VECTREN UTILITY HOLDINGS INC
Form 10-Q
August 13, 2015

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015
OR

[_]	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to __________________

Commission file number: 1-16739

VECTREN UTILITY HOLDINGS, INC.
(Exact name of registrant as specified in its charter)

INDIANA	35-2104850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

One Vectren Square, Evansville, IN 47708
(Address of principal executive offices)
(Zip Code)

(812) 491-4000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
ý Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

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

Common Stock- Without Par Value	10	July 31, 2015
Class	Number of Shares	Date

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports, including those of its wholly owned subsidiaries, free of charge through its website at www.vectren.com as soon as reasonably practicable after electronically filing or furnishing the reports to the SEC, or by request, directed to Investor Relations at the mailing address, phone number, or email address that follows:

Mailing Address: One Vectren Square Evansville, Indiana 47708	Phone Number: (812) 491-4000	Investor Relations Contact: M. Naveed Mughal Treasurer and Vice President, Investor Relations vvcir@vectren.com

Definitions

AFUDC: allowance for funds used during construction	MDth / MMDth: thousands / millions of dekatherms
DOT: Department of Transportation	MISO: Midcontinent Independent System Operator
EPA: Environmental Protection Agency	BTU / MMBTU: British thermal units/ millions of BTU
FAC: Fuel Adjustment Clause	MW: megawatts
FASB: Financial Accounting Standards Board	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FERC: Federal Energy Regulatory Commission	ASC: Accounting Standards Codification
IDEM: Indiana Department of Environmental Management	ASU: Accounting Standards Update
GCA: Gas Cost Adjustment	OUCC: Indiana Office of the Utility Consumer Counselor
IURC: Indiana Utility Regulatory Commission	XBRL: eXtensible Business Reporting Language
kV: Kilovolt	PUCO: Public Utilities Commission of Ohio

MCF / BCF: thousands / billions of cubic feet

Throughput: combined gas sales and gas transportation volumes

GAAP: Generally Accepted Accounting Principles

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited – In millions)

	June 30, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash & cash equivalents	$6.7	$19.3
Accounts receivable - less reserves of $5.0 & $3.9, respectively	59.8	113.0
Accrued unbilled revenues	55.7	122.4
Inventories	104.0	113.2
Recoverable fuel & natural gas costs	—	9.8
Prepayments & other current assets	33.8	83.5
Total current assets	260.0	461.2
Utility Plant		
Original cost	5,887.1	5,718.7
Less: accumulated depreciation & amortization	2,352.3	2,279.7
Net utility plant	3,534.8	3,439.0
Investments in unconsolidated affiliates	0.2	0.2
Other investments	25.3	25.6
Nonutility plant - net	144.5	149.2
Goodwill - net	205.0	205.0
Regulatory assets	138.1	128.3
Other assets	36.4	19.6
TOTAL ASSETS	$4,344.3	$4,428.1

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited – In millions)

	June 30, 2015	December 31, 2014
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$95.8	$180.4
Payables to other Vectren companies	47.4	28.6
Refundable fuel & natural gas costs	22.7	—
Accrued liabilities	125.4	122.3
Short-term borrowings	27.3	156.4
Current maturities of long-term debt	88.0	95.0
Total current liabilities	406.6	582.7
Long-Term Debt - Net of Current Maturities	1,164.5	1,162.3
Deferred Credits & Other Liabilities		
Deferred income taxes	708.5	685.1
Regulatory liabilities	424.3	410.3
Deferred credits & other liabilities	126.7	109.2
Total deferred credits & other liabilities	1,259.5	1,204.6
Commitments & Contingencies (Notes 8 - 11)		
Common Shareholder's Equity		
Common stock (no par value)	796.7	793.7
Retained earnings	717.0	684.8
Total common shareholder's equity	1,513.7	1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,344.3	$4,428.1

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

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VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited – In millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
OPERATING REVENUES				
Gas utility	$128.6	$132.4	$481.5	$576.0
Electric utility	147.8	152.0	301.7	315.0
Other	0.1	0.1	0.2	0.1
Total operating revenues	276.5	284.5	783.4	891.1
OPERATING EXPENSES				
Cost of gas sold	36.4	43.7	208.4	314.6
Cost of fuel & purchased power	47.0	48.1	97.0	105.1
Other operating	78.5	81.5	181.3	179.8
Depreciation & amortization	52.0	50.6	104.2	100.5
Taxes other than income taxes	12.1	12.5	31.2	32.6
Total operating expenses	226.0	236.4	622.1	732.6
OPERATING INCOME	50.5	48.1	161.3	158.5
Other income - net	4.3	3.7	9.2	7.6
Interest expense	16.4	16.7	33.0	33.4
INCOME BEFORE INCOME TAXES	38.4	35.1	137.5	132.7
Income taxes	14.0	12.2	50.1	48.5
NET INCOME	$24.4	$22.9	$87.4	$84.2

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

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VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited – In millions)

	Six Months Ended June 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$87.4	$84.2
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	104.2	100.5
Deferred income taxes & investment tax credits	23.2	17.0
Expense portion of pension & postretirement periodic benefit cost	2.4	2.3
Provision for uncollectible accounts	4.1	2.3
Other non-cash items - net	3.4	1.5
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	115.8	102.8
Inventories	9.2	16.4
Recoverable/refundable fuel & natural gas costs	30.0	(22.7)
Prepayments & other current assets	50.6	4.1
Accounts payable, including to Vectren companies & affiliated companies	(89.0)	(88.9)
Accrued liabilities	5.6	(5.6)
Changes in noncurrent assets	(5.7)	5.8
Changes in noncurrent liabilities	(4.4)	(6.5)
Net cash provided by operating activities	336.8	213.2
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from additional capital contribution	3.0	3.2
Requirements for:		
Dividends to parent	(55.2)	(54.3)
Retirement of long-term debt	(5.0)	—
Net change in short-term borrowings	(129.1)	(24.9)
Net cash used in financing activities	(186.3)	(76.0)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	0.1	0.1
Requirements for capital expenditures, excluding AFUDC equity	(163.2)	(141.0)
Net cash used in investing activities	(163.1)	(140.9)
Net change in cash & cash equivalents	(12.6)	(3.7)
Cash & cash equivalents at beginning of period	19.3	8.6
Cash & cash equivalents at end of period	$6.7	$4.9

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

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VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 583,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and over 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 316,000 natural gas customers located near Dayton in west central Ohio.

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These condensed consolidated financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2014, filed with the Securities and Exchange Commission on March 5, 2015, on Form 10-K. Because of the seasonal nature of the Company's utility operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

3. Subsidiary Guarantor and Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of Utility Holdings' $350 million in short-term credit facilities, of which approximately $27 million was outstanding at June 30, 2015. The operating utility companies are also guarantors of Utility Holdings' unsecured senior notes with a par value of $875 million outstanding at June 30, 2015. The guarantees are full and unconditional and joint and several, and Utility Holdings has no direct subsidiaries other than the subsidiary guarantors. However, Utility Holdings does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are 100 percent owned, separate from the parent company's operations is required. Following are condensed consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

Condensed Consolidating Balance Sheet as of June 30, 2015 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$6.4	$0.3	$—	$6.7
Accounts receivable - less reserves	59.8	—	—	59.8
Intercompany receivables	62.6	130.2	(192.8)	—
Accrued unbilled revenues	55.7	—	—	55.7
Inventories	104.0	—	—	104.0
Prepayments & other current assets	23.5	29.3	(19.0)	33.8
Total current assets	312.0	159.8	(211.8)	260.0
Utility Plant				
Original cost	5,887.1	—	—	5,887.1
Less: accumulated depreciation & amortization	2,352.3	—	—	2,352.3
Net utility plant	3,534.8	—	—	3,534.8
Investments in consolidated subsidiaries	—	1,451.0	(1,451.0)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.2	4.1	—	25.3
Nonutility plant - net	1.6	142.9	—	144.5
Goodwill - net	205.0	—	—	205.0
Regulatory assets	117.1	21.0	—	138.1
Other assets	42.9	1.5	(8.0)	36.4
TOTAL ASSETS	$4,234.8	$2,526.8	$(2,417.3)	$4,344.3

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$92.0	$3.8	$—	$95.8
Intercompany payables	7.4	—	(7.4)	—
Payables to other Vectren companies	47.4	—	—	47.4
Refundable fuel & natural gas costs	22.7	—	—	22.7
Accrued liabilities	132.6	11.8	(19.0)	125.4
Short-term borrowings	—	27.3	—	27.3
Intercompany short-term borrowings	48.7	62.6	(111.3)	—
Current maturities of long-term debt	13.0	75.0	—	88.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	437.9	180.5	(211.8)	406.6
Long-Term Debt				
Long-term debt	364.7	799.8	—	1,164.5
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,111.2	799.8	(746.5)	1,164.5
Deferred Credits & Other Liabilities				
Deferred income taxes	680.9	27.6	—	708.5
Regulatory liabilities	422.9	1.4	—	424.3
Deferred credits & other liabilities	130.9	3.8	(8.0)	126.7
Total deferred credits & other liabilities	1,234.7	32.8	(8.0)	1,259.5
Common Shareholder's Equity				
Common stock (no par value)	810.0	796.7	(810.0)	796.7

Retained earnings	641.0	717.0	(641.0)	717.0
Total common shareholder's equity	1,451.0	1,513.7	(1,451.0)	1,513.7
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,234.8	$2,526.8	$(2,417.3)	$4,344.3

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Condensed Consolidating Balance Sheet as of December 31, 2014 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$6.9	$12.4	$—	$19.3
Accounts receivable - less reserves	113.0	—	—	113.0
Intercompany receivables	0.8	186.7	(187.5)	—
Accrued unbilled revenues	122.4	—	—	122.4
Inventories	113.2	—	—	113.2
Recoverable fuel & natural gas costs	9.8	—	—	9.8
Prepayments & other current assets	94.8	38.1	(49.4)	83.5
Total current assets	460.9	237.2	(236.9)	461.2
Utility Plant				
Original cost	5,718.7	—	—	5,718.7
Less: accumulated depreciation & amortization	2,279.7	—	—	2,279.7
Net utility plant	3,439.0	—	—	3,439.0
Investments in consolidated subsidiaries	—	1,416.9	(1,416.9)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.3	4.3	—	25.6
Nonutility plant - net	1.8	147.4	—	149.2
Goodwill - net	205.0	—	—	205.0
Regulatory assets	106.7	21.6	—	128.3
Other assets	29.4	1.7	(11.5)	19.6
TOTAL ASSETS	$4,264.3	$2,575.6	$(2,411.8)	$4,428.1

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$176.2	$4.2	$—	$180.4
Intercompany payables	15.6	0.8	(16.4)	—
Payables to other Vectren companies	28.6	—	—	28.6
Accrued liabilities	136.7	35.0	(49.4)	122.3
Short-term borrowings	—	156.4	—	156.4
Intercompany short-term borrowings	97.0	—	(97.0)	—
Current maturities of long-term debt	20.0	75.0	—	95.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	548.2	271.4	(236.9)	582.7
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	362.6	799.7	—	1,162.3
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,109.1	799.7	(746.5)	1,162.3
Deferred Credits & Other Liabilities				
Deferred income taxes	665.8	19.3	—	685.1
Regulatory liabilities	408.8	1.5	—	410.3
Deferred credits & other liabilities	115.5	5.2	(11.5)	109.2
Total deferred credits & other liabilities	1,190.1	26.0	(11.5)	1,204.6
Common Shareholder's Equity				

Common stock (no par value)	806.9	793.7	(806.9)	793.7
Retained earnings	610.0	684.8	(610.0)	684.8
Total common shareholder's equity	1,416.9	1,478.5	(1,416.9)	1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,264.3	$2,575.6	$(2,411.8)	$4,428.1

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Condensed Consolidating Statement of Income for the three months ended June 30, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$128.6	$—	$—	$128.6
Electric utility	147.8	—	—	147.8
Other	—	10.2	(10.1)	0.1
Total operating revenues	276.4	10.2	(10.1)	276.5
OPERATING EXPENSES				
Cost of gas sold	36.4	—	—	36.4
Cost of fuel & purchased power	47.0	—	—	47.0
Other operating	87.9	—	(9.4)	78.5
Depreciation & amortization	45.5	6.4	0.1	52.0
Taxes other than income taxes	11.7	0.4	—	12.1
Total operating expenses	228.5	6.8	(9.3)	226.0
OPERATING INCOME	47.9	3.4	(0.8)	50.5
Other income - net	4.3	9.9	(9.9)	4.3
Interest expense	15.8	11.3	(10.7)	16.4
INCOME BEFORE INCOME TAXES	36.4	2.0	—	38.4
Income taxes	13.3	0.7	—	14.0
Equity in earnings of consolidated companies, net of tax	—	23.1	(23.1)	—
NET INCOME	$23.1	$24.4	$(23.1)	$24.4

