income, foreign currency remeasurement gains and losses, and additional minority interest expense not allocated to the segment results.

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Segment assets in the following table are net of intercompany advances, intercompany notes receivable, intercompany current assets, intercompany derivative assets and investments in subsidiaries.

Segment Assets (in millions)

	June 30, 2004	December 31, 2003
Franchised Electric	$ 16,595	$ 16,088
Natural Gas Transmission	16,108	16,384
Field Services	6,803	6,417
Duke Energy North America	8,118	9,184
International Energy	3,228	4,550
Crescent	1,585	1,653
Total reportable segments	52,437	54,276
Other	2,929	2,585
Eliminations [a]	(539)	(658)
Total consolidated assets	$ 54,827	$ 56,203

[a] Represents elimination of intercompany assets, such as accounts receivable and interest receivable, that have been created based on arm s length transactions (transactions that have been conducted as though the parties were unrelated).

Segment assets include goodwill of $3,855 million as of June 30, 2004 and $3,962 million as of December 31, 2003, with $3,124 million as of June 30, 2004 allocated to Natural Gas Transmission, $490 million to Field Services, $234 million to International Energy and $7 million to Crescent. The $107 million decrease from December 31, 2003 to June 30, 2004 was related solely to foreign currency exchange rate fluctuations of $99 million at Natural Gas Transmission, $5 million at International Energy and $3 million at Field Services.

11. Risk Management Instruments

The following table shows the carrying value of Duke Energy s derivative portfolio as of June 30, 2004 and December 31, 2003.

Derivative Portfolio Carrying Value (in millions)

	June 30, 2004	December 31, 2003
Hedging	$ 626	$ 424

Trading	151	177
Undesignated	(361)	(215)
Total	$ 416	$ 386

The amounts in the table above represent the combination of assets and (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on Duke Energy s Consolidated Balance Sheets. All amounts represent fair value, except that the net asset amounts for hedging include assets of $196 million as of June 30, 2004 and $267 million as of December 31, 2003, that were frozen upon Duke Energy s initial application of the normal purchases and normal sales exception to its forward power sales contracts as of July 1, 2001. Those balances will reduce upon settlement of the associated contracts.

The $202 million increase in the hedging derivative portfolio carrying value is due primarily to increases in forward gas prices, partially offset by the realization of gas hedge gains as well as other hedge activity.

The $146 million decrease in the undesignated derivative portfolio fair value is due primarily to increases in power and gas prices on forward contracts formerly designated as hedges of future production from DENA s southeastern plants and deferred western plants along with settlements of net mark-to-market gains during the six months ended June 30, 2004, partially offset by other hedge activity.

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Changes in Fair Value of Duke Energy s Trading Contracts During 2004 (in millions)

Fair value of contracts outstanding as of December 31, 2003	$ 177
Contracts realized or otherwise settled during the year	(34)
Other changes in fair values	8
Fair value of contracts outstanding as of June 30, 2004	$ 151

12. Regulatory Matters

FERC Orders No. 2004, 2004-A and 2004-B (Standards of Conduct). In November 2003, the Federal Energy Regulatory Commission (FERC) issued Order 2004, which harmonizes the standards of conduct applicable to natural gas pipelines and electric transmitting public utilities (Transmission Providers) previously subject to differing standards. In December 2003, Duke Energy filed a request for clarification and rehearing with the FERC regarding: (1) restrictions on how companies and their affiliates interact and share information, including corporate governance information, and (2) expansion of coverage to affiliated gatherers, processors, and intrastate and Hinshaw pipelines. (A Hinshaw pipeline is a regulated pipeline company engaged in the transportation of interstate natural gas or the sale of interstate natural gas for resale. A Hinshaw pipeline company receives natural gas from another person within or at the boundary of a state, and then consumes that natural gas within that state.) On April 16, 2004, the FERC issued Order 2004-A, revising the standards of conduct governing information flow between Transmission Providers and their energy affiliates. Order 2004-A accommodates unique corporate governance issues raised by Duke Energy s corporate structure and clarifies provisions governing information flow for governance purposes. The FERC also clarified the rules expanded coverage to gatherers, processors, and intrastate and Hinshaw pipelines. On August 2, 2004, the FERC issued Order 2004-B, reaffirming the previous two orders and providing clarification on a number of issues. Duke Energy has implemented compliance programs to meet the requirements of the order related to information flow and governance processes. Duke Energy expects to be in full compliance with the orders, including significant training and information posting requirements, by the September 22, 2004 deadline, and expects the orders to have no material adverse effect on its consolidated results of operations, cash flows or financial position.

Franchised Electric. *Rate Related Information.* The North Carolina Utilities Commision (NCUC) and the Public Service Commission of South Carolina (PSCSC) approve rates for retail electric sales within their states. The FERC approves Franchised Electric s rates for electric sales to wholesale customers, except for the other joint owners of the Catawba Nuclear Station whose rates are set through contractual agreements.

In 2002, the state of North Carolina passed clean air legislation that freezes electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy, to significantly reduce emissions of sulfur dioxide and nitrogen oxides from the state s coal-fired power plants over the next ten years. The legislation allows electric utilities, including Duke Energy, to accelerate the recovery of compliance costs by amortizing them over seven years (2003-2009). Franchised Electric s amortization expense related to this clean air legislation totals $148 million from inception, with $33 million recorded for the first six months of 2004 and $35 million recorded for the first six months of 2003. The legislation provides for significant flexibility in the amount of annual amortization recorded, allowing utilities to vary the amount amortized, within limits, although the legislation does require that a minimum of 70% of the total estimated cost of $1.5 billion be amortized within the rate freeze period.

Bulk Power Marketing Profit Sharing. On June 9, 2004, the NCUC approved Duke Energy s proposal to share an amount equal to 50% of the North Carolina retail allocation of the profits from certain wholesale sales of bulk power from Duke Power generating units at market based rates (BPM Profits). Duke Energy also informed the NCUC that it would no longer include BPM Profits in calculating its North Carolina retail jurisdictional rate of return for its quarterly reports to the NCUC. As approved by the NCUC, the sharing arrangement provides for 50% of the North Carolina allocation of BPM Profits to be distributed through various assistance programs, up to a maximum of $5 million per year. Any

amounts exceeding the maximum will be used to reduce rates for industrial customers in North Carolina.

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On June 29, 2004, Duke Energy informed the PSCSC that it would no longer include BPM Profits in calculating its South Carolina retail jurisdictional rate of return for its quarterly reports to the PSCSC. Duke Energy proposed to establish an entity to receive 50% of the South Carolina allocable share of the BPM Profits to support public assistance programs, education programs to promote economic development, and grants to promote the attraction and retention of industrial customers. The PSCSC has not addressed the proposed change in reporting BPM Profits. Duke Energy s sharing proposal does not require PSCSC approval.

The sharing agreement in both states applies to BPM Profits from January 1, 2004 until the earlier of December 31, 2007, or the effective date of any rates approved by the respective commission after a general rate case. The 2004 year-to-date total of $27 million of shared profits was recorded as a $14 million decrease to revenues (for the portion related to reduced industrial customers rates) and a $13 million charge to expenses (for the portion related to donations to charitable, educational and economic development programs in North Carolina and South Carolina) in the second quarter of 2004.

Depreciation and Decommissioning Studies. The operating licenses for Duke Energy s nuclear units are subject to renewal. In December 2003, Duke Energy was granted renewed operating licenses for the Catawba and McGuire Nuclear Stations. In 2000, Duke Energy was granted a renewed operating license for the Oconee Nuclear Station. The renewed license term of the nuclear units will not impact depreciation or nuclear decommissioning rates unless justified by depreciation and decommissioning studies and funding plans filed with the NCUC and the PSCSC. Preparation of the depreciation study is currently underway and is expected to be completed during 2004.

In June 2004 Duke Power filed with the NCUC and PSCSC the results of a 2003 decommissioning study, which indicate an estimated cost of $2.32 billion to decommission the facilities. The previous study, conducted in 1999, estimated a decommissioning cost of $1.91 billion ($2.15 billion in 2003 dollars at 3% inflation). The estimated increase is due primarily to inflation and cost increases for the size of the organization needed to manage the decommissioning project (based on current industry experience at facilities undergoing decommissioning). Duke Power will use information from this new decommissioning study to determine the level of decommissioning expense expected to be incurred over the next several years, and to evaluate potential impacts to the nuclear decommissioning asset retirement obligation. NCUC rules require Duke Power to file a funding plan based on the updated decommissioning study by October 2004, and allow stakeholders time to evaluate and comment on the study and funding plan. The NCUC would then rule on whether any change in Duke Power s decommissioning expense is necessary. As a result, any potential change in decommissioning expense or the asset retirement obligation cannot be determined at this time.

In the second quarter of 2004, Duke Energy made an approximately $262 million contribution to its external nuclear decommissioning fund. This contribution was shown as an investing activity on the Consolidated Statement of Cash Flows for 2004.

Other Matters. In 2001, the NCUC and the PSCSC began a joint investigation, along with the Public Staff of the NCUC, regarding some Duke Power regulatory accounting entries for 1998, including the classification of nuclear insurance distributions. As part of their investigation, the NCUC and the PSCSC jointly engaged an independent firm to conduct an accounting investigation of Duke Power s accounting records from 1998 through June 30, 2001. In 2002, Duke Power entered into a settlement agreement with the staffs of the NCUC and the PSCSC in which the parties agreed to accounting changes primarily related to nuclear insurance distributions, a one-time $25 million credit to Duke Power s deferred fuels account for the benefit of North Carolina and South Carolina customers, the reclassification of $50 million of a $58 million suspense account to a nuclear insurance operation reserve account, and an additional $2 million adjustment to the nuclear insurance operation reserve account. The remaining $8 million in the suspense account was credited to income, resulting in a net $19 million pre-tax charge in 2002. The NCUC and the

PSCSC approved the settlement in 2003. A residential retail customer and the Carolina Utility Customers Association Inc., (CUCA), a group that represents certain industrial customers in regulatory proceedings before the NCUC, appealed the NCUC decision to the North Carolina Court of Appeals, which affirmed the NCUC s decision on February 17, 2004. CUCA has since filed a request with the Supreme Court of North Carolina for review of the Court of Appeals decision. This request is pending.

In 2002, the NCUC denied a petition by CUCA to initiate a general rate proceeding and dismissed its complaint alleging unjust and unreasonable rates charged by Duke Power. CUCA appealed this order to the North Carolina Court of Appeals, which ruled on February 17, 2004 that the NCUC s denial of CUCA s petition and complaint was proper and affirmed the NCUC s order. On March 22, 2004, CUCA filed a request with the Supreme Court of North Carolina for review of the Court of Appeals decision. This request is also pending.

Natural Gas Transmission. *Rate Related Information.* On December 1, 2003, The British Columbia Pipeline System (BC Pipeline) filed an application with the National Energy Board (NEB) for approval of 2004 tolls. In March 2004, BC Pipeline reached an agreement in principle with its major stakeholders to establish tolls for the period from January 1, 2004 through December 31, 2005. On June 30, 2004, BC Pipeline filed an application with the NEB for approval of the 2004 tolls established in the settlement agreement.

Union Gas Limited (Union Gas) filed cost of service evidence with the Ontario Energy Board (OEB) in 2003 to establish rates for 2004. The OEB issued a decision in March 2004 and Union Gas implemented these rates in May 2004.

Maritimes & Northeast Pipeline LLC filed its Section 4 rate case with the FERC on June 30, 2004 seeking an increase in rates from $0.695 per Decatherm (Dth) to $1.07/Dth. The FERC has issued an order accepting the rate filing and suspending the rates until January 1, 2005, at which time they will become effective, subject to refund. The rate case has been set for hearing.

13. Commitments and Contingencies

Environmental

Duke Energy is subject to international, federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters.

Remediation activities. Duke Energy and its affiliates are responsible for environmental remediation at various impacted properties and contaminated sites, similar to others in the energy industry. These include some properties that are part of ongoing Duke Energy operations, sites formerly owned or used by Duke Energy entities, and sites owned by third parties. These matters typically involve management of contaminated soils and may involve ground water remediation. Managed in conjunction with relevant federal, state and local agencies, they vary with respect to site conditions and locations, remedial requirements, complexity and sharing of responsibility. If they involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Duke Energy may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of the respective business or affiliate operations. Management believes that completion or resolution of these matters will have no material adverse effect on consolidated results of operations, cash flows or financial position.

Air Quality Control. In 1998, the Environmental Protection Agency (EPA) issued a final rule on regional ozone control that required 22 eastern states and the District of Columbia to revise their State Implementation Plans (SIPs) to significantly reduce emissions of nitrogen oxide by May 1, 2003. The EPA rule was challenged in court by various states, industry and other interests, including Duke Energy and the states of North Carolina and South Carolina. In 2000, the court upheld most aspects of the EPA rule. The same court subsequently extended the compliance deadline for emission reductions to May 31, 2004. Both North Carolina and South Carolina have revised their SIPs in response to the EPA s 1998 rule, and the EPA has approved those revisions. Duke Energy has incurred approximately $633 million in capital costs for emission controls through June 2004 for compliance with the EPA s rule. Management estimates that Duke Energy s remaining capital expenditures to complete the installation of emission controls needed to comply with the EPA s rule will be approximately $20 million. Those remaining expenditures will be incurred by Duke Power in the third quarter of 2004.

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Global Climate Change. The United Nations-sponsored Kyoto Protocol prescribes specific greenhouse gas emission reduction targets for developed countries as a response to concerns over global warming and climate change. The focus is on lowering emissions at the source, including fossil-fueled electric power generation and natural gas operations. Canada is presently the only country in which Duke Energy has assets that would have a greenhouse gas reduction obligation under the Kyoto Protocol. If Russia ratifies the Kyoto Protocol, it will enter into force and Canada will be obligated to reduce its average greenhouse gas emissions to 6% below 1990 levels over the period 2008 to 2012. In anticipation of the Protocol s entry into force, the Canadian government is developing an implementation plan that includes a carbon dioxide (CO_2) cap and trade program for large final emitters (LFE), and Parliament may consider authorizing legislation by the end of 2004 or early 2005. If an LFE program is enacted, then all of Duke Energy s Canadian operations would likely be subject to such a program, with compliance options ranging from the purchase of CO_2 emissions credits to actual emissions reductions at the source, or a combination of strategies. It is unclear how, or if, Canada s current CO_2 emissions management policy direction might change if Russia fails to ratify the Protocol. The recent Canadian elections, which resulted in a minority government led by the Liberal party, might also affect the final policy timing and outcome.

In 2001 President George W. Bush declared that the United States would not ratify the Kyoto Protocol. Instead, the U.S. greenhouse gas policy currently favors voluntary actions, continued research, and technology development over near-term mandatory greenhouse gas reduction requirements. Although several bills have been introduced in Congress that would compel CO_2 emissions reductions, none have advanced through the legislature. Presently there are no federal mandatory greenhouse gas reduction requirements. The likelihood of a federally mandated CO_2 emissions reduction program being enacted in the near future, or the specific requirements of any such regime that were to become law, is highly uncertain. Some states are contemplating or have taken steps to manage greenhouse gas emissions, and while a number of states in the Northeast and far West recently began discussing the possibility of regional greenhouse gas reduction programs in the future, the outcome of such discussions is very uncertain. If significant greenhouse gas emissions reduction policies are legally adopted or promulgated in the United States or its various states, those requirements could have far-reaching and significant implications for industry in those jurisdictions, including the respective energy sectors.

Duke Energy cannot estimate with certainty the potential effect of the Canadian greenhouse gas reduction policy currently under development, or estimate the potential effect of U.S. federal or state level greenhouse gas policy on future consolidated results of operations, cash flows or financial position due to the uncertainty of the Canadian policy and the speculative nature of U.S. federal and state policy. Duke Energy will continue to assess and respond to the potential implications of greenhouse gas policies applicable to Duke Energy s business operations in the United States, Canada and Latin America.

Extended Environmental Activities, Accruals. Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities were accruals related to extended environmental-related activities of $87 million as of June 30, 2004 and $94 million as of December 31, 2003. The accrual for extended environmental-related activities represents Duke Energy s provisions for costs associated with remediation activities at some of its current and former sites and certain other environmental matters. Management believes that completion or resolution of these matters will have no material adverse effect on consolidated results of operations, cash flows or financial position.

Litigation

New Source Review (NSR)/EPA Litigation. In 2000, the U.S. Justice Department, acting on behalf of the EPA, filed a complaint against Duke Energy in the U.S. District Court in Greensboro, North Carolina, for alleged violations of the NSR provisions of the Clean Air Act (CAA). The EPA claims that 29 projects performed at 25 of Duke Energy s coal-fired units were major modifications, as defined in the CAA, and that Duke Energy violated the CAA s NSR requirements when it undertook those projects without obtaining

permits and installing emission controls for sulfur dioxide, nitrogen oxide and particulate matter. The complaint asks the Court to order Duke Energy to stop operating the coal-fired units identified in the complaint, install additional emission controls and pay unspecified civil penalties.

Duke Energy asserts that there were no CAA violations because the applicable regulations do not require permitting in cases where the projects undertaken are routine or otherwise do not result in a net increase in emissions. Moreover, the EPA s allegations run counter to previous EPA guidance regarding the applicability of the NSR permitting requirements. In 2003, the Court issued an opinion in response to the parties motions for summary judgment which effectively adopted Duke Energy s position regarding the legal tests for determining what is routine and for calculation of emissions. Based upon a joint motion of the parties in the case, the Court on April 15, 2004 entered an Order and Final Judgment finding in favor of Duke Energy. The joint motion notified the Court that the government could not prove its allegations at trial against Duke Energy in light of the legal standards established by the Court in its 2003 order. The judgment reflects that Duke Energy did not violate the NSR program under the CAA. The government filed its appeal of the judgment to the U.S. 4th Circuit Court of Appeals in June 2004. Based on the current rulings by the trial court, Duke Energy does not believe the outcome of this matter will have a material adverse effect on its consolidated results of operations, cash flows or financial position. Subsequent rulings by an appellate court could significantly affect the outcome.

*Western Energy Litigation***.** Commencing in 2000, plaintiffs have filed 31 lawsuits in state and federal courts in California, Montana, Oregon and Washington against energy companies, including Duke Energy affiliates, and current and former Duke Energy executives. Most of the suits seek class-action certification on behalf of electricity and/or natural gas purchasers residing in the states of California, Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana. The plaintiffs allege that the defendants manipulated the electricity and/or natural gas markets in violation of state and/or federal antitrust, unfair business practices and other laws. Plaintiffs in some of the cases further allege that such activities, including engaging in round trip trades, providing false information to natural gas trade publications and unlawfully exchanging information resulted in artificially high energy prices. Plaintiffs seek aggregate damages or restitution of billions of dollars from the defendants. To date, eight suits have been dismissed on filed rate and federal preemption grounds. Plaintiffs are appealing the dismissals. One suit was dismissed voluntarily.

In July 2004, Duke Energy reached an agreement in principle resolving the class-action litigation involving the purchase of electricity filed on behalf of ratepayers and other electricity consumers in California, Washington, Oregon, Utah and Idaho. This agreement is part of a more comprehensive agreement involving FERC refunds and other proceedings. This agreement (the California Settlement) is addressed in more detail in the *Western Energy Regulatory Matters and Investigations* section below.

Suits filed on behalf of electricity ratepayers in other western states, on behalf of entities that purchased electricity directly from a generator and on behalf of natural gas purchasers, remain pending. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these lawsuits, but, based on rulings by trial courts and the California Settlement, Duke Energy does not presently believe the outcome of these matters will have a material adverse effect on its consolidated results of operations, cash flows or financial position. Subsequent rulings by appellate courts could significantly affect the outcome.

In 2003, Pacific Gas and Electric Company (PG&E) initiated arbitration proceedings regarding disputes with DETM relating to amounts owed in connection with the termination of a bilateral power contract between the parties in early 2001. PG&E sought in excess of $25 million from DETM pursuant to a disputed true-up agreement between the parties. The PG&E true-up dispute was resolved in connection with the California Settlement.

In 2002, Southern California Edison Company (SCE) initiated arbitration proceedings regarding disputes with DETM relating to amounts owed in connection with the termination of bilateral power contracts between the parties in early 2001. SCE disputes DETM s termination calculation and seeks in excess of $80 million.

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This dispute is not resolved in the California Settlement. Based on the level of damages claimed by the plaintiff and Duke Energy s assessment of possible outcomes in this matter, Duke Energy does not expect that the resolution of this matter will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

Western Energy Regulatory Matters and Investigations. Several investigations and regulatory proceedings at the state and federal levels are looking into the causes of high wholesale electricity prices in the western United States during 2000 and 2001. Duke Energy has resolved these issues, which are described in detail below, through the California Settlement.

In FERC refund proceedings, the FERC has ordered some sellers, including DETM, to refund, or to offset against outstanding accounts receivable, amounts billed for electricity sales in excess of a FERC-established proxy price. In 2002, the presiding administrative law judge in the FERC refund proceedings issued preliminary estimates that indicated DETM had refund liability of approximately $95 million.

The FERC issued staff recommendations and an order in 2003 relating to the refund proceeding and investigations into the causes of high wholesale electricity prices in the western United States during 2000 and 2001. The order modified the prior refund methodology by changing the gas proxy price used in the refund calculation. Duke Energy cannot predict with certainty the outcome of the methodology change, but Platts, an energy industry publication, reported that a FERC spokesman announced that the methodology change could increase the total aggregate refund amount for all generators from $1.8 billion to at least $3.3 billion. The 2003 order allowed generators to receive a gas cost credit in instances where companies incurred fuel costs exceeding the gas proxy price. DENA and DETM submitted gas cost data to the FERC and sought a gas price credit in the range of $72 million. The California parties challenged both the amount and availability of the credit. Resolution of the refund proceeding is included in the California Settlement.

In 2003, the FERC issued an Order to Show Cause concerning Enron-type gaming behavior, and a companion order requiring suppliers, including DETM, to justify bids in the CAISO and CalPX markets made above the level of $250 per megawatt hour from May 1, 2000 through October 1, 2000. Also in 2003, the FERC Staff and Duke Energy announced two agreements to resolve all matters at issue in both of those orders. Duke Energy agreed to pay up to $4.59 million to benefit California and western electricity consumers, pending final approval by the FERC. The FERC approved the agreement involving bidding practices and rejected the California parties objections to the agreement. The California parties sought review of the FERC s ruling on this agreement from the 9th Circuit U.S. Court of Appeals. On April 19, 2004, the administrative law judge reviewing the remaining agreement approved the settlement and rejected the California parties objections. That agreement was submitted to the FERC for review. The California parties challenge of the two agreements is resolved through the California Settlement.

At the state level, the California Public Utilities Commission (CPUC), a California State Senate Select Committee, the California Attorney General (with participation by the Attorneys General of Washington and Oregon) and the San Diego District Attorney are conducting formal and informal investigations involving Duke Energy regarding the California energy markets, including review of alleged manipulation of energy prices. In addition, the U.S. Attorney s Office in San Francisco served a grand jury subpoena on Duke Energy in 2002 seeking information relating to possible manipulation of the California electricity markets, including potential antitrust violations. All investigations, other than criminal investigations, are resolved through the California Settlement. Duke Energy does not believe the outcome of any remaining criminal investigation will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

In July 2004, Duke Energy reached an agreement in principle (the California Settlement), to settle the FERC refund proceedings and other significant litigation related to the western energy markets during 2000-2001. The parties to the settlement agreement include the FERC staff, the state of California, the state of Washington, the state of Oregon, PG&E, SCE, San Diego Gas & Electric Company, the California Department of Water Resources, the CPUC staff, private litigants and Duke Energy. The settlement is subject to approval by the FERC and the CPUC, and the class-action settlements are subject to court approval**.**

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As part of the agreement, Duke Energy will provide approximately $208 million in cash and credits. In exchange, the parties to the agreement will forgo all claims relating to refunds or other monetary damages for sales of electricity during the settlement period, and claims alleging Duke Energy received unjust or unreasonable rates for the sale of electricity during the settlement period. The settlement resolves:

All western refund proceedings pending before the FERC

Market price investigations by attorneys general in California, Washington and Oregon

Private electricity-related class-action litigation filed on behalf of California, Washington, Oregon, Idaho and Utah ratepayers

Natural gas price issues raised by the California attorney general, PG&E, SCE and San Diego Gas & Electric Company.

Duke Energy recorded an approximate $105 million pre-tax charge in the second quarter of 2004 at DENA to reflect the settlement agreement. This charge was recorded in Operation, Maintenance and Other on the Consolidated Statements of Operations.

Financial Effect of California Settlement (in millions)

Cash	$ 85
Write-off of receivables and credits due to Duke Energy	123
Settlement total	**208**
Reserves and offsets	(103)
Second quarter 2004 pre-tax earnings impact	$ 105

Trading Related Litigation. Beginning in 2002, 17 shareholder class-action lawsuits were filed against Duke Energy: 13 in the U.S. District Court for the Southern District of New York and four in the U.S. District Court for the Western District of North Carolina. These lawsuits arose out of allegations that Duke Energy improperly engaged in round trip trades which resulted in an alleged overstatement of revenues over a three-year period. By late 2003, the two federal courts had dismissed all 17 lawsuits. Plaintiffs in the New York cases have appealed the dismissal order to the 2nd Circuit U.S. Court of Appeals. Duke Energy intends to vigorously defend against that appeal. By letter dated April 16, 2004, Duke Energy received notice that a shareholder has reactivated a litigation demand sent to Duke Energy in 2002. Arising out of the same issues raised in the dismissed shareholder lawsuits, the notice states that the shareholder intends to initiate derivative shareholder litigation within 90 days from the date of the letter. Duke Energy s Board of Directors appointed a special committee to review the demand. The committee determined that there are no grounds to the allegations made in the derivative demand to commence or maintain an action on behalf of Duke Energy against the individuals named in the derivative demand, and that, accordingly, it would not be in the best interests of Duke Energy to bring such claims.

Since August 2003, plaintiffs have filed three class-action lawsuits in U.S. District Court for the Southern District of New York on behalf of entities who bought and sold natural gas futures and options contracts on the New York Mercantile Exchange during the years 2000 through 2002. The lawsuits initially named Duke Energy as a defendant, along with numerous other entities. In the latest consolidated complaint filed in January 2004, the plaintiffs dropped Duke Energy from the cases and added DETM as a defendant. Claiming defendants violated the Commodity Exchange Act by reporting false and misleading trading information to trade publications, resulting in monetary losses to the

plaintiffs, plaintiffs seek class action certification, unspecified damages and other relief. These cases are in very early stages. It is not possible to predict whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur.

Trading Related Investigations. In 2002 and 2003, Duke Energy responded to information requests and subpoenas from the Securities and Exchange Commission (SEC) and to grand jury subpoenas issued by the U.S. Attorney s office in Houston, Texas. The information requests and subpoenas sought documents and information related to trading activities, including so-called round-trip trading. Duke Energy received notice in 2002 that the SEC formalized its trading-related investigation and is cooperating with the SEC. The investigation remains open, and Duke Energy cannot predict the outcome.