Condensed Consolidating Statement of Income for the three months ended June 30, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$132.4	$—	$—	$132.4
Electric utility	152.0	—	—	152.0
Other	—	9.5	(9.4)	0.1
Total operating revenues	284.4	9.5	(9.4)	284.5
OPERATING EXPENSES				
Cost of gas sold	43.7	—	—	43.7
Cost of fuel & purchased power	48.1	—	—	48.1
Other operating	90.3	—	(8.8)	81.5
Depreciation & amortization	44.6	5.9	0.1	50.6
Taxes other than income taxes	12.1	0.4	—	12.5
Total operating expenses	238.8	6.3	(8.7)	236.4
OPERATING INCOME	45.6	3.2	(0.7)	48.1
Other income - net	2.8	10.9	(10.0)	3.7
Interest expense	16.1	11.3	(10.7)	16.7
INCOME BEFORE INCOME TAXES	32.3	2.8	—	35.1
Income taxes	11.7	0.5	—	12.2
Equity in earnings of consolidated companies, net of tax	—	20.6	(20.6)	—
NET INCOME	$20.6	$22.9	$(20.6)	$22.9

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Condensed Consolidating Statement of Income for the six months ended June 30, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$481.5	$—	$—	$481.5
Electric utility	301.7	—	—	301.7
Other	—	20.4	(20.2)	0.2
Total operating revenues	783.2	20.4	(20.2)	783.4
OPERATING EXPENSES				
Cost of gas sold	208.4	—	—	208.4
Cost of fuel & purchased power	97.0	—	—	97.0
Other operating	200.3	—	(19.0)	181.3
Depreciation & amortization	91.2	12.8	0.2	104.2
Taxes other than income taxes	30.3	0.9	—	31.2
Total operating expenses	627.2	13.7	(18.8)	622.1
OPERATING INCOME	156.0	6.7	(1.4)	161.3
Other income - net	8.4	20.7	(19.9)	9.2
Interest expense	31.7	22.6	(21.3)	33.0
INCOME BEFORE INCOME TAXES	132.7	4.8	—	137.5
Income taxes	50.1	—	—	50.1
Equity in earnings of consolidated companies, net of tax	—	82.6	(82.6)	—
NET INCOME	$82.6	$87.4	$(82.6)	$87.4

Condensed Consolidating Statement of Income for the six months ended June 30, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$576.0	$—	$—	$576.0
Electric utility	315.0	—	—	315.0
Other	—	19.1	(19.0)	0.1
Total operating revenues	891.0	19.1	(19.0)	891.1
OPERATING EXPENSES				
Cost of gas sold	314.6	—	—	314.6
Cost of fuel & purchased power	105.1	—	—	105.1
Other operating	197.8	—	(18.0)	179.8
Depreciation & amortization	89.0	11.3	0.2	100.5
Taxes other than income taxes	31.7	0.8	0.1	32.6
Total operating expenses	738.2	12.1	(17.7)	732.6
OPERATING INCOME	152.8	7.0	(1.3)	158.5
Other income - net	5.8	21.6	(19.8)	7.6
Interest expense	31.9	22.6	(21.1)	33.4
INCOME BEFORE INCOME TAXES	126.7	6.0	—	132.7
Income taxes	48.5	—	—	48.5
Equity in earnings of consolidated companies, net of tax	—	78.2	(78.2)	—
NET INCOME	$78.2	$84.2	$(78.2)	$84.2

Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$317.7	$19.1	$—	$336.8
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Additional capital contribution from parent	3.0	3.0	(3.0)	3.0
Requirements for:				
Dividends to parent	(51.6)	(55.2)	51.6	(55.2)
Retirement of long term debt	(5.0)	—	—	(5.0)
Net change in intercompany short-term borrowings	(48.2)	62.6	(14.4)	—
Net change in short-term borrowings	—	(129.1)	—	(129.1)
Net cash used in financing activities	(101.8)	(118.7)	34.2	(186.3)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	51.6	(51.6)	—
Other investing activities	—	0.1	—	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(153.8)	(9.4)	—	(163.2)
Consolidated subsidiary investments	—	(3.0)	3.0	—
Net change in short-term intercompany notes receivable	(62.6)	48.2	14.4	—
Net cash used in investing activities	(216.4)	87.5	(34.2)	(163.1)
Net change in cash & cash equivalents	(0.5)	(12.1)	—	(12.6)
Cash & cash equivalents at beginning of period	6.9	12.4	—	19.3
Cash & cash equivalents at end of period	$6.4	$0.3	$—	$6.7

Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$181.9	$31.3	$—	$213.2
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	124.2	—	(124.2)	—
Additional capital contribution from parent	3.2	3.2	(3.2)	3.2
Requirements for:				
Dividends to parent	(50.8)	(54.3)	50.8	(54.3)
Net change in intercompany short-term borrowings	(49.2)	87.8	(38.6)	—
Net change in short-term borrowings	—	(24.9)	—	(24.9)
Net cash used in financing activities	27.4	11.8	(115.2)	(76.0)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	50.8	(50.8)	—
Other investing activities	—	0.1	—	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(126.8)	(14.2)	—	(141.0)

Consolidated subsidiary investments	—	(3.2)	3.2	—
Net change in long-term intercompany notes receivable	—	(124.2)	124.2	—
Net change in short-term intercompany notes receivable	(87.8)	49.2	38.6	—
Net cash used in investing activities	(214.6)	(41.5)	115.2	(140.9)
Net change in cash & cash equivalents	(5.3)	1.6	—	(3.7)
Cash & cash equivalents at beginning of period	8.2	0.4	—	8.6
Cash & cash equivalents at end of period	$2.9	$2.0	$—	$4.9

4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $5.4 million and $5.5 million in the three months ended June 30, 2015 and 2014, respectively. For the six months ended June 30, 2015 and 2014, these taxes totaled $17.1 million and $18.4 million, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Supplemental Cash Flow Information

As of June 30, 2015 and December 31, 2014, the Company has accruals related to utility and nonutility plant purchases totaling approximately $21.3 million and $19.0 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc. (Vectren Fuels)
On August 29, 2014, Vectren closed on a transaction to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Prior to the sale, SIGECO purchased coal used for electric generation from Vectren Fuels. The Company purchased $37.8 million and $68.6 million for the three and six months ended June 30, 2014, respectively. After the exit of the coal mining business by Vectren, Sunrise has assumed Vectren Fuels' supply contracts and has also negotiated new contracts for similar quality coal that will result in the Company purchasing most of its coal supply from Sunrise.

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of Vectren, provides underground pipeline construction and repair services. VISCO's customers include Utility Holdings' utilities and fees incurred by Utility Holdings and its subsidiaries totaled $31.6 million and $22.0 million for the three months ended June 30, 2015 and 2014, respectively, and for the six months ended June 30, 2015 and 2014 totaled $49.3 million and $33.4 million, respectively. Amounts owed to VISCO at June 30, 2015 and December 31, 2014 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Support Services & Purchases
Vectren provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. For the three months ended June 30, 2015 and 2014, Utility Holdings received corporate allocations totaling $11.9 million and $14.6 million, respectively. For the six months ending June 30, 2015 and 2014, Utility Holdings received corporate allocations totaling $27.5 million and $29.3 million, respectively.

The Company does not have share-based compensation plans and pension and other postretirement plans separate from Vectren and allocated costs include participation in Vectren's plans. The allocation methodology for retirement costs is consistent with FASB guidance related to “multiemployer” benefit accounting.

7. Financing Activities

Indiana Gas Unsecured Note Retirement
On March 15, 2015, a $5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded by the Company's commercial paper program.

Utility Holdings Debt Transactions
On June 11, 2015, Vectren Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors have agreed to purchase the following tranches of notes: (i) $25 million of 3.90% Guaranteed Senior Notes, Series A, due December 15, 2035, (ii) $135 million of 4.36% Guaranteed Senior Notes, Series B, due December, 15,

2045, and (iii) $40 million of 4.51% Guaranteed Senior Notes, Series C, due December 15, 2055. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, the financing is scheduled to close on or about December 15, 2015.

8. Commitments & Contingencies

Commitments
The Company has both firm and non-firm commitments to purchase natural gas, electricity, and coal as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Legal & Regulatory Proceedings
The Company is party to various legal proceedings, audits, and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations or cash flows.

9. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a result of federal pipeline safety requirements. Laws passed in both Indiana and Ohio provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the Commission, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs is deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. The legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying projects to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At June 30, 2015 and December 31, 2014, the Company has regulatory assets totaling $18.3 million and $16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms
On August 27, 2014, the IURC issued an Order (August 2014 Order) approving the Company’s seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In June 2015, the Indiana Court of Appeals issued an opinion in favor of the Company that agreed with the IURC finding as issued in its original August 2014 Order.

On January 14, 2015, the IURC issued an Order approving the Company’s initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost fluctuations. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with federal pipeline safety rules.
In April 2015, a group of industrial customers intervened as part of the pending appeal of the Company's Order referenced above, asking the Court of Appeals in light of a court decision related to another utility's seven-year plan, to consider whether the Company had failed to provide sufficient detail regarding its planned projects after year one of the plan. In the June 2015 decision, the Indiana Court of Appeals denied this request given that this issue was not raised during the Company's case or on appeal during the briefing period. As a result, the Company's Order approving its plan is final.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. On June 1, 2015, the Company amended its case to delay the recovery of a portion of the investment associated with the Senate Bill 560 approved investment made from July 2014 to December 2014, until its next filing in October 2015. The Company has offered to provide additional detail related to its seven-year plan in its update to be filed October 1, 2015. On July 22, 2015, the IURC issued an Order, approving the recovery of these investments consistent with the Company's proposal, with modification, specifically to the rate of return applicable to the Senate Bill 251 compliance component. The IURC found that the overall rate of return to be applied to the investment in determining the revenue requirement is to be updated with each filing, reflecting the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last base rate case. This IURC interpretation of the overall rate of return to be used is the same as that already in place for the Senate Bill 560 component.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $167.2 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $15.6 million and $13.1 million at June 30, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however, is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2015, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2014. A procedural schedule has been set in this proceeding, and the Company expects an order by September 2015.

Given the extension of the DRR through 2017 as discussed above and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining three-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. As of June 30, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2015, which covers the Company’s capital expenditure program through calendar year 2015.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue
On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review,

the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of $3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company’s supply administrator was filed in this proceeding. The IURC issued an Order on June 10, 2015 which approved the stipulation and settlement agreement, which resulted in recovery of approximately $1.4 million of the disputed amount via the Company’s GCA mechanism, with the remaining $1.6 million received from the gas supply administrator.

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing was held in May 2015. The Company expects an order later in 2015.

10. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of June 30, 2015, approximately $30 million has been spent on equipment to control mercury in both air and water emissions, and $21 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $75 and $85 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of June 30, 2015, the Company has approximately $1.4 million deferred related to depreciation, property tax, and operating expense, and $0.5 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company's investments and proposed accounting treatment. The Company believes the IURC's Order satisfies applicable legal standards and filed its response on August 12, 2015. The Court is expected to decide on these issues later this year.

Coal Procurement Procedures
Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels, previously Vectren's wholly owned coal mining subsidiary, and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the IURC determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $31.8 million remains as of June 30, 2015.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011 the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in

2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the six months ended June 30, 2015 and 2014, the Company recognized Electric utility revenue of $4.8 million and $4.4 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the IURC's December 2009 Order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. As defined within the procedural schedule set August 6, 2015, the OUCC and other stakeholders will file testimony in October 2015 and a hearing will be held November 13, 2015.

FERC Return on Equity (ROE) Complaint

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners’ rates, including SIGECO’s formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of June 30, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $141.9 million at June 30, 2015.

This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. A settlement has not been reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which defines a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of these complaints.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new

ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

11. Environmental Matters

Indiana Senate Bill 251

Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations in addition to the impact on its gas utility operations. The Company continues with its ongoing evaluation of the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently pursuing involving carbon and air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality

Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR's first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air
pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. Reductions are to be achieved within three years of publication of the final rule in the Federal Register. MATS compliance was required to commence April 16, 2015, and the Company is in full compliance with all requirements of MATS.

Legal challenges to the MATS Rule continue. In July 2014, a coalition of twenty-one states, including Indiana, filed a petition with the U.S. Supreme Court seeking review of the decision of the appellate court that found that the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015 the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule back to the appellate court for further proceedings consistent with the opinion. The parties to the litigation are expected to be asked by the appellate court for briefing as to whether the court should vacate the rule, or leave it in place while the EPA supplements the rulemaking record pursuant to the Supreme Court opinion. Vectren continues to operate in full compliance with the MATS rule during the pendency of the appellate court remand which could take several months.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. The EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 however the rule is not yet finalized. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water Regulations
To comply with Indiana’s implementation plan of the Clean Air Act, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with Alcoa Power Generating, Inc. SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO’s electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO’s coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Utilization of the Company’s NOx and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding NOV from the EPA. The total investment is estimated to be between $75 and $85 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds

In December 2014 the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from approximately $30 million for final capping and monitoring costs if the ponds are permitted to continue to operate to the end of the life of the generating units, to $100 million if existing ponds at both F.B. Culley and A.B. Brown generating stations are required to be closed and bottom ash conversions completed at each generating unit.