On April 21, 2004, the Houston-based federal grand jury issued indictments for three former employees of DETMI Management Inc. (DETMI), which is one of two members of DETM. The indictments state that the employees did knowingly devise, intend to devise, and participate in a scheme to defraud and to obtain money and property from Duke Energy by means of materially false and fraudulent pretenses, representations and promises, and material omissions, and to deprive Duke Energy and its shareholders of the intangible right to the honest services of employees of Duke Energy. They further state that the alleged conduct was purportedly motivated, in part, by a desire to increase individual bonuses. Statements made by the U.S. Attorney s office characterized Duke Energy as a victim in this activity and commended Duke Energy for its cooperation with the investigation. The alleged conduct was identified in the spring and summer of 2002 and was related to DETM s Eastern Region trading activities. In 2002, Duke Energy recorded the appropriate financial adjustments associated with the cited activities, and did not consider the financial effect to be material. In February 2004, Duke Energy received a request for information from the U.S. Attorney s office in Houston focused on the natural gas price reporting activity of a former DETM trader. Duke Energy is cooperating with the government in this investigation and cannot predict the outcome.

Sonatrach/Citrus Trading Corporation (Citrus). Duke Energy LNG Sales Inc. (Duke LNG) claims in an arbitration that Sonatrach, the Algerian state-owned energy company, together with its subsidiary, Sonatrading Amsterdam B.V. (Sonatrading), breached their shipping obligations under a liquefied natural gas (LNG) purchase agreement and related transportation agreements (the LNG Agreements) relating to Duke LNG s purchase of LNG from Algeria and its transportation by LNG tanker to Lake Charles, Louisiana. Sonatrading and Sonatrach claim that Duke LNG repudiated the LNG Agreements by allegedly failing to perform LNG marketing obligations. In 2003, an arbitration panel issued a Partial Award on liability issues, finding that Sonatrach and Sonatrading breached their obligations to provide shipping, making them liable to Duke LNG for any resulting damages. The panel also found that Duke LNG breached the LNG Purchase Agreement by failing to perform marketing obligations. Also in 2003, Sonatrading terminated the LNG Agreements and seeks to recover resulting damages from Duke LNG. The final hearing on damages issues has been tentatively scheduled for September 2005.

In conjunction with the Sonatrach LNG Agreements, Duke LNG entered into a natural gas purchase contract (the Citrus Agreement) with Citrus. Citrus filed a lawsuit in Texas against Duke LNG (now pending in U.S. District Court in Houston, Texas) alleging that Duke LNG breached the Citrus Agreement by failing to provide sufficient volumes of gas to Citrus. Duke LNG contends that Sonatrach caused Duke LNG to experience a loss of LNG supply that affected Duke LNG s obligations and termination rights under the Citrus Agreement. Citrus seeks monetary damages and a judicial determination that Duke LNG did not experience such a loss. After Citrus filed its lawsuit, Duke LNG terminated the Citrus Agreement and filed a counterclaim asserting that Citrus had breached the agreement by, among other things, failing to provide sufficient security for the gas transactions. Citrus denies that Duke LNG had the right to terminate the agreement and contends that Duke LNG s termination of the agreement was itself a breach, entitling Citrus to terminate the agreement and recover damages. On March 16, 2004, Citrus filed suit against PanEnergy Corp in Harris County, Texas district court, alleging that PanEnergy is financially responsible for losses incurred by Citrus as a result of Duke LNG s alleged breaches. The action against PanEnergy has now been consolidated with the original Citrus lawsuit in federal court. No trial date has been set, and discovery is proceeding. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with the Sonatrach and Citrus matters.

Enron Bankruptcy. In December 2001, Enron filed for relief pursuant to Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. Other Enron affiliates have since filed for bankruptcy. Duke Energy affiliates engaged in transactions with various Enron entities prior to the bankruptcy filings. In 2001, Duke Energy recorded a reserve to offset its exposure to Enron. In 2002, various Enron trading entities demanded payment from DETM and DEM for some energy commodity sales transactions without regard to any set-off rights. DETM and DEM filed an adversary proceeding against Enron, seeking, among other things, a declaration affirming each plaintiff s right to set off its respective debts to Enron. In 2003, DETM, DEM and other Duke Energy affiliates entered into an agreement in principle with Enron and its trading entities to resolve the outstanding disputes pending before the bankruptcy court. The proposed agreement was approved by the Unsecured Creditor s Committee and on March 11, 2004, the bankruptcy court approved the settlement. No party appealed the court s approval of the agreement prior to the April 12, 2004 deadline, and the agreement is now final. The terms of the agreement are confidential but resulted in a net pre-tax gain in the second quarter of 2004 of approximately $130 million (net of minority interest expense of $5 million), due to the write-off of net payables to Enron that were on the Consolidated Balance Sheet. Of the gain, $113 million was recorded at DENA, $21 million at DEM and $1 million at Field Services as a credit to Operation, Maintenance and Other on the Consolidated Statements of Operations.

ExxonMobil Disputes. On April 8, 2004, Mobil Natural Gas, Inc. (MNGI) and 3946231 Canada, Inc. (3946231, and collectively with MNGI, ExxonMobil) filed a Demand for Arbitration against Duke Energy, DETMI, DTMSI Management Ltd. (DTMSI) and other affiliates of Duke Energy. MNGI and DETMI are the sole members of DETM. DTMSI and 3946231 are the sole beneficial owners of Duke Energy Marketing Limited Partnership (DEMLP, and with DETM, the Ventures). Among other allegations, ExxonMobil alleges that DETMI and DTMSI engaged in wrongful actions relating to affiliate trading, payment of service fees, expense allocations and distribution of earnings in breach of agreements and fiduciary duties relating to the Ventures. ExxonMobil seeks to recover actual damages, plus attorneys fees and exemplary damages not clearly quantified in the arbitration demand. Duke Energy denies these allegations, will vigorously defend against ExxonMobil s claims, and has filed counterclaims asserting that ExxonMobil breached its Ventures obligations and other contractual obligations. These matters are in very early stages. It is not possible to predict with certainty whether Duke Energy or any of its affiliates will incur any liability as a result of these matters, or to estimate the damages, if any, that might be incurred.

On November 13, 2003, MNGI filed a Demand for Arbitration against Duke Energy and DETMI. MNGI claims that, under the terms of the limited liability company agreement of DETM and general fiduciary principles, DETMI and Duke Energy have full financial responsibility for the settlement reached between DETM and the Commodity Futures Trading Commission (CFTC). MNGI demands reimbursement for a 40% share of the $28 million CFTC settlement, plus 40% of all related expenses incurred by DETM. On March 5, 2004, MNGI filed an amended claim, adding DENA as a party. In June 2004, the parties settled the dispute. Due to a previously established reserve, the settlement did not have a material adverse effect on Duke Energy s consolidated results of operations, cash flows or financial position.

Asbestos-related Injuries and Damages Claims. Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Power on its electric generation plants during the 1960s and 1970s. In late 1999, after experiencing a significant increase in claims and conducting a comprehensive review, Duke Energy recorded an $800 million accrual to reflect the purchase of a third-party insurance policy and to cover anticipated future claims not recoverable under that policy. The insurance policy, combined with amounts covered by self-insurance reserves, provides for paid claims to an aggregate of $1.6 billion. Duke Energy conducted another review in 2003, and continues to estimate that claims will not exceed such amount. Duke Energy is uncertain as to when claims will be received, and portions may not be received and paid for 30 or more years. While Duke Energy has recorded an accrual related to this estimated liability, such estimates cannot be made with certainty and may change. Factors such as the frequency and magnitude of claims could change the estimates of the injuries and damages liability and insurance recoveries and result in a different amount than is currently reflected in the

Consolidated Financial Statements. However, due to Duke Energy s insurance program relating to this liability, management believes that any changes in the estimates would have no material adverse effect on consolidated results of operations, cash flows or financial position.

Other Litigation and Legal Proceedings. Duke Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding performance, contracts, royalty disputes, mismeasurement and mispayment claims (some of which are brought as class actions), and other matters arising in the ordinary course of business, some of which involve substantial amounts. Management believes that the final disposition of these proceedings will have no material adverse effect on consolidated results of operations, cash flows or financial position.

14. Guarantees and Indemnifications

Duke Energy and its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party.

Mixed Oxide (MOX) Guarantees. Duke COGEMA Stone & Webster LLC (DCS) is the prime contractor to the U.S. Department of Energy (the DOE) under a contract (the Prime Contract) pursuant to which DCS will design, construct, operate and deactivate a MOX fuel fabrication facility (the MOX FFF). The domestic MOX fuel project was prompted by an agreement between the United States and the Russian Federation to dispose of excess plutonium in their respective nuclear weapons programs by fabricating MOX fuel and irradiating such MOX fuel in commercial nuclear reactors. As of June 30, 2004, Duke Energy, through its indirect wholly owned subsidiary, Duke Project Services Group Inc. (DPSG), held a 40% ownership interest in DCS.

The Prime Contract consists of a Base Contract phase and successive option phases. The DOE has the right to extend the term of the Prime Contract to cover the option phases on a sequential basis, subject to DCS and the DOE reaching agreement, through good-faith negotiations on certain remaining open terms applying to each of the option phases. As of June 30, 2004, DCS performance obligations under the Prime Contract included only the Base Contract phase and an initial option phase.

DPSG and the other owners of DCS have issued a guarantee to the DOE which, in conjunction with the applicable guarantee provisions as recently clarified in a contract amendment to the Prime Contract (collectively, the DOE Guarantee), obligates the owners of DCS to jointly and severally guarantee to the DOE that the owners of DCS will reimburse the DOE (in the event that DCS fails to provide such reimbursement) for any payments made by the DOE to DCS pursuant to the Prime Contract that DCS expends on costs that are not allowable under certain applicable federal acquisition regulations. DPSG has recourse to the other owners of DCS for any amounts paid under the DOE Guarantee in excess of its proportional ownership percentage of DCS. Although the DOE Guarantee does not provide for a specific limitation on a guarantor s reimbursement obligations, Duke Energy estimates that the maximum potential amount of future payments DPSG could be required to make under the DOE Guarantee is immaterial. As of June 30, 2004, Duke Energy had no liabilities recorded on its Consolidated Balance Sheet for the DOE Guarantee due to the immaterial amount of the estimated fair value of such guarantee.

In connection with the Prime Contract, Duke Energy, through its Duke Power franchised electric business, has entered into a subcontract with DCS (the Duke Power Subcontract) pursuant to which Duke Power will prepare its McGuire and Catawba nuclear reactors (the Mission Reactors) for use of the MOX fuel, and which also includes terms and conditions applicable to Duke Power s purchase of MOX fuel produced at the MOX FFF for use in the Mission Reactors. The Duke Power Subcontract consists of a Base

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Subcontract phase and successive option phases. DCS has the right to extend the term of the Duke Power Subcontract to cover the option phases on a sequential basis, subject to Duke Power and DCS reaching agreement, through good-faith negotiations on certain remaining open terms applying to each of the option phases. As of June 30, 2004, DCS performance obligations under the Duke Power Subcontract included only the Base Subcontract phase and the first option phase.

DPSG and the other owners of DCS have issued a guarantee to Duke Power (the Duke Power Guarantee) pursuant to which the owners of DCS jointly and severally guarantee to Duke Power all of DCS obligations under the Duke Power Subcontract or any other agreement between DCS and Duke Power implementing the Prime Contract. DPSG has recourse to the other owners of DCS for any amounts paid under the Duke Power Guarantee in excess of its proportional ownership percentage of DCS. Even though the Duke Power Guarantee does not provide for a specific limitation on a guarantor s guarantee obligations, it does provide that any liability of such guarantor under the Duke Power Guarantee is directly related to and limited by the terms and conditions in the Duke Power Subcontract and any other agreements between Duke Power and DCS implementing the Prime Contract. Duke Energy is unable to estimate the maximum potential amount of future payments DPSG could be required to make under the Duke Power Guarantee due to the uncertainty of whether:

DCS will exercise its options under the Duke Power Subcontract, which will depend upon whether the DOE will exercise its options under the Prime Contract

the parties to the Prime Contract and the Duke Power Subcontract, respectively, will reach agreement on the remaining open terms for each option phase under the contracts, and if so, what the terms and conditions might be and

the U.S. Congress will authorize funding for DCS work under the Prime Contract, which will affect DCS decision whether to exercise its options under the Duke Power Subcontract.

Duke Energy has not recorded on its Consolidated Balance Sheet any liability for the potential exposure under the Duke Power Guarantee per FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, because DPSG and Duke Power are under common control.

Other Guarantees and Indemnifications. Duke Capital has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. The maximum potential amount of future payments Duke Capital could have been required to make under these performance guarantees as of June 30, 2004 was approximately $750 million. Of this amount, approximately $475 million relates to guarantees of the payment and performance of less than wholly owned consolidated entities. Approximately $45 million of the performance guarantees expire between 2004 and 2005, and approximately $300 million expires in 2006 and thereafter; the remaining performance guarantees have no contractual expiration. Additionally, Duke Capital has issued joint and several guarantees to some of the D/FD project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments. These guarantees have no contractual expiration and no stated maximum amount of future payments that Duke Capital could be required to make. Additionally, Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners. In accordance with the D/FD partnership agreement, each of the partners is responsible for 50% of any payments to be made under those guarantees.

Westcoast has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method projects, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of an unconsolidated entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees as of June 30, 2004 was approximately $100 million. Of those guarantees, approximately $30 million expire from 2004 to 2006, with the remainder expiring after 2006 or having no contractual expiration.

Duke Capital uses bank-issued stand-by letters of credit to secure the performance of non-wholly owned entities to a third party or customer. Under these arrangements, Duke Capital has payment obligations to the issuing bank which are triggered by a draw by the third party or customer due to the failure of the non-wholly owned entity to perform according to the terms of its underlying contract. Most of these letters of credit expire in 2004. The maximum potential amount of future payments Duke Capital could have been required to make under these letters of credit as of June 30, 2004 was approximately $100 million. Of this amount, approximately $15 million relates to letters of credit issued on behalf of less than wholly owned consolidated entities.

Duke Capital has guaranteed the issuance of surety bonds, obligating itself to make payment upon the failure of a non-wholly owned entity to honor its obligations to a third party. As of June 30, 2004, Duke Capital had guaranteed approximately $100 million of outstanding surety bonds related to obligations of non-wholly owned entities. The majority of these bonds expire in various amounts between 2004 and 2005. Of this amount, approximately $15 million relates to obligations of less than wholly owned consolidated entities.

Natural Gas Transmission and International Energy have issued guarantees of debt and performance guarantees associated with non-consolidated entities and less than wholly-owned entities. If such entities were to default on payments or performance, Natural Gas Transmission or International Energy would be required under the guarantees to make payment on the obligation of the non-consolidated entity. As of June 30, 2004, Natural Gas Transmission was the guarantor of approximately $15 million of debt at Westcoast associated with less than wholly owned entities, with no contractual expiration. International Energy was the guarantor of approximately $10 million of performance guarantees associated with less than wholly-owned entities, most of which expire in 2004.

Duke Energy has issued guarantees to customers or other third parties related to the payment or performance obligations of certain entities that were previously wholly owned but which have been sold to third parties, such as DukeSolutions Inc. (DukeSolutions) and Duke Engineering & Services Inc (DE&S). These guarantees are primarily related to payment of lease obligations, debt obligations, and performance guarantees related to goods and services provided. Duke Energy has received back-to-back indemnification from the buyer of DE&S indemnifying Duke Energy for any amounts paid by Duke Energy related to the DE&S guarantees. Duke Energy also received indemnification from the buyer of DukeSolutions for the first $2.5 million paid by Duke Energy related to the Duke Solutions guarantees. Further, Duke Energy granted indemnification to the buyer with respect to losses arising under some energy services agreements retained by DukeSolutions after the sale, provided that the buyer agreed to bear 100% of the performance risk and 50% of any other risk up to an aggregate maximum of $2.5 million (less any amounts paid by the buyer under the indemnity discussed above). Additionally, for certain performance guarantees, Duke Energy has recourse to subcontractors involved in providing services to a customer. These guarantees have various terms ranging from 2004 to 2019, with others having no specific term. Duke Energy is unable to estimate the total maximum potential amount of future payments under these guarantees, since some of the underlying agreements have no limits on potential liability.

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy s maximum potential exposure under these indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Duke Energy is unable to estimate the total maximum potential amount of future payments under these indemnification agreements due to several factors, including uncertainty as to whether claims will be made.

As of June 30, 2004, the amounts recorded for the guarantees and indemnifications mentioned above are immaterial, both individually and in the aggregate.

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15. New Accounting Standards

The following new accounting standards have been adopted by Duke Energy subsequent to January 1, 2003 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. In April 2003, the FASB issued SFAS No. 149, which amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities, including the qualifications for the normal purchases and normal sales exception, under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. This amendment reflects decisions made by the FASB and the Derivative Implementation Group (DIG) process in connection with issues raised about the application of SFAS No. 133. Generally, the provisions of SFAS No. 149 are to be applied prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The provisions of SFAS No. 149 which resulted from the DIG process and became effective in quarters beginning before June 15, 2003 continue to be applied based on their original effective dates. Duke Energy adopted the provisions of SFAS No. 149 on July 1, 2003. Certain modifications and changes to the applicability of the normal purchase and normal sales scope exception for contracts to deliver electricity led Duke Energy to re-evaluate its accounting policy for forward sales contracts. As a result, Duke Energy elected to designate substantially all forward contracts to sell power entered into after July 1, 2003 as cash flow hedges on a prospective basis. Contracts that were being accounted for under the normal purchases and normal sales exception under SFAS No. 133 as of June 30, 2003 will continue to be accounted for under such exception, including any modifications to those contracts, as long as the requirements for applying the normal purchases and normal sales exception are met.

SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity. In May 2003, the FASB issued SFAS No. 150 which establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equities. Under SFAS No. 150, those instruments are required to be classified as liabilities in the statement of financial position. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets, and certain obligations that can be settled with shares of stock. SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and has been applied to Duke Energy s existing financial instruments beginning July 1, 2003.

Duke Energy s financial statements do not include any effects for the application of SFAS No. 150 to non-controlling interests in certain limited-life entities, which are required to be liquidated or dissolved on a certain date, based on the decision of the FASB in November 2003 to defer these provisions indefinitely with the issuance of FASB Staff Position 150-3, Effective Date, Disclosures, and Transition for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests under FASB Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity. Duke Energy has a controlling interest in a limited-life entity in Bolivia, which is required to be liquidated 99 years after formation. A non-controlling interest in the entity is held by third parties. Upon termination or liquidation of the entity in 2094, the remaining assets of the entity are to be sold, the liabilities liquidated and any remaining cash distributed to the owners based upon their ownership percentages. As of June 30, 2004 the carrying value of the entity s non-controlling interest of approximately $47 million approximates its fair value. Duke Energy continues to evaluate the potential significance of these aspects of SFAS No. 150, but does not anticipate this will have a material impact on Duke Energy s consolidated results of operations, cash flows or financial position. SFAS No. 150 continues to be interpreted by the FASB and it is possible that significant future changes could be made by the FASB. Therefore, Duke Energy is not able to conclude whether such future changes would materially affect the amounts already recorded and disclosed under the provisions of SFAS No. 150.

FASB Interpretation No. 46 (FIN 46), Consolidation of Variable Interest Entities. In January 2003, the FASB issued FIN 46 which requires the primary beneficiary of a variable interest entity s activities to

consolidate the variable interest entity. FIN 46 defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. The primary beneficiary absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity s activities. In December 2003, the FASB issued FIN 46 (Revised December 2003) (FIN 46R), Consolidation of Variable Interest Entities An Interpretation of ARB No. 51, which supercedes and amends the provisions of FIN 46. While FIN 46R retains many of the concepts and provisions of FIN 46, it also provides additional guidance and additional scope exceptions, and incorporates FASB Staff Positions related to the application of FIN 46.

The provisions of FIN 46 apply immediately to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003, while the provisions of FIN 46R are required to be applied to those entities, except for special purpose entities, by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy). For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 or FIN 46R was required to be applied to special-purpose entities by the end of the first reporting period ending after December 15, 2003 (December 31, 2003 for Duke Energy), and was required to be applied to all other non-special purpose entities by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy). FIN 46 and FIN 46R may be applied prospectively with a cumulative-effect adjustment as of the date it is first applied, or by restating previously issued financial statements with a cumulative-effect adjustment as of the beginning of the first year restated. FIN 46 and FIN 46R also require certain disclosures of an entity s relationship with variable interest entities.

Duke Energy has not identified any material variable interest entities created, or interests in variable entities obtained, after January 31, 2003 which require consolidation or disclosure under FIN 46R. Under the provisions of FIN 46R, effective March 31, 2004, Duke Energy has consolidated certain non-special purpose operating entities, previously accounted for under the equity method of accounting. These entities, which are substantive entities, had total assets of approximately $210 million as of June 30, 2004. As a result of consolidating these entities, inclusive of intercompany eliminations, the impact to Duke Energy s total assets was not material. Duke Energy adopted the provisions of FIN 46R on December 31, 2003, related to its special-purpose entities consisting of the trust subsidiaries that issued trust preferred securities. Since Duke Energy is not the primary beneficiary of those trust subsidiaries, those entities have been deconsolidated in the accompanying Consolidated Financial Statements. As a result, affiliate debt to the trusts is reflected in Long-term Debt in the Consolidated Balance Sheets. Interest paid to the subsidiary trust is classified as Interest Expense in the accompanying Consolidated Statements of Operations for periods after December 31, 2003. Additionally, Duke Energy previously had a significant variable interest in, but was not the primary beneficiary of, DCS. However, as further discussed in Note 14, Duke Energy no longer holds a significant variable interest in DCS as a result of the clarification in a contract amendment received in April 2004.

Various changes and clarifications to the provisions of FIN 46 have been made by the FASB since its original issuance in January 2003. While not anticipated at this time, any additional clarifying guidance or further changes to these complex rules could have an impact on Duke Energy s Consolidated Financial Statements.

EITF Issue No. 01-08, Determining Whether an Arrangement Contains a Lease. In May 2003, the EITF reached consensus in EITF Issue No. 01-08 to clarify the requirements of identifying whether an arrangement should be accounted for as a lease at its inception. The guidance in the consensus is designed to broaden the scope of arrangements accounted for as leases. EITF Issue No. 01-08 requires both parties to an arrangement to determine whether a service contract or similar arrangement is or includes a lease within the scope of SFAS No. 13, Accounting for Leases. Duke Energy has historically provided and leased storage capacity to outside parties, as well as entered into pipeline and electricity capacity agreements, both as the lessee and as a lessor. The accounting requirements under the consensus may impact the timing of revenue and expense recognition, and amounts previously reported as revenues may be required to be reported as rental or lease income. Should capital lease treatment be necessary, purchasers of transportation, electricity capacity and storage services are required to recognize assets on their balance sheets. The

consensus is being applied prospectively to arrangements agreed to, modified, or acquired on or after July 1, 2003. Previous arrangements that would be leases or would contain a lease according to the consensus will continue to be accounted for under historical accounting. The adoption of EITF Issue No. 01-08 did not have a material effect on Duke Energy s consolidated results of operations, cash flows or financial position.

EITF Issue No. 03-06, Participating Securities and the Two-Class Method under FASB Statement No. 128, Earnings Per Share . In March 2004, the EITF reached consensus in EITF Issue No. 03-06, which requires the two-class method for calculating basic earnings per share (EPS) for certain securities that are considered to participate in earnings with common shareholders. EITF Issue No. 03-06 is effective for Duke Energy beginning with the second quarter of 2004, and may require restatement of previously reported EPS measures if any changes to the EPS calculation are required pursuant to the consensus. Duke Energy s Equity Units are considered participating securities under the consensus; however, such participation is contingent upon future events. As a result, the Equity Units will not impact the calculation of EPS until the occurrence of the future events.

EITF Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes.* In July 2003, the EITF reached consensus in EITF Issue No. 03-11 that determining whether realized gains and losses on derivative contracts not held for trading purposes should be reported on a net or gross basis is a matter of judgment that depends on relevant facts and circumstances and the economic substance of the transaction. In analyzing those facts and circumstances, EITF Issue No. 99-19, Reporting Revenue Gross as a Principle versus Net as an Agent, and APB Opinion No. 29, Accounting for Nonmonetary Transactions, should be considered. EITF Issue No. 03-11 was effective for transactions or arrangements entered into after September 30, 2003. The adoption of EITF Issue No. 03-11 did not have a material effect on Duke Energy s consolidated results of operations, cash flows or financial position.

FASB Staff Position (FSP) FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.* In May 2004, the FASB staff issued FSP FAS 106-2, which superseded FSP FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. FSP FAS 106-2 provides accounting guidance for the effects of the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). The Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care benefit plans that include prescription drug benefits. FSP FAS 106-2 requires a sponsor to determine if its prescription drug benefits are actuarially equivalent to the drug benefit provided under Medicare Part D as of the date of enactment of the Act, and if it is therefore entitled to receive the subsidy. If a sponsor determines that its prescription drug benefits are actuarially equivalent to the Medicare Part D benefit, the sponsor should recognize the expected subsidy in the measurement of the accumulated postretirement benefit obligation (APBO) under SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions. Any resulting reduction in the APBO is to be accounted for as an actuarial experience gain. The subsidy s reduction, if any, of the sponsor s share of future costs under its prescription drug plan is to be reflected in current-period service cost.

The provisions of FSP FAS 106-2 are effective for the first interim period beginning after June 15, 2004 for all public companies, with early application encouraged. Duke Energy adopted FSP FAS 106-2 retroactively to the date of enactment of the Act, December 8, 2003, as allowed by the FSP. See Note 6 for discussion of the effects of adopting this FSP.

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The following new accounting standard has been issued but has not yet been fully adopted by Duke Energy as of June 30, 2004:

Revised SFAS No. 132, Employers Disclosures about Pensions and Other Postretirement Benefits. In December 2003, the FASB revised the provisions of SFAS No. 132 to include additional disclosures related to defined-benefit pension plans and other defined-benefit post-retirement plans, such as the following:

The long-term rate of return on plan assets, along with a narrative discussion on the basis for selecting the rate of return used

Information about plan assets for each major asset category (i.e. equity securities, debt securities, real estate, etc.) along with the targeted allocation percentage of plan assets for each category and the actual allocation percentages at the measurement date

The amount of benefit payments expected to be paid in each of the next five years and the following five-year period in the aggregate

The current best estimate of the range of contributions expected to be made in the following year

The accumulated benefit obligation for defined-benefit pension plans

Disclosure of the measurement date utilized.

Additionally, interim reports require additional disclosures related to the components of net periodic pension costs and the amounts paid or expected to be paid to the plan in the current fiscal year, if materially different than amounts previously disclosed. The provisions of revised SFAS No. 132 do not change the measurement or recognition provisions of defined-benefit pension and post-retirement plans as required by previous accounting standards. The provisions of revised SFAS No. 132 were applied by Duke Energy effective December 31, 2003 with the interim period disclosures applied for the quarter ended June 30, 2004, except for the disclosure provisions of estimated future benefit payments which will be effective for Duke Energy for the year ending December 31, 2004.

16. Subsequent Events

On July 2, 2004, Duke Energy realigned certain subsidiaries resulting in all of its wholly owed merchant generation facilities being owned by a newly created entity, Duke Energy Americas, LLC (DEA), a directly wholly owned subsidiary of Duke Capital. DEA and Duke Capital are pass-through entities for U.S. income tax purposes. As a result of these changes, Duke Capital will recognize a federal and state tax expense of approximately $900 million in the third quarter of 2004 from the elimination of the deferred tax assets that existed on its balance sheet prior to the July 2, 2004 reorganization. Correspondingly, Duke Energy, the parent of Duke Capital, will reflect, through consolidation, the elimination of the $900 million deferred tax asset at Duke Capital and the creation of a deferred tax asset of approximately $900 million on its balance sheet. Duke Energy will additionally recognize an approximate $45 million income tax benefit and corresponding deferred tax asset as a result of restating its deferred taxes to reflect a change in state tax rates. In future periods, as these deferred tax assets are converted into cash due to the realization of certain tax losses, Duke Energy intends to infuse the related cash flows back into Duke Capital. Most of these cash benefits result from tax losses arising from the sales of DENA s southeastern U.S. generation assets and the Moapa facility.

In July 2004, Duke Energy entered into the California Settlement, an agreement in principle to settle the FERC refund proceedings and other significant litigation related to the western energy markets during 2000-2001. For information related to this agreement, see Note 13.

As disclosed in Note 8 to the Consolidated Financial Statements, Assets Held for Sale and Discontinued Operations, in Duke Energy s Quarterly Report on Form 10-Q/A for March 31, 2004, on May 4, 2004 Duke Energy announced the sale of its merchant generation business in the southeastern United States to KGen Partners LLC (KGen). The sale transaction has obtained all required regulatory approvals and consents and closed on August 5, 2004. This transaction resulted in a cumulative pre-tax loss of approximately $367 million, of which approximately $360 million was recognized in the first quarter of 2004 to reduce the carrying value of those assets to their estimated fair values, while the remaining amount of the loss will be recognized by Duke

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Energy in the third quarter of 2004. Subsequent to the closing of the transaction, DENA will continue to provide certain transitional services and operating and maintenance services for the sold assets, including potential exercise of limited plant dispatch rights for a period not to exceed six months form the date of August 5, 2004. DENA anticipates recognizing the sale transaction in the third quarter of 2004, pending resolution of certain continuing involvement provisions.

In conjunction with the sale of DENA s southeastern assets to KGen, Duke Energy arranged a letter of credit with a face amount of $120 million in favor of Georgia Power Company, to secure obligations of a KGen subsidiary under a seven-year power sales agreement, commencing in May 2005, under which KGen will provide power from its Murray facility to Georgia Power. Duke Energy is the primary obligor to the letter of credit provider, but KGen has an obligation to reimburse Duke Energy for any payments made by it under the letter of credit, as well as expenses incurred by Duke Energy in connection with the letter of credit. Duke Energy will operate the Murray facility under an operation and maintenance agreement with a KGen subsidiary.

For information on subsequent events related to debt and credit facilities, see Note 5.

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

INTRODUCTION

Management s Discussion and Analysis should be read with the Consolidated Financial Statements.

Overview of Business Strategy and Economic Factors

Duke Energy s business strategy is to develop integrated energy businesses in targeted regions where Duke Energy s capabilities in developing energy assets; operating power plants, natural gas liquid (NGL) plants and natural gas pipelines; optimizing commercial operations, including an affiliated real estate operation; and managing risk can provide comprehensive energy solutions for customers and create value for shareholders. For an in-depth discussion of Duke Energy s business strategy and economic factors, see Management s Discussion and Analysis of Results of Operations and Financial Condition in Duke Energy s Annual Report on Form 10-K/A for the year ended December 31, 2003.

RESULTS OF OPERATIONS

Results of Operations and Variances (in millions)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2004	**2003[a]**	**Increase (Decrease)**	**2004**	**2003[a]**	**Increase (Decrease)**
Operating revenues	$ 5,360	$ 5,152	$ 208	$ 11,049	$ 11,322	$ (273)
Operating expenses	4,584	4,486	98	9,561	9,771	(210)
Gains on sales of investments in commercial and multi-family real estate	62	9	53	121	11	110
(Losses) gains on sales of other assets, net	(11)	1	(12)	(349)	3	(352)
Operating income	827	676	151	1,260	1,565	(305)
Other income and expenses, net	89	295	(206)	148	369	(221)
Interest expense	337	325	12	693	651	42
Minority interest expense	41	50	(9)	79	100	(21)
Earnings from continuing operations before income taxes	538	596	(58)	636	1,183	(547)
Income tax expense from continuing operations	133	195	(62)	166	390	(224)

Income from continuing operations	405	401	4	470	793	(323)
Income from discontinued operations, net of tax	27	23	4	273	18	255
Income before cumulative effect of change in accounting principle	432	424	8	743	811	(68)
Cumulative effect of change in accounting principle, net of tax and minority interest					(162)	162
Net income	432	424	8	743	649	94
Dividends and premiums on redemption of preferred and preference stock	3	7	(4)	5	10	(5)
Earnings available for common stockholders	$ 429	$ 417	$ 12	$ 738	$ 639	$ 99

[a]As revised, see Note 1 to the Consolidated Financial Statements

Overview of Drivers and Variances

Three Months Ended June 30, 2004 as Compared to June 30, 2003. Earnings available for common stockholders were relatively flat for the quarter, compared to the prior year. Significant increases for the quarter included:

A $130 million (net of minority interest) pre-tax gain related to the settlement of the Enron bankruptcy proceedings (see Note 13 to the Consolidated Financial Statements)

A $39 million net increase in the pre-tax gains ($30 million increase to the after tax gains) originally recorded on the sales of International Energy s Asia-Pacific power generation and natural gas transmission business (see Note 9 to the Consolidated Financial Statements) and its European operations

The release of various income tax reserves totaling approximately $52 million (see Note 1 to the Consolidated Financial Statements)

Increased earnings at Crescent, due to the sale of the Alexandria land tract in the Washington, D.C. area and increased residential developed lot sales, and

Increased earnings at Field Services, due primarily to the favorable effects of commodity prices, net of hedging.

Those items were offset by:

A $105 million pre-tax charge related to the California and western U.S. energy markets settlement (see Note 13 to the Consolidated Financial Statements)

A $175 million pre-tax gain in 2003 from the sale of Duke Energy North America s (DENA s) 50% interest in Duke/UAE Ref-Fuel, and
An $80 million decrease in DENA s 2004 total gross margin from lower net sales, lower values realized from hedge positions and lower mark-to-market earnings.

Six Months Ended June 30, 2004 as Compared to June 30, 2003. In addition to the quarterly items described above, significant items that contributed to increased earnings available for common stockholders for the six months included:

A $256 million pre-tax gain ($238 million net of tax) recorded in the first quarter of 2004 on the sale of International Energy s Asia-Pacific power generation and natural gas transmission business (see Note 9 to the Consolidated Financial Statements)

Charges in 2003 related to changes in accounting principles of $162 million, net of tax and minority interest

Increased 2004 earnings at Field Services due to improved results from trading and marketing activities, and

Increased land management (legacy land sales) at Crescent, due to several large sales closed in the first quarter of 2004.

Those items were partially offset by:

An approximate $360 million pre-tax charge in the first quarter of 2004 associated with the announced sale of DENA s southeastern plants (see Note 9 to the Consolidated Financial Statements), and

An additional $229 million decrease in DENA s 2004 total gross margin from lower net sales, lower values realized from hedge positions and lower mark-to-market earnings.

On a consolidated and a segment reporting basis, June 30, 2004 results may not be indicative of the full year. Management has not changed its financial outlook for the remainder of the year for Duke Energy, nor the estimated EBIT growth targets for any of the business segments over the next three years.

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Consolidated Operating Revenues

Three Months Ended June 30, 2004 as Compared to June 30, 2003. The increase was driven by:

A $150 million increase in Regulated Electric revenues, due primarily to favorable weather and increased unbilled fuel revenues at Franchised Electric; and

A $59 million increase in Non-regulated Electric, Natural Gas, Natural Gas Liquids and Other revenues, driven by increased revenues at Field Services, due primarily to increased natural gas and NGL prices, partially offset by decreased revenues at DENA related to decreased sales volumes as a result of the wind-down of Duke Energy Trading and Marketing, LLC (DETM, Duke Energy s 60/40 joint venture with ExxonMobil Corporation).

Six Months Ended June 30, 2004 as Compared to June 30, 2003. The decrease was driven by a $497 million decrease in Non-regulated Electric, Natural Gas, Natural Gas Liquids and Other revenues, due primarily to:

Decreased revenues at DENA related to decreased sales volumes as a result of the wind-down of DETM and decreased gas prices, and

Decreased revenues at Duke Energy Merchants LLC (DEM), as a result of the decision in 2003 to exit the refined products and NGL business at DEM, partially offset by

Increased revenues at Field Services, due primarily to an increase in NGL prices and volumes.

Partially offsetting the decrease in Non-regulated Electric, Natural Gas, Natural Gas Liquids and Other revenues were:

A $122 million increase in Regulated Electric revenues, due primarily to favorable weather and increased unbilled fuel revenues at Franchised Electric, and

A $102 million increase in Regulated Natural Gas revenues, due primarily to foreign currency impacts related to Natural Gas Transmission s Canadian operations due to the strengthening Canadian dollar.

For a more detailed discussion of operating revenues, see the segment discussions that follow.

Consolidated Operating Expenses

Three Months Ended June 30, 2004 as Compared to June 30, 2003. The increase was driven by a $238 million increase in Fuel Used in Electric Generation and Purchased Power, due primarily to:

Increased plant fuel costs at DENA, due primarily to overall higher average realized natural gas prices due to lower value recognized from financial gas hedges, and

Increased fuel expenses at Franchised Electric, due to increased coal costs and increased sales to retail customers.

Partially offsetting the above increase was a $70 million decrease in Natural Gas and Petroleum Products Purchased, due primarily to:

Decreased natural gas purchases at DENA as a result of the continued wind down of DETM s operations, and

Decreased purchases at DEM, due to the decision in 2003 to exit the refined products and NGL business at DEM, partially offset by

Increased costs for raw natural gas at Field Services.

Also offsetting the above increase was a $44 million decrease in Operation, Maintenance and Other, due primarily to:

The pre-tax gain related to the settlement of the Enron bankruptcy proceedings, as previously described, partially offset by

The charge related to the California and western U.S. energy markets settlement, as previously described.

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Six Months Ended June 30, 2004 as Compared to June 30, 2003. The decrease was driven by a $530 million decrease in Natural Gas and Petroleum Products Purchased, due primarily to:

- Decreased natural gas purchases at DENA as a result of the continued wind down of DETM s operations, and

- Decreased purchases at DEM, due to the decision in 2003 to exit the refined products and NGL business at DEM.

Partially offsetting the above decrease was a $254 million increase in Fuel Used in Electric Generation and Purchased Power, due to the same factors that caused the quarterly variance, as described above.

Also offsetting the above decrease was a $73 million increase in Operation, Maintenance and Other, due primarily to:

- The charge related to the California and western U.S. energy markets settlement, as previously described

- Increased foreign currency impacts related to Natural Gas Transmission s Canadian operations due to the strengthening Canadian dollar, and

- An increase in the volume of Crescent s developed lot sales, partially offset by

- The pre-tax gain related to the settlement of the Enron bankruptcy proceedings, as previously described.

For a more detailed discussion of operating expenses, see the segment discussions that follow.

Consolidated Gains on Sales of Investments in Commercial and Multi-Family Real Estate

Three Months Ended June 30, 2004 as Compared to June 30, 2003. The increase was due to a $49 million increase in real estate land sales due primarily to the sale of the Alexandria land tract in the Washington, D.C. area in June 2004.

Six Months Ended June 30, 2004 as Compared to June 30, 2003. The increase was due primarily to:

- A $20 million increase in commercial project sales, due to the sale of a commercial project in the Washington, D.C. area in March 2004, compared to no commercial project sales in the first six months of 2003

A $49 million increase in real estate land sales due primarily to the sale of the Alexandria land tract in the Washington, D.C. area in June 2004, and

A $42 million increase in legacy land sales, due to several large sales closed in the first quarter of 2004.

Consolidated (Losses) Gains on Sales of Other Assets, net

Three Months Ended June 30, 2004 as Compared to June 30, 2003. Consolidated (losses) gains on sales of other assets for the quarter were relatively flat, compared to the prior year quarter.

Six Months Ended June 30, 2004 as Compared to June 30, 2003. The decrease was due primarily to an approximate $360 million loss in 2004 associated with the announced sale of DENA s southeastern plants, as discussed above.

Consolidated Operating Income

Three Months Ended June 30, 2004 as Compared to June 30, 2003. The increase was due primarily to:

- Increased operating income at Field Services, due to the favorable effects of commodity prices, net of hedging, and
- Increased operating income at Crescent, due to the sale of the Alexandria land tract in the Washington, D.C. area and increased residential developed lot sales, partially offset by
- Decreased operating income at DENA, due primarily to decreased total gross margin from lower net sales, lower values realized from hedge positions and lower mark-to-market earnings.

Six Months Ended June 30, 2004 as Compared to June 30, 2003. The decrease was due primarily to:

- Decreased operating income at DENA, due primarily to the 2004 loss on the sale of DENA s southeastern plants, and decreased total gross margin from lower net sales, lower values realized from hedge positions and lower mark-to-market earnings, partially offset by:
- Increased operating income at Field Services, due to the favorable effects of commodity prices, net of hedging, and improved results from Duke Energy Field Services LLC s (DEFS) trading and marketing activities, and
- Increased operating income at Crescent, due to the sale of a commercial project and the Alexandria land tract in the Washington, D.C. area, increased legacy land sales and increased residential developed lot sales.

For more detailed discussions, see the segment discussions that follow.

Consolidated Other Income and Expenses

Other Income and Expenses decreased $206 million for the three months and $221 million for the six months ended June 30, 2004, compared to the same periods in 2003, due primarily to a $175 million gain in the second quarter of 2003 from the sale of DENA s 50% interest in Duke/UAE Ref-Fuel and gains of $31 million on the sales of Natural Gas Transmission s interests in Alliance Pipeline and the associated Aux Sable liquids plant in the second quarter of 2003.

Segment Results

Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages legacy land holdings, primarily in the southeastern and southwestern United States. All other entities previously part of Other Operations and now within Other still remain, primarily: DukeNet Communications LLC, DEM and Duke Energy s 50% equity investment in Duke/Fluor Daniel (D/FD). Unallocated corporate costs are also recorded in Other in the following table.

Management evaluates segment performance primarily based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT). On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash and cash equivalents are managed centrally by Duke Energy, so the gains and losses on foreign currency remeasurement associated with cash balances, and interest income on those balances, are generally excluded from the segments EBIT. Management considers segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of Duke Energy s ownership interest in operations without regard to financing methods or capital structures.

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EBIT is viewed as a non-Generally Accepted Accounting Principles (GAAP) measure under the rules of the Securities and Exchange Commission (SEC). EBIT should not be considered an alternative to, or more meaningful than, operating income or operating cash flow as determined in accordance with GAAP. Duke Energy s EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner.

EBIT by Business Segment (in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Franchised Electric	$ 338	$ 316	$ 762	$ 770
Natural Gas Transmission	311	306	709	729
Field Services	94	53	186	83
Duke Energy North America	(39)	211	(596)	234
International Energy	68	91	97	131
Crescent	87	21	147	21
Total reportable segment EBIT	859	998	1,305	1,968
Other	(26)	(69)	(31)	(117)
Total reportable segment and Other EBIT	833	929	1,274	1,851
Interest expense	(337)	(325)	(693)	(651)
Minority interest expense and other [a]	42	(8)	55	(17)
Consolidated earnings from continuing operations before income taxes	$ 538	$ 596	$ 636	$ 1,183

[a] Includes interest income, foreign currency remeasurement gains and losses, and additional minority interest expense not allocated to the segment results.

The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

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Franchised Electric

(in millions, except where noted)	Three Months Ended June 30, 2004	2003	Increase (Decrease)	Six Months Ended June 30, 2004	2003	Increase (Decrease)
Operating revenues	$ 1,228	$ 1,110	$ 118	$ 2,499	$ 2,361	$ 138
Operating expenses	896	809	87	1,747	1,622	125
Gains on sales of other assets, net	3		3	3	1	2
Operating income	335	301	34	755	740	15
Other income, net of expenses	3	15	(12)	7	30	(23)
EBIT	$ 338	$ 316	$ 22	$ 762	$ 770	$ (8)
Sales, Gigawatt-hours (GWh)	20,087	19,415	672	42,050	41,458	592

The following table shows the changes in GWh sales and average number of customers for Franchised Electric.

Increase (decrease) over prior year	Three Months Ended	Six Months Ended
Residential sales [a]	18.6%	9.6%
General service sales [a]	9.1%	5.9%
Industrial sales [a]	2.2%	(0.8)%
Wholesale sales	(39.4)%	(17.9)%
Total Franchised Electric sales [b]	3.5%	1.4%
Average number of customers	1.7%	1.6%

[a] Major components of Franchised Electric s retail sales

[b] Consists of all components of Franchised Electric s sales, including retail sales, and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

Three Months Ended June 30, 2004 as Compared to June 30, 2003

Operating Revenues. The increase was driven primarily by:

A $66 million increase in GWh sales to retail customers, due to favorable weather during the quarter

A $47 million increase in unbilled fuel revenues, due to increased fuel expense, primarily resulting from increased coal costs, not yet collected in rates

A $22 million increase in collected fuel revenues, driven by increased fuel rates for retail customers due primarily to increased coal costs and increased sales resulting from favorable weather

An $8 million increase due to continued growth in the number of residential and general service customers in Franchised Electric s service territory

A $14 million decrease due to sharing of profits from wholesale power sales with customers in North Carolina in 2004 (see Note 12 to the Consolidated Financial Statements)

A $13 million decrease in wholesale power revenues, due primarily to lower sales volumes resulting from lower generation availability

A $9 million decrease in sales to industrial customers, due primarily to the continuing decline in sales to textile customers in North Carolina and South Carolina.

Operating Expenses. The increase was driven primarily by:

Increased fuel expenses of $66 million, due primarily to increased coal costs and increased sales to retail customers

Increased donations of $13 million, due to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina (see Note 12 to the Consolidated Financial Statements)

Increased fossil expenses of $14 million, driven by increased fossil outage costs during the period.

Other Income, net of expenses. The decrease in other income was driven primarily by a decrease in the allowance for funds used during construction, due primarily to large construction projects that were completed in 2003, and a decrease in the return on deferred costs related to the purchase of capacity from the joint owners of the Catawba Nuclear Station.

EBIT. The increase in EBIT resulted primarily from increased sales to retail customers due to favorable weather, and continued growth in the number of residential and general service customers. These changes were partially offset by the sharing of profits from wholesale power sales, lower sales to wholesale customers and increased expenses related to fossil outages.

Six Months Ended June 30, 2004 as Compared to June 30, 2003

Operating Revenues. The increase was driven primarily by:

A $72 million increase in GWh sales to retail customers, due to favorable weather during the period

A $49 million increase in unbilled fuel revenues, due to increased fuel expense, primarily resulting from increased coal costs, not yet collected in rates

A $48 million increase in collected fuel revenues, driven by increased fuel rates for retail customers, due primarily to increased coal costs, and increased sales resulting from favorable weather

A $16 million increase due to continued growth in the number of residential and general service customers in Franchised Electric s service territory

A $31 million decrease in wholesale power revenues, due primarily to increased fuel costs and lower sales volumes resulting from lower generation availability

A $17 million decrease in sales to industrial customers, due primarily to the continuing decline in sales to textile customers in North Carolina and South Carolina

A $14 million decrease due to sharing of profits from wholesale power sales with customers in North Carolina in 2004 (see Note 12 to the Consolidated Financial Statements).

Operating Expenses. The increase was driven primarily by:

Increased fuel expenses of $98 million, due primarily to increased coal costs and increased sales to retail customers

Increased nuclear and fossil outage costs of $22 million, driven by increased outage days during the period

Increased donations of $13 million, due to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina (see Note 12 to the Consolidated Financial Statements)

Decreased storm costs of $16 million.

Other Income, net of expenses. The decrease in other income was driven primarily by:

A $14 million decrease in the allowance for funds used during construction, due primarily to large construction projects that were completed in 2003

A $9 million decrease in the return on deferred costs related to the purchase of capacity from the joint owners of the Catawba Nuclear Station.

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EBIT. The decrease in EBIT resulted primarily from lower sales to wholesale customers, sharing of profits from wholesale power sales, increased expenses related to nuclear and fossil outages, and lower sales to industrial customers. These changes were partially offset by increased sales to retail customers due to favorable weather, continued growth in the number of residential and general service customers, and lower storm costs.

Natural Gas Transmission

	Three Months Ended June 30,			Six Months Ended June 30,		
(in millions, except where noted)	**2004**	**2003**	**Increase (Decrease)**	**2004**	**2003**	**Increase (Decrease)**
Operating revenues	$ 688	$ 692	$ (4)	$ 1,726	$ 1,660	$ 66
Operating expenses	397	421	(24)	1,035	988	47
Gains on sales of other assets, net	9		9	9	1	8
Operating income	300	271	29	700	673	27
Other income, net of expenses	13	45	(32)	19	79	(60)
Minority interest expense	2	10	(8)	10	23	(13)
EBIT	$ 311	$ 306	$ 5	$ 709	$ 729	$ (20)
Proportional throughput, TBtu [a]	726	742	(16)	1,815	1,824	(9)

[a] Trillion British thermal units. Revenues are not significantly impacted by pipeline throughput fluctuations, since revenues are primarily composed of demand charges.

Three Months Ended June 30, 2004 as Compared to June 30, 2003

Operating Revenues. The decrease was driven primarily by:

- A $22 million decrease as a result of the sale of Pacific Northern Gas Limited (PNG) in December 2003
- A $20 million decrease in gas distribution revenues, due primarily to reduced volumes
- A $13 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses)
- A $10 million increase due to improved operational results

A $10 million increase from completed and operational business expansion projects in the United States.

Operating Expenses. The decrease was driven primarily by:

A $20 million decrease as a result of operations sold in 2003

An $18 million decrease in gas purchases for distribution, due primarily to reduced volumes

A $17 million decrease related to the 2004 resolution of ad valorem tax adjustments in various states, partly offset by the resolution of contingency items of $5 million in the second quarter of 2003

A $10 million increase caused by foreign exchange impacts.

Other Income, net of expenses. The decrease was driven primarily by gains of $31 million on the sales of Natural Gas Transmission s interests in Alliance Pipeline and the associated Aux Sable liquids plant in April 2003.

EBIT. EBIT increased primarily as a result of contributions from improved operational results, U.S. business expansions, and foreign exchange EBIT impacts from the strengthening Canadian currency, partially offset by gains from sales of equity investments (included in other income) recorded in the prior year second quarter and forgone earnings from various equity investments sold during 2003.

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Six Months Ended June 30, 2004 as Compared to June 30, 2003

Operating Revenues. The increase was driven primarily by:

- A $104 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses)
- A $27 million increase due to improved operational results
- A $21 million increase from completed and operational business expansion projects in the United States
- A $53 million decrease as a result of the sale of Empire State Pipeline in February 2003 and of PNG in December 2003
- A $40 million decrease in gas distribution revenues, resulting from lower volumes partly offset by higher commodity costs that are passed through to customers without mark-up.

Operating Expenses. The increase was driven primarily by:

- A $75 million increase caused by foreign exchange impacts
- An $8 million increase associated with the business expansion projects placed in service
- Cost increases of $18 million, including depreciation and processing plant maintenance activity in Canada.
- A $30 million decrease in gas purchases for distribution, due primarily to reduced volumes partly offset by higher commodity costs
- A $44 million decrease as a result of operations sold in 2003
- A $17 million decrease related to the 2004 resolution of ad valorem tax adjustments in various states, offset by the resolution of various contingencies of $25 million in the 2003 period.

Other Income, net of expenses. The decrease was driven primarily by:

- A $15 million decrease in equity earnings as a result of investments sold in 2003

A $47 million decrease as a result of prior year gains on sales, primarily the gain on the sale of Natural Gas Transmission s interests in Northern Border Partners L.P. in January 2003 and in Alliance Pipeline and the Aux Sable liquids plant in April 2003.

Minority Interest Expenses. The decrease was driven primarily by the sale of PNG in 2003.

EBIT. EBIT decreased primarily as a result of gains from sales of equity investments (included in other income) recorded in the prior year and forgone earnings from various equity investments sold during 2003. Those decreases were partially offset by contributions from improved operational results, U.S. business expansions, and foreign exchange EBIT impacts from the strengthening Canadian currency.

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Field Services

(in millions, except where noted)	Three Months Ended June 30, 2004	2003	Increase (Decrease)	Six Months Ended June 30, 2004	2003	Increase (Decrease)
Operating revenues	$ 2,356	$ 2,048	$ 308	$ 4,731	$ 4,598	$ 133
Operating expenses	2,225	1,991	234	4,474	4,500	(26)
Operating income	131	57	74	257	98	159
Other income, net of expenses	15	24	(9)	33	39	(6)
Minority interest expense	52	28	24	104	54	50
EBIT	$ 94	$ 53	$ 41	$ 186	$ 83	$ 103
Natural gas gathered and processed/transported, TBtu/d [a]	7.5	7.6	(0.1)	7.4	7.6	(0.2)
NGL production, MBbl/d [b]	371	352	19	364	360	4
Average natural gas price per MMBtu [c, d, e]	$ 5.99	$ 5.41	$ 0.58	$ 5.84	$ 6.00	$ (0.16)
Average NGL price per gallon [d, e]	$ 0.61	$ 0.49	$ 0.12	$ 0.60	$ 0.54	$ 0.06

[a] Trillion British thermal units per day
[b] Thousand barrels per day
[c] Million British thermal units
[d] Index-based market price
[e] Does not reflect results of commodity hedges.

Three Months Ended June 30, 2004 as Compared to June 30, 2003

Operating Revenues. The increase was driven primarily by:

- A $175 million increase due to higher average NGL prices
- A $125 million increase due to higher average natural gas prices
- A $35 million increase related to the acquisition of gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips during the three months ended June 30, 2004
- A $30 million decrease primarily related to lower wholesale propane marketing activity partially offset by higher NGL sales volumes

A $5 million increase from higher processed volumes resulting from favorable processing economics. Overall, throughput decreased due primarily to slightly lower gathering and transportation volumes.