In the second quarter 2015, the Company recorded an asset retirement obligation (ARO) in the amount of $15.6 million which reflects the current present value of the costs to cap the existing ponds at the end of the life of the generating units. The estimated obligation is based on assumptions such as future ash levels, existing life of generating units, compliance assessments within the final rule at future dates, and costs for future construction services. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO. It is expected that any costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized three sets of GHG regulations that apply to the Company’s generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

In July 2013, the President announced a Climate Action Plan, which called on the EPA to finalize the rule for new construction expeditiously and, by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. On June 2, 2014, the EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule required states to adopt plans to reduce CO2 emissions by 30 percent from 2005 levels by 2030. The proposal set state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals were calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal used a 2012 emission rate of 1,923 lb CO2/MWh, and set an interim goal of 1,607 lb CO2/MWh and a final emission goal of 1,531 lb CO2/MWh, or a 20 percent reduction in Indiana’s total CO2 emission rate, that must be met by 2030. Under this proposal, these CO2 emission rate goals do not apply directly to individual units or generating systems, but are instead state goals. As such, the state would be required to establish a framework that would guide how compliance would be met on a statewide basis. Indiana’s interim, or “phase in”, goal of 1,607 lb CO2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022. These individual state goals were based upon the application of four “building blocks” of emission rate improvements identified as the Best System of Emission Reduction, which defines

EPA’s authority under Section 111(d).

The Company timely filed comments to the Clean Power Plan (CPP) proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rule prior to finalization by the EPA. In June 2015 these consolidated challenges were determined to be premature by the reviewing court, but the court’s decision did not preclude the parties from raising the arguments against the final rulemaking after EPA has published the final CPP in the Federal Register.

On August 3, 2015, the EPA released its final CPP which requires a 32 percent reduction in carbon emissions from 2005 levels. The original proposal in June 2014 called for a 30 percent reduction. The final CPP is significantly different in many respects from the June 2014 proposal. The EPA removed the energy efficiency block in the final rule and increased the assumption related to reliance upon renewables for compliance. In addition to the change in energy efficiency and renewables assumptions, the EPA also incorporated a new emission rate factor as a means of leveling the emission reduction requirements across the states. This resulted in the final emission rate reduction goal for Indiana of 1,242 lb CO_2 / MWh to be achieved by 2030, as compared to a goal of 1,531 lb CO_2/ MWh as proposed in June of 2014. Final state goals now fall within a narrower, lower range (between 771 lb CO_2/MWh and 1305 lb CO_2/MWh), with states having higher percentages of coal-fired generation receiving more stringent emission rate goals than those in the original proposal. The new rule also gives states an additional year to submit a state implementation plan, now September of 2018. Under the CPP, states have the flexibility to include energy efficiency and other measures should it choose to implement a state measures plan as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction glide path over the 2022-29 time period.

In the event that a state does not submit a state implementation plan (SIP), the EPA also released a proposed federal implementation plan (FIP), which would be imposed in those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on affected units. Under the proposed FIP the CO_2 emission rate limit for coal-fired units would start at 1671 lbs CO_2 / MWh in 2022 and decrease to a final emission rate cap of 1305 lbs CO_2 / MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent, the cap would apply directly to affected units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. Since the FIP has just been proposed, it will be subject to extensive public comments prior to finalization.

Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO_2. The Company's share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company's emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. With respect to CO_2 emission rate, since 2005 the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company will undertake a detailed review of the requirements of the CPP and the proposed FIP and commence a review of potential compliance options for Vectren's affected units. In 2016 the Company will file its next integrated resource plan that will model compliance assumptions and costs and evaluate possible compliance alternatives. The Company will also continue to remain engaged with the State of Indiana to assess the final rule and to develop a plan that is the least cost to its customers. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon

emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

Manufactured Gas Plants
In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $43.4 million ($23.2 million at Indiana Gas and $20.2 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.3 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2015 and December 31, 2014, approximately $3.4 million and $3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Fair Value Measurements

The carrying values and estimated fair values using primarily Level 2 assumptions of the Company's other financial instruments follow:

	June 30, 2015		December 31, 2014	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,252.5	$1,382.6	$1,257.3	$1,408.0
Short-term borrowings	27.3	27.3	156.4	156.4
Cash & cash equivalents	6.7	6.7	19.3	19.3

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding, and no material assets or liabilities valued using Level 3 inputs.

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's long-term debt was estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for instruments with similar characteristics. Because of the maturity dates and variable interest rates of short-term borrowings and cash & cash equivalents, those carrying amounts approximate fair value. Because of the inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition of this debt would not be expected to have a material effect on the Company's results of operations.

13. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. On July 9, 2015, the FASB approved a one year deferral of the effective date to December 15, 2017 with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company adopted this guidance on January 1, 2015. The adoption of this guidance had no impact on the Company's financial statements.

Simplifying the Presentation of Debt Issuance Costs

In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements. Adoption will have no impact on the Company's consolidated income statement.

14. Segment Reporting

The Company’s operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio. The Electric Utility Services segment provides electric distribution services primarily to southwestern Indiana, and includes the Company’s power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Company reports three operating segments: Gas Utility Services, Electric Utility Services, and Other Shared Service operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company’s reportable segments is summarized as follows.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Revenues				
Gas Utility Services	$128.6	$132.4	$481.5	$576.0
Electric Utility Services	147.8	152.0	301.7	315.0
Other Operations	10.2	9.5	20.4	19.1
Eliminations	(10.1)	(9.4)	(20.2)	(19.0)
Total Revenues	$276.5	$284.5	$783.4	$891.1
Profitability Measure - Net Income				
Gas Utility Services	$3.4	$0.7	$43.8	$39.0
Electric Utility Services	19.7	19.9	38.9	39.2
Other Operations	1.3	2.3	4.7	6.0
Total Net Income	$24.4	$22.9	$87.4	$84.2

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings, or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation’s (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also earns a return on shared assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 583,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and over 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 316,000 natural gas customers located near Dayton in west central Ohio. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company’s 2014 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In the second quarter of 2015, Utility Holdings' earnings were $24.4 million, compared to $22.9 million in 2014. In the six months ended June 30, 2015, Utility Holdings earned $87.4 million, compared to $84.2 million in 2014. The quarter and year to date increases are largely driven by increases in gas utility margin from returns on the Indiana and Ohio infrastructure replacement programs, small customer growth, and large customer usage. Decreases in operating expenses related to performance-based compensation also favorably impacted earnings in both the quarter and year to date periods. Quarter and year to date results in 2015 were unfavorably impacted by a decrease in wholesale electric margin due primarily to lower market pricing compared to 2014 periods.

Gas Utility Services
During the second quarter of 2015, Gas Utility Services earned $3.4 million compared to earnings of $0.7 million in the second quarter of 2014. In the six months ended June 30, 2015, Gas Utility Services earnings were $43.8 million, compared to earnings of $39.0 million in 2014. Customer margin increased in 2015 from small customer growth, large customer usage, and the returns from the Indiana and Ohio infrastructure replacement programs. Overall, operating expenses were favorably impacted by a decrease in performance-based compensation compared to the 2014 periods.

Electric Utility Services
During the second quarter of 2015, Electric Utility Services' earnings were $19.7 million, compared to $19.9 million in the second quarter of 2014. Electric Utility Services earned $38.9 million year to date in 2015, compared to earnings of $39.2 million for the six months ended June 30, 2014. The decreases in the quarter and year to date

periods are driven by the impact of weather on retail electric margin, which management estimates the unfavorable after tax impact to be approximately $0.5 million in the second quarter of 2015 and $1.1 million year to date, as compared to the 2014 periods. Quarter and year to date results were also unfavorably impacted by decreases in wholesale margin due primarily to lower market pricing. These decreases were offset somewhat by lower operating expenses in 2015 driven by the timing of power supply maintenance as well as increased performance-based compensation expense in 2014.

Results of Operations
Margin

Throughout this discussion, the terms Gas Utility margin and Electric Utility margin are used. Gas Utility margin is calculated as Gas utility revenues less the Cost of gas sold. Electric Utility margin is calculated as Electric utility revenues less Cost of fuel & purchased power. The Company believes Gas Utility and Electric Utility margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers.

In addition, the Company separately reflects regulatory expense recovery mechanisms within Gas Utility margin and Electric Utility margin. These amounts represent dollar-for-dollar recovery of operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. For example, demand side management and conservation expenses for both the gas and electric utilities; MISO administrative expenses for the Company's electric operations; uncollectible expense associated with the Company's Ohio gas customers; and recoveries of state mandated revenue taxes in both Indiana and Ohio are included in these amounts. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin (Gas utility revenues less Cost of gas sold)
Gas Utility margin and throughput by customer type follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Gas utility revenues	$128.6	$132.4	$481.5	$576.0
Cost of gas sold	36.4	43.7	208.4	314.6
Total gas utility margin	$92.2	$88.7	$273.1	$261.4
Margin attributed to:				
Residential & commercial customers	$69.7	$67.5	$196.0	$190.7
Industrial customers	13.0	12.1	32.3	30.9
Other	2.5	2.8	5.9	6.4
Regulatory expense recovery mechanisms	7.0	6.3	38.9	33.4
Total gas utility margin	$92.2	$88.7	$273.1	$261.4
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	10.7	12.0	72.9	77.6
Industrial customers	28.3	23.7	66.3	59.7
Total sold & transported volumes	39.0	35.7	139.2	137.3

Gas Utility margins were $92.2 million and $273.1 million for the three and six months ended June 30, 2015, and compared to 2014, increased $3.5 million quarter over quarter and $11.7 million year to date. Customer margin from small customer growth and large customer usage increased $1.1 million quarter over quarter and $1.9 million year to date compared to 2014. Additionally quarter over quarter margin was favorably impacted by increased return from infrastructure replacement programs in Indiana and Ohio of $2.2 million. Year to date margin was also favorably impacted by increased return from infrastructure replacement programs of $5.1 million. Year to date pass through margin increased $5.5 million in 2015 compared to 2014 due to increases in costs recovered through regulatory expense mechanisms.

Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power)
Electric Utility margin and volumes sold by customer type follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Electric utility revenues	$147.8	$152.0	$301.7	$315.0
Cost of fuel & purchased power	47.0	48.1	97.0	105.1
Total electric utility margin	$100.8	$103.9	$204.7	$209.9
Margin attributed to:				
Residential & commercial customers	$62.8	$64.4	$126.5	$128.7
Industrial customers	28.4	27.9	55.2	53.9
Other	0.5	1.1	1.5	2.0
Regulatory expense recovery mechanisms	1.9	1.8	5.3	6.6
Subtotal: retail	$93.6	$95.2	$188.5	$191.2
Wholesale power & transmission system margin	7.2	8.7	16.2	18.7
Total electric utility margin	$100.8	$103.9	$204.7	$209.9
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	643.1	658.4	1,345.7	1,377.5
Industrial customers	719.4	692.4	1,392.3	1,352.5
Other customers	4.8	4.9	10.9	10.9
Total retail volumes sold	1,367.3	1,355.7	2,748.9	2,740.9

Retail

Electric retail utility margins were $93.6 million and $188.5 million for the three and six months ended June 30, 2015, and compared to 2014, decreased by $1.6 million in the quarter and $2.7 million year to date. Electric results, which are not protected by weather normalizing mechanisms, reflect a $0.9 million decrease in small customer margin related to weather as annualized cooling degree days in the second quarter of 2015 were 107 percent of normal compared to 109 percent of normal in 2014. Similarly for the year to date period, electric results were unfavorably impacted by weather and resulted in a year to date decrease of $1.8 million in small customer margin. Small customer margin also decreased $0.6 million quarter over quarter and $0.8 million year to date compared to 2014 related to decreased electric volumes sold primarily related to continued customer conservation. Margin from regulatory expense recovery mechanisms decreased $1.3 million in the 2015 year to date period compared to 2014, driven primarily by a corresponding decrease in operating expenses associated with the electric conservation programs. Additionally, results reflect an increase in large customer usage of $0.6 million quarter over quarter and $1.3 million year to date compared to 2014, largely driven by large customer growth.

On December 3, 2013, SABIC Innovative Plastics (SABIC), a large industrial utility customer of the Company, announced its plans to build a cogeneration (cogen) facility to be operational at the end of 2016 or early 2017, in order to generate power to meet a significant portion of its ongoing power needs. Electric service is currently provided to SABIC by the Company under a long-term contract that expires in May of 2016. SABIC's historical peak electric usage has been approximately 120 megawatts (MW). The cogen facility is expected to provide 80 MW of capacity. Therefore, the Company will continue to provide all of SABIC's power requirements above the 80 MW capacity of the cogen, which is projected to be 40 MW. The Company also expects to provide back-up power, when required. The Company is actively working with SABIC on a transitional contractual arrangement. The Company continues to pursue and respond to economic development opportunities, among other things, as offsets to the margin lost from SABIC's cogeneration decision and as such, does not anticipate any significant impact on its future financial results.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO's regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales are generated in the MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
MISO Transmission system margin	$6.4	$6.6	$12.9	$12.7
MISO Off-system margin	0.8	2.1	3.3	6.0
Total wholesale margin	$7.2	$8.7	$16.2	$18.7

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $12.9 million and $12.7 million during the six months ended June 30, 2015 and 2014, respectively. As of June 30, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $141.9 million at June 30, 2015. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Although the allowed return is currently being challenged as discussed below in Rate and Regulatory Matters, once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance. Operating expenses are also recovered. The Company has established a reserve pending the outcome of this complaint. The 345 kV project is the largest of these qualifying projects, with a cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction.