A $5 million decrease related to cash flow hedging, which reduced revenues by approximately $50 million for the three months ended June 30, 2004 and by $45 million for the three months ended June 30, 2003.

Operating Expenses. The increase was driven primarily by:

A $240 million increase due to higher average costs of raw natural gas supply

A $25 million decrease from lower processed raw natural gas supply volume and lower wholesale propane marketing activity

A $30 million increase related to the acquisition of gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips during the three months ended June 30,2004

	A $5 millionsize:10pt;">	97,522		92,515		
Net DSO Receivables	340,461		292,524		201,674	
Current quarter total revenue	$	801,274	$	666,681	$	630,162
Less: Granite’s interest in unconsolidated construction joint venture revenue	167,201		135,830		162,009	
Net DSO Revenue	634,073		530,851		468,153	
DSO	48		50		39	

DSO decreased 2 days to 48 days as of December 31, 2017 when compared to 50 days at December 31, 2016.

We manage our accounts payable and accrued expenses and other current liabilities balances, our primary working capital liabilities, using day’s payables outstanding (“DPO”). We calculate DPO by dividing Net DPO Payables by Net DPO Expenses for the current quarter multiplied by 90 days, as presented below:

December 31,	2017	2016	2015
(in thousands)			
Accounts payable	$237,673	$199,029	$157,571
Plus: accrued expenses and other current liabilities	236,407	218,587	200,935
Less: performance guarantees	88,606	83,110	65,514
Less: deficit in unconsolidated construction joint ventures	15,939	16,648	8,626
Net DPO Payables	369,535	317,858	284,366
Current quarter total cost of revenue	$700,567	$585,431	$529,538
Less: Granite’s interest in unconsolidated construction joint venture cost of revenue	165,817	136,396	148,163
Plus: current quarter selling, general and administrative expenses	59,068	59,342	60,010

Net DPO Expenses	593,818	508,377	441,385
DPO	56	56	58

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Accrued expenses and other current liabilities typically include items such as accruals for salaries and related benefits, insurance and sales, use and property tax, some of which are not scalable to our cost volume. DPO remained flat at 56 days as of December 31, 2017 when compared to December 31, 2016.
Cash provided by operating activities of $146.2 million during 2017 increased $73.0 million when compared to 2016. The increase was primarily due to a $33.8 million increase in net income after adjusting for non-cash items, a $15.5 million increase in net distributions from unconsolidated joint ventures and a $23.7 million increase in cash from working capital. The increase in cash from working capital was due to a $16.9 million increase in cash provided by working capital liabilities and a $6.8 million decrease in cash used in working capital assets. The increase in cash provided by working capital liabilities was primarily due to an increase in cost volume and the decrease in cash used in working capital assets was primarily due to a one day improvement in DSO partially offset by an increase in revenue volume.
Cash used in investing activities of $59.2 million during 2017 represents a $37.2 million decrease from the amount of cash used by investing activities in 2016. The change was primarily due to a decrease in purchases, net of sales proceeds, of property and equipment (see Capital Expenditures discussion below) and an increase in maturities, net of purchases and proceeds, of marketable securities.
Cash used in financing activities of $42.6 million during 2017 represents a $2.4 million increase in cash used when compared to 2016. The change was primarily due to a $5.0 million decrease in proceeds from long term debt and a $1.8 million increase in repurchases of common stock related to shares surrendered to pay taxes for vested restricted stock units partially offset by a $4.4 million increase in net contributions from non-controlling partners related to consolidated joint ventures.
Prior Year
DSO increased 11 days to 50 days at December 31, 2016 when compared to 39 days at December 31, 2015. DPO decreased to 56 days at December 31, 2016 compared to 58 at December 31, 2015.
Cash provided by operating activities of $73.1 million during 2016 increased $6.2 million when compared to 2015. The increase was primarily due to a $5.5 million increase in net income after adjusting for non-cash items and a $23.5 million increase in net distributions from unconsolidated joint ventures partially offset by a $22.8 million decrease in cash from working capital. The decrease in cash from working capital was due to a $41.8 million increase in cash used by working capital assets partially offset by an $18.9 million increase in cash provided by working capital liabilities. The increase in cash used by working capital assets was primarily due to a decrease in cash from accounts receivable from an increase in revenue volume, an increase in DSO due to an increase in contracts with customers in the private sector, which are typically slower paying than customers in the public sector and the timing of new consolidated projects in our Large Project Construction segment. The increase in cash provided by working capital liabilities was primarily due to an increase in cost of revenue volume from new consolidated construction joint ventures year over year.
Cash used in investing activities of $96.4 million during 2016 represents a $65.7 million increase from the amount of cash used by investing activities in 2015. The increase was primarily due to a $47.0 million increase in purchases, net of sales proceeds, of property and equipment (see Capital Expenditures discussion below) and a $24.0 million increase in purchases of marketable securities net of calls and maturities of investments.
Cash used in financing activities of $40.3 million during 2016 was in line with 2015 driven by dividend payments and net payments on outstanding indebtedness.
Capital Expenditures
During the year ended December 31, 2017, we had capital expenditures of $67.7 million compared to $91.0 million during 2016. Major capital expenditures are typically for aggregate and asphalt production facilities, aggregate reserves, construction equipment, buildings and leasehold improvements and investments in our information technology systems. The timing and amount of such expenditures can vary based on the progress of planned capital projects, the type and size of construction projects, changes in business outlook and other factors. The decrease in capital expenditures during 2017 when compared to 2016 was primarily due to an increase in leasing equipment during 2017 and a decrease in job specific equipment purchases for our Large Project Construction segment. We currently anticipate 2018 capital expenditures to be between $100.0 million and $105.0 million.

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Derivatives

We recognize derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value using Level 2 inputs.

In January 2016, we entered into an interest rate swap designed to convert the interest rate on our term loan from a variable to fixed interest rate (see Credit Agreement section below).

In December 2016, we terminated the interest rate swap we entered in March 2014 due to the possibility of increasing interest rates (see Senior Notes Payable section below).

Debt and Contractual Obligations

The following table summarizes our significant obligations outstanding as of December 31, 2017:

	Payments Due by Period				
(in thousands)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt – principal[1]	$225,056	$46,277	$178,779	$—	$—
Long-term debt – interest[2]	20,872	9,651	11,221	—	—
Operating leases[3]	47,951	12,169	16,943	11,668	7,171
Other purchase obligations[4]	13,696	13,484	212	—	—
Deferred compensation obligations[5]	24,696	4,298	3,580	1,881	14,937
Asset retirement obligations[6]	22,527	4,701	5,002	2,752	10,072
Total	$354,798	$90,580	$215,737	$16,301	$32,180

[1]Debt issuance costs are excluded from the table.

[2]Included in the total is $7.9 million in interest related to borrowings under our Credit Agreement, calculated using the fixed rate associated with the cash flow hedge of 1.47% plus the applicable margin in effect as of December 31, 2017. The future payments were calculated using the applicable margin in effect as of December 31, 2017 and may differ from actual results. In addition, included in the total is $7.3 million in interest related to borrowings under the 2019 Notes, the terms of which include a 6.11% per annum interest rate. See Note 11 of “Notes to the Consolidated Financial Statements.”

[3]These obligations represent the minimum rental commitments and minimum royalty requirements under all noncancellable operating leases. See Note 16 of “Notes to the Consolidated Financial Statements.”

[4]These obligations represent firm purchase commitments for equipment and other goods and services not directly connected with our construction contract backlog which are individually greater than $10,000 and have an expected fulfillment date after December 31, 2017.

[5]The timing of expected payment of deferred compensation is based on estimated dates of retirement. Actual dates of retirement could be different and could cause the timing of payments to change.

[6]Asset retirement obligations represent reclamation and other related costs associated with our owned and leased quarry properties, the majority of which have an estimated settlement date beyond five years. See Note 8 of “Notes to the Consolidated Financial Statements.”

In addition to the significant obligations described above, as of December 31, 2017, we had approximately $3.6 million associated with uncertain tax positions filed on our tax returns which were excluded because we cannot make a reasonably reliable estimate of the timing of potential payments relative to such reserves.

Credit Agreement

As of December 31, 2017, we had a $290.0 million credit facility (the “Credit Agreement”), of which $200.0 million was a revolving credit facility and $90.0 million was a term loan that matures on October 28, 2020 (the “Maturity Date”). The Credit Agreement has a sublimit for letters of credit of $100.0 million. As of December 31, 2017 and 2016, $6.2 million and $5.0 million of the term loan balance was included in current maturities of long-term debt, respectively, and the remaining $83.8 million and $90.0 million, respectively, was included in long-term debt in the consolidated balance sheets.

Of the $95.0 million term loan outstanding as of December 31, 2016, we paid $5.0 million of the principal balance during 2017. Of the remaining $90.0 million outstanding as of December 31, 2017, 1.25% of the original principal

balance is due in three quarterly installments beginning in March 2018, 2.50% of the original principal balance is due in eight quarterly installments beginning in December 2018 and the remaining balance is due on the Maturity Date. As of December 31, 2017, the total stated amount of all issued and outstanding letters of credit under the Credit Agreement was $8.3 million. As of December 31, 2017 and 2016, $25.0 million and $30.0 million had been drawn for the 2017 and 2016 installments of the 2019 Notes (defined below), respectively. As of December 31, 2017, the total unused availability under the Credit Agreement was $136.7 million. The letters of credit will expire between July 2018 and October 2018.

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Borrowings under the Credit Agreement bear interest at LIBOR or a base rate (at our option), plus an applicable margin based on certain financial ratios calculated quarterly. LIBOR varies based on the applicable loan term, market conditions and other external factors. The applicable margin was 1.75% for loans bearing interest based on LIBOR and 0.75% for loans bearing interest at the base rate at December 31, 2017. Accordingly, the effective interest rate using three-month LIBOR and base rate was 3.44% and 5.25%, respectively, at December 31, 2017 and we elected to use LIBOR. Borrowings at the base rate have no designated term and could be repaid without penalty any time prior to the Maturity Date. Borrowings bearing interest at a LIBOR rate have a term no less than one month and no greater than six months (or such longer period not to exceed 12 months if approved by all lenders). At the end of each term, such borrowings can be paid or continued at our discretion as either a borrowing at the base rate or a borrowing at a LIBOR rate with similar terms. Our obligations under the Credit Agreement are guaranteed by certain of our subsidiaries and are collateralized on an equivalent basis with the obligations under the 2019 Notes (defined below) by first priority liens (subject only to other permitted liens) on substantially all of the assets of the Company and our subsidiaries that are guarantors or borrowers under the Credit Agreement.

In January 2016, we entered into an interest rate swap designated as a cash flow hedge with an effective date of April 2016 and an initial notional amount of $98.8 million which matures in October 2020. The interest rate swap is designed to convert the interest rate on the term loan from a variable rate of interest of LIBOR plus an applicable margin to a fixed rate of 1.47% plus the same applicable margin. The interest rate swap is reported at fair value using Level 2 inputs in the consolidated balance sheets. Gains or losses on the effective portion are initially reported as a component of accumulated other comprehensive income (loss) and subsequently reclassified to interest expense in the consolidated statements of operations when the quarterly hedged interest payment is settled. As of December 31, 2017, and 2016, the fair value of the cash flow hedge was $1.4 million and $0.8 million, respectively, and was included in other current assets in the consolidated balance sheets. The unrealized gains and losses, net of taxes, on the effective portion reported as a component of accumulated other comprehensive income (loss) and the interest expense reclassified from accumulated other comprehensive income (loss) were both immaterial during the years ended December 31, 2017 and 2016.

The Credit Agreement provides for the release of the liens securing the obligations, at our option and expense, so long as certain conditions as defined by the terms in the Credit Agreement are satisfied ("Collateral Release Period"). However, if subsequent to exercising the option, our Consolidated Fixed Charge Coverage Ratio is less than 1.25 or our Consolidated Leverage Ratio is greater than 2.50, then we would be required to promptly re-pledge substantially all of the assets of the Company and our subsidiaries that are guarantors or borrowers under the Credit Agreement. As of December 31, 2017, the conditions for the exercise of our right under the Credit Agreement to have liens released were not satisfied.

Senior Notes Payable

As of December 31, 2017 and 2016, senior notes payable in the amount of $80.0 million and $120.0 million, respectively, were due to a group of institutional holders and had an interest rate of 6.11% per annum ("2019 Notes"). As of December 31, 2017, two equal annual installments for 2018 and 2019 were remaining. As of December 31, 2017, $40.0 million of the outstanding balance was included in long-term debt in the consolidated balance sheets and the remaining $40.0 million was included in current maturities of long-term debt in the consolidated balance sheets. As of December 31, 2016, $110.0 million of the outstanding balance was included in long-term debt in the consolidated balance sheets, including $30.0 million due for the 2017 installment as we had the ability and intent to pay the 2017 installment using borrowings under the Credit Agreement (defined above) or by obtaining other sources of financing. The remaining $10.0 million was included in current maturities of long-term debt in the consolidated balance sheets.

In December 2016, we terminated the interest rate swap we entered in March 2014 due to the possibility of increasing interest rates. The interest rate swap is reported at fair value using Level 2 inputs in the consolidated balance sheets. Gains or losses, including net periodic settlement amounts, are recorded in other income, net, in our consolidated statements of operations. During the years ended December 31, 2016 and 2015, we recorded net gains of $0.3 million and $1.5 million, respectively.

Our obligations under the note purchase agreement governing the 2019 Notes (the "2019 NPA") are guaranteed by certain of our subsidiaries and are collateralized on an equivalent basis with the Credit Agreement by liens on substantially all of the assets of the Company and subsidiaries that are guarantors or borrowers under the Credit Agreement. The 2019 NPA provides for the release of liens and re-pledge of collateral on substantially the same terms and conditions as those set forth in the Credit Agreement.

Surety Bonds and Real Estate Mortgages

We are generally required to provide various types of surety bonds that provide an additional measure of security under certain public and private sector contracts. At December 31, 2017, approximately $3.5 billion of our contract backlog was bonded. Performance bonds do not have stated expiration dates; rather, we are generally released from the bonds after the owner accepts the work performed under contract. The ability to maintain bonding capacity to support our current and future level of contracting requires that we maintain cash and working capital balances satisfactory to our sureties.

Our investments in real estate affiliates are subject to mortgage indebtedness. This indebtedness is non-recourse to Granite but is recourse to the real estate entities. The terms of this indebtedness are typically renegotiated to reflect the evolving nature of the real estate projects as they progress through acquisition, entitlement and development. Modification of these terms may include changes in loan-to-value ratios requiring the real estate entity to repay portions of the debt. The debt associated with our unconsolidated real estate ventures is disclosed in Note 7 of "Notes to the Consolidated Financial Statements."

Covenants and Events of Default

Our debt and credit agreements require us to comply with various affirmative, restrictive and financial covenants, including the financial covenants described below. Our failure to comply with any of these covenants, or to pay principal, interest or other amounts when due thereunder, would constitute an event of default under the applicable agreements. Under certain circumstances, the occurrence of an event of default under one of our debt or credit agreements (or the acceleration of the maturity of the indebtedness under one of our agreements) may constitute an event of default under one or more of our other debt or credit agreements. Default under our debt and credit agreements could result in (i) us no longer being entitled to borrow under the agreements; (ii) termination of the agreements; (iii) the requirement that any letters of credit under the agreements be cash collateralized; (iv) acceleration of the maturity of outstanding indebtedness under the agreements and/or (v) foreclosure on any collateral securing the obligations under the agreements.

The most significant financial covenants under the terms of our Credit Agreement and 2019 Notes require the maintenance of a minimum Consolidated Tangible Net Worth, a minimum Consolidated Interest Coverage Ratio and a maximum Consolidated Leverage Ratio.

As of December 31, 2017 and pursuant to the definitions in the agreements, our Consolidated Tangible Net Worth was $953.6 million, which exceeded the minimum of $752.0 million, our Consolidated Leverage Ratio was 1.25 which did not exceed the maximum of 3.00 and our Consolidated Interest Coverage Ratio was 15.59 which exceeded the minimum of 4.00.

As of December 31, 2017, we were in compliance with all covenants contained in the Credit Agreement and related to the 2019 Notes. We are not aware of any non-compliance by any of our unconsolidated real estate entities with the covenants contained in their debt agreements.

Share Purchase Program

On April 7, 2016, the Board of Directors authorized us to purchase up to $200.0 million of our common stock at management's discretion, which replaced the former authorization including the amount available. We did not purchase shares under the share purchase program in any of the periods presented. The specific timing and amount of any future purchases will vary based on market conditions, securities law limitations and other factors.

Recently Issued and Adopted Accounting Pronouncements

See "Note 1 - Summary of Significant Accounting Policies" of "Notes to the Consolidated Financial Statements" under the captions Recently Issued Accounting Pronouncements and Recently Adopted Accounting Pronouncements.

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We maintain an investment portfolio of various holdings, types and maturities. We purchase instruments that meet high credit quality standards, as specified in our investment policy. It also limits the amount of credit exposure to any one issue, issuer or type of instrument. The portfolio and accompanying cash balances are targeted to an average maturity of no more than one year from the date the purchase is settled. On an ongoing basis we monitor credit ratings, financial condition and other factors that could affect the carrying amount of our investment portfolio. Marketable securities, consisting of U.S. government and agency obligations, commercial paper and corporate bonds, are classified as held-to-maturity and are stated at cost, adjusted for amortization of premiums and discounts to maturity.

Given the short-term nature of certain investments, our investment income is subject to the general level of interest rates in the United States at the time of maturity and reinvestment. We have managed the financial market risks due largely to changes in interest rates primarily by managing the maturities in our investment portfolio. We do not have any material business transactions in foreign currencies.

The fair value of our short-term held-to-maturity investment portfolio and related income would not be significantly affected by changes in interest rates since the investment maturities are short. The fair value of our long-term held-to-maturity investment portfolio may be affected by changes in interest rates.

We are exposed to various commodity price risks, including, but not limited to, diesel fuel, natural gas, propane, steel, cement and liquid asphalt arising from transactions that are entered into in the normal course of business. In order to manage or reduce commodity price risk, we monitor the costs of these commodities at the time of bid and price them into our contracts accordingly. Additionally, some of our contracts include commodity price escalation clauses which partially protect us from increasing prices. At times we enter into supply agreements or pre-purchase commodities to secure pricing and may use financial contracts to further manage price risk.

As of December 31, 2017, $80.0 million of senior notes payable were due to a group of institutional holders in two remaining equal installments in 2018 and 2019 and bear interest at 6.11% per annum.

As of December 31, 2017, a $90.0 million term loan was outstanding under the Credit Agreement that had an effective interest rate of 3.44% using three-month LIBOR and the applicable margin, that we converted under a swap arrangement to a fixed rate of 1.47% plus the same applicable margin. The applicable margin is based on certain financial ratios calculated quarterly and can vary in future periods. Each 25 basis point increase in the applicable margin would result in $0.2 million annually in additional interest expense.

As of December 31, 2017, $55.0 million had been drawn and was outstanding under the revolving portion of the Credit Agreement that had an effective interest rate of 3.44% using three-month LIBOR and the applicable margin. We had the option of electing LIBOR or the base rate and we elected to use LIBOR. LIBOR is a variable rate subject to market changes over the life of the loan with no guarantees to fix as forecasted. Each 25 basis point increase in one-month LIBOR or in the applicable margin of the loan would result in an additional $0.1 million of annual interest expense.

See “Liquidity and Capital Resources” section above for further discussion on the senior notes payable and Credit Agreement.

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The table below presents principal amounts due by year and related weighted average interest rates for our cash and cash equivalents, held-to-maturity investments and significant debt obligations as of December 31, 2017 (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Assets							
Cash, cash equivalents, held-to-maturity investments	$301,486	$30,015	$25,000	$10,000	$—	$ —	$366,501
Weighted average interest rate	1.33 %	1.40 %	1.50 %	1.94 %	—%	— %	1.37 %
Liabilities							
Fixed rate debt							
Senior notes payable	$40,000	$40,000	$—	$—	$—	$ —	$80,000
Interest rate	6.11 %	6.11 %	— %	— %	—%	— %	6.11 %
Variable rate debt							
Credit Agreement - term loan	$6,250	$10,000	$73,750	$—	$—	$ —	$90,000
Effective interest rate[1]	3.22 %	3.22 %	3.22 %	— %	—%	— %	3.22 %
Credit Agreement - revolving credit facility[2]	$—	$—	$55,000	$—	$—	$ —	$55,000
Effective interest rate[3]	— %	— %	3.44 %	— %	—%	— %	3.44 %

[1] The weighted average interest rate was calculated using the fixed rate associated with the cash flow hedge of 1.47% plus the applicable margin in effect as of December 31, 2017 and may differ from actual results.

[2]Credit Agreement - revolving credit facility consists of $25.0 million and $30.0 million that had been drawn for the 2017 and 2016 installments of the 2019 Notes, respectively.

[3]The weighted average interest rate was calculated using three-month LIBOR rates and the applicable margin in effect as of December 31, 2017 and may differ from actual results.

The estimated fair value of our cash, cash equivalents and short-term held-to-maturity investments approximates the principal amounts reflected above based on the generally short maturities of these financial instruments. Based on the fixed borrowing rates currently available to us for bank loans with similar terms and average maturities, the fair value of the senior notes payable was approximately $82.2 million and $124.7 million as of as of December 31, 2017 and 2016, respectively. The fair value of the term loan under the Credit Agreement was approximately $89.9 million and $94.0 million as of December 31, 2017 and 2016, respectively. The fair value of the revolving credit facility under the Credit Agreement was approximately $55.1 million and $29.5 million as of December 31, 2017 and 2016, respectively.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following consolidated financial statements of Granite, the supplementary data and the independent registered public accounting firm's report are incorporated by reference from Part IV, Item 15(1) and (2):

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets - At December 31, 2017 and 2016
Consolidated Statements of Operations - Years Ended December 31, 2017, 2016 and 2015
Consolidated Statements of Comprehensive Income - Years Ended December 31, 2017, 2016 and 2015
Consolidated Statements of Shareholders' Equity - Years Ended December 31, 2017, 2016 and 2015
Consolidated Statements of Cash Flows - Years Ended December 31, 2017, 2016 and 2015
Notes to the Consolidated Financial Statements
Quarterly Financial Data (unaudited)

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures: Our management carried out, as of December 31, 2017, with the participation of our Chief Executive Officer and our Chief Financial Officer, an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2017, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us in reports we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting: During the quarter ended December 31, 2017, we implemented new transition and adoption controls as part of our efforts to adopt Accounting Standards Codification Topic 606, Revenue from Contracts with Customers and the related Accounting Standards Updates ("Topic 606"). These controls will be effective until the adoption of Topic 606 is complete and relate to evaluation of our contracts with customers and the resulting impact, if any, to our balance sheet and prospective revenue, upon the adoption of Topic 606, the monitoring of the adoption process and evaluation of the amounts used in the disclosures in Note 1 of "Notes to the Consolidated Financial Statements" within Item 15 of this Annual Report on Form 10-K. As the transition and adoption process continues, there may be additional changes in internal controls over financial reporting. However, there were no other changes to our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting: Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d -15(f). Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in "Internal Control—Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2017.

Independent Registered Public Accounting Firm Report: PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued a report on the Company's internal control over financial reporting as of December 31, 2017. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, is included in "Item 15. Exhibits and Financial Statement Schedules" under the

heading “Report of Independent Registered Public Accounting Firm.”

Item 9B. OTHER INFORMATION

Not Applicable.

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PART III

Certain information required by Part III is omitted from this report. We will file our definitive proxy statement for our Annual Meeting of Shareholders to be held on June 7, 2018 (the “Proxy Statement”) not later than 120 days after the end of the fiscal year covered by this report, and certain information included therein is incorporated herein by reference.

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information regarding our Directors and compliance with Section 16(a) of the Securities Exchange Act of 1934, we direct you to the sections entitled “Proposal 1 - Election and Ratification of Directors” and “Section 16(a) Beneficial Ownership Reporting Compliance,” respectively, in the Proxy Statement. For information regarding our Audit/Compliance Committee and our Audit/Compliance Committee’s financial expert, we direct you to the section entitled “Information about the Board of Directors and Corporate Governance - Committees of the Board - Audit/Compliance Committee” in the Proxy Statement. For information regarding our Code of Conduct, we direct you to the section entitled “Information about the Board of Directors and Corporate Governance - Code of Conduct” in the Proxy Statement. Information regarding our executive officers is contained in the section entitled “Executive Officers of the Registrant,” in Part I, Item I of this report. This information is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION

For information regarding our Executive Compensation, we direct you to the section captioned “Executive and Director Compensation and Other Matters” in the Proxy Statement. This information is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

This information is located in the sections captioned “Stock Ownership of Beneficial Owners and Certain Management” and “Equity Compensation Plan Information” in the Proxy Statement. This information is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

You will find this information in the sections captioned “Transactions with Related Persons” and “Information about the Board of Directors and Corporate Governance - Director Independence” in the Proxy Statement. This information is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

You will find this information in the section captioned “Independent Registered Public Accountants - Principal Accountant Fees and Services” in the Proxy Statement. This information is incorporated herein by reference.

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PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

1. Financial Statements. The following consolidated financial statements and related documents are filed as part of this report:

Financial Statements	Page
Report of Independent Registered Public Accounting Firm	F-1 to F-2
Consolidated Balance Sheets at December 31, 2017 and 2016	F-3
Consolidated Statements of Operations for the Years Ended December 31, 2017, 2016 and 2015	F-4
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015	F-5
Consolidated Statements of Shareholders’ Equity for the Years Ended December 31, 2017, 2016 and 2015	F-6
Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015	F-7 to F-8
Notes to the Consolidated Financial Statements	F-9 to F-37
Quarterly Financial Data (unaudited)	F-38

2. Financial Statement Schedules. Schedules are omitted because they are not required or applicable, or the required information is included in the Financial Statements or related notes.

3. Exhibits. The Exhibits listed in the accompanying Exhibit Index, which is incorporated herein by reference, are filed or incorporated by reference as part of, or furnished with, this report.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Granite Construction Incorporated:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Granite Construction Incorporated and its subsidiaries as of December 31, 2017 and 2016 and the related consolidated statements of operations, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
San Francisco, California
February 16, 2018

We have served as the Company's auditor since 1982.