For the six months ended June 30, 2015, margin from off-system sales was $3.3 million, compared to $6.0 million in 2014. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year be shared equally with customers. Results for the periods presented reflect the impact of that sharing as well as a decrease in volumes sold due to lower market pricing.

Operating Expenses

Other Operating

During the second quarter of 2015, other operating expenses were $78.5 million, a decrease of $3.0 million, compared to 2014. For the six months ended June 30, 2015, other operating expenses were $181.3 million, an increase of $1.5 million, compared to 2014. The increase in other operating costs for the year to date period is primarily due to increases in costs that are recovered directly in margin. Excluding these pass through costs, other operating expenses decreased $4.3 million in 2015, compared to the same period in 2014. Both quarter and year to date periods reflect decreased performance-based compensation expense, as well as lower operating expenses in 2015 due to the timing of power supply maintenance in 2014.

Depreciation & Amortization

In the second quarter of 2015, depreciation and amortization expense was $52.0 million compared to $50.6 million in 2014. For the six months ended June 30, 2015, depreciation and amortization expense was $104.2 million, which represents an increase of $3.7 million compared to 2014. Both quarter and year to date periods reflect increased plant placed in service.

Taxes Other Than Income Taxes

Taxes other than income taxes were $12.1 million for the second quarter of 2015, a decrease of $0.4 million compared to 2014. Year to date, taxes other than income taxes were $31.2 million compared to $32.6 million for the year to date period in 2014. The decrease in both the year to date and quarter periods is primarily due to decreased revenue taxes. These taxes are offset dollar-for-dollar with lower gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income - Net

Other income-net reflects income of $4.3 million for the second quarter of 2015, an increase of $0.6 million, compared to 2014. Year to date, other income-net reflects income of $9.2 million compared to $7.6 million in 2014. The increase is primarily due to higher AFUDC driven by increased capital expenditures related to gas utility infrastructure replacement investments, as well as higher AFUDC rates.

Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a result of federal pipeline safety requirements. Laws passed in both Indiana and Ohio provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the Commission, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs is deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. The legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying projects to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At June 30, 2015 and December 31, 2014, the Company has regulatory assets totaling $18.3 million and $16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms

On August 27, 2014, the IURC issued an Order (August 2014 Order) approving the Company's seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company's next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In June 2015, the Indiana Court of Appeals issued an opinion in favor of the Company that agreed with the IURC finding as issued in its original August 2014 Order.

On January 14, 2015, the IURC issued an Order approving the Company's initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company's update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost fluctuations. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with federal pipeline safety rules.
In April 2015, a group of industrial customers intervened as part of the pending appeal of the Company's Order referenced above, asking the Court of Appeals in light of a court decision related to another utility's seven-year plan, to consider whether the Company had failed to provide sufficient detail regarding its planned projects after year one of the plan. In the June 2015 decision, the Indiana Court of Appeals denied this request given that this issue was not raised during the Company's case or on appeal during the briefing period. As a result, the Company's Order approving its plan is final.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. On June 1, 2015, the Company amended its case to delay the recovery of a portion of the investment associated with the Senate Bill 560 approved investment made from July 2014 to December 2014, until its next filing in October 2015. The Company has offered to provide additional detail related to its seven-year plan in its update to be filed October 1, 2015. On July 22, 2015, the IURC issued an Order, approving the recovery of these investments consistent with the Company's proposal, with modification, specifically to the rate of return applicable to the Senate Bill 251 compliance component. The IURC found that the overall rate of return to be applied to the investment in determining the revenue requirement is to be updated with each filing, reflecting the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last base rate case. This IURC interpretation of the overall rate of return to be used is the same as that already in place for the Senate Bill 560 component.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $167.2 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $15.6 million and $13.1 million at June 30, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of

the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however, is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2015, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2014. A procedural schedule has been set in this proceeding, and the Company expects an order by September 2015.

Given the extension of the DRR through 2017 as discussed above and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining three-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. As of June 30, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2015, which covers the Company’s capital expenditure program through calendar year 2015.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue
On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of $3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company’s supply administrator was filed in this proceeding. The IURC issued an Order on June 10, 2015 which approved the stipulation and settlement agreement, which resulted in recovery of approximately $1.4 million of the disputed amount via the Company’s GCA mechanism, with the remaining $1.6 million received from the gas supply administrator.

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing was held in May 2015. The Company expects an order later in 2015.

Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of June 30, 2015, approximately $30 million has been spent on equipment to control mercury in both air and water emissions, and $21

million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $75 and $85 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of June 30, 2015, the Company has approximately $1.4 million deferred related to depreciation, property tax, and operating expense, and $0.5 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company's investments and proposed accounting treatment. The Company believes the IURC's Order satisfies applicable legal standards and filed its response on August 12, 2015. The Court is expected to decide on these issues later this year.

Coal Procurement Procedures
Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels, previously Vectren's wholly owned coal mining subsidiary, and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the IURC determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $31.8 million remains as of June 30, 2015.

SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011 the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the six months ended June 30, 2015 and 2014, the Company recognized Electric utility revenue of $4.8 million and $4.4 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the IURC's December 2009 Order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company's eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years

2016 and 2017. As defined within the procedural schedule set August 6, 2015, the OUCC and other stakeholders will file testimony in October 2015 and a hearing will be held November 13, 2015.

FERC Return on Equity (ROE) Complaint
On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of June 30, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $141.9 million at June 30, 2015.

This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. A settlement has not been reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which defines a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of these complaints.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

Environmental Matters

Indiana Senate Bill 251
Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations in addition to the impact on its gas utility operations. The Company continues with its ongoing evaluation of the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently pursuing involving carbon and air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality
Cross-State Air Pollution Rule
In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2 and NOx allowances, CSAPR

reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR’s first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air
pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. Reductions are to be achieved within three years of publication of the final rule in the Federal Register. MATS compliance was required to commence April 16, 2015, and the Company is in full compliance with all requirements of MATS.

Legal challenges to the MATS Rule continue. In July 2014, a coalition of twenty-one states, including Indiana, filed a petition with the U.S. Supreme Court seeking review of the decision of the appellate court that found that the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015 the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule back to the appellate court for further proceedings consistent with the opinion. The parties to the litigation are expected to be asked by the appellate court for briefing as to whether the court should vacate the rule, or leave it in place while the EPA supplements the rulemaking record pursuant to the Supreme Court opinion. Vectren continues to operate in full compliance with the MATS rule during the pendency of the appellate court remand which could take several months.

Notice of Violation for A.B. Brown Power Plant
The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior

to determining BTA for the Company’s facilities. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. The EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 however the rule is not yet finalized. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water Regulations
To comply with Indiana’s implementation plan of the Clean Air Act, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with Alcoa Power Generating, Inc. SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO’s electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO’s coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Utilization of the Company’s NOx and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding NOV from the EPA. The total investment is estimated to be between $75 and $85 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds
In December 2014 the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from approximately $30 million for final capping and monitoring costs if the ponds are permitted to continue to operate to the end of the life of the generating units, to $100 million if existing ponds at both F.B. Culley and A.B. Brown generating stations are required to be closed and bottom ash conversions completed at each generating unit.

In the second quarter 2015, the Company recorded an asset retirement obligation (ARO) in the amount of $15.6 million which reflects the current present value of the costs to cap the existing ponds at the end of the life of the generating units. The estimated obligation is based on assumptions such as future ash levels, existing life of generating units, compliance assessments within the final rule at future dates, and costs for future construction services. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO. It is expected that any costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change

As a wholly owned subsidiary of Vectren, Utility Holdings is committed to responsible environmental stewardship and conservation efforts, and if a national climate change policy is implemented, believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to baseload generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for investment in advanced clean coal technology and support for research and development; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company’s direct CO2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA’s e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions
The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Focusing the Company’s mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report received C level certification by the Global Reporting Initiative. This certification creates shared value, demonstrates the Company's commitment to sustainability and denotes transparency in operations;
- Implementing conservation initiatives in the Company’s Indiana and Ohio gas utility service territories;
- Implementing conservation and demand side management initiatives in the electric service territory;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Reducing the Company’s carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology; and
- Reducing methane emissions through continued replacement of bare steel and cast iron gas distribution pipeline

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized three sets of GHG regulations that apply to the Company’s generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

In July 2013, the President announced a Climate Action Plan, which called on the EPA to finalize the rule for new construction expeditiously and, by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. On June 2, 2014, the EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule required states to adopt plans to reduce CO2 emissions by 30 percent from 2005 levels by 2030. The proposal set state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals were calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal used a 2012 emission rate of 1,923 lb CO2/MWh, and set an interim goal of 1,607 lb CO2/MWh and a final emission goal of 1,531 lb CO2/MWh, or a 20 percent reduction in Indiana's total CO2 emission rate, that must be met by 2030. Under this proposal, these CO2 emission rate goals do not apply directly to individual units or generating systems, but are instead state goals. As such, the state would be required to establish a framework that would guide how compliance would be met on a statewide basis. Indiana's interim, or "phase in", goal of 1,607 lb CO2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022. These individual state goals were based upon the application of four "building blocks" of emission rate improvements identified as the Best System of Emission Reduction, which defines EPA's authority under Section 111(d).

The Company timely filed comments to the Clean Power Plan (CPP) proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rule prior to finalization by the EPA. In June 2015 these consolidated challenges were determined to be premature by the reviewing court, but the court's decision did not preclude the parties from raising the arguments against the final rulemaking after EPA has published the final CPP in the Federal Register.

On August 3, 2015, the EPA released its final CPP which requires a 32 percent reduction in carbon emissions from 2005 levels. The original proposal in June 2014 called for a 30 percent reduction. The final CPP is significantly different in many respects from the June 2014 proposal. The EPA removed the energy efficiency block in the final rule and increased the assumption related to reliance upon renewables for compliance. In addition to the change in energy efficiency and renewables assumptions, the EPA also incorporated a new emission rate factor as a means of leveling the emission reduction requirements across the states. This resulted in the final emission rate reduction goal for Indiana of 1,242 lb CO2 / MWh to be achieved by 2030, as compared to a goal of 1,531 lb CO2/ MWh as proposed in June of 2014. Final state goals now fall within a narrower, lower range (between 771 lb CO2/MWh and 1305 lb CO2/MWh), with states having higher percentages of coal-fired generation receiving more stringent emission rate goals than those in the original proposal. The new rule also gives states an additional year to submit a state implementation plan, now September of 2018. Under the CPP, states have the flexibility to include energy efficiency and other measures should it choose to implement a state measures plan as provided in the final rule. While states are given an interim goal (1,451 lb CO2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction glide path over the 2022-29 time period.

In the event that a state does not submit a state implementation plan (SIP), the EPA also released a proposed federal implementation plan (FIP), which would be imposed in those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on affected units. Under the proposed FIP the CO2 emission rate limit for coal-fired units would start at 1671 lbs CO2 / MWh in 2022 and decrease to a final emission rate cap of 1305 lbs CO2 / MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent, the cap would apply directly to affected units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. Since the FIP has just been proposed, it will be subject to extensive public comments prior to finalization.

Indiana is the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO2. The Company's share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company's emissions of CO2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment.

With respect to CO_2 emission rate, since 2005 the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company will undertake a detailed review of the requirements of the CPP and the proposed FIP and commence a review of potential compliance options for Vectren's affected units. In 2016 the Company will file its next integrated resource plan that will model compliance assumptions and costs and evaluate possible compliance alternatives. The Company will also continue to remain engaged with the State of Indiana to assess the final rule and to develop a plan that is the least cost to its customers. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $43.4 million ($23.2 million at Indiana Gas and $20.2 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.3 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2015 and December 31, 2014, approximately $3.4 million and $3.6

million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. On July 9, 2015, the FASB approved a one year deferral of the effective date to December 15, 2017 with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.
Financial Reporting of Discontinued Operations
In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company adopted this guidance on January 1, 2015. The adoption of this guidance had no impact on the Company’s financial statements.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements. Adoption will have no impact on the Company's consolidated income statement.

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiary operations. Vectren does not guarantee Utility Holdings' debt. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. The guarantees are full and unconditional and joint and several, and Utility Holdings has no direct subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 3 to the consolidated financial statements. Utility Holdings' long-term debt, including current maturities, outstanding at June 30, 2015 approximated $875 million. As of June 30, 2015, Utility Holdings had $27 million in short-term borrowings outstanding. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at June 30, 2015, was approximately $378 million. Utility Holdings' operations have historically been the primary funding source for Vectren's common stock dividends.

The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO and Indiana Gas, at June 30, 2015, are A-/A2 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings' commercial paper has a credit rating of A-2/P-1. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 50-60 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 55 percent of long-term capitalization at June 30, 2015 and 54 percent at December 31, 2014. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholder's equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of June 30, 2015, the Company was in compliance with all debt covenants.

Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it anticipates funding future capital expenditures and dividends principally through internally generated funds supplemented with incremental external debt financing. However, the resources required for capital investment remain uncertain for a variety of factors including expanded EPA regulations for air, water, and fly ash. These regulations may result in the need to raise additional debt and equity capital in the coming years.

On March 15, 2015, a $5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded by the Company's commercial paper program.

On June 11, 2015, Vectren Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors have agreed to purchase the following tranches of notes: (i) $25 million of 3.90% Guaranteed Senior Notes, Series A, due December 15, 2035, (ii) $135 million of 4.36% Guaranteed Senior Notes, Series B, due December, 15, 2045, and (iii) $40 million of 4.51% Guaranteed Senior Notes, Series C, due December 15, 2055. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc.

The proceeds from these issuances will be used to refinance existing indebtedness and for general corporate purposes including the Company's capital expenditure program. Subject to the satisfaction of customary conditions precedent, the financing is scheduled to close on or about December 15, 2015.

Consolidated Short-Term Borrowing Arrangements

At June 30, 2015, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $323 million was available at June 30, 2015. This short-term credit facility was amended on October 31, 2014 to, among other things, extend the maturity until October 31, 2019. The maximum limit of the facility remained unchanged. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

The Company has historically funded its short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient.

Following is certain information regarding these short-term borrowing arrangements.

(In millions)	2015	2014
As of June 30		
Balance Outstanding	$27.3	$3.7
Weighted Average Interest Rate	0.36%	0.30%
Six Months Ended June 30 Average		
Balance Outstanding	$36.2	$1.3
Weighted Average Interest Rate	0.39%	0.28%
Maximum Month End Balance Outstanding	$121.5	$3.7

(In millions)	2015	2014
Quarterly Average - June 30		
Balance Outstanding	$3.5	$0.6
Weighted Average Interest Rate	0.35%	0.33%
Maximum Month End Balance Outstanding	$27.3	$3.7

Potential Uses of Liquidity

Pension Funding Obligations
For the six months ended June 30, 2015, Vectren contributed $20 million to its qualified pension plans. Utility Holdings will fund a portion of the total contribution as it relates to its plans. Vectren does not anticipate making further contributions in 2015.

Planned Capital Expenditures
Capital expenditures are estimated at $235 million for the remainder of 2015.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow
The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $336.8 million and $213.2 million for the six months ended June 30, 2015 and 2014, respectively. The increase is driven primarily by certain weather related impacts to working capital accounts. Weather related impacts include the fluctuation in the recoverable/refundable natural gas and fuel costs and accounts

receivable. Additionally, a decrease in prepaid taxes was due to a federal refund received in 2015 related to the extension of bonus depreciation in 2014.

Financing Cash Flow
Net cash flow required for financing activities was $186.3 million and $76.0 million during the six months ended June 30, 2015 and 2014, respectively. The current year period, compared to the second quarter of 2014, reflects a greater decrease of short term borrowings of $104.2 million. Financing activity in both periods presented reflects the payment of dividends.

Investing Cash Flow
Cash flow required for investing activities was $163.1 million and $140.9 million during the six months ended June 30, 2015 and 2014, respectively. The primary use of cash in both periods presented reflect expenditures for utility capital expenditures.

Forward-Looking Information

A “safe harbor” for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management’s Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management’s beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words “believe”, “anticipate”, “endeavor”, “estimate”, “expect”, “objective”, “projection”, “forecast”, “goal”, “likely”, and expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas and electricity; impacts on both gas and electric large customers; lower residential and commercial customer counts; and higher operating expenses.

- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.

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- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company’s risk management program includes, among other things, the use of derivatives. The Company executes derivative contracts in the normal course of operations while buying and selling commodities and occasionally when managing interest rate risk.

The Company has in place a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren Utility Holdings, Inc. 2014 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended June 30, 2015, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of June 30, 2015, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of June 30, 2015, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and

2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, rate and regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees ("claimants") who participated in the Pension Plan for Salaried Employees of SIGECO ("SIGECO Salaried Plan"). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan ("Vectren Combined Plan") effective July 1, 2000. The claims relate to the claimants' election for benefits to be calculated under the Vectren Combined Plan's cash-balance formula rather than the SIGECO Salaried Plan formula in effect prior to the formation of Vectren. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the Complaint.

The Company is unable to quantify any potential impact of the claims. The Company does not expect, however, the outcome would have a material adverse effect on the Company's liquidity, results of operations or financial condition.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company's operating results and financial condition, causing them to be materially adversely affected. The Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren Utility Holdings 2014 Form 10-K and are therefore not presented herein.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not Applicable

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

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ITEM 6. EXHIBITS

Exhibits and Certifications

4.1	Note Purchase Agreement, dated June 11, 2015, between Vectren Utility Holdings, Inc. and each of the purchasers named therein. (Filed and designated in Form 8-K dated June 12, 2015 File No. 1-16739, as Exhibit 4.1).
10.2	Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-16739, as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.3	Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-16739, as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.4	Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-16739, as Exhibit 10.4.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
31.1	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer
31.2	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer
32	Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002
101	Interactive Data File.
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 Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

VECTREN UTILITY HOLDINGS, INC.
Registrant

August 13, 2015

/s/M. Susan Hardwick
M. Susan Hardwick
Senior Vice President and Chief Financial Officer
(Signing on behalf of the registrant and as Principal Accounting & Financial Officer)

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2021
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During the year ended December 31, 2016, the Company recorded a favorable lease impairment charge of approximately $0.3 million related to a theatre closure. The Company did not record an impairment of any intangible assets during the years ended December 31, 2015 or January 1, 2015.

Debt Acquisition Costs

Debt acquisition costs are deferred and amortized to interest expense using the effective interest method over the terms of the related agreements. In April 2015, the FASB issued ASU 2015-03, Interest—Imputation of Interest, which intended to simplify the presentation of debt issuance costs. Prior to the issuance of ASU 2015-03, debt issuance costs were reported on the balance sheet as assets and amortized as interest expense. ASU 2015-03 requires that they be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability. The costs will continue to be amortized to interest expense using the effective interest method. ASU 2015-03 is to be applied retrospectively and is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. The Company adopted this guidance during the quarter ended March 31, 2016. Debt issuance costs associated with long-term debt, net of accumulated amortization, were $25.8 million and $30.7 million as of December 31, 2016 and December 31, 2015, respectively. The balance sheet as of December 31, 2015 has been recast to reflect the reclassification of debt issuances costs, net of accumulated amortization, from "Other Non-Current Assets" to a reduction of "Long-Term Debt, Less Current Portion."

Investments

The Company primarily accounts for its investments in non-consolidated subsidiaries using the equity method of accounting and has recorded the investments within "Other Non-Current Assets" and "Other Non-Current Liabilities" as applicable in its consolidated balance sheets. The Company records equity in earnings and losses of these entities in its consolidated statements of income. As of December 31, 2016, the Company holds a 19.7% interest in National CineMedia, LLC ("National CineMedia" or "NCM"), a 46.7% interest in Digital Cinema Implementation Partners, LLC, a 50% interest in Open Road Films, a 32% interest in AC JV, LLC and a 14.6% interest in Digital Cinema Distribution Coalition (each as described further under Note 4—"Investments"). In addition, as described further under Note 4—"Investments," the Company holds an equity investment in Atom Tickets, LLC, an internet ticketing partner of the Company. Such investment is accounted for under the cost method. The carrying value of the Company's investment in these entities as of December 31, 2016 and December 31, 2015 was approximately $367.7 million and $321.8 million, respectively.

The Company reviews investments in non-consolidated subsidiaries accounted for under the equity method for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be fully recoverable. The Company reviews unaudited financial statements on a quarterly basis and audited financial statements on an annual basis for indicators of triggering events or circumstances that indicate the potential impairment of these investments as well as current equity prices for its investment in National CineMedia and discounted projections of cash flows for certain of its other investees. Additionally, the Company has periodic discussions with the management of significant investees to assist in the identification of any factors that might indicate the potential for impairment. In order to determine whether the carrying value of investments may have experienced an other-than-temporary decline in value necessitating the write-down of the recorded investment, the Company considers various factors, including the period of time during which the fair value of the investment remains substantially below the recorded amounts, the investees' financial condition and quality of assets, the length of time the investee has been operating, the severity and nature of losses sustained in current and prior years, a reduction or cessation in the investees dividend payments, suspension of trading in the security, qualifications in accountant's reports due to liquidity or going concern issues, investee announcement of adverse changes, downgrading of investee debt, regulatory actions, changes in reserves for product liability, loss of a principal customer, negative operating cash flows or working capital deficiencies and the recording of an impairment charge by the investee for goodwill, intangible or long-lived assets. Once a determination is made that an other-than-temporary impairment exists, the Company writes down its investment to fair value.

There was no impairment of the Company's investments during the years ended December 31, 2016, December 31, 2015 and January 1, 2015.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. The Company records a valuation allowance if it is deemed more likely than not that its deferred income tax assets will not be realized. The Company expects that certain deferred income tax assets are not more likely than not to be recovered and therefore has established a valuation allowance. The Company reassesses its need for the valuation allowance for its deferred income taxes on an ongoing basis.

Additionally, income tax rules and regulations are subject to interpretation, require judgment by the Company and may be challenged by the taxation authorities. As described further in Note 7—"Income Taxes," the Company applies the provisions of ASC Subtopic 740-10, Income Taxes—Overview. In accordance with ASC Subtopic 740-10, the Company recognizes a tax benefit only for tax positions that are determined to be more likely than not sustainable based on the technical merits of the tax position. With respect to such tax positions for which recognition of a benefit is appropriate, the benefit is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. Tax positions are evaluated on an ongoing basis as part of the Company's process for determining the provision for income taxes.

Interest Rate Swaps

Regal Cinemas has entered into hedging relationships via interest rate swap agreements to hedge against interest rate exposure of its variable rate debt obligations under Regal Cinemas' Amended Senior Credit Facility. Certain of these interest rate swaps qualify for cash flow hedge accounting treatment and as such, the change in the fair values of the interest rate swaps is recorded on the Company's consolidated balance sheet as an asset or liability with the effective portion of the interest rate swaps' gains or losses reported as a component of other comprehensive income and the ineffective portion reported in earnings. As interest expense is accrued on the debt obligation, amounts in accumulated other comprehensive income/loss related to the interest rate swaps will be reclassified into earnings. In the event that an interest rate swap is terminated or de-designated prior to maturity, gains or losses accumulated in other comprehensive income or loss remain deferred and are reclassified into earnings in the periods during which the hedged forecasted transaction affects earnings. See Note 14—"Fair Value of Financial Instruments" for discussion of the Company’s interest rate swaps’ fair value estimation methods and assumptions. The fair value of the Company's interest rate swaps is based on Level 2 inputs as described in ASC Topic 820, Fair Value Measurements and Disclosures, which include observable inputs such as dealer quoted prices for similar assets or liabilities, and represents the estimated amount Regal Cinemas would receive or pay to terminate the agreements taking into consideration various factors, including current interest rates, credit risk and counterparty credit risk. The counterparties to the Company's interest rate swaps are major financial institutions. The Company evaluates the bond ratings of the financial institutions and believes that credit risk is at an acceptably low level.

Deferred Revenue

Deferred revenue relates primarily to the amount we received for agreeing to the 2007 ESA modification, amounts recorded in connection with the receipt of newly issued common units of National CineMedia, cash received from the sale of bulk tickets and gift cards, and amounts received in connection with vendor marketing programs. The amount we received for agreeing to the ESA modification is being amortized to advertising revenue over the 30 year term of the agreement following the units of revenue method. In addition, as described in Note 4—"Investments," amounts recorded as deferred revenue in connection with the receipt of newly issued common units of National CineMedia pursuant to the provisions of the Common Unit Adjustment Agreement are being amortized to advertising revenue over the remaining term of the ESA following the units of revenue method. As of December 31, 2016 and December 31, 2015, approximately $425.0 million and $426.7 million of deferred revenue, respectively, related to the ESA was recorded as components of current and non-current deferred revenue in the accompanying consolidated balance sheets. Deferred revenue related to gift cards and bulk ticket sales and vendor marketing programs is recognized as revenue as described above in this Note 2 under "Revenue Recognition." As of December 31, 2016 and December 31, 2015, approximately $175.6 million and $188.5 million of deferred revenue, respectively, related to the gift cards and bulk tickets was recorded as a component of current deferred revenue in the accompanying consolidated balance sheets.