GRANITE CONSTRUCTION INCORPORATED
CONSOLIDATED BALANCE SHEETS
(dollars in thousands, except share and per share data)

December 31,	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents ($94,359 and $73,115 related to consolidated construction joint ventures (“CCJVs”))	$233,711	$189,326
Short-term marketable securities	67,775	64,884
Receivables, net ($52,031 and $52,613 related to CCJVs)	479,791	419,345
Costs and estimated earnings in excess of billings ($1,437 and $5,046 related to CCJVs)	103,965	73,102
Inventories	62,497	55,245
Equity in construction joint ventures	247,826	247,182
Other current assets ($10,384 and $7,500 related to CCJVs)	36,513	39,908
Total current assets	1,232,078	1,088,992
Property and equipment, net ($38,361 and $20,500 related to CCJVs)	407,418	406,650
Long-term marketable securities	65,015	62,895
Investments in affiliates	38,469	35,668
Goodwill	53,799	53,799
Other noncurrent assets	75,199	85,449
Total assets	$1,871,978	$1,733,453
LIABILITIES AND EQUITY		
Current liabilities		
Current maturities of long-term debt	$46,048	$14,796
Accounts payable ($34,795 and $26,419 related to CCJVs)	237,673	199,029
Billings in excess of costs and estimated earnings ($37,701 and $33,704 related to CCJVs)	135,146	97,522
Accrued expenses and other current liabilities ($2,126 and $1,544 related to CCJVs)	236,407	218,587
Total current liabilities	655,274	529,934
Long-term debt	178,453	229,498
Deferred income taxes, net	1,361	5,441
Other long-term liabilities	44,085	45,989
Commitments and contingencies		
Equity		
Preferred stock, $0.01 par value, authorized 3,000,000 shares, none outstanding	—	—
Common stock, $0.01 par value, authorized 150,000,000 shares; issued and outstanding 39,871,314 shares as of December 31, 2017 and 39,621,140 shares as of December 31, 2016	399	396
Additional paid-in capital	160,376	150,337
Accumulated other comprehensive income (loss)	634	(371)
Retained earnings	783,699	735,626
Total Granite Construction Incorporated shareholders’ equity	945,108	885,988
Non-controlling interests	47,697	36,603
Total equity	992,805	922,591
Total liabilities and equity	$1,871,978	$1,733,453

The accompanying notes are an integral part of these consolidated financial statements.

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GRANITE CONSTRUCTION INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

Years Ended December 31,	2017	2016	2015
Revenue			
Construction	$1,664,708	$1,365,198	$1,262,675
Large Project Construction	1,032,229	888,193	812,720
Construction Materials	292,776	261,226	295,634
Total revenue	2,989,713	2,514,617	2,371,029
Cost of revenue			
Construction	1,417,694	1,155,983	1,075,169
Large Project Construction	1,002,436	824,056	733,253
Construction Materials	254,650	233,208	262,771
Total cost of revenue	2,674,780	2,213,247	2,071,193
Gross profit	314,933	301,370	299,836
Selling, general and administrative expenses	222,811	219,299	203,817
Restructuring gains	(2,411)	(1,925)	(6,003)
Gain on sales of property and equipment	(4,182)	(8,358)	(8,286)
Operating income	98,715	92,354	110,308
Other (income) expense			
Interest income	(4,742)	(3,225)	(2,135)
Interest expense	10,800	12,366	14,257
Equity in income of affiliates	(7,107)	(7,177)	(3,210)
Other income, net	(4,699)	(5,972)	(2,031)
Total other (income) expense	(5,748)	(4,008)	6,881
Income before provision for income taxes	104,463	96,362	103,427
Provision for income taxes	28,662	30,162	35,179
Net income	75,801	66,200	68,248
Amount attributable to non-controlling interests	(6,703)	(9,078)	(7,763)
Net income attributable to Granite Construction Incorporated	$69,098	$57,122	$60,485
Net income per share attributable to common shareholders (see Note 14)			
Basic	$1.74	$1.44	$1.54
Diluted	$1.71	$1.42	$1.52
Weighted average shares of common stock			
Basic	39,795	39,557	39,337
Diluted	40,372	40,225	39,868
Dividends per common share	$0.52	$0.52	$0.52

The accompanying notes are an integral part of these consolidated financial statements.

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GRANITE CONSTRUCTION INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

Years Ended December 31,	2017	2016	2015
Net income	$75,801	$66,200	$68,248
Other comprehensive income (loss), net of tax:			
Net unrealized gain on derivatives	$191	$184	$—
Less: reclassification for net losses included in interest expense	159	319	—
Net change	$350	$503	$—
Foreign currency translation adjustments, net	655	626	(1,072)
Other comprehensive income (loss)	$1,005	$1,129	$(1,072)
Comprehensive income	$76,806	$67,329	$67,176
Non-controlling interests in comprehensive income	(6,703)	(9,078)	(7,763)
Comprehensive income attributable to Granite	$70,103	$58,251	$59,413

The accompanying notes are an integral part of these consolidated financial statements.

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GRANITE CONSTRUCTION INCORPORATED
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands, except share data)

	Outstanding Shares	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Granite Shareholders' Equity	Non-controlling Interests	Total Equity
Balances at December 31, 2014	39,186,386	$ 392	$134,605	$ (428)	$659,816	$794,385	$ 22,721	$817,106
Net income	—	—	—	—	60,485	60,485	7,763	68,248
Other comprehensive loss	—	—	—	(1,072)	—	(1,072)	—	(1,072)
Restricted stock units vested	317,524	3	—	—	—	3	—	3
Amortized restricted stock units	—	—	8,763	—	—	8,763	—	8,763
Purchase of common stock	(114,969)	(1)	(3,855)	—	—	(3,856)	—	(3,856)
Cash dividends on common stock	—	—	—	—	(20,476)	(20,476)	—	(20,476)
Transactions with non-controlling interests, net	—	—	—	—	—	—	400	400
Employee Stock Purchase Plan ("ESPP") and other	23,936	—	1,399	—	(394)	1,005	—	1,005
Balances at December 31, 2015	39,412,877	394	140,912	(1,500)	699,431	839,237	30,884	870,121
Net income	—	—	—	—	57,122	57,122	9,078	66,200
Other comprehensive income	—	—	—	1,129	—	1,129	—	1,129
Restricted stock units vested	308,619	3	—	—	—	3	—	3
Amortized restricted stock units	—	—	13,383	—	—	13,383	—	13,383
Purchase of common stock	(116,355)	(1)	(5,226)	—	—	(5,227)	—	(5,227)
Cash dividends on common stock	—	—	—	—	(20,590)	(20,590)	—	(20,590)
Transactions with non-controlling interests, net	—	—	—	—	—	—	(3,359)	(3,359)
ESPP and other	15,999	—	1,268	—	(337)	931	—	931
Balances at December 31, 2016	39,621,140	396	150,337	(371)	735,626	885,988	36,603	922,591
Net income	—	—	—	—	69,098	69,098	6,703	75,801
Other comprehensive income	—	—	—	1,005	—	1,005	—	1,005
Restricted stock units vested	375,100	4	—	—	—	4	—	4
	—	—	15,764	—	—	15,764	—	15,764

Amortized restricted stock units								
Purchase of common stock	(140,070)	(1)	(6,976)	—	—	(6,977)	—	(6,977)
Cash dividends on common stock	—	—	—	—	(20,720)	(20,720)	—	(20,720)
Transactions with non-controlling interests, net	—	—	—	—	—	—	4,391	4,391
ESPP and other	15,144	—	1,251	—	(305)	946	—	946
Balances at December 31, 2017	39,871,314	$ 399	$ 160,376	$ 634	$ 783,699	$ 945,108	$ 47,697	$ 992,805

The accompanying notes are an integral part of these consolidated financial statements.

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GRANITE CONSTRUCTION INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

Years Ended December 31,	2017	2016	2015
Operating activities			
Net income	$75,801	$66,200	$68,248
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash restructuring gains	(939)	(1,000)	(1,044)
Depreciation, depletion and amortization	66,345	64,375	64,309
Gain on sales of property and equipment	(4,182)	(8,358)	(8,286)
Change in deferred income taxes	(4,824)	9,842	28,258
Stock-based compensation	15,764	13,383	8,763
Equity in net loss (income) from unconsolidated construction joint ventures	14,634	(15,614)	(43,374)
Net income from affiliates	(7,107)	(7,177)	(3,210)
Changes in assets and liabilities:			
Receivables	(60,272)	(75,756)	(32,877)
Costs and estimated earnings in excess of billings, net	(26,066)	2,100	(22,374)
Inventories	(7,252)	308	13,367
Contributions to unconsolidated construction joint ventures	(16,937)	(11,795)	(69,313)
Distributions from unconsolidated construction joint ventures	39,955	19,344	53,367
Prepaid and other assets, net	13,211	(13,873)	(1,078)
Accounts payable	36,716	37,731	8,363
Accrued expenses and other current liabilities	11,348	(6,564)	3,859
Net cash provided by operating activities	146,195	73,146	66,978
Investing activities			
Purchases of marketable securities	(124,543)	(129,685)	(104,971)
Maturities of marketable securities	120,000	50,000	29,260
Proceeds from called marketable securities	—	55,000	75,000
Purchases of property and equipment ($18,309 million, $17,810 million and $0 related to CCJVs)	(67,695)	(90,970)	(44,179)
Proceeds from sales of property and equipment	10,202	12,946	13,148
Collection of notes receivable	1,052	4,331	943
Other investing activities, net	1,798	1,988	92
Net cash used in investing activities	(59,186)	(96,390)	(30,707)
Financing activities			
Proceeds from long-term debt	25,000	30,000	30,000
Debt principal payments	(45,000)	(45,025)	(46,763)
Cash dividends paid	(20,687)	(20,563)	(20,445)
Purchases of common stock	(6,977)	(5,227)	(3,777)
Contributions from non-controlling partners	11,500	5,250	7,462
Distributions to non-controlling partners	(7,109)	(5,258)	(6,992)
Other financing activities	649	557	1,119
Net cash used in financing activities	(42,624)	(40,266)	(39,396)
Increase (decrease) in cash and cash equivalents	44,385	(63,510)	(3,125)
Cash and cash equivalents at beginning of year	189,326	252,836	255,961
Cash and cash equivalents at end of year	$233,711	$189,326	$252,836

The accompanying notes are an integral part of these consolidated financial statements.

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GRANITE CONSTRUCTION INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS - (Continued)
(in thousands)

Years Ended December 31,	2017	2016	2015
Supplementary Information			
Cash paid during the period for:			
Interest	$11,446	$13,392	$14,601
Income taxes	33,948	29,872	4,298
Other non-cash activities:			
Performance guarantees	5,497	17,596	(10,306)
Non-cash investing and financing activities:			
Restricted stock units issued, net of forfeitures (See Note 13)	$11,505	$21,101	$6,220
Accrued cash dividends	5,183	5,151	5,124
Accrued equipment purchases	(1,945)	(3,865)	2,891

The accompanying notes are an integral part of these consolidated financial statements.

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GRANITE CONSTRUCTION INCORPORATED
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies
Description of Business: Granite Construction Incorporated is one of the largest diversified heavy civil contractors and construction materials producers in the United States, engaged in the construction and improvement of streets, roads, highways, mass transit facilities, airport infrastructure, bridges, trenchless and underground utilities, power-related facilities, water-related facilities, utilities, tunnels, dams and other infrastructure-related projects. We have permanent offices located in Alaska, Arizona, California, Florida, Illinois, Nevada, New York, Texas, Utah and Washington. Unless otherwise indicated, the terms "we," "us," "our," "Company" and "Granite" refer to Granite Construction Incorporated and its wholly owned and consolidated subsidiaries.
Principles of Consolidation: The consolidated financial statements include the accounts of Granite Construction Incorporated and its wholly owned and consolidated subsidiaries. All material inter-company transactions and accounts have been eliminated. Additionally, we participate in various joint ventures ("joint ventures"). We consolidate these joint ventures where we have determined that through our participation we have a variable interest and are the primary beneficiary as defined by Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 810, Consolidation, and related standards. The factors we use to determine the primary beneficiary of a variable interest entity ("VIE") may include the decision authority of each partner, which partner manages the day-to-day operations of the project and the amount of our equity investment in relation to that of our partners. If we determine that the power to direct the significant activities is shared equally by two or more joint venture parties, then there is no primary beneficiary and no party consolidates the VIE.
Where we have determined we are not the primary beneficiary of a joint venture but do exercise significant influence, we account for our share of the operations of unconsolidated construction joint ventures on a pro rata basis in revenue and cost of revenue in the consolidated statements of operations and in equity in construction joint ventures in the consolidated balance sheets. We account for non-construction unconsolidated joint ventures under the equity method of accounting and include our share of the operations in equity in income from affiliates in the consolidated statements of operations and in investment in affiliates in the consolidated balance sheets. We have been divesting equity method investments in real estate affiliates as part of our 2010 Enterprise Improvement Plan ("EIP").
Use of Estimates in the Preparation of Financial Statements: The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). The preparation of these financial statements requires management to make estimates that affect the reported amounts of assets and liabilities, revenue and expenses, and related disclosure of contingent assets and liabilities. Our estimates and related judgments and assumptions are continually evaluated based on available information and experiences; however, actual amounts could differ from those estimates.
Revenue Recognition - Construction Contracts: Revenue and earnings on construction contracts, including construction joint ventures, are recognized under the percentage of completion method using the ratio of costs incurred to estimated total costs.
Revenue from unapproved change orders is recognized to the extent the related costs have been incurred, the amount can be reliably estimated and recovery is probable.
On certain projects we have submitted and have pending unresolved contract modifications and affirmative claims ("affirmative claims") to recover additional costs to which the Company believes it is entitled under the terms of contracts with customers, subcontractors, vendors or others. The owners or their authorized representatives and/or other third parties may be in partial or full agreement with the modifications or affirmative claims, or may have rejected or disagree entirely or partially as to such entitlement.
Revenue related to affirmative claims with customers is recognized to the extent of costs incurred when it is probable that a claim settlement with a customer will result in additional revenue and the amount can be reasonably estimated.
A reduction to costs related to affirmative claims with non-customers with whom we have a contractual arrangement ("back charges") is recognized when the estimated recovery is probable and the amount can be reasonably estimated.
Except for contractual back charges, a reduction to cost related to affirmative claims against non-customers is

recognized when the claims are settled. Recognizing affirmative claims and back charge recoveries requires significant judgments of certain factors including, but not limited to, dispute resolution developments and outcomes, anticipated negotiation results, and the cost of resolving such matters.

Provisions are recognized in the consolidated statements of operations for the full amount of estimated losses on uncompleted contracts whenever evidence indicates that the estimated total cost of a contract exceeds its estimated total revenue. All contract costs, including those associated with affirmative claims, back charges and change orders, are recorded as incurred and revisions to estimated total costs are reflected as soon as the obligation to perform is determined. Contract costs consist of direct costs on contracts, including labor and materials, amounts payable to subcontractors, direct overhead costs and equipment expense (primarily depreciation, fuel, maintenance and repairs). All state and federal government contracts and many of our other contracts provide for termination of the contract at the convenience of the party contracting with us, with provisions to pay us for work performed through the date of termination. Pre-contract costs are expensed as incurred.

The accuracy of our revenue and profit recognition in a given period depends on the accuracy of our estimates of the cost to complete each project. Cost estimates for all of our projects use a detailed “bottom up” approach and we believe our experience allows us to create materially reliable estimates. There are a number of factors that can contribute to changes in estimates of contract cost and profitability. The most significant of these include:

- the completeness and accuracy of the original bid;
- costs associated with scope changes;
- changes in costs of labor and/or materials;
- extended overhead and other costs due to owner, weather and other delays;
- subcontractor performance issues;
- changes in productivity expectations;
- site conditions that differ from those assumed in the original bid;
- changes from original design on design-build projects;
- the availability and skill level of workers in the geographic location of the project;
- a change in the availability and proximity of equipment and materials;
- our ability to fully and promptly recover on affirmative claims and back charges for additional contract costs; and
- the customer’s ability to properly administer the contract.

The foregoing factors, as well as the stage of completion of contracts in process and the mix of contracts at different margins may cause fluctuations in gross profit and gross profit margin from period to period. Significant changes in cost estimates, particularly in our larger, more complex projects have had, and can in future periods have, a significant effect on our profitability.

Revenue Recognition - Materials: Revenue from the sale of materials is recognized when delivery occurs and risk of ownership passes to the customer.

Balance Sheet Classifications: Prepaid expenses and amounts receivable and payable under construction contracts (principally retentions) that may exist over the duration of the contract and could extend beyond one year are included in current assets and liabilities. A one-year time period is used as the basis for classifying all other current assets and liabilities.

Cash and Cash Equivalents: Cash equivalents are securities having maturities of three months or less from the date of purchase. Included in cash and cash equivalents in the consolidated balance sheets as of December 31, 2017 and 2016, was $94.4 million and $73.1 million, respectively, related to CCJVs. Our access to joint venture cash may be limited by the provisions of the venture agreements.

Costs and Estimated Earnings in Excess of Billings: Costs and estimated earnings in excess of billings represent unbilled amounts earned and reimbursable under contracts. These amounts become billable according to the contract terms, which usually consider the passage of time, achievement of milestones or completion of the project. With the exception of customer affirmative claims, generally, such unbilled amounts will be billed and collected over the next twelve months. Settlement with the customer of outstanding affirmative claims is dependent on the claims resolution process and could extend beyond one year or the project operating cycle. Based on our historical experience, we generally consider the collection risk related to these amounts to be low. When events or conditions indicate that the

amounts outstanding may become uncollectible, an allowance is estimated and recorded.

Marketable Securities: We determine the classification of our marketable securities at the time of purchase and re-evaluate these determinations at each balance sheet date. Debt securities are classified as held-to-maturity when we have the positive intent and ability to hold the securities to maturity. Held-to-maturity investments are stated at amortized cost and are periodically assessed for other-than-temporary impairment. Amortized cost of debt securities is adjusted for amortization of premiums and accretion of discounts to maturity, and is included in interest income. The cost of securities redeemed or called is based on the specific identification method.

Derivative Instruments: We recognize derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value using Level 2 inputs. To receive hedge accounting treatment, derivative instruments that are designated as cash flow hedges must be highly effective in offsetting changes to expected future cash flows on hedged transactions. The effective portion of the gain or loss on cash flow hedges is reported as a component of accumulated other comprehensive income (loss) and subsequently reclassified to interest expense in the consolidated statements of operations when the periodic hedged cash flows are settled. Adjustments to fair value on derivative instruments that do not qualify for hedge accounting treatment are reported through other (income) expense in the consolidated statements of operations. We do not enter into derivative instruments for speculative or trading purposes.

Fair Value of Financial Assets and Liabilities: We measure and disclose certain financial assets and liabilities at fair value. ASC Topic 820, Fair Value Measurements and Disclosures, defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC Topic 820 also establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Observable inputs other than Level 1 prices such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

We utilize the active market approach to measure fair value for our financial assets and liabilities. We report separately each class of assets and liabilities measured at fair value on a recurring basis and include assets and liabilities that are disclosed but not recorded at fair value in the fair value hierarchy.

The carrying value of marketable securities approximates their fair value as determined by market quotes. Rates currently available to us for debt with similar terms and remaining maturities are used to estimate the fair value of existing debt. The carrying value of receivables and other amounts arising out of normal contract activities, including retentions, which may be settled beyond one year, is estimated to approximate fair value.

Concentrations of Credit Risk and Other Risks: Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of cash and cash equivalents, short-term and long-term marketable securities, and accounts receivable. We maintain our cash and cash equivalents and our marketable securities with several financial institutions. We invest with high credit quality financial institutions and, by policy, limit the amount of credit exposure to any one financial institution.

Our receivables are from customers concentrated in the United States, and we have no material receivables from foreign operations as of December 31, 2017 or 2016. We perform ongoing credit evaluations of our customers and generally do not require collateral, although the law provides us the ability to file mechanics' liens on real property improved for private customers in the event of non-payment by such customers. We maintain an allowance for doubtful accounts which has historically been within management's estimates.

Inventories: Inventories consist primarily of quarry products valued at the lower of average cost or market. We write down the inventories based on estimated quantities of materials on hand in excess of approximately one year of demand. At December 31, 2017 and 2016, inventory also included $11.9 million and $5.0 million, respectively, of materials specifically related to a project in our Kenny Large Project Construction operating group and was valued at cost.

Investments in Real Estate Affiliates: Each real estate development project accounted for under the equity method of accounting is reviewed in accordance with ASC Topic 323, Investments - Equity Method and Joint Ventures. These projects are evaluated for impairment using the other-than-temporary impairment model, which requires an

impairment charge to be recognized if our investment’s carrying amount exceeds its fair value, and the decline in fair value is deemed to be other than temporary.

Events or changes in circumstances, which would cause us to review undiscounted future cash flows include, but are not limited to:

- significant decreases in the market price of the asset;
- significant adverse changes in legal factors or the business climate;
- significant changes to the development or business plans of a project;
- accumulation of costs significantly in excess of the amount originally expected for the acquisition, development or construction of the asset; and
- current period cash flow or operating losses combined with a history of losses, or a forecast of continuing losses associated with the use of the asset.

Future undiscounted cash flows and fair value assessments are estimated based on entitlement status, market conditions, cost of construction, debt load, development schedules, status of joint venture partners and other factors applicable to the specific project. Fair value is estimated based on the expected future cash flows attributable to the asset or group of assets and on other assumptions that market participants would use in determining fair value, such as market discount rates, transaction prices for other comparable assets, and other market data. Our estimates of cash flows may differ from actual cash flows due to, among other things, fluctuations in interest rates, decisions made by jurisdictional agencies, economic conditions, or changes to our business operations.

Property and Equipment: Property and equipment are stated at cost. Depreciation for construction and other equipment is primarily provided using accelerated methods over lives ranging from three to seven years, and the straight-line method over lives from three to twenty years for the remaining depreciable assets. We believe that accelerated methods best approximate the service provided by the construction and other equipment. Depletion of quarry property is based on the usage of depletable reserves. We frequently sell property and equipment that has reached the end of its useful life or no longer meets our needs, including depleted quarry property. At the time that an asset or an asset group meets the held-for-sale criteria as defined by ASC Topic 360, Property, Plant, and Equipment, we write it down to fair value, if the fair value is below the carrying value. Fair value is estimated by a variety of factors including, but not limited to, market comparative data, historical sales prices, broker quotes and third party valuations. If material, such property is separately disclosed, otherwise it is held in property and equipment until sold. The cost and accumulated depreciation or depletion of property sold or retired is removed from the balance sheet and the resulting gains or losses, if any, are reflected in operating income for the period. In the case that we abandon an asset, an amount equal to the carrying amount of the asset, less salvage value, if any, will be recognized as expense in the period that the asset was abandoned. Repairs and maintenance are charged to operations as incurred.

Costs related to the development of internal-use software during the preliminary project and post-implementation stages are expensed as incurred. Costs incurred during the application development stage are capitalized. These costs consist primarily of software, hardware and consulting fees, as well as salaries and related costs. Amounts capitalized are reported as a component of office furniture and equipment within property and equipment. Capitalized software costs are depreciated using the straight-line method over the estimated useful life of the related software, which range from three to seven years. During the years ended December 31, 2017, 2016 and 2015, we capitalized $7.9 million, $6.6 million and $2.3 million, respectively, of internal-use software development and related hardware costs.

Long-lived Assets: We review property and equipment and amortizable intangible assets for impairment at an asset group level whenever events or changes in circumstances indicate the net book value of an asset group may not be recoverable. Recoverability of these asset groups is measured by comparison of their net book values to the future undiscounted cash flows the asset groups are expected to generate. If the asset groups are considered to be impaired, an impairment charge will be recognized equal to the amount by which the net book value of the asset groups exceed their fair value. We group construction and plant equipment assets at a regional level, which represents the lowest level for which identifiable cash flows are largely independent of the cash flows of other groups of assets. When an individual asset or group of assets is determined to no longer contribute to the vertically integrated asset group, it is assessed for impairment independently.

As of December 31, 2017, amortizable intangible assets include covenants not to compete, permits, trade names and customer lists which are being amortized on a straight-line basis over remaining terms from three to twenty years.
Capitalized Interest: Interest, to the extent it is incurred in connection with the construction of certain self-constructed assets and real estate development projects, is capitalized and recorded as part of the asset to which it relates. Capitalized interest on self-constructed assets is amortized over their estimated useful lives and is expensed on real estate projects as they are sold.

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GRANITE CONSTRUCTION INCORPORATED
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Goodwill: As of December 31, 2017 and 2016, we had five reporting units in which goodwill was recorded as follows:
- Kenny Group Construction
- Kenny Group Large Project Construction
- Northwest Group Construction
- Northwest Group Construction Materials
- California Group Construction

The most significant goodwill balances reside in the reporting units associated with the Kenny Group. See Note 9 for balances by reportable segment.
We perform impairment tests annually as of November 1 and more frequently when events and circumstances occur that indicate a possible impairment of goodwill. In addition, we evaluate goodwill for impairment if events or circumstances change between annual tests indicating a possible impairment. Examples of such events or circumstances include the following:
- a significant adverse change in legal factors or in the business climate;
- an adverse action or assessment by a regulator;
- a more likely than not expectation that a segment or a significant portion thereof will be sold; or
- the testing for recoverability of a significant asset group within the segment.

We elected to only perform the quantitative goodwill impairment tests for the 2017 annual test. In performing the quantitative goodwill impairment tests, we calculate the estimated fair value of the reporting unit in which the goodwill is recorded using the discounted cash flows and market multiple methods. Judgments inherent in these methods include the determination of appropriate discount rates, the amount and timing of expected future cash flows and growth rates, and appropriate benchmark companies. The cash flows used in our 2017 discounted cash flow model were based on five-year financial forecasts, which in turn were based on the 2018-2020 operating plan developed internally by management adjusted for market participant based assumptions. Our discount rate assumptions are based on an assessment of the equity cost of capital and appropriate capital structure for our reporting units. In assessing the reasonableness of our determined fair values of our reporting units, we evaluate the reasonableness of our results against our current market capitalization.
The estimated fair value is compared to the net book value of the reporting unit, including goodwill. If the fair value of the reporting unit exceeds its net book value, goodwill of the reporting unit is considered not impaired. If the fair value of the reporting unit is less than its net book value, goodwill is impaired and the excess of the reporting unit's net book value over the fair value is recognized as an impairment loss.
The results of our annual goodwill impairment tests, performed in accordance with ASC 350, Intangibles - Goodwill and Other, indicated that the estimated fair values of our reporting units exceeded their net book values (i.e., cushion) by at least 20% for the reporting units with goodwill. Out of the five reporting units with goodwill, the Kenny Large Project Construction business is the most susceptible to fluctuations in results depending on awarded work given the large size and limited frequency of awards. While we believe the current cushion for the reporting unit is adequate to absorb these fluctuations, a material decline in job win rates could have a material impact to this reporting unit's estimated fair value.
Billings in Excess of Costs and Estimated Earnings: Billings in excess of costs and estimated earnings is comprised of cash collected from customers and billings to customers on contracts in advance of work performed, including advance payments negotiated as a contract condition. Generally, unearned project-related costs will be earned over the next twelve months.

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Asset Retirement Obligations: We account for the costs related to legal obligations to reclaim aggregate mining sites and other facilities by recording our estimated asset retirement obligation at fair value, capitalizing the estimated liability as part of the related asset's carrying amount and allocating it to expense over the asset's useful life. To determine the fair value of the obligation, we estimate the cost for a third-party to perform the legally required reclamation including a reasonable profit margin. This cost is then increased for future estimated inflation based on the estimated years to complete and discounted to fair value using present value techniques with a credit-adjusted, risk-free rate. In estimating the settlement date, we evaluate the current facts and conditions to determine the most likely settlement date.

We review reclamation obligations at least annually for a revision to the cost or a change in the estimated settlement date. Additionally, reclamation obligations are reviewed in the period that a triggering event occurs that would result in either a revision to the cost or a change in the estimated settlement date.

Warranties: Many of our construction contracts contain warranty provisions covering defects in equipment, materials, design or workmanship that generally run from six months to one year after our customer accepts the contract. Because of the nature of our projects, including contract owner inspections of the work both during construction and prior to acceptance, we have not experienced material warranty costs for these short-term warranties and, therefore, do not believe an accrual for these costs is necessary. Certain construction contracts carry longer warranty periods, ranging from two to ten years, for which we have accrued an estimate of warranty cost. The warranty liability is estimated based on our experience with the type of work and any known risks relative to the project and was not material as of December 31, 2017 and 2016.

Accrued Insurance Costs: We carry insurance policies to cover various risks, primarily general liability, automobile liability, workers compensation and employee medical expenses, under which we are liable to reimburse the insurance company for a portion of each claim paid. The amounts for which we are liable for general liability and workers compensation generally range from the first $0.5 million to $1.0 million per occurrence. We accrue for probable losses, both reported and unreported, that are reasonably estimable using actuarial methods based on historic trends modified, if necessary, by recent events. Changes in our loss assumptions caused by changes in actual experience would affect our assessment of the ultimate liability and could have an effect on our operating results and financial position up to $1.0 million per occurrence for general liability and workers compensation or $0.3 million for medical insurance.

Performance Guarantees: Agreements with our joint venture partners ("partner(s)") for both construction joint ventures and line item joint ventures define each partner's management role and financial responsibility in the project. The amount of operational exposure is generally limited to our stated ownership interest. However, due to the joint and several nature of the performance obligations under the related owner contracts, if one of the partners fails to perform, we and the remaining partners, if any, would be responsible for performance of the outstanding work (i.e., we provide a performance guarantee). We estimate our liability for performance guarantees for our unconsolidated construction joint ventures and line item joint ventures using estimated partner bond rates and include them in accrued expenses and other current liabilities (see Note 10) with a corresponding increase in equity in construction joint ventures in the consolidated balance sheets. We reassess our liability when and if changes in circumstances occur. The liability and corresponding asset are removed from the consolidated balance sheets upon customer acceptance of the project. Circumstances that could lead to a loss under these agreements beyond our stated ownership interest include the failure of a partner to contribute additional funds to the venture in the event the project incurs a loss or additional costs that we could incur should a partner fail to provide the services and resources that it had committed to provide in the agreement.

Contingencies: We are currently involved in various claims and legal proceedings. Loss contingency provisions are recorded if the potential loss from any asserted or unasserted claim or legal proceeding is considered probable and the amount can be reasonably estimated. If a potential loss is considered probable but only a range of loss can be determined, the low-end of the range is recorded. These accruals represent management's best estimate of probable

loss. Disclosure is also provided when it is reasonably possible that a loss will be incurred or when it is reasonably possible that the amount of a loss will exceed the amount recorded. Significant judgment is required in both the determination of probability of loss and the determination as to whether an exposure is reasonably estimable. Because of uncertainties related to these matters, accruals are based only on the best information available at the time. As additional information becomes available, we reassess the potential liability related to claims and litigation and may revise our estimates. See Note 17 and "Item 3. Legal Proceedings" for additional information.

Stock-Based Compensation: We measure and recognize compensation expense, net of estimated forfeitures, over the requisite vesting periods for all stock-based payment awards made. Stock-based compensation is included in selling, general and administrative expenses and cost of revenue on our consolidated statements of operations.

Restructuring (Gains) Charges: Pursuant to an approved plan, we record severance costs when an employee has been notified, unless the employee provides future service, in which case severance costs are expensed ratably over the future service period. Other restructuring costs are recognized when the liability is incurred. Costs associated with terminating a lease contract are recorded at the contract termination date, in accordance with contract terms, or on the cease-use date, net of estimated sublease income, if applicable. In determining the amount related to termination of a lease, various assumptions are used including the time period over which facilities will be vacant, expected sublease term and sublease rates. These assumptions may be adjusted upon the occurrence of future events. Asset impairment analyses resulting from restructuring events are performed in accordance with ASC subtopic 360-10, Property, Plant and Equipment. See the Property and Equipment and Long-lived Assets accounting policies above for further information on asset impairment charges. During the years ended December 31, 2017, 2016 and 2015 we recorded net restructuring gains of $2.4 million, $1.9 million and $6.0 million (including amounts attributable to non-controlling interests of $3.3 million), respectively, related to our EIP.

Income Taxes: Deferred taxes are provided on a liability method whereby deferred tax assets are recognized for deductible temporary differences and operating loss carry-forwards and deferred tax liabilities are recognized for taxable temporary differences. Temporary differences are the differences between the reported amounts of assets and liabilities in the consolidated financial statements and their respective tax bases. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

We report a liability in other long-term liabilities in the consolidated balance sheets for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. We recognize interest and penalties, if any, related to unrecognized tax benefits in other (income) expense in the consolidated statements of operations.

Computation of Earnings Per Share: Basic net income per share is computed using the weighted-average number of common shares outstanding during the period. Diluted net income per share is computed using the weighted-average number of common shares and dilutive potential common shares outstanding during the period. Potential common shares include stock options and restricted stock units, under the 2012 Equity Incentive Plan.

Recently Issued Accounting Pronouncements:

In May 2014, the FASB issued ASC Topic 606, Revenue from Contracts with Customers, and subsequently issued several related Accounting Standards Updates (“ASU”s) (“Topic 606”), which provide guidance for recognizing revenue from contracts with customers. The core principle of Topic 606 is that revenue will be recognized when promised goods or services are transferred to customers in an amount that reflects consideration for which entitlement is expected in exchange for those goods or services. Topic 606 will be effective commencing with our quarter ending March 31, 2018.

We will adopt Topic 606 using the modified retrospective transition approach, which we will elect to apply Topic 606 to contracts with customers that are not substantially complete, i.e. less than 90% complete, as of January 1, 2018. We do not expect Topic 606 to have a material impact on our Construction Materials segment’s revenue. The impact of Topic 606 primarily relates to our Construction and Large Project Construction segments specifically in the following areas:

- Multiple performance obligations - In accordance with Topic 606, we have reviewed construction contracts with customers, including those related to contract modifications, to determine if there are multiple performance obligations. Based on this review, we have identified one unconsolidated joint venture contract in our Large Project Construction segment that will have multiple performance obligations.
- Multiple contracts - We reviewed contracts containing task orders and identified one Large Project Construction segment contract and one Construction segment contract that consist of multiple individual contracts as defined by Topic 606.

- Provision for losses - Provisions for losses will be recognized in the consolidated statements of operations for the full amount of estimated losses at the uncompleted performance obligation level whenever evidence indicates that the estimated total cost of a performance obligation exceeds its estimated total revenue. Currently provisions for losses are recorded at the contract level. We have identified one unconsolidated joint venture contract in our Large Project Construction segment that will have, as of the effective date, actual and provisions for losses related to completed and uncompleted performance obligations, respectively.

Based on our estimated costs to complete and our assessment of the impact from the adoption of Topic 606 as of December 31, 2017, we estimate a net cumulative decrease to retained earnings between $15.0 million and $18.0 million as of January 1, 2018.

In addition to the above, we expect to separately present contract assets and liabilities in the consolidated balance sheets. Contract assets will include amounts due under contractual retainage provisions, unbilled receivables, costs and estimated earnings in excess of billings and capitalized mobilization costs. Contract liabilities will include provisions for losses and billings in excess of costs and estimated earnings.

There will also be new disclosures related to revenue including information about unearned revenue and revenue disaggregated by operating group. Unearned revenue will be similar to our existing contract backlog but will only include project amounts when the related contract, contract options and task orders, as applicable, are executed rather than when awarded and funding is probable.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, which, among other things, eliminates the requirement to disclose the method(s) and significant assumptions used to estimate the disclosed fair value of financial instruments measured at amortized cost on the consolidated balance sheets. This ASU will be effective commencing with our quarter ending March 31, 2018. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) and subsequently issued a related ASU, which requires lessees to recognize the following for all leases (with the exception of short-term leases) at the commencement date: (a) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (b) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The ASU will be effective commencing with our quarter ending March 31, 2019. We expect the adoption of this ASU to have a material and essentially equal increase to current assets and current liabilities on our consolidated balance sheets.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. The amendments in this ASU clarify and provide specific guidance on eight cash flow classification issues that are not currently addressed by current U.S. GAAP. This ASU will be effective commencing with our quarter ending March 31, 2018. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

In October 2016, the FASB issued ASU No. 2016-16, Intra-Entity Transfers of Assets Other Than Inventory. The amendments in this ASU require the income tax consequences of an intra-entity transfer of an asset other than inventory to be recognized when the transfer occurs instead of when the asset is sold to an outside party. This ASU will be effective commencing with our quarter ending March 31, 2018. Although we do not expect the adoption of this ASU to have a material impact on our consolidated financial statements upon adoption, it may have a material impact if applicable transactions occur.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which is intended to help companies evaluate whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses by providing a more robust framework to use in determining when a set of assets and activities is a business. This ASU will be effective commencing with our quarter ending March 31, 2018. Although we do not expect the adoption of this ASU to have a material impact on our consolidated financial statements upon adoption, ir may have a material impact if applicable transactions occur.

In May 2017, the FASB issued ASU No. 2017-09, Compensation-Stock Compensation (Topic 718) Scope of Modification Accounting, which clarifies that changes to the value, vesting conditions, or award classification of share-based payment awards must be accounted for as modifications. This ASU will be effective commencing with our quarter ending March 31, 2018. Although we do not expect the adoption of this ASU to have a material impact on our consolidated financial statements upon adoption, it may have a material impact if applicable transactions occur.

In August 2017, the FASB issued ASU No. 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities, which refines and expands hedge accounting for both financial (e.g., interest rate) and commodity risks. This ASU will be effective commencing with our quarter ending March 31, 2019. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

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Recently Adopted Accounting Pronouncements:

In March 2016, the FASB issued ASU No. 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, which clarifies that a change in the counterparty to a derivative instrument that has been designated as a hedging instrument does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The ASU was effective commencing with our quarter ending March 31, 2017 and had no impact on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-04, Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment. This ASU eliminated Step 2 from the goodwill impairment test, which measures goodwill impairment by comparing the implied fair value of a reporting unit's goodwill to its carrying amount. According to the ASU, an impairment charge should be recorded if a reporting unit's net book value exceeds its fair value, limited to the amount of goodwill allocated to that reporting unit. We elected to early adopt the ASU, effective January 1, 2017. The estimated fair value of our reporting units exceeded the net book values; therefore, the adoption of this ASU had no impact on our consolidated financial statements.

In March 2017, the FASB issued ASU No. 2017-08, Receivables—Nonrefundable Fees and Other Costs (Subtopic 310-20), Premium Amortization on Purchased Callable Debt Securities, which requires the premium for certain callable debt securities held at a premium to be amortized to the earliest call date rather than at maturity. The ASU does not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity. The ASU was effective commencing with our quarter ending March 31, 2017 and had an immaterial impact on our consolidated financial statements.

2. Revisions in Estimates

Our profit recognition related to construction contracts is based on estimates of costs to complete each project. These estimates can vary significantly in the normal course of business as projects progress, circumstances develop and evolve, and uncertainties are resolved. When we experience significant changes in our estimates of costs to complete, we undergo a process that includes reviewing the nature of the changes to ensure that there are no material amounts that should have been recorded in a prior period rather than as revisions in estimates for the current period. We use the cumulative catch-up method applicable to construction contract accounting to account for revisions in estimates. Under this method, revisions in estimates are accounted for in their entirety in the period of change. There can be no assurance that we will not experience further changes in circumstances or otherwise be required to revise our cost estimates in the future. In our review of these changes for the year ended December 31, 2017 we identified and corrected amounts that should have been recorded during the year ended December, 31, 2016. This correction resulted in a $4.9 million decrease to Large Project Construction revenue and gross profit and a $1.6 million decrease in net income attributable to Granite Construction Incorporated. We have assessed the impact of this correction to the financial statements of prior periods' and to the financial statements for the year ended December 31, 2017 and have concluded that the amounts are not material. In our review of these changes for the years ended 2016 and 2015, we did not identify any material amounts that should have been recorded in a prior period.

In the normal course of business, we have revisions in estimated costs some of which are associated with unresolved affirmative claims and back charges. The estimated or actual recovery related to these estimated costs associated with unresolved affirmative claims and back charges may be recorded in future periods or may be at values below the associated cost, which can cause fluctuations in the gross profit impact from revisions in estimates.

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Affirmative Claims

Revisions in estimates for the years ended December 31, 2017, 2016 and 2015, included increases in revenue of $34.9 million, $37.3 million and $48.5 million, respectively, related to the estimated cost recovery of customer affirmative claims. Of these totals, $30.9 million, $25.4 million and $37.3 million, were offset by an increase in estimated contract costs that were in excess of the estimated recovery during the years ended December 31, 2017, 2016 and 2015, respectively. For the remaining $4.0 million, $11.9 million and $11.2 million, respectively, estimated contract costs in excess of estimated cost recovery were recorded in prior periods.

Back Charges

Revisions in estimates for the years ended December 31, 2017, 2016 and 2015, included reduction of cost of revenue of $4.6 million, $15.7 million and $7.0 million, respectively, related to the estimated recovery of back charges. Of these totals, $2.5 million, $4.8 million and $0.5 million, were offset by an increase in estimated contract costs that were in excess of the estimated recovery during the years ended December 31, 2017, 2016 and 2015, respectively. For the remaining $2.1 million, $10.9 million and $6.5 million, respectively, estimated contract costs in excess of estimated cost recovery were recorded in prior periods.

The tables below include the impact to gross profit from significant revisions in estimates related to estimated and actual recovery of customer affirmative claims and back charges as well as the associated estimated contract costs.

Construction

The net changes in project profitability from revisions in estimates, both increases and decreases, which individually had an impact of $1.0 million or more on gross profit were net increases of $4.0 million, $1.3 million and $19.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. The projects are summarized as follows (dollars in millions):

Increases

Years Ended December 31,	2017	2016	2015
Number of projects with upward estimate changes	10	7	14
Range of increase in gross profit from each project, net	$1.1 - 3.9	$1.1 - 4.8	$1.1 - 6.6
Increase on project profitability	$17.2	$14.2	$30.7

The increases during the years ended December 31, 2017, 2016 and 2015 were due to lower costs and higher productivity than originally anticipated and owner directed scope changes. The 2017 and 2016 increases were also due to estimated cost recovery from affirmative claims.

Decreases

Years Ended December 31,	2017	2016	2015
Number of projects with downward estimate changes	6	7	5
Range of reduction in gross profit from each project, net	$1.0 - 4.4	$1.0 - 3.9	$1.0 - 3.3
Decrease on project profitability	$13.2	$12.9	$10.8

The decreases during the years ended December 31, 2017, 2016 and 2015 were due to additional costs and lower productivity than originally anticipated. The 2017 decreases were also due to increases in estimated cost to complete from outstanding affirmative claims and change orders.

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GRANITE CONSTRUCTION INCORPORATED
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Large Project Construction

The net changes in project profitability from revisions in estimates, both increases and decreases, which individually had an impact of $1.0 million or more on gross profit were net decreases of $66.6 million and $13.5 million and a net increase of $7.6 million for the years ended December 31, 2017, 2016 and 2015, respectively. Amounts attributable to non-controlling interests were $2.1 million and $4.3 million of the net decreases and $3.0 million of the net increase for the years ended December 31, 2017, 2016 and 2015, respectively. The projects are summarized as follows (dollars in millions):

Increases

Years Ended December 31,	2017	2016	2015
Number of projects with upward estimate changes	1	8	7
Range of increase in gross profit from each project, net	$2.0	$1.2 - 6.5	$1.5 - 6.7
Increase on project profitability	$2.0	$27.2	$27.9

The increases during the years ended December 31, 2017 and 2016 were due to higher productivity and lower costs than anticipated and settlement of affirmative claims as well as estimated cost recovery from affirmative claims during 2016. The increases during the year ended December 31, 2015 were due to owner-directed scope changes and lower costs than anticipated, as well as estimated cost recovery from affirmative claims.

Decreases

Years Ended December 31,	2017	2016	2015
Number of projects with downward estimate changes	7	5	6
Range of reduction in gross profit from each project, net	$1.3 - 17.2	$1.3 - 13.6	$1.0 - 5.5
Decrease on project profitability	$68.6	$40.7	$20.3

The decreases during the years ended December 31, 2017, 2016 and 2015 were primarily due to additional design, weather and owner-related costs and lower productivity than originally anticipated, net of estimated and actual recovery from customer affirmative claims and back charges. As of December 31, 2017, there were three projects for which additional costs were reasonably possible in excess of the probable amounts included in the cost forecast. The reasonably possible aggregate range that has the potential to adversely impact gross profit during the year ended December 31, 2018 was zero to $44.0 million. As the related projects proceed, future estimates may change and could have a material effect on our financial position, results of operations and/or cash flows in the future.

3. Marketable Securities

All marketable securities were classified as held-to-maturity as of the dates presented and the carrying amounts of held-to-maturity securities were as follows (in thousands):

December 31,	2017	2016
U.S. Government and agency obligations	$17,910	$10,002
Commercial paper	49,865	54,882
Total short-term marketable securities	67,775	64,884
U.S. Government and agency obligations	59,993	62,895
Corporate bonds	5,022	—
Total long-term marketable securities	65,015	62,895
Total marketable securities	$132,790	$127,779

Scheduled maturities of held-to-maturity investments were as follows (in thousands):

December 31, 2017	
Due within one year	$67,775
Due in one to five years	65,015
Total	$132,790

4. Fair Value Measurement

The following tables summarize significant assets and liabilities measured at fair value in the consolidated balance sheets on a recurring basis for each of the fair value levels (in thousands):

	Fair Value Measurement at Reporting Date Using			
December 31, 2017	Level 1	Level 2	Level 3	Total
Cash equivalents				
Money market funds	$37,284	$ —	$ —	$37,284
Commercial paper	9,967	—	—	9,967
Total assets	$47,251	$ —	$ —	$47,251

	Fair Value Measurement at Reporting Date Using			
December 31, 2016	Level 1	Level 2	Level 3	Total
Cash equivalents				
Money market funds	$10,057	$ —	$ —	$10,057
Total assets	$10,057	$ —	$ —	$10,057

Derivatives

The commodity swaps that we entered in 2014 were settled in October 2015. Gains or losses, including net periodic settlement amounts, were recorded in other income, net in our consolidated statements of operations. During the year ended December 31, 2015, we recorded a net loss of $0.4 million.

Interest Rate Swaps

In December 2016, we terminated the fixed to variable interest rate swap we entered in March 2014 due to the possibility of increasing interest rates. The interest rate swap is reported at fair value using Level 2 inputs in the consolidated balance sheets. Gains or losses, including net periodic settlement amounts, are recorded in other income, net in our consolidated statements of operations. During the years ended December 31, 2016 and 2015, we recorded net gains of $0.3 million and $1.5 million, respectively.

In January 2016, we entered into an interest rate swap designated as a cash flow hedge with an effective date of April 2016 and an initial notional amount of $98.8 million which matures in October 2020. The interest rate swap is designed to convert the interest rate on the term loan described in Note 11 from a variable rate of interest of LIBOR plus an applicable margin to a fixed rate of 1.47% plus the same applicable margin. The interest rate swap is reported at fair value using Level 2 inputs in the consolidated balance sheets. Gains or losses on the effective portion are initially reported as a component of accumulated other comprehensive income (loss) and subsequently reclassified to interest expense in the consolidated statements of operations when the quarterly hedged interest payment is settled. As of December 31, 2017 and 2016, the fair value of the cash flow hedge was $1.4 million and $0.8 million, respectively, and was included in other current assets in the consolidated balance sheets. Associated gains or losses were recorded in the consolidated statements of operations and were immaterial during the years ended December 31, 2017 and 2016.

Other Assets and Liabilities

The carrying values and estimated fair values of our financial instruments that are not required to be recorded at fair value in the consolidated balance sheets are as follows (in thousands):

December 31,		2017		2016	
	Fair Value Hierarchy	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:					
Held-to-maturity marketable securities	Level 1	$132,790	$132,002	$127,779	$127,365
Liabilities (including current maturities):					
Senior notes payable[1]	Level 3	$80,000	$82,190	$120,000	$124,654
Credit Agreement term loan[1]	Level 3	$90,000	$89,871	$95,000	$93,991
Credit Agreement - revolving credit facility, 2016 draw[1]	Level 3	$30,000	$30,105	$30,000	$29,452
Credit Agreement - revolving credit facility, 2017 draw[1]	Level 3	$25,000	$24,949	$—	$—

[1]The fair values of the senior notes payable and Credit Agreement (defined in Note 11) loan are based on borrowing rates available to us for long-term loans with similar terms, average maturities, and credit risk.

We measure certain nonfinancial assets and liabilities at fair value on a nonrecurring basis, at least annually. As of December 31, 2017 and 2016, the nonfinancial assets and liabilities included our asset retirement and reclamation obligations, as well as assets and corresponding liabilities associated with performance guarantees.

The fair value of asset retirement obligations were measured using Level 3 inputs and performance guarantees were measured using Level 2 inputs. Asset retirement obligations were initially measured using internal discounted cash flow calculations based upon our estimates of future retirement costs - see Note 8 for details of the asset retirement balances and Note 1 for further discussion on fair value measurements. Performance guarantees were measured using estimated partner bond rates - see Note 10 for the liability balances and Note 1 for further discussion on performance guarantees.

During the years ended December 31, 2017, 2016 and 2015, nonfinancial assets and liabilities fair value adjustments were related to our asset retirement obligations and restructuring gains associated with our EIP, detailed as follows:

- Asset retirement obligations adjustments were $0.5 million, $2.1 million and $0.2 million, respectively. See Note 8 for further information.
- Restructuring gains associated with our EIP were $2.4 million, $1.9 million and $6.0 million (including amounts attributable to non-controlling interests of $3.3 million), during the years ended December 31, 2017, 2016 and 2015, respectively, primarily associated with the release of lease obligations, sale of a real estate asset related to our equity method investments and the sale of a previously impaired consolidated real estate asset.

5. Receivables, net (in thousands)

December 31,	2017	2016
Construction contracts completed and in progress:		
Billed	$252,467	$206,570
Unbilled	77,135	81,590
Retentions	91,135	84,878
Total construction contracts completed and in progress	420,737	373,038
Construction material sales	42,192	29,357
Other	17,014	17,523
Total gross receivables	479,943	419,918
Less: allowance for doubtful accounts	152	573
Total net receivables	$479,791	$419,345

Receivables include amounts billed and billable to clients for services provided as of the end of the applicable period and do not bear interest. To the extent costs are not contractually billable or have not been earned, including claim recovery estimates, the associated revenue is included in costs and estimated earnings in excess of billings or billings in excess of costs and estimated earnings in the consolidated balance sheets. As of December 31, 2017 and 2016, the aggregate claim recovery estimates included in these balances were approximately $26.7 million and $12.3 million, respectively. Included in other receivables at December 31, 2017 and 2016 were items such as estimated recovery from back charge claims, notes receivable, fuel tax refunds, receivables from vendors and income tax refunds. No such receivables individually exceeded 10% of total net receivables at any of these dates. As of December 31, 2017 and 2016, the estimated recovery from back charge claims included in Other receivables was $1.1 million and $0.3 million, respectively.

During the year ended December 31, 2017, our largest volume customer, including both prime and subcontractor arrangements, was the California Department of Transportation (“Caltrans”). Revenue recognized from contracts with Caltrans during 2017 represented $281.7 million (9.4% of our total revenue) of which $219.9 million (13.2% of segment revenue) was in the Construction segment, $57.2 million (5.5% of segment revenue) in the Large Project Construction segment and $4.6 million (1.6% of segment revenue) was in the Construction Materials segment. During the year ended December 31, 2016, our largest volume customer, including both prime and subcontractor arrangements, was Caltrans. Revenue recognized from contracts with Caltrans during 2016 represented $222.4 million (8.8% of total revenue), of which $173.4 million (12.7% of segment revenue) was in the Construction segment and $48.7 million (5.5% of segment revenue) was in the Large Project Construction segment. During the year ended December 31, 2015, our largest volume customer, including both prime and subcontractor arrangements, was the New York State Department of Transportation (“NYSDOT”). Revenue recognized from contracts with NYSDOT during 2015 represented $199.0 million (8.4% of total revenue), all of which was in the Large Project Construction segment (24.5% of segment revenue).

We regularly review our accounts receivable, including past due amounts, to determine their probability of collection. If it is probable that an amount is uncollectible, it is charged to bad debt expense and a corresponding reserve is established in allowance for doubtful accounts. If it is deemed certain that an amount is uncollectible, the amount is written off.

Certain construction contracts include retainage provisions. The balances billed but not paid by customers pursuant to these provisions generally become due upon completion and acceptance of the project work or products by the owners. No retention receivable individually exceeded 10% of total net receivables at any of the presented dates. As of December 31, 2017, the majority of the retentions receivable are expected to be collected within one year. As of December 31, 2017 and 2016, there were no retentions receivables determined to be uncollectible.

6. Construction Joint Ventures

We participate in various construction joint ventures (“joint ventures”).

Due to the joint and several nature of the performance obligations under the related owner contracts, if any of the partners fail to perform, we and the remaining partners, if any, would be responsible for performance of the outstanding work (i.e., we provide a performance guarantee). At December 31, 2017, there was $4.6 billion of construction revenue to be recognized on unconsolidated and line item construction joint venture contracts of which $1.5 billion represented our share and the remaining $3.1 billion represented our partners’ share. We are not able to estimate amounts that may be required beyond the remaining cost of the work to be performed. These costs could be offset by billings to the customer or by proceeds from our partners’ corporate and/or other guarantees. See Note 10 for disclosure of the performance guarantee amounts recorded in the consolidated balance sheets and Note 1 for additional discussion.

Generally, each construction joint venture is formed to accomplish a specific project and is jointly controlled by the joint venture partners. The joint venture agreements typically provide that our interests in any profits and assets, and our respective share in any losses and liabilities, that may result from the performance of the contracts are limited to

our stated percentage interest in the project. Under our joint venture contractual arrangements, we provide capital to these joint ventures in return for an ownership interest. In addition, partners dedicate resources to the joint ventures necessary to complete the contracts and are reimbursed for their cost. The operational risks of each construction joint venture are passed along to the joint venture members. As we absorb our share of these risks, our investment in each venture is exposed to potential gains and losses.