Deferred Rent

The Company recognizes rent on a straight-line basis after considering the effect of rent escalation provisions resulting in a level monthly rent expense for each lease over its term. The deferred rent liability is included in other non-current liabilities in the accompanying consolidated balance sheets.

Film Costs

The Company estimates its film cost expense and related film cost payable based on management's best estimate of the ultimate settlement of the film costs with the distributors. Generally, less than one-third of our quarterly film expense is estimated at period-end. The length of time until these costs are known with certainty depends on the ultimate duration of the film's theatrical run, but is typically "settled" within 2 to 3 months of a particular film's opening release. Upon settlement with our film distributors, film cost expense and the related film cost payable are adjusted to the final film settlement.

Loyalty Program

Members of the Regal Crown Club® earn credits for each dollar spent at the Company's theatres and can redeem such credits for movie tickets, concession items and movie memorabilia at the theatre or in an online reward center. Because the Company believes that the value of the awards granted to Regal Crown Club® members is insignificant in relation to the value of the transactions necessary to earn the award, the Company records the estimated incremental cost of providing awards under the Regal Crown Club® loyalty program at the time the awards are earned. Historically, and for the years ended December 31, 2016, December 31, 2015 and January 1, 2015, the costs of these awards have not been significant to the Company's consolidated financial statements.

Advertising and Start-Up Costs

The Company expenses advertising costs as incurred. Start-up costs associated with a new theatre are also expensed as incurred.

Share-Based Compensation

As described in Note 9—"Capital Stock And Share-Based Compensation," we apply the provisions of ASC Subtopic 718-10, Compensation—Stock Compensation—Overall. Under ASC Subtopic 718-10, share-based compensation cost is measured at the grant date, based on the estimated fair value of the award, and is recognized as expense over the employee's requisite service period.

Under ASC Subtopic 718-10, the Company elected to adopt the alternative transition method for calculating the tax effects of share-based compensation. The alternative transition method includes a simplified method to establish the beginning balance of the additional paid-in capital pool related to the tax effects of employee share-based compensation, which is available to absorb tax deficiencies that could be recognized subsequent to the adoption of ASC Subtopic 718-10.

Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include, but are not limited to, deferred revenue, property and equipment, goodwill, income taxes and purchase accounting. Actual results could differ from those estimates.

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Segments

As of December 31, 2016, December 31, 2015 and January 1, 2015, the Company managed its business under one reportable segment: theatre exhibition operations.

Acquisitions

The Company accounts for acquisitions under the acquisition method of accounting. The acquisition method requires that the acquired assets and liabilities, including contingencies, be recorded at fair value determined on the acquisition date and changes thereafter reflected in income. For significant acquisitions, the Company obtains independent third party valuation studies for certain of the assets acquired and liabilities assumed to assist the Company in determining fair value. The estimation of the fair values of the assets acquired and liabilities assumed involves a number of estimates and assumptions that could differ materially from the actual amounts recorded. The results of the acquired businesses are included in the Company's results from operations beginning from the day of acquisition.

Comprehensive Income

Total comprehensive income, net of tax, for the years ended December 31, 2016, December 31, 2015 and January 1, 2015 was $171.3 million, $152.6 million and $106.1 million, respectively. Total comprehensive income consists of net income and other comprehensive income, net of tax, related to the change in the aggregate unrealized gain/loss on the Company's interest rate swap arrangement, the change in fair value of available for sale equity securities (including other-than-temporary impairments), the reclassification adjustment for gain on sale of available for sale securities recognized in net income and the change in fair value of equity method investee interest rate swap transactions during each of the years ended December 31, 2016, December 31, 2015 and January 1, 2015. The Company's interest rate swap arrangements and available for sale equity securities are further described in Note 13—"Derivative Instruments" and Note 14—"Fair Value of Financial Instruments."

Adoption of New Accounting Pronouncements

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810) - Amendments to the Consolidation Analysis, which provides guidance on evaluating whether a reporting entity should consolidate certain legal entities. Specifically, the amendments modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities ("VIEs") or voting interest entities. Further, the amendments eliminate the presumption that a general partner should consolidate a limited partnership, as well as affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships. ASU 2015-02 is effective for interim and annual reporting periods beginning after December 15, 2015. Early adoption is permitted. A reporting entity may apply the amendments using a modified retrospective approach or a full retrospective application. The Company's adoption of ASU 2015-02 during the quarter ended March 31, 2016 had no impact on the Company's consolidated financial statements and related disclosures.

As further described above in this Note 2 under "Debt Acquisition Costs," in April 2015, the FASB issued ASU 2015-03, Interest—Imputation of Interest. The Company adopted this guidance during the quarter ended March 31, 2016. Debt issuance costs associated with long-term debt, net of accumulated amortization, were $25.8 million and $30.7 million as of December 31, 2016 and December 31, 2015, respectively. The balance sheet as of December 31, 2015 has been recast to reflect the reclassification of debt issuances costs, net of accumulated amortization, from

"Other Non-Current Assets" to a reduction of "Long-Term Debt, Less Current Portion."

In August 2015, the FASB issued ASU 2015-15, Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements. ASU 2015-15 adds clarification to the guidance presented in ASU 2015-03, as that guidance did not address the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements. We adopted ASU 2015-15 along with the original guidance in ASU 2015-03 discussed above. The guidance in ASU 2015-15 did not have an impact on our consolidated financial statements and related disclosures.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740) - Balance Sheet Classification of Deferred Taxes, which requires the presentation of deferred tax liabilities and assets be classified as non-current in a classified statement of financial position. The amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. The amendments in ASU 2015-17 may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We adopted this guidance during the quarter ended March 31, 2016 and elected the prospective approach. Therefore, deferred taxes as of December 31, 2016 are recorded as long-term deferred tax assets and long-term deferred tax liabilities on the balance sheet. Balances as of December 31, 2015 have not been recast.

Recently Issued FASB Accounting Standard Codification Updates

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014-09 will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective. The standard permits the use of either the retrospective or modified retrospective transition method. ASU 2014-09 was originally effective for annual and interim reporting periods beginning after December 15, 2016. However, the standard was deferred by ASU 2015-14, issued by the FASB in August 2015, and is now effective for fiscal years beginning on or after December 15, 2017, including interim reporting periods within that reporting period, with early adoption permitted as of the original effective date. The Company believes that the adoption of ASU 2014-09 will primarily impact its accounting for its (i) loyalty program, (ii) gift cards and bulk tickets, (iii) customer incentives and (iv) amounts recorded as deferred revenue and the method of amortization for advanced payments received in connection with the 2007 National CineMedia ESA modification and subsequent receipts of common units of National CineMedia pursuant to the provisions of the Common Unit Adjustment Agreement, each as described in Note 4—"Investments." The Company has selected the modified retrospective method for adoption of ASU 2014-09 and is continuing to further evaluate the full impact that ASU 2014-09 will have on its consolidated financial statements and related disclosures. To that end, the Company has conducted initial analyses, developed project management relative to the process of adopting ASU 2014-09, and is currently completing detailed contract reviews to determine necessary adjustments to existing accounting policies and to support an evaluation of the standard's impact on the Company's consolidated results of operations and financial condition.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). ASU 2016-02 establishes a right-of-use ("ROU") model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company is evaluating the impact that ASU 2016-02 will have on its consolidated financial statements and related disclosures and believes that the significance of its future minimum rental payments will result in a material increase in ROU assets and lease liabilities.

In March 2016, the FASB issued ASU 2016-07, Investments – Equity Method and Joint Ventures (Topic 323). The purpose of ASU 2016-07 is to eliminate the requirement that when an investment qualifies for use of the equity method as a result of an increase in the level of ownership interest or degree of influence, an investor must adjust the investment, results of operations, and retained earnings retroactively on a step-by-step basis as if the equity method had been in effect during all previous periods that the investment was held. ASU 2016-07 is effective for fiscal years beginning after December 15, 2016. Early adoption is permitted. The Company does not expect the adoption of ASU

2016-07 to have a material impact on its consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenues Gross versus Net). The purpose of ASU 2016-08 is to clarify the implementation of revenue recognition guidance related to principal versus agent considerations. ASU 2016-08 is effective for fiscal years beginning after December 15, 2017, including interim periods within that year, concurrent with ASU 2014-09. Early adoption is permitted. The Company is evaluating the impact that ASU 2016-08 will have on its consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which relates to the accounting for employee share-based payments. ASU 2016-09 simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. ASU

2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years and early adoption is permitted. The Company is evaluating the impact that ASU 2016-09 will have on its consolidated financial statements and related disclosures.

In April 2016, the FASB issued ASU 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing. The purpose of ASU 2016-10 is to provide more detailed guidance in the following key areas: identifying performance obligations and licenses of intellectual property. ASU 2016-10 is effective for fiscal years beginning after December 15, 2017, including interim periods within that year, concurrent with ASU 2014-09. Early adoption is permitted. The Company is evaluating the impact that ASU 2016-10 will have on its consolidated financial statements and related disclosures.

In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients. The purpose of ASU 2016-12 is to address certain narrow aspects of ASC Topic 606 including assessing collectability, presentation of sales and other similar taxes, noncash considerations, contract modifications and completed contracts at transition. ASU 2016-12 is effective for fiscal years beginning after December 15, 2017, including interim periods within that year, concurrent with ASU 2014-09. Early adoption is permitted. The Company is evaluating the impact that ASU 2016-12 will have on its consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. The purpose of ASU 2016-15 is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within that year. The Company is evaluating the impact that ASU 2016-15 will have on its consolidated financial statements and related disclosures.

In October 2016, the FASB issued ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory, which requires that an entity recognize the income tax consequences of intra-entity transfers of assets other than inventory at the time of the transfer instead of deferring the tax consequences until the asset has been sold to an outside party, as current GAAP requires. ASU 2016-16 is effective for annual periods, and interim periods therein, beginning after December 15, 2017. Early application is permitted in any interim or annual period. The Company is evaluating the impact that ASU 2016-16 will have on its consolidated financial statements and related disclosures.

In October 2016, the FASB issued ASU 2016-17, Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control, which requires when assessing which party is the primary beneficiary in a VIE, the decision maker considers interests held by entities under common control on a proportionate basis instead of treating those interests as if they were that of the decision maker itself, as current GAAP requires. ASU 2016-17 is effective for annual periods, and interim periods therein, beginning after December 15, 2016. Early application is permitted in any interim or annual period. The Company does not expect the adoption of ASU 2016-17 to have a material impact on its consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. The purpose of ASU 2017-01 is to clarify the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within that year. The amendments in ASU 2017-01 should be applied prospectively on or after the effective date. Early adoption is permitted. We do not expect ASU 2017-01 to have an impact on our consolidated financial statements.

In January 2017, the FASB issued ASU 2017-04, Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment. The purpose of ASU 2017-04 is to simplify the subsequent measurement of goodwill by removing the second step of the two-step impairment test. The amendment should be applied on a prospective basis. ASU 2017-04 is effective for fiscal years beginning after December 15, 2019, including interim periods within that year. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. The Company is evaluating the impact that ASU 2017-04 will have on its consolidated financial statements and related disclosures.

3. ACQUISITION

On September 3, 2015, Regal completed the acquisition of five theatres with 61 screens from entities affiliated with Georgia Theatre Company for an aggregate net cash purchase price of $9.2 million. The acquisition enhanced the Company's presence in the state of Georgia. The aggregate net cash purchase price was allocated to the identifiable assets acquired for each of the respective theatre locations based on their estimated fair values at the date of acquisition using the acquisition method of accounting. The allocation of the purchase price is based on management's judgment after evaluating several factors. The results of operations of the five acquired theatres have been included in the Company's consolidated financial statements for periods subsequent to the acquisition date.

The following is a summary of the allocation of the aggregate net cash purchase price to the estimated fair values of the identifiable assets acquired that have been recognized by the Company in its consolidated balance sheet as of the date of acquisition (in millions):

Property and equipment	$0.9
Goodwill	8.3
Total purchase price	$9.2

4. INVESTMENTS

Investment in National CineMedia, LLC

We maintain an investment in National CineMedia. National CineMedia provides in-theatre advertising for its theatrical exhibition partners, which include us, AMC and Cinemark.

On February 13, 2007, National CineMedia, Inc. ("NCM, Inc."), the sole manager of National CineMedia, completed an initial public offering ("IPO") of its common stock. NCM, Inc. sold 38.0 million shares of its common stock for $21 per share in the IPO, less underwriting discounts and expenses. NCM, Inc. used a portion of the net cash proceeds from the IPO to acquire newly issued common units from National CineMedia. At the closing of the IPO, the underwriters exercised their over-allotment option to purchase an additional 4.0 million shares of common stock of NCM, Inc. at the initial offering price of $21 per share, less underwriting discounts and commissions. In connection with this over-allotment option exercise, Regal, AMC and Cinemark each sold to NCM, Inc. common units of National CineMedia on a pro rata basis at the initial offering price of $21 per share, less underwriting discounts and expenses. Upon completion of this sale of common units, Regal held approximately 21.2 million common units of National CineMedia ("Initial Investment Tranche"). Such common units are immediately redeemable on a one-to-one basis for shares of NCM, Inc. common stock.