We have determined that certain of these joint ventures are consolidated because they are VIEs and we are the primary beneficiary. We continually evaluate whether there are changes in the status of the VIEs or changes to the primary beneficiary designation of the VIE. Based on our assessments during the years ended December 31, 2017, 2016 and 2015, we determined no change was required for existing construction joint ventures.

The volume and stage of completion of contracts from our consolidated and unconsolidated construction joint ventures may cause fluctuations in cash and cash equivalents and, for consolidated construction joint ventures, billings in excess of costs and estimated earnings, costs in excess of billings and estimated earnings and property and equipment between periods.

The assets and liabilities of each consolidated and unconsolidated construction joint venture relate solely to that joint venture. The decision to distribute joint venture assets must generally be made jointly by a majority of the members and, accordingly, these assets, including those associated with estimated cost recovery of customer affirmative claims and back charge claims, are generally not available for the working capital needs of Granite until distributed.

Consolidated Construction Joint Ventures

At December 31, 2017, we were engaged in six active consolidated construction joint venture projects, with contract values ranging from $49.8 million to $409.6 million and a combined total of $1.2 billion. Our share of revenue remaining to be recognized on these consolidated joint ventures was $492.8 million and ranged from $4.9 million to $201.3 million. Our proportionate share of the equity in these joint ventures was between 50.0% and 65.0%. During the years ended December 31, 2017, 2016 and 2015, total revenue from consolidated construction joint ventures was $185.5 million, $119.8 million and $54.4 million, respectively. During the years ended December 31, 2017 and 2016 consolidated construction joint ventures provided $36.9 million and $37.8 million, respectively, of operating cash flows and used $16.4 million during the year ended December 31, 2015.

Unconsolidated Construction Joint Ventures

As of December 31, 2017, we were engaged in eleven active unconsolidated joint venture projects with contract values ranging from $77.3 million to $3.7 billion and a combined total of $12.4 billion of which our share was $3.7 billion. Our proportionate share of the equity in these unconsolidated joint ventures ranged from 20.0% to 50.0%. As of December 31, 2017, our share of the revenue remaining to be recognized on these unconsolidated joint ventures was $1.5 billion and ranged from $0.5 million to $365.0 million.

The following is summary financial information related to unconsolidated construction joint ventures (in thousands):

December 31,	2017	2016
Assets:		
Cash, cash equivalents and marketable securities	$289,940	$537,991
Other current assets[1]	812,577	644,809
Noncurrent assets	219,825	207,240
Less partners' interest	869,782	935,615
Granite's interest[1,2]	452,560	454,425
Liabilities:		
Current liabilities	682,832	696,215
Less partners' interest and adjustments[3]	462,159	472,324
Granite's interest	220,673	223,891
Equity in construction joint ventures[4]	$231,887	$230,534

[1]Included in this balance and in accrued and other current liabilities on our consolidated balance sheets as of December 31, 2017 and 2016 was $88.6 million and $83.1 million, respectively, related to performance guarantees (see Note 10 of "Notes to the Consolidated Financial Statements").

[2]Included in this balance as of December 31, 2017 and 2016 was $74.3 million and $65.4 million, respectively, related to Granite's share of estimated cost recovery of customer affirmative claims. In addition, the balances as of December 31, 2017 and 2016 included $11.8 million and $5.6 million, respectively, related to Granite's share of estimated recovery of back charge claims.

[3]Partners' interest and adjustments includes amounts to reconcile total net assets as reported by our partners to Granite's interest adjusted to reflect our accounting policies primarily related to gross profit forecast differences.

[4]As of December 31, 2017 and 2016, this balance included $15.9 million and $16.6 million, respectively, of deficit in construction joint ventures that is included in accrued expenses and other current liabilities in the consolidated balance sheets.

Years Ended December 31,	2017	2016	2015
Revenue:			
Total	$2,057,336	$1,958,158	$1,924,544
Less partners' interest and adjustments[1]	1,469,550	1,387,532	1,341,334
Granite's interest	587,786	570,626	583,210
Cost of revenue:			
Total	1,995,915	1,915,376	1,819,257
Less partners' interest and adjustments[1]	1,394,347	1,360,459	1,279,954
Granite's interest	601,568	554,917	539,303
Granite's interest in gross (loss) profit	$(13,782)	$15,709	$43,907

[1]Partners' interest and adjustments includes amounts to reconcile total revenue and total cost of revenue as reported by our partners to Granite's interest adjusted to reflect our accounting policies primarily related to gross profit forecast differences.

During the years ended December 31, 2017, 2016 and 2015, unconsolidated construction joint venture net income was $62.2 million, $41.8 million and $105.6 million, respectively, of which our share was net loss of $14.4 million and net income of $15.6 million and $43.4 million, respectively. The differences between our share of the joint venture net loss when compared to the joint venture net income during the year ended December 31, 2017 primarily resulted from differences between our estimated total revenue and cost of revenue when compared to that of our partners' on four projects. These joint venture net income amounts exclude our corporate overhead required to manage the joint ventures and include taxes only to the extent the applicable states have joint venture level taxes.

Line Item Joint Ventures

We participate in various "line item" joint venture agreements under which each partner is responsible for performing certain discrete items of the total scope of contracted work. The revenue for each line item joint venture partners' discrete items of work is defined in the contract with the project owner and each joint venture partner bears the profitability risk associated with its own work. There is not a single set of books and records for a line item joint venture. Each partner accounts for its items of work individually as it would for any self-performed contract. We include only our portion of revenue and cost of revenue associated with these contracts in our consolidated financial statements. As of December 31, 2017, we had one active line item joint venture construction project with a total contract value of $66.2 million of which our portion was $49.0 million. As of December 31, 2017, our share of revenue remaining to be recognized on the line item joint venture was $1.4 million. During the years ended December 31, 2017, 2106 and 2015, our portion of revenue from line item joint ventures was $22.9 million, $35.0 million and $26.0 million, respectively.

7. Investments in Affiliates

Our investments in affiliates balance is related to our investments in unconsolidated non-construction entities that we account for using the equity method of accounting, including investments in real estate entities and a non-real estate entity.

The real estate entities were formed to accomplish specific real estate development projects in which our wholly-owned subsidiary, Granite Land Company ("GLC"), participates with third-party partners. The non-real estate entity is a 50% interest in a limited liability company which owns and operates an asphalt terminal and operates an emulsion plant in Nevada.

We have determined that the real estate entities are not consolidated because although they are VIEs, we are not the primary beneficiary. We have determined that the non-real estate entity is not consolidated because it is not a VIE and we do not hold the majority voting interest. As such, this entity is accounted for using the equity method. We account for our share of the operating results of the equity method investments in other income in the consolidated statements of operations and as a single line item in the consolidated balance sheets as investments in affiliates.

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Our investments in affiliates balance consists of the following (in thousands):

December 31,	2017	2016
Equity method investments in real estate affiliates	$29,472	$25,911
Equity method investments in other affiliate	8,997	9,757
Total investments in affiliates	$38,469	$35,668

The following table provides summarized balance sheet information for our affiliates accounted for under the equity method on a combined basis (in thousands):

December 31,	2017	2016
Current assets	$31,320	$30,836
Noncurrent assets	129,039	124,670
Total assets	160,359	155,506
Current liabilities	30,131	18,485
Long-term liabilities[1]	31,636	37,217
Total liabilities	61,767	55,702
Net assets	98,592	99,804
Granite's share of net assets	$38,469	$35,668

[1]The balance primarily relates to debt associated with our real estate investments. See Note 11 for further discussion.

The equity method investments in real estate affiliates included $24.3 million and $20.8 million in residential real estate in Texas as of December 31, 2017 and 2016, respectively. The remaining balances were in commercial real estate in Texas. Of the $160.4 million in total assets as of December 31, 2017, real estate entities had total assets ranging from less than $1.6 million to $68.5 million and the non-real estate entity had total assets of $28.1 million. The following table provides summarized statement of operations information for our affiliates accounted for under the equity method on a combined basis (in thousands):

Years Ended December 31,	2017	2016	2015
Revenue	$56,372	$56,127	$47,457
Gross profit	23,007	22,398	19,117
Income before taxes	17,154	19,117	8,446
Net income	17,154	19,117	8,446
Granite's interest in affiliates' net income	7,107	7,177	3,210

8. Property and Equipment, net

Balances of major classes of assets and allowances for depreciation and depletion are included in property and equipment, net in the consolidated balance sheets as follows (in thousands):

December 31,	2017	2016
Equipment and vehicles	$778,549	$756,602
Quarry property	182,267	174,839
Land and land improvements	108,830	110,999
Buildings and leasehold improvements	82,601	82,762
Office furniture and equipment	56,894	56,381
Property and equipment	1,209,141	1,181,583
Less: accumulated depreciation and depletion	801,723	774,933
Property and equipment, net	$407,418	$406,650

Depreciation and depletion expense primarily included in cost of revenue in our consolidated statements of operations was $63.8 million for the year ended December 31, 2017 and was $61.0 million for both years ended December 31, 2016 and 2015.

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Capitalized interest costs related to certain self-constructed assets were immaterial for the years ended December 31, 2017, 2016 and 2015 and were included in investments in affiliates and property and equipment in the consolidated balance sheets.

We have recorded liabilities associated with our legally required obligations to reclaim owned and leased quarry property and related facilities. As of December 31, 2017 and 2016, $4.8 million and $1.9 million, respectively, of our asset retirement obligations were included in accrued expenses and other current liabilities and $17.7 million and $20.1 million, respectively, were included in other long-term liabilities in the consolidated balance sheets.

The following is a reconciliation of these asset retirement obligations (in thousands):

Years Ended December 31,	2017	2016
Beginning balance	$21,936	$26,558
Revisions to estimates	462	(2,058)
Liabilities settled	(966)	(3,806)
Accretion	1,095	1,242
Ending balance	$22,527	$21,936

9. Intangible Assets

Indefinite-lived Intangible Assets

Indefinite-lived intangible assets primarily consist of goodwill. The following table presents the goodwill balance by reportable segment (in thousands):

December 31,	2017	2016
Construction	$29,260	$29,260
Large Project Construction	22,593	22,593
Construction Materials	1,946	1,946
Total goodwill	$53,799	$53,799

Amortized Intangible Assets

The following is the breakdown of our amortized intangible assets that are included in other noncurrent assets in the consolidated balance sheets (in thousands):

December 31, 2017	Gross Value	Accumulated Amortization	Net Value
Permits	$25,959	$ (12,504)	$13,455
Customer lists	2,200	(1,467)	733
Trade name	4,100	(2,159)	1,941
Covenants not to compete and other	50	(26)	24
Total amortized intangible assets	$32,309	$ (16,156)	$16,153
December 31, 2016			
Permits	$25,959	$(11,514)	$14,445
Acquired backlog	1,500	(1,472)	28
Customer lists	2,200	(1,174)	1,026
Trade name	4,100	(1,727)	2,373
Covenants not to compete and other	50	(24)	26
Total amortized intangible assets	$33,809	$(15,911)	$17,898

Amortization expense related to amortized intangible assets for the years ended December 31, 2017, 2016 and 2015 was $1.7 million, $2.0 million and $2.2 million, respectively, and was primarily included in selling, general and administrative expenses in the consolidated statements of operations. In addition, during the years ended December 31, 2017 and 2016, the gross value and associated accumulated amortization was adjusted for fully amortized intangible assets that we no longer intend to use. Based on the amortized intangible assets balance at

December 31, 2017, amortization expense expected to be recorded in the future is as follows: $1.7 million in 2018; $1.7 million in 2019; $1.6 million in 2020; $1.4 million in 2021; and $9.7 million thereafter.

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10. Accrued Expenses and Other Current Liabilities (in thousands):

December 31,	2017	2016
Payroll and related employee benefits	$68,210	$53,802
Accrued insurance	39,946	44,471
Performance guarantees (see Note 1)	88,606	83,110
Other	39,645	37,204
Total	$236,407	$218,587

Other includes dividends payable, accrued legal reserves, warranty reserves, asset retirement obligations, remediation reserves and other miscellaneous accruals, none of which are greater than 5% of total current liabilities.

11. Long-Term Debt and Credit Arrangements (in thousands):

December 31,	2017	2016
Senior notes payable	$80,000	$120,000
Credit Agreement term loan	90,000	95,000
Credit Agreement revolving credit loan	55,000	30,000
Debt issuance costs	(499)	(706)
Total debt	224,501	244,294
Less current maturities	46,048	14,796
Total long-term debt	$178,453	$229,498

The aggregate minimum principal maturities of long-term debt, including current maturities, for each of the three years following December 31, 2017 are as follows: 2018 - $46.3 million; 2019 - $50.0 million; and 2020 - $128.8 million. We have no long-term debt payments due after 2020.

Senior Notes Payable

As of December 31, 2017 and 2016, senior notes payable in the amount of $80.0 million and $120.0 million, respectively, were due to a group of institutional holders and had an interest rate of 6.11% per annum (“2019 Notes”). As of December 31, 2017, $40.0 million of the outstanding balance was included in long-term debt in the consolidated balance sheets and the remaining $40.0 million was included in current maturities of long-term debt in the consolidated balance sheets. As of December 31, 2016, $110.0 million of the outstanding balance was included in long-term debt in the consolidated balance sheets, including $30.0 million due for the 2017 installment as we had the ability and intent to pay the 2017 installment using borrowings under the Credit Agreement (defined below) or by obtaining other sources of financing. The remaining $10.0 million was included in current maturities of long-term debt in the consolidated balance sheets.

Our obligations under the note purchase agreement governing the 2019 Notes (the “2019 NPA”) are guaranteed by certain of our subsidiaries and are collateralized on an equivalent basis with the Credit Agreement discussed below by liens on substantially all of the assets of the Company and subsidiaries that are guarantors or borrowers under the Credit Agreement. The 2019 NPA provides for the release of liens and re-pledge of collateral on substantially the same terms and conditions as those set forth in the Credit Agreement.

Credit Agreement

As of December 31, 2017, we had a $290.0 million credit facility (the “Credit Agreement”), of which $200.0 million was a revolving credit facility and $90.0 million was a term loan that matures on October 28, 2020 (the “Maturity Date”). The Credit Agreement has a sublimit for letters of credit of $100.0 million. As of December 31, 2017 and 2016, $6.2 million and $5.0 million of the term loan balance was included in current maturities of long-term debt, respectively, and the remaining $83.8 million and $90.0 million, respectively, was included in long-term debt in the consolidated balance sheets.

Of the $95.0 million term loan outstanding as of December 31, 2016, we paid $5.0 million of the principal balance during 2017. Of the remaining $90.0 million outstanding as of December 31, 2017, 1.25% of the original principal balance is due in three quarterly installments beginning in March 2018, 2.50% of the original principal balance is due in eight quarterly installments beginning in December 2018 and the remaining balance is due on the Maturity Date.

As of December 31, 2017, the total stated amount of all issued and outstanding letters of credit under the Credit Agreement was $8.3 million. As of December 31, 2017 and 2016, $25.0 million and $30.0 million had been drawn for the 2017 and 2016 installments of the 2019 Notes, respectively. The total unused availability under the Credit Agreement was $136.7 million. The letters of credit will expire between July 2018 and October 2018.

Borrowings under the Credit Agreement bear interest at LIBOR or a base rate (at our option), plus an applicable margin based on certain financial ratios calculated quarterly. LIBOR varies based on the applicable loan term, market conditions and other external factors. The applicable margin was 1.75% for loans bearing interest based on LIBOR and 0.75% for loans bearing interest at the base rate at December 31, 2017. Accordingly, the effective interest rate using three-month LIBOR and base rate was 3.44% and 5.25%, respectively, at December 31, 2017 and we elected to use LIBOR. Borrowings at the base rate have no designated term and could be repaid without penalty any time prior to the Maturity Date. Borrowings bearing interest at a LIBOR rate have a term no less than one month and no greater than six months (or such longer period not to exceed 12 months if approved by all lenders). At the end of each term, such borrowings can be paid or continued at our discretion as either a borrowing at the base rate or a borrowing at a LIBOR rate with similar terms. Our obligations under the Credit Agreement are guaranteed by certain of our subsidiaries and are collateralized on an equivalent basis with the obligations under the 2019 Notes (defined above) by first priority liens (subject only to other permitted liens) on substantially all of the assets of the Company and our subsidiaries that are guarantors or borrowers under the Credit Agreement.

In January 2016, we entered into an interest rate swap designated as a cash flow hedge with an effective date of April 2016 and an initial notional amount of $98.8 million which matures in October 2020. The interest rate swap is designed to convert the interest rate on the term loan described above from a variable rate of interest of LIBOR plus an applicable margin to a fixed rate of 1.47% plus the same applicable margin (see Note 4 for details).

The Credit Agreement provides for the release of the liens securing the obligations, at our option and expense, so long as certain conditions as defined by the terms in the Credit Agreement are satisfied (“Collateral Release Period”). However, if subsequent to exercising the option, our Consolidated Fixed Charge Coverage Ratio is less than 1.25 or our Consolidated Leverage Ratio is greater than 2.50, then we would be required to promptly re-pledge substantially all of the assets of the Company and our subsidiaries that are guarantors or borrowers under the Credit Agreement. As of December 31, 2017, the conditions for the exercise of our right under the Credit Agreement to have liens released were not satisfied.

Real Estate Indebtedness

Our unconsolidated investments in real estate entities is subject to mortgage indebtedness. This indebtedness is non-recourse to Granite, but is recourse to the real estate entity. The terms of this indebtedness are typically renegotiated to reflect the evolving nature of the real estate project as it progresses through acquisition, entitlement and development. Modification of these terms may include changes in loan-to-value ratios requiring the real estate entity to repay portions of the debt. The debt associated with our unconsolidated real estate entities is disclosed in Note 7.

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Covenants and Events of Default

Our debt and credit agreements require us to comply with various affirmative, restrictive and financial covenants, including the financial covenants described below. Our failure to comply with any of these covenants, or to pay principal, interest or other amounts when due thereunder, would constitute an event of default under the applicable agreements. Under certain circumstances, the occurrence of an event of default under one of our debt or credit agreements (or the acceleration of the maturity of the indebtedness under one of our agreements) may constitute an event of default under one or more of our other debt or credit agreements. Default under our debt and credit agreements could result in (i) us no longer being entitled to borrow under the agreements; (ii) termination of the agreements; (iii) the requirement that any letters of credit under the agreements be cash collateralized; (iv) acceleration of the maturity of outstanding indebtedness under the agreements and/or (v) foreclosure on any collateral securing the obligations under the agreements.

The most significant financial covenants under the terms of our Credit Agreement and 2019 NPA require the maintenance of a minimum Consolidated Tangible Net Worth, a minimum Consolidated Interest Coverage Ratio and a maximum Consolidated Leverage Ratio.

As of December 31, 2017 and pursuant to the definitions in the agreements, our Consolidated Tangible Net Worth was $953.6 million, which exceeded the minimum of $752.0 million, our Consolidated Leverage Ratio was 1.25 which did not exceed the maximum of 3.00 and our Consolidated Interest Coverage Ratio was 15.59 which exceeded the minimum of 4.00.

As of December 31, 2017, we were in compliance with all covenants contained in the Credit Agreement and related to the 2019 NPA. We are not aware of any non-compliance by any of our unconsolidated real estate entities with the covenants contained in their debt agreements.

12. Employee Benefit Plans

Profit Sharing and 401(k) Plan: The Profit Sharing and 401(k) Plan (the “401(k) Plan”) is a defined contribution plan covering all employees except employees covered by collective bargaining agreements and certain employees of our consolidated construction joint ventures. Each employee’s combined pre-tax 401(k) and post-tax (Roth) contributions cannot exceed 50% of their eligible pay or Internal Revenue Code annual contribution limits. Our 401(k) matching contributions can be up to 6% of an employee’s gross pay at the discretion of the Board of Directors. Our 401(k) matching contributions to the 401(k) Plan for the years ended December 31, 2017, 2016 and 2015 were $12.1 million, $11.0 million and $5.4 million, respectively. Profit sharing contributions from the Company may be made to the 401(k) Plan in an amount determined by the Board of Directors. We made no profit sharing contributions during the years ended December 31, 2017, 2016 and 2015.

Non-Qualified Deferred Compensation Plan: We offer a Non-Qualified Deferred Compensation Plan (“NQDC Plan”) to a select group of our highly compensated employees. The NQDC Plan provides participants the opportunity to defer payment of certain compensation as defined in the NQDC Plan. In October 2008, a Rabbi Trust was established to fund our NQDC Plan obligation and was fully funded as of December 31, 2017. The assets held by the Rabbi Trust at December 31, 2017 and 2016 are substantially in the form of Company-owned life insurance and are included in other noncurrent assets in the consolidated balance sheets. As of December 31, 2017, there were 61 active participants in the NQDC Plan. NQDC Plan obligations were $24.7 million and $21.5 million as of December 31, 2017 and 2016, respectively.

Multi-employer Pension Plans: Four of our wholly-owned subsidiaries, Granite Construction Company, Granite Construction Northeast, Inc., Granite Industrial, Inc., and Kenny Construction Company contribute to various multi-employer pension plans on behalf of union employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the multi-employer plan by one employer may be used to provide benefits to employees of other participating employers.
-

- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers.
- If we chose to stop participating in some of the multi-employer plans, we may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability.

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The following table presents our participation in these plans (dollars in thousands):

	Pension Plan Employer Identification Number	Pension Protection Act ("PPA") Certified Zone Status[1]		FIP / RP Status Pending / Implemented[2]	Contributions			Surcharge Imposed	Expiration Date of Collective Bargaining Agreement[3]
Pension Trust Fund		2017	2016		2017	2016	2015		
Locals 302 and 612 IUOE-Employers Construction Industry Retirement Plan	91-6028571	Green	Green	No	$3,646	$3,113	$3,000	No	12/31/2017 5/31/2018 12/31/2019
Pension Trust Fund for Operating Engineers Pension Plan	94-6090764	Red	Red	Yes	10,431	9,266	9,070	No	1/31/2018 10/31/2018 6/30/2019 5/15/2020 6/15/2020 6/30/2020 9/30/2020
Operating Engineers Pension Trust Fund	95-6032478	Yellow	Red	Yes	4,692	5,357	3,647	No	6/30/2019
Laborers Pension Trust Fund for Northern California Construction	94-6277608	Yellow	Yellow	Yes	2,464	2,215	2,403	No	6/30/2019
Laborers Pension Trust for Southern California	43-6159056	Green	Green	No	2,002	2,095	1,349	No	6/30/2018
Laborers Pension Fund	36-2514514	Green	Green	No	3,208	2,328	1,919	No	5/31/2021
All other funds (38 as of December 31, 2017)					10,341	8,708	7,171		
			Total Contributions:		$36,784	$33,082	$28,559		

[1]The most recent PPA zone status available in 2017 and 2016 is for the plan's year-end during 2016 and 2015, respectively. The zone status is based on information that we received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the orange zone are less than 80 percent funded and have an Accumulated Funding Deficiency in the current year or projected into the next six years, plans in the yellow zone are less than 80 percent funded, and plans in the green zone are at least 80 percent funded. Subsequent to December 31, 2016, the Operating Engineers Pension Trust Fund zone status changed from red to yellow for the plan's year-end during 2015.
[2]The "FIP/RP Status Pending/Implemented" column indicates plans for which a financial improvement plan ("FIP") or a rehabilitation plan ("RP") is either pending or has been implemented.
[3]Lists the expiration date(s) of the collective-bargaining agreement(s) to which the plans are subject. Pension trust funds with a range of expiration dates have various collective bargaining agreements. Expired collective bargaining agreements are under negotiation.

Based upon the most recently available annual reports, the Company's contribution to each of the individually significant plans listed in the table above was less than 5% of each plan's total contributions. We currently have no intention of withdrawing from any of the multi-employer pension plans in which we participate that would result in a significant withdrawal liability. In addition, we do not have any significant future obligations or funding requirements related to these plans other than the ongoing contributions that are paid as hours are worked by plan participants.

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13. Shareholders' Equity

Stock-based Compensation: The 2012 Equity Incentive Plan provides for the issuance of restricted stock, restricted stock units ("RSUs") and stock options to eligible employees and to members of our Board of Directors. A total of 1,595,675 shares of our common stock have been reserved for issuance of which 1,072,750 remained available as of December 31, 2017. No stock options or restricted stock were granted during the years ended December 31, 2017, 2016 and 2015. There were no stock options or restricted stock outstanding as of December 31, 2017.

Restricted Stock Units: RSUs are issued for services to be rendered and may not be sold, transferred or pledged for such a period as determined by our Compensation Committee. RSU stock compensation cost is measured at our common stock's fair value based on the market price at the date of grant. We recognize compensation cost only for RSUs that we estimate will ultimately vest. We estimate the number of shares that will ultimately vest at each grant date based on our historical experience and adjust compensation cost based on changes in those estimates over time. RSU compensation cost is recognized ratably over the shorter of the vesting period (generally three years) or the period from grant date to the first maturity date after the holder reaches age 62 and has completed certain specified years of service, when all RSUs become fully vested. Vesting of RSUs is not subject to any market or performance conditions and vesting provisions are at the discretion of the Compensation Committee. An employee may not sell or otherwise transfer unvested RSUs and, in the event employment is terminated prior to the end of the vesting period, any unvested RSUs are surrendered to us. We have no obligation to purchase these RSUs that are surrendered to us.

A summary of the changes in our RSUs during the years ended December 31, 2017, 2016 and 2015 is as follows (shares in thousands):

Years Ended December 31,	2017		2016		2015	
	RSUs	Weighted-Average Grant-Date Fair Value per RSU	RSUs	Weighted-Average Grant-Date Fair Value per RSU	RSUs	Weighted-Average Grant-Date Fair Value per RSU
Outstanding, beginning balance	681	$ 39.15	451	$ 32.73	565	$ 31.38
Granted	259	51.31	572	43.17	228	33.40
Vested	(372)	43.89	(307)	36.24	(300)	31.50
Forfeited	(44)	43.51	(35)	40.97	(42)	33.38
Outstanding, ending balance	524	$ 41.51	681	$ 39.15	451	$ 32.73

Compensation cost related to RSUs was $15.8 million ($11.4 million net of effective tax rate), $13.4 million ($9.2 million net of effective tax rate), and $8.8 million ($5.8 million net of effective tax rate) for the years ended December 31, 2017, 2016 and 2015, respectively. The grant date fair value of RSUs vested during the years ended December 31, 2017, 2016 and 2015 was $16.7 million, $11.5 million and $10.3 million, respectively. As of December 31, 2017, there was $10.0 million of unrecognized compensation cost related to RSUs which will be recognized over a remaining weighted-average period of 1.2 years.

401(k) Plan: As of December 31, 2017, the 401(k) Plan owned 1,454,844 shares of our common stock. Dividends on shares held by the 401(k) Plan are charged to retained earnings and all shares held by the 401(k) Plan are treated as outstanding in computing our earnings per share.