As a result of the transactions associated with the IPO and receipt of proceeds in excess of our investment balance, the Company reduced its investment in National CineMedia to zero. Accordingly, we will not provide for any additional losses, as we have not guaranteed obligations of National CineMedia and we are not otherwise committed to provide further financial support for National CineMedia. In addition, subsequent to the IPO, the Company determined it would not recognize its share of any undistributed equity in the earnings of National CineMedia pertaining to the Company's Initial Investment Tranche in National CineMedia until National CineMedia's future net earnings, net of distributions received, equal or exceed the amount of the above described excess distribution. Until such time, equity in earnings related to the Company's Initial Investment Tranche in National CineMedia will be recognized only to the extent that the Company receives cash distributions from National CineMedia. The Company believes that the accounting model provided by ASC 323-10-35-22 for recognition of equity investee losses in excess of an investor's basis is analogous to the accounting for equity income subsequent to recognizing an excess distribution. The Company's Initial Investment Tranche is recorded at $0 cost.

In connection with the completion of the IPO, the joint venture partners, including RCI, amended and restated their exhibitor services agreements with National CineMedia in exchange for a significant portion of its pro rata share of the IPO proceeds. The modification extended the term of the exhibitor services agreement ("ESA") to 30 years, provided National CineMedia with a 5-year right of first refusal beginning one year prior to the end of the term and changed the basis upon which RCI is paid by National CineMedia from a percentage of revenues associated with advertising contracts entered into by

National CineMedia to a monthly theatre access fee. The theatre access fee is composed of a fixed $0.0756 payment per patron for fiscal 2016 and increases by 8% every 5 years starting at the end of fiscal 2011, a fixed $800 payment per digital screen each year, which increases by 5% annually starting at the end of fiscal 2007 (or $1,241 for fiscal 2016) and an additional payment per digital screen of $638 for fiscal 2016. The access fee revenues received by the Company under its contract are determined annually based on a combination of both fixed and variable factors which include the total number of theatre screens, attendance and actual revenues (as defined in the ESA) generated by National CineMedia. The ESA does not require us to maintain a minimum number of screens and does not provide a fixed amount of access fee revenue to be earned by the Company in any period. The theatre access fee paid in the aggregate to us, AMC and Cinemark will not be less than 12% of NCM's aggregate advertising revenue, or it will be adjusted upward to meet this minimum payment. On-screen advertising time provided to our beverage concessionaire is provided by National CineMedia under the terms of the ESA. In addition, we receive mandatory quarterly distributions of any excess cash from National CineMedia. The modified ESA has, except with respect to certain limited services, a remaining term of approximately 20 years.

The amount we received for agreeing to the ESA modification was approximately $281.0 million, which represents the estimated fair value of the ESA modification payment. We estimated the fair value of the ESA payment based upon a valuation performed by the Company with the assistance of third party specialists. This amount has been recorded as deferred revenue and is being amortized to advertising revenue over the 30 year term of the ESA following the units of revenue method. Under the units of revenue method, amortization for a period is calculated by computing a ratio of the proceeds received from the ESA modification payment to the total expected decrease in revenues due to entry into the new ESA over the 30 year term of the agreement and then applying that ratio to the current period's expected decrease in revenues due to entry into the new ESA.

Also in connection with the IPO, the joint venture partners entered into a Common Unit Adjustment Agreement with National CineMedia. Pursuant to our Common Unit Adjustment Agreement, from time to time, common units of National CineMedia held by the joint venture partners will be adjusted up or down through a formula primarily based on increases or decreases in the number of theatre screens operated and theatre attendance generated by each joint venture partner. The common unit adjustment is computed annually, except that an earlier common unit adjustment will occur for a joint venture partner if its acquisition or disposition of theatres, in a single transaction or cumulatively since the most recent common unit adjustment, will cause a change of two percent or more in the total annual attendance of all of the joint venture partners. In the event that a common unit adjustment is determined to be a negative number, the joint venture partner shall cause, at its election, either (a) the transfer and surrender to National CineMedia a number of common units equal to all or part of such joint venture partner's common unit adjustment or (b) pay to National CineMedia, an amount equal to such joint venture partner's common unit adjustment calculated in accordance with the Common Unit Adjustment Agreement. If the Company elects to surrender common units as part of a negative common unit adjustment, the Company would record a reduction to deferred revenue at the then fair value of the common units surrendered and a reduction of the Company’s Additional Investments Tranche at an amount equal to the weighted average cost for the Additional Investments Tranche common units, with the difference between the two values recorded as a non-operating gain or loss.

As described further below, subsequent to the IPO and through December 31, 2016, the Company received from National CineMedia approximately 12.4 million newly issued common units of National CineMedia ("Additional Investments Tranche") as a result of the adjustment provisions of the Common Unit Adjustment Agreement. The Company follows the guidance in ASC 323-10-35-29 (formerly EITF 02-18, Accounting for Subsequent Investments in an Investee after Suspension of Equity Loss Recognition) by analogy, which also refers to AICPA Technical

Practice Aid 2220.14, which indicates that if a subsequent investment is made in an equity method investee that has experienced significant losses, the investor must determine if the subsequent investment constitutes funding of prior losses. The Company concluded that the construction or acquisition of new theatres that has led to the common unit adjustments included in its Additional Investments Tranche equates to making additional investments in National CineMedia. The Company evaluated the receipt of the additional common units in National CineMedia and the assets exchanged for these additional units and has determined that the right to use its incremental new screens would not be considered funding of prior losses. As such, the Additional Investments Tranche is accounted for separately from the Company's Initial Investment Tranche following the equity method with undistributed equity earnings included as a component of "Earnings recognized from NCM" in the accompanying consolidated financial statements.

The NCM, Inc. IPO and related transactions have the effect of reducing the amounts NCM, Inc. would otherwise pay in the future to various tax authorities as a result of an increase in Regal's proportionate share of tax basis in NCM Inc.'s tangible and intangible assets. On the IPO date, NCM, Inc., the Company, AMC and Cinemark entered into a tax receivable agreement. Under the terms of this agreement, NCM, Inc. will make cash payments to us, AMC and Cinemark in amounts equal to 90% of NCM, Inc.'s actual tax benefit realized from the tax amortization of the intangible assets described above. For purposes of the

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tax receivable agreement, cash savings in income and franchise tax will be computed by comparing NCM, Inc.'s actual income and franchise tax liability to the amount of such taxes that NCM, Inc. would have been required to pay had there been no increase in NCM Inc.'s proportionate share of tax basis in NCM's tangible and intangible assets and had the tax receivable agreement not been entered into. The tax receivable agreement shall generally apply to NCM, Inc.'s taxable years up to and including the 30th anniversary date of the NCM, Inc. IPO and related transactions.

The Company accounts for its investment in National CineMedia following the equity method of accounting and such investment is included as a component of "Other Non-Current Assets" in the consolidated balance sheets. Below is a summary of activity with National CineMedia included in the Company's consolidated financial statements as of and for the years ended December 31, 2016, December 31, 2015 and January 1, 2015 (in millions):

	As of the period ended			For the period ended	
	Investment in NCM	Deferred Revenue	Cash Received	Earnings recognized from NCM	Other NCM Revenues
Balance as of and for the period ended December 26, 2013	$158.5	$(432.2)	$ 93.5	$(37.5)	$ (19.9)
Receipt of additional common units(1)	5.9	(5.9)	—	—	—
Receipt of excess cash distributions(2)	(10.2)	—	27.1	(16.9)	—
Receipt under tax receivable agreement(2)	(3.9)	—	12.0	(8.1)	—
Revenues earned under ESA(3)	—	—	14.2	—	(14.2)
Amortization of deferred revenue(4)	—	9.6	—	—	(9.6)
Equity income attributable to additional common units(5)	7.1	—	—	(7.1)	—
Balance as of and for the period ended January 1, 2015	$157.4	$(428.5)	$ 53.3	$(32.1)	$ (23.8)
Receipt of additional common units(1)	9.0	(9.0)	—	—	—
Receipt of excess cash distributions(2)	(11.8)	—	30.5	(18.7)	—
Receipt under tax receivable agreement(2)	(3.5)	—	9.5	(6.0)	—
Revenues earned under ESA(3)	—	—	16.7	—	(16.7)
Amortization of deferred revenue(4)	—	10.8	—	—	(10.8)
Equity income attributable to additional common units(5)	6.3	—	—	(6.3)	—
Balance as of and for the period ended December 31, 2015	$157.4	$(426.7)	$ 56.7	$(31.0)	$ (27.5)
Receipt of additional common units(1)	9.9	(9.9)	—	—	—
Receipt of excess cash distributions(2)	(9.3)	—	23.3	(14.0)	—
Receipt under tax receivable agreement(2)	(4.5)	—	11.4	(6.9)	—
Revenues earned under ESA(3)	—	—	16.7	—	(16.7)
Amortization of deferred revenue(4)	—	11.6	—	—	(11.6)
Equity income attributable to additional common units(5)	8.5	—	—	(8.5)	—
Balance as of and for the period ended December 31, 2016	$162.0	$(425.0)	$ 51.4	$(29.4)	$ (28.3)

(1) On March 17, 2016, March 17, 2015, and March 13, 2014, we received from National CineMedia approximately 0.7 million, 0.6 million and 0.4 million, respectively, newly issued common units of National CineMedia in accordance with the annual adjustment provisions of the Common Unit Adjustment Agreement. The Company recorded the additional common units (Additional Investments Tranche) at fair value using the available closing stock prices of NCM, Inc. as of the dates on which the units were issued. As a result of these adjustments, the

Company recorded increases to its investment in National CineMedia (along with corresponding increases to deferred revenue) of $9.9 million, $9.0 million and $5.9 million during the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively. Such deferred revenue amounts are being amortized to advertising revenue over the remaining term of the ESA between RCI and National CineMedia following the units of revenue method as described in (4) below. As of December 31, 2016, we held approximately 27.1 million common units of National CineMedia. On a fully diluted basis, we own a 19.7% interest in NCM, Inc. as of December 31, 2016.

(2) During the years ended December 31, 2016, December 31, 2015 and January 1, 2015, the Company received $34.7 million, $40.0 million, $39.1 million, respectively, in cash distributions from National CineMedia, exclusive of receipts for services performed under the ESA (including payments of $11.4 million, $9.5 million, and $12.0 million received under the tax receivable agreement). Approximately $13.8 million, $15.3 million and $14.1 million of these cash distributions received during the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively, were attributable to the Additional Investments Tranche and were recognized as a reduction in our investment in National CineMedia. The remaining amounts were recognized in equity earnings during each of these periods and have been included as components of "Earnings recognized from NCM" in the accompanying consolidated financial statements.

(3) The Company recorded other revenues, excluding the amortization of deferred revenue, of approximately $16.7 million, $16.7 million and $14.2 million for the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively, pertaining to our agreements with National CineMedia, including per patron and per digital screen theatre access fees (net of payments $12.2 million, $11.8 million and $14.0 million for the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively, for on-screen advertising time provided to our beverage concessionaire) and other NCM revenues. These advertising revenues are presented as a component of "Other operating revenues" in the Company's consolidated financial statements.

(4) Amounts represent amortization of ESA modification fees received from NCM to advertising revenue utilizing the units of revenue amortization method. These advertising revenues are presented as a component of "Other operating revenues" in the Company's consolidated financial statements.

(5) Amounts represent the Company's share in the net income of National CineMedia with respect to the Additional Investments Tranche. Such amounts have been included as a component of "Earnings recognized from NCM" in the consolidated financial statements.

As of December 31, 2016, approximately $2.8 million and $1.3 million due from/to National CineMedia were included in "Trade and other receivables, net" and "Accounts payable," respectively. As of December 31, 2015, approximately $2.8 million and $1.3 million due from/to National CineMedia were included in "Trade and other receivables, net" and "Accounts payable," respectively.

As of the date of this Form 10-K, no summarized financial information for National CineMedia was available for the year ended December 31, 2016. Summarized consolidated statements of income information for National CineMedia for the years ended December 31, 2015, January 1, 2015 and December 26, 2013 is as follows (in millions):

	Year Ended December 31, 2015	Year Ended January 1, 2015	Year Ended December 26, 2013
Revenues	$ 446.5	$ 394.0	$ 462.8
Income from operations	140.5	159.2	202.0
Net income	87.5	96.3	162.9

Summarized consolidated balance sheet information for National CineMedia as of December 31, 2015 and January 1, 2015 is as follows (in millions):

	December 31, 2015	January 1, 2015
Current assets	$ 159.5	$ 134.9
Noncurrent assets	623.1	546.2
Total assets	782.6	681.1

Current liabilities	113.1	106.5
Noncurrent liabilities	936.0	892.0
Total liabilities	1,049.1	998.5
Members' deficit	(266.5)	(317.4)
Liabilities and members' deficit	782.6	681.1

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December 31, 2016, December 31, 2015 and January 1, 2015

Investment in Digital Cinema Implementation Partners

We maintain an investment in Digital Cinema Implementation Partners, LLC, a Delaware limited liability company ("DCIP"). DCIP is a joint venture company formed by Regal, AMC and Cinemark. DCIP funds the cost of digital projection principally through the collection of virtual print fees from motion picture studios and equipment lease payments from participating exhibitors, including us. In addition to its U.S. digital deployment, DCIP actively manages the deployment of over 1,800 digital systems in Canada for Canadian Digital Cinema Partnership, a joint venture between Cineplex Inc. and Empire Theatres Limited.