Employee Stock Purchase Plan: Our ESPP allows qualifying employees to purchase shares of our common stock through payroll deductions of up to 15% of their compensation, subject to Internal Revenue Code limitations, at a price of 95% of the fair market value as of the end of each of the six-month offering periods, which commence on May 15 and November 15 of each year. During each of the years ended December 31, 2017, 2016 and 2015, proceeds from the ESPP were $0.8 million for 16,413, 16,717 and 22,567 shares, respectively.

Share Purchase Program: On April 7, 2016, the Board of Directors authorized us to purchase up to $200.0 million of our common stock at management's discretion, which replaced the former authorization including the amount available. We did not purchase shares under the share purchase program in any of the periods presented. The specific timing and amount of any future purchases will vary based on market conditions, securities law limitations and other

factors.

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14. Weighted Average Shares Outstanding and Net Income Per Share

The following table presents a reconciliation of the weighted average shares outstanding used in calculating basic and diluted net income per share as well as the calculation of basic and diluted net income per share (in thousands except per share amounts):

Years Ended December 31,	2017	2016	2015
Numerator (basic and diluted):			
Net income allocated to common shareholders for basic calculation	$69,098	$57,122	$60,485
Denominator:			
Weighted average common shares outstanding, basic	39,795	39,557	39,337
Dilutive effect of stock options and restricted stock units	577	668	531
Weighted average common shares outstanding, diluted	40,372	40,225	39,868
Net income per share, basic	$1.74	$1.44	$1.54
Net income per share, diluted	$1.71	$1.42	$1.52

15. Income Taxes

Following is a summary of the provision for income taxes (in thousands):

Years Ended December 31,	2017	2016	2015
Federal:			
Current	$27,877	$15,657	$4,810
Deferred	(4,397)	9,919	25,955
Total federal	23,480	25,576	30,765
State:			
Current	5,520	4,567	1,914
Deferred	(338)	19	2,500
Total state	5,182	4,586	4,414
Total provision for income taxes	$28,662	$30,162	$35,179

Following is a reconciliation of our provision for income taxes based on the Federal statutory tax rate to our effective tax rate (dollars in thousands):

Years Ended December 31,	2017		2016		2015	
Federal statutory tax	$36,562	35.0 %	$33,728	35.0 %	$35,165	34.0 %
State taxes, net of federal tax benefit	3,814	3.7	2,990	3.1	3,769	3.6
Percentage depletion deduction	(1,368)	(1.3)	(1,352)	(1.4)	(1,444)	(1.4)
Domestic production activities deduction	(2,765)	(2.7)	(1,624)	(1.7)	(306)	(0.3)
Non-controlling interests	(2,346)	(2.3)	(3,177)	(3.3)	(2,639)	(2.6)
Nondeductible expenses	1,128	1.1	1,094	1.1	219	0.2
Tax Cuts and Jobs Act of 2017	(3,664)	(3.5)	—	—	—	—
Other	(2,699)	(2.6)	(1,497)	(1.5)	415	0.5
Total	$28,662	27.4 %	$30,162	31.3 %	$35,179	34.0 %

On December 22, 2017 the U.S. Tax Cuts and Jobs Act of 2017 (“Tax Reform”) was signed into law. As a result of Tax Reform, the U.S. statutory tax rate was lowered from 35% to 21% effective January 1, 2018, among other changes. ASC Topic 740, Accounting for Income Taxes, requires companies to recognize the effect of tax law changes in the period of enactment; therefore, we were required to revalue our deferred tax assets and liabilities at December 31, 2017 at the new rate. The Securities and Exchange Commission issued Staff Accounting Bulletin No. 118 (“SAB 118”) to address the application of U.S. GAAP in situations when a registrant does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for certain tax effects of Tax Reform. The Company has recognized the provisional tax impacts of Tax Reform in its consolidated financial statements for the year ended December 31, 2017. The majority of the $3.7 million provisional benefit above is related to the revaluation of deferred tax assets and liabilities at December 31, 2017 as a result of Tax Reform. The ultimate impact may differ from this provisional amount, possibly materially, as a result of additional analysis, changes in interpretations and assumptions the Company has made, additional regulatory guidance that may be issued, and actions the Company may take as a result of Tax Reform. The accounting is expected to be complete when the 2017 U.S. corporate income tax return is filed in 2018.

Following is a summary of the deferred tax assets and liabilities (in thousands):

December 31,	2017	2016
Long-term deferred tax assets:		
Receivables	$526	$573
Inventory	1,513	2,212
Insurance	7,401	12,524
Deferred compensation	8,985	12,740
Other accrued liabilities	1,525	2,294
Accrued compensation	1,738	11,031
Other	1,379	2,481
Net operating loss carryforwards	2,614	2,341
Valuation allowance	(2,471)	(2,153)
Total long-term deferred tax assets	23,210	44,043
Long-term deferred tax liabilities:		
Property and equipment	16,832	29,400
Contract income recognition	7,739	20,084
Total long-term deferred tax liabilities	24,571	49,484
Net long-term deferred tax liabilities	$(1,361)	$(5,441)

As of December 31, 2017, our deferred tax asset for net operating loss carryforwards relates to state and local net operating loss carryforwards with the significant carryforwards expiring beginning in 2035. We have provided a valuation allowance on the net deferred tax assets for certain state and local jurisdictions because we do not believe it is more likely than not that they will be realized.

The following is a summary of the change in valuation allowance (in thousands):

December 31,	2017	2016	2015
Beginning balance	$2,153	$641	$1,185
Additions (deductions), net	318	1,512	(544)
Ending balance	$2,471	$2,153	$641

The additions to the valuation allowance are related to the revaluation of our net deferred tax assets related to U.S. Tax Reform enacted during the year ended December 31, 2017 discussed above. Deductions to the valuation allowance are insignificant for the year ended December 31, 2017.

Uncertain tax positions: We file income tax returns in the U.S. and various state and local jurisdictions. We are currently under examination by various state taxing authorities for various tax years. We do not anticipate that any of these audits will result in a material change in our financial position. We are no longer subject to U.S. federal examinations by tax authorities for years before 2012. With few exceptions, as of December 31, 2017, we are no longer subject to state examinations by taxing authorities for years before 2010.

We had approximately $3.2 million and $3.3 million of total gross unrecognized tax benefits as of December 31, 2017 and 2016, respectively. There were approximately $3.1 million and $3.2 million of unrecognized tax benefits that would affect the effective tax rate in any future period at December 31, 2017 and 2016, respectively. We do not anticipate a significant increase or decrease in our unrecognized tax benefits that will impact our effective tax rate in 2018.

The following is a tabular reconciliation of unrecognized tax benefits (in thousands) the balance of which is included in other long-term liabilities on the consolidated balance sheets:

December 31,	2017	2016	2015
Beginning balance	$3,262	$1,578	$887
Gross increases – current period tax positions	—	1,902	1,006
Gross decreases – current period tax positions	(73)	(125)	(156)
Gross increases – prior period tax positions	1	2	—
Gross decreases – prior period tax positions	(6)	(5)	—
Settlements with taxing authorities/lapse of statute of limitations	(13)	(90)	(159)
Ending balance	$3,171	$3,262	$1,578

We record interest on uncertain tax positions in interest expense in our consolidated statements of operations. During the years ended December 31, 2017, 2016 and 2015, we recognized approximately $0.2 million interest expense, $0.1 million interest expense and $0.1 million of interest income, respectively. Approximately $0.4 million and $0.2 million of accrued interest related to our uncertain tax position liability was included in other long-term liabilities in our consolidated balance sheets at December 31, 2017 and 2016, respectively.

16. Commitments, Contingencies and Guarantees

Leases: Minimum rental commitments and minimum royalty requirements under all noncancellable operating leases, primarily quarry property, in effect at December 31, 2017 were (in thousands):

Years Ending December 31,	
2018	$12,169
2019	8,946
2020	7,997
2021	6,874
2022	4,794
Later years (through 2046)	7,171
Total	$47,951

Operating lease and equipment rental and royalty expense primarily included in cost of revenue in our consolidated statements of operations was $16.4 million, $18.2 million and $11.3 million in 2017, 2016 and 2015, respectively.

Performance Guarantees

We participate in various joint ventures and line item joint ventures under which each partner is responsible for performing certain discrete items of the total scope of contracted work. See Note 1, Note 6 and Note 10 for further details.

Surety Bonds

We are generally required to provide various types of surety bonds that provide an additional measure of security under certain public and private sector contracts. At December 31, 2017, $3.5 billion of our contract backlog was bonded. Performance bonds do not have stated expiration dates; rather, we are generally released from the bonds after

the owner accepts the work performed under contract. The ability to maintain bonding capacity to support our current and future level of contracting requires that we maintain cash and working capital balances satisfactory to our sureties.

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17. Legal Proceedings

In the ordinary course of business, we and our affiliates are involved in various legal proceedings alleging, among other things, liability issues or breach of contract or tortious conduct in connection with the performance of services and/or materials provided, the various outcomes of which cannot be predicted with certainty. We and our affiliates are also subject to government inquiries in the ordinary course of business seeking information concerning our compliance with government construction contracting requirements and various laws and regulations, the outcomes of which cannot be predicted with certainty.

Some of the matters in which we or our joint ventures and affiliates are involved may involve compensatory, punitive, or other claims or sanctions that, if granted, could require us to pay damages or make other expenditures in amounts that are not probable to be incurred or cannot currently be reasonably estimated. In addition, in some circumstances our government contracts could be terminated, we could be suspended, debarred or incur other administrative penalties or sanctions, or payment of our costs could be disallowed. While any of our pending legal proceedings may be subject to early resolution as a result of our ongoing efforts to resolve the proceedings, whether or when any legal proceeding will be resolved is neither predictable nor guaranteed.

Accordingly, it is possible that future developments in such proceedings and inquiries could require us to (i) adjust existing accruals, or (ii) record new accruals that we did not originally believe to be probable or that could not be reasonably estimated. Such changes could be material to our financial condition, results of operations and/or cash flows in any particular reporting period. In addition to matters that are considered probable for which the loss can be reasonably estimated, disclosure is also provided when it is reasonably possible and estimable that a loss will be incurred or when it is reasonably possible that the amount of a loss will exceed the amount recorded.

Liabilities relating to legal proceedings and government inquiries, to the extent that we have concluded such liabilities are probable and the amounts of such liabilities are reasonably estimable, are recorded in the consolidated balance sheets. The aggregate liabilities recorded as of December 31, 2017 and 2016 related to these matters were approximately $0.9 million and $4.3 million, respectively, and were primarily included in accounts payable and accrued expenses and other current liabilities in our consolidated balance sheets. The aggregate range of possible loss related to (i) matters considered reasonably possible, and (ii) reasonably possible amounts in excess of accrued losses recorded for probable loss contingencies, including those related to liquidated damages, could have a material impact on our consolidated financial statements if they become probable and the reasonably estimable amount is determined.

18. Business Segment Information

Our reportable segments are: Construction, Large Project Construction and Construction Materials.

In addition to business segments, we review our business by operating groups. Our operating groups are defined as follows: (i) California; (ii) Northwest, which primarily includes offices in Alaska, Arizona, Nevada, Utah and Washington; (iii) Heavy Civil, which primarily includes offices in California, Florida, New York and Texas and (iv) Kenny, which primarily includes offices in Illinois. Each of these operating groups may include financial results from our Construction and Large Project Construction segments. Our California and Northwest operating groups include financial results from our Construction Materials segment.

The Construction segment performs various construction projects with a large portion of the work focused on new construction and improvement of streets, roads, highways, bridges, site work, underground, power-related facilities, water-related facilities, utilities and other infrastructure projects. These projects are typically bid-build projects completed within two years with a contract value of less than $75 million.

The Large Project Construction segment focuses on large, complex infrastructure projects which typically have a longer duration than our Construction segment work. These projects include major highways, mass transit facilities, bridges, tunnels, waterway locks and dams, pipelines, canals, power-related facilities, water-related facilities, utilities and airport infrastructure. This segment primarily includes bid-build, design-build, construction management/general contractor contracts, together with various contract methods relating to public-private partnerships, generally with contract values in excess of $75 million.

The Construction Materials segment mines and processes aggregates and operates plants that produce construction materials for internal use and for sale to third parties.

The accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (see Note 1). We evaluate segment performance based on gross profit or loss, and do not include selling, general and administrative expenses or non-operating income or expense. Segment assets include property and equipment, intangibles, goodwill, inventory and equity in construction joint ventures.

GRANITE CONSTRUCTION INCORPORATED
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Summarized segment information is as follows (in thousands):

Years Ended December 31,	Construction	Large Project Construction	Construction Materials	Total
2017				
Total revenue from reportable segments	$ 1,664,708	$ 1,032,229	$ 467,140	$ 3,164,077
Elimination of intersegment revenue	—	—	(174,364)	(174,364)
Revenue from external customers	1,664,708	1,032,229	292,776	2,989,713
Gross profit	247,014	29,793	38,126	314,933
Depreciation, depletion and amortization	22,517	11,087	22,393	55,997
Segment assets	136,031	340,105	282,709	758,845
2016				
Total revenue from reportable segments	$ 1,365,198	$ 888,193	$ 425,029	$ 2,678,420
Elimination of intersegment revenue	—	—	(163,803)	(163,803)
Revenue from external customers	1,365,198	888,193	261,226	2,514,617
Gross profit	209,215	64,137	28,018	301,370
Depreciation, depletion and amortization	22,816	6,796	23,437	53,049
Segment assets	151,475	314,823	282,472	748,770
2015				
Total revenue from reportable segments	$ 1,262,675	$ 812,720	$ 432,284	$ 2,507,679
Elimination of intersegment revenue	—	—	(136,650)	(136,650)
Revenue from external customers	1,262,675	812,720	295,634	2,371,029
Gross profit	187,506	79,467	32,863	299,836
Depreciation, depletion and amortization	20,117	10,343	22,389	52,849
Segment assets	139,399	274,975	288,900	703,274

A reconciliation of segment gross profit to consolidated income before provision for income taxes is as follows (in thousands):

Years Ended December 31,	2017	2016	2015
Total gross profit from reportable segments	$ 314,933	$ 301,370	$ 299,836
Selling, general and administrative expenses	222,811	219,299	203,817
Restructuring gains	(2,411)	(1,925)	(6,003)
Gain on sales of property and equipment	(4,182)	(8,358)	(8,286)
Total other (income) expense	(5,748)	(4,008)	6,881
Income before provision for income taxes	$ 104,463	$ 96,362	$ 103,427

A reconciliation of segment assets to consolidated total assets is as follows (in thousands):

December 31,	2017	2016	2015
Total assets for reportable segments	$ 758,845	$ 748,770	$ 703,274
Assets not allocated to segments:			
Cash and cash equivalents	233,711	189,326	252,836
Short-term and long-term marketable securities	132,790	127,779	105,695
Receivables, net	479,791	419,345	340,822
Deferred income taxes, net	—	—	4,329
Other current assets, excluding segment assets	140,478	113,010	85,556
Property and equipment, net, excluding segment assets	29,242	32,397	36,721
Investments in affiliates	38,469	35,668	33,182
Other noncurrent assets, excluding segment assets	58,652	67,158	64,463
Consolidated total assets	$ 1,871,978	$ 1,733,453	$ 1,626,878

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GRANITE CONSTRUCTION INCORPORATED
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

19. Subsequent Events Footnote

On February 13, 2018, the Company entered into an Agreement and Plan of Merger (“Merger Agreement”) to acquire Layne Christensen Company (“Layne”), a U.S.-based global water management, construction and drilling company. The acquisition is subject to the approval by Layne stockholders and other customary closing conditions.

The transaction is structured as a stock-for-stock merger in which each outstanding share of Layne common stock will be exchanged for 0.27 share of Company common stock. All outstanding stock options, restricted stock awards and unvested performance shares will be cashed out in accordance with the terms of the Merger Agreement. Using Granite’s closing share price as of February 16, 2018 of $60.36, the purchase price of the transaction in stock and cash would be approximately $360 million, excluding the assumption of approximately $209 million of debt at its estimated fair market value using Level 3 inputs as of February 16, 2018. The ultimate value of the transaction will be determined on the closing date in accordance with the terms of the Merger Agreement.

Following the completion of the acquisition, two outstanding issuances of Layne’s convertible notes will remain outstanding. The 4.25% convertible notes (the “4.25% Notes”) have outstanding principal of $69.5 million, a current conversion price of $22.93 per Layne share and mature on November 15, 2018. As permitted under the terms of the 4.25% Note indenture, following the closing, the conversion provisions of the 4.25% Notes will be amended to provide that the 4.25% notes will be cash settled only. The 8.0% convertible notes (the “8.0% Notes”) have outstanding principal of $99.9 million, a current conversion price of $11.70 per Layne share and mature on May 1, 2019. The maturity of the 8.0% Notes accelerates to August 15, 2018 if the 4.25% Notes remain outstanding on that date. At closing, the 8.0% Notes will become convertible into shares of Company common stock. At closing, the Company will also assume Layne’s $24.5 million of letters of credit, or issue new letters of credit. These additional debt obligations assumed at closing would exceed the amount of indebtedness currently permitted under the Company’s existing credit facility and private placement notes. The Company will seek consents or waivers from its existing lenders with respect to this additional indebtedness. The Company has also received a commitment letter for a new $370 million backstop financing facility, which the Company will use to the extent these consents or waivers are not received prior to closing.

Item 16. FORM 10-K SUMMARY

None.

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Quarterly Financial Data

The following table sets forth selected unaudited quarterly financial information for the years ended December 31, 2017 and 2016. This information has been prepared on the same basis as the audited consolidated financial statements and, in the opinion of management, contains all adjustments necessary for a fair statement thereof. Net income (loss) per share calculations are based on the weighted average common shares outstanding for each period presented. Accordingly, the sum of the quarterly net income (loss) per share amounts may not equal the per share amount reported for the year.

QUARTERLY FINANCIAL DATA

(unaudited - dollars in thousands, except per share data)

2017 Quarters Ended	December 31,	September 30,	June 30,	March 31,
Revenue	$801,274	$957,126	$762,913	$468,400
Gross profit	100,707	114,530	74,570	25,126
As a percent of revenue	12.6 %	12.0 %	9.8 %	5.4 %
Net income (loss)	$35,325	$48,055	$16,272	$(23,851)
As a percent of revenue	4.4 %	5.0 %	2.1 %	(5.1)%
Net income (loss) attributable to Granite	$32,773	$45,982	$14,133	$(23,790)
As a percent of revenue	4.1 %	4.8 %	1.9 %	(5.1)%
Net income (loss) per share attributable to common shareholders:				
Basic	$0.82	$1.15	$0.35	$(0.60)
Diluted	$0.81	$1.14	$0.35	$(0.60)

2016 Quarters Ended	December 31,	September 30,	June 30,	March 31,
Revenue	$666,681	$803,905	$604,579	$439,452
Gross profit	81,250	107,674	73,201	39,245
As a percent of revenue	12.2 %	13.4 %	12.1 %	8.9 %
Net income (loss)	$19,264	$38,172	$18,526	$(9,762)
As a percent of revenue	2.9 %	4.7 %	3.1 %	(2.2)%
Net income (loss) attributable to Granite	$16,173	$37,190	$14,199	$(10,440)
As a percent of revenue	2.4 %	4.6 %	2.3 %	(2.4)%
Net income (loss) per share attributable to common shareholders:				
Basic	$0.41	$0.94	$0.36	$(0.27)
Diluted	$0.40	$0.92	$0.35	$(0.27)

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INDEX TO 10-K EXHIBITS

Exhibit No.		Exhibit Description
2.1	*	Agreement and Plan of Merger by and among Granite Construction Incorporated, Layne Christensen Company and Lowercase Merger Sub Incorporated, dated as of February 13, 2018 [Exhibit 2.1 to the Company's Form 8-K filed on February 14, 2018]
2.2	*	Stock Purchase Agreement, dated December 28, 2012, by and between Granite Construction Incorporated and Kenny Industries, Inc. [Exhibit 2.1 to the Company's Form 8-K filed on January 4, 2013]
3.1	*	Certificate of Incorporation of Granite Construction Incorporated, as amended [Exhibit 3.1.b to the Company's Form 10-Q for quarter ended June 30, 2006]
3.2	*	Amended Bylaws of Granite Construction Incorporated [Exhibit 3.1 to the Company's Form 8-K filed on November 15, 2011]
10.1	* **	Key Management Deferred Compensation Plan II, as amended and restated [Exhibit 10.1 to the Company's Form 10-Q for quarter ended March 31, 2010]
10.2	* **	Granite Construction Incorporated Amended and Restated 1999 Equity Incentive Plan as Amended and Restated [Exhibit 10.1 to the Company's Form 10-Q for quarter ended June 30, 2009]
10.2.a	* **	Amendment No. 1 to the Granite Construction Incorporated Amended and Restated 1999 Equity Incentive Plan as Amended and Restated [Exhibit 10.2.a to the Company's Form 10-K for year ended December 31, 2009]
10.7	*	Note Purchase Agreement between Granite Construction Incorporated and Certain Purchasers dated December 12, 2007 [Exhibit 10.1 to the Company's Form 8-K filed January 31, 2008]
10.8	*	First Amendment to the Note Purchase Agreement, dated October 11, 2012, between Granite Construction Incorporated and the holders of the 2019 Notes party thereto. [Exhibit 10.7 to the Company's Form 10-Q for the quarter ended September 30, 2012]
10.9	*	Subsidiary Guaranty Agreement from the Subsidiaries of Granite Construction Incorporated as Guarantors of the Guaranty of Notes and Note Agreement and the Guaranty of Payment and Performance dated December 12, 2007 [Exhibit 10.10 to the Company's Form 10-K for year ended December 31, 2007]
10.11	* **	Form of Amended and Restated Director and Officer Indemnification Agreement [Exhibit 10.10 to the Company's Form 10-K for year ended December 31, 2002]
10.12	* **	Executive Retention and Severance Plan II effective as of March 9, 2011 [Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2011]
10.13	* **	Form of Restricted Stock Agreement effective March 2010 [Exhibit 10.18 to the Company's Form 10-K for the year ended December 31, 2010]
10.14	* **	Form of Non-employee Director Stock Option Agreement as amended and effective April 7, 2006 [Exhibit 10.19 to the Company's Form 10-K for the year ended December 31, 2010]
10.15	* **	Form of Restricted Stock Units Agreement effective January 1, 2010 [Exhibit 10.20 to the Company's Form 10-K for the year ended December 31, 2010]
10.16	* **	Form of Non-employee Director Restricted Stock Units Agreement effective January 1, 2010 [Exhibit 10.21 to the Company's Form 10-K for the year ended December 31, 2010]
10.17	* **	Granite Construction Incorporated Annual Incentive Plan effective January 1, 2010, as amended [Exhibit 10.22 to the Company's Form 10-K for the year ended December 31, 2011]
10.18	* **	Amendment No. 2 to the Granite Construction Incorporated Annual Incentive Plan effective January 1, 2012 [Exhibit 10.23 to the Company's Form 10-K for the year ended December 31, 2011]
10.19	*	

	**	Granite Construction Incorporated Long Term Incentive Plan effective January 1, 2010, as amended [Exhibit 10.24 to the Company’s Form 10-K for the year ended December 31, 2011]
10.20	* **	Amendment No. 2 to the Granite Construction Incorporated Long Term Incentive Plan effective January 1, 2012 [Exhibit 10.25 to the Company’s Form 10-K for the year ended December 31, 2011]
10.21	* **	Granite Construction Incorporated 2012 Equity Incentive Plan [Exhibit 10.1 to the Company’s Form 8-K filed on May 25, 2012]
10.22	* **	Form of Non-Employee Director Restricted Stock Unit Agreement effective May 22, 2012 [Exhibit 10.2 to the Company’s Form 8-K filed on May 25, 2012]
10.23	* **	Granite Construction Incorporated NEO LTIP Awards Form of Restricted Stock Unit Agreement (Vesting on Date of Grant) [Exhibit 10.30 to the Company's Form 10-K for the year ended December 31, 2012]
10.24	* **	Granite Construction Incorporated NEO LTIP Awards Form of Restricted Stock Unit Agreement (3 Year Vesting Schedule) [Exhibit 10.31 to the Company's Form 10-K for the year ended December 31, 2012]

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Exhibit No.		Exhibit Description
10.25	*	Second Amendment to Note Purchase Agreement, dated as of March 3, 2014 [Exhibit 10.32 to the Company's Form 10-K for the year ended December 31, 2013]
10.26	*	Second Amended and Restated Credit Agreement, dated October 28, 2015, by and among Granite Construction Incorporated, Granite Construction Company, GILC Incorporated, the lenders party thereto and Bank of America, N.A., as Administrative Agent, Collateral Agent, Swing Line Lender and L/C Issuer [Exhibit 10.26 to the Company's Form 10-K for the year ended December 31, 2015]
10.27	*	Second Amended and Restated Guaranty Agreement, dated October 28, 2015, by and among Granite Construction Incorporated, the guarantors party thereto and Bank of America, N.A., as Administrative Agent [Exhibit 10.26 to the Company's Form 10-K for the year ended December 31, 2015]
18.1	*	Preferability Letter from PricewaterhouseCoopers LLP [Exhibit 18 to the Company's Form 10-Q for quarter ended March 31, 2015]
21	†	List of Subsidiaries of Granite Construction Incorporated
23.1	†	Consent of PricewaterhouseCoopers LLP
31.1	†	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	†	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	††	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95	†	Mine Safety Disclosure
101.INS	†	XBRL Instance Document
101.SCH	†	XBRL Taxonomy Extension Schema
101.CAL	†	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	†	XBRL Taxonomy Extension Definition Linkbase
101.LAB	†	XBRL Taxonomy Extension Label Linkbase
101.PRE	†	XBRL Taxonomy Extension Presentation Linkbase

* Incorporated by reference
** Compensatory plan or management contract
† Filed herewith
†† Furnished herewith

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GRANITE
CONSTRUCTION
INCORPORATED

By: /s/ Laurel J. Krzeminski
Laurel J. Krzeminski
Executive Vice President and
Chief Financial Officer
(Principal Financial and
Accounting Officer)

Date: February 16, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant in the capacities indicated and on the dates indicated.

/s/ William H. Powell William H. Powell, Chairman of the Board and Director	February 16, 2018
/s/ James H. Roberts James H. Roberts, President and Chief Executive Officer	February 16, 2018
By: /s/ Laurel J. Krzeminski Laurel J. Krzeminski	February 16, 2018
/s/ Claes G. Bjork Claes G. Bjork, Director	February 16, 2018
/s/ James W. Bradford, Jr. James W. Bradford, Jr., Director	February 16, 2018
/s/ David C. Darnell David C. Darnell, Director	February 16, 2018
/s/ Patricia D. Galloway Patricia D. Galloway, Director	February 16, 2018
/s/ David H. Kelsey David H. Kelsey, Director	February 16, 2018
/s/ Celeste B. Mastin Celeste B. Mastin, Director	February 16, 2018
/s/ Michael F. McNally	

Michael F. McNally, Director	February 16, 2018
/s/ Gaddi H. Vasquez Gaddi H. Vasquez, Director	February 16, 2018