Regal holds a 46.7% economic interest in DCIP as of December 31, 2016 and a one-third voting interest along with each of AMC and Cinemark. Since the Company does not have a controlling financial interest in DCIP or any of its subsidiaries, it accounts for its investment in DCIP under the equity method of accounting. The Company's investment in DCIP is included as a component of "Other Non-Current Assets" in the accompanying consolidated balance sheets. The changes in the carrying amount of our investment in DCIP for the years ended December 31, 2016, December 31, 2015, and January 1, 2015 are as follows (in millions):

Balance as of December 26, 2013	$101.6
Equity contributions	3.6
Equity in earnings of DCIP(1)	28.6
Receipt of cash distributions(2)	(6.3)
Change in fair value of equity method investee interest rate swap transactions	(1.2)
Balance as of January 1, 2015	126.3
Equity contributions	0.4
Equity in earnings of DCIP(1)	37.0
Receipt of cash distributions(2)	(2.0)
Change in fair value of equity method investee interest rate swap transactions	(1.0)
Balance as of December 31, 2015	160.7
Equity contributions	0.5
Equity in earnings of DCIP(1)	41.6
Receipt of cash distributions(2)	(9.7)
Change in fair value of equity method investee interest rate swap transactions	0.1
Balance as of December 31, 2016	$193.2

(1) Represents the Company's share of the net income of DCIP. Such amount is presented as a component of "Equity in income of non-consolidated entities and other, net" in the accompanying consolidated statements of income.
(2) Represents cash distributions from DCIP as a return on its investment.

In accordance with the master equipment lease agreement (the "Master Lease"), the digital projection systems are leased from a subsidiary of DCIP under a 12-year term with ten one-year fair value renewal options. The Master Lease also contains a fair value purchase option. On March 31, 2014, the junior capital raised by DCIP in the initial financing transactions was paid in full by DCIP. In connection with this repayment, the Master Lease was amended to eliminate the incremental minimum rent payment provision of $2,000 per digital projection system. DCIP incurred a loss on debt extinguishment of approximately $6.0 million as a result of the debt repayment and Regal recorded its pro rata share of such loss (approximately $2.8 million) during the year ended January 1, 2015 as a reduction of equity in earnings of DCIP. As a result of the amendment to the Master Lease, the Company's deferred rent balance associated with the incremental minimum rental payment of $2,000 per digital projection system is being amortized on a straight-line basis as a reduction of rent expense from the effective date of the amendment (March 31, 2014) through the end of the remaining lease term. As of December 31, 2016, under the Master Lease, the Company pays annual minimum rent of $1,000 per digital projection system through the end of the lease term. The Company considers the $1,000 rent payment to be a minimum rental, and accordingly, records such rent on a straight-line basis in its consolidated financial statements. The Company is also subject to various types of other rent if such digital projection systems

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do not meet minimum performance requirements as outlined in the Master Lease. Certain of the other rent payments are subject to either a monthly or an annual maximum. The Company accounts for the Master Lease as an operating lease for accounting purposes. During the years ended December 31, 2016, December 31, 2015, and January 1, 2015, the Company incurred total rent expense of approximately $5.3 million, $5.4 million, and $7.7 million, respectively, associated with the leased digital projection systems. Such rent expense is presented as a component of "Other operating expenses" in the Company's consolidated statements of income.

Summarized consolidated statements of operations information for DCIP for the years ended December 31, 2016, December 31, 2015, and December 31, 2014 is as follows (in millions):

	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Net revenues	$ 178.8	$ 172.3	$ 170.7
Income from operations	107.9	103.4	102.0
Net income	89.2	79.3	61.3

Summarized consolidated balance sheet information for DCIP as of December 31, 2016 and 2015 is as follows (in millions):

	December 31, 2016	December 31, 2015
Current assets	$ 45.1	$ 48.8
Noncurrent assets	858.6	952.2
Total assets	903.7	1,001.0
Current liabilities	44.8	32.5
Noncurrent liabilities	461.5	638.9
Total liabilities	506.3	671.4
Members' equity	397.4	329.6
Liabilities and members' equity	903.7	1,001.0

Investment in Open Road Films

We maintain an investment in Open Road Films, a film distribution company jointly owned by us and AMC. The Company has committed to a cash investment of $30.0 million in Open Road Films. We account for our investment in Open Road Films using the equity method of accounting. As of March 27, 2014, $30.0 million of cumulative losses were recorded in Open Road Films. Consistent with the accounting model provided by ASC 323-10-35-22, since March 27, 2014, the Company has not provided for any additional losses of Open Road Films, since it has not guaranteed obligations of Open Road Films and otherwise has not committed to provide further financial support for Open Road Films above its initial $30.0 million commitment. Accordingly, the Company discontinued equity method accounting for its investment in Open Road Films as of March 27, 2014. The amount of losses incurred through December 31, 2016 continued to be in excess of the Company's initial $30.0 million commitment by approximately $49.1 million. During the year ended December 31, 2016, the Company effected equity contributions of $8.3 million in cash to Open Road Films, and as of December 31, 2016, the Company has funded a total of $28.3 million of its initial $30.0 million commitment. As a result of the equity contributions, the carrying value of the Company's investment in Open Road Films totaled approximately $(1.7) million as of December 31, 2016.

The Company's investment in Open Road Films is included as a component of "Other Non-Current Liabilities" in the consolidated balance sheets. The changes in the carrying amount of our investment in Open Road Films for the years ended December 31, 2016, December 31, 2015 and January 1, 2015 are as follows (in millions):

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REGAL ENTERTAINMENT GROUP
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December 31, 2016, December 31, 2015 and January 1, 2015

Balance as of December 26, 2013	$(7.1)
Equity in loss attributable to Open Road Films(1)	(2.9)
Balance as of January 1, 2015	(10.0)
Equity in earnings attributable to Open Road Films(1)	—
Balance as of December 31, 2015	(10.0)
Equity in earnings attributable to Open Road Films(1)	—
Equity contributions	8.3
Balance as of December 31, 2016	$(1.7)

(1) Represents the Company's recorded share of the net income (loss) of Open Road Films. Such amount is presented as a component of "Equity in income of non-consolidated entities and other, net" in the accompanying consolidated statements of income.

As of the date of this Form 10-K, no summarized financial information for Open Road Films was available for the year ended December 31, 2016. Summarized consolidated statements of operations information for Open Road Films for the years ended December 31, 2015, December 31, 2014, and December 31, 2013 is as follows (in millions):

	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Revenues	$ 119.2	$ 175.4	$ 140.4
Income (loss) from operations	(27.6)	(13.3)	12.3
Net income (loss)	(29.8)	(15.2)	9.7

Summarized consolidated balance sheet information for Open Road Films as of December 31, 2015 and 2014 is as follows (in millions):

	December 31, 2015	December 31, 2014
Current assets	$ 49.0	$ 44.5
Noncurrent assets	52.3	12.3
Total assets	101.3	56.8
Current liabilities	65.1	41.1
Noncurrent liabilities	95.9	45.6
Total liabilities	161.0	86.7
Members' deficit	(59.7)	(29.9)
Liabilities and members' deficit	101.3	56.8

As of December 31, 2016, approximately $4.2 million and $2.1 million due from/to Open Road Films were included in "Trade and other receivables, net" and "Accounts payable," respectively. As of December 31, 2015, approximately $2.4 million and $2.0 million due from/to Open Road Films were included in "Trade and other receivables, net" and "Accounts payable," respectively.

Investment in RealD, Inc.

As of December 31, 2015, the Company held 322,780 common shares in RealD, Inc., an entity specializing in the licensing of 3D technologies. On February 24, 2016, RealD, Inc. stockholders approved an all-cash merger whereby Rizvi Traverse Management, LLC acquired RealD, Inc. for $11.00 per share. Under the terms of the merger agreement, RealD, Inc. shareholders received $11.00 in cash for each share of RealD, Inc.’s common stock. On March 24, 2016, the Company received approximately $3.6 million in cash consideration for its remaining 322,780 RealD, Inc. common shares. As a result of the transaction, the Company recorded a gain of approximately $1.0 million during the quarter ended March 31, 2016. See Note 14—"Fair Value of Financial Instruments" for a discussion of fair value estimation methods with respect to the Company’s investment in RealD, Inc.

Investment in AC JV, LLC

We maintain an investment in AC JV, LLC (“AC JV”), a Delaware limited liability company owned 32% by each of RCI, AMC and Cinemark and 4% by National CineMedia. AC JV acquired the Fathom Events business from National CineMedia on December 26, 2013. AC JV owns and manages the Fathom Events business, which markets and distributes live and pre-recorded entertainment programming to various theatre operators (including us, AMC and Cinemark) to provide additional programs to augment their feature film schedule and includes events such as live and pre-recorded concerts, opera and symphony, marketing events, theatrical premieres, Broadway plays, live sporting events and other special events. In consideration for the sale, National CineMedia received a total of $25 million in promissory notes from RCI, Cinemark and AMC (one-third or approximately $8.3 million from each). The notes bear interest at 5.0% per annum. Interest and principal payments are due annually in six equal installments commencing on the first anniversary of the closing. National CineMedia recorded a gain of approximately $25.4 million in connection with the sale. The Company's proportionate share of such gain (approximately $1.9 million) was excluded from equity earnings in National CineMedia and recorded as a reduction in the Company's investment in AC JV. The remaining outstanding balance of the note payable from the Company to National CineMedia as of December 31, 2016 was $4.2 million. Since the Company does not have a controlling financial interest in AC JV, it accounts for its investment in AC JV under the equity method of accounting. The Company’s investment in AC JV is included as a component of "Other Non-Current Assets." The changes in the carrying amount of our investment in AC JV for the years ended December 31, 2016, December 31, 2015 and January 1, 2015 are as follows (in millions):

Balance as of December 26, 2013	$6.7
Equity in earnings attributable to AC JV, LLC(1)	1.4
Balance as of January 1, 2015	8.1
Receipt of cash distributions(2)	(1.6)
Equity in earnings attributable to AC JV, LLC(1)	1.0
Balance as of December 31, 2015	7.5
Receipt of cash distributions(2)	(1.6)
Equity in earnings attributable to AC JV, LLC(1)	0.6
Balance as of December 31, 2016	$6.5

(1) Represents the Company’s recorded share of the net income of AC JV. Such amount is presented as a component of “Equity in income of non-consolidated entities and other, net” in the accompanying consolidated statements of income.
(2) Represents cash distributions from AC JV as a return on its investment.

Investment in Digital Cinema Distribution Coalition

The Company is a party to a joint venture with certain exhibitors and distributors called Digital Cinema Distribution Coalition ("DCDC"). DCDC has established a satellite distribution network that distributes digital content to theatres via satellite. The Company has an approximate 14.6% ownership in DCDC as of December 31, 2016. The Company's investment in DCDC is accounted for under the equity method and is included within "Other Non-Current Assets." The carrying value of the Company's investment in DCDC was approximately $2.8 million and $2.9 million as of December 31, 2016 and December 31, 2015, respectively.

Investment in Atom Tickets, LLC

We maintain an investment in Atom Tickets, LLC ("Atom Tickets"), an internet ticketing partner of the Company that provides our patrons the ability to pre-purchase box office tickets and concession items via their mobile device. The Company's investment in Atom Tickets is included within "Other Non-Current Assets" and is accounted for under the cost method. The carrying value of the Company's investment in Atom Tickets was approximately $5.0 million and $0 as of December 31, 2016 and December 31, 2015, respectively.

5. DEBT OBLIGATIONS

Debt obligations at December 31, 2016 and December 31, 2015 consist of the following (in millions):

	December 31, 2016	December 31, 2015
Regal Cinemas Amended Senior Credit Facility, net of debt discount	$ 954.7	$ 958.8
Regal $5^{3}/_{4}$% Senior Notes Due 2022	775.0	775.0
Regal $5^{3}/_{4}$% Senior Notes Due 2025	250.0	250.0
Regal $5^{3}/_{4}$% Senior Notes Due 2023	250.0	250.0
Lease financing arrangements, weighted average interest rate of 11.23% as of December 31, 2016, maturing in various installments through November 2028	97.1	89.4
Capital lease obligations, 7.8% to 10.7%, maturing in various installments through December 2030	9.2	11.1
Other	4.1	8.1
Total debt obligations	2,340.1	2,342.4
Less current portion	25.5	27.4
Less debt issuance costs, net of accumulated amortization of $18.5 and $16.2, respectively (1)	25.8	30.7
Total debt obligations, less current portion and debt issuance costs	$ 2,288.8	$ 2,284.3

(1) See Note 2—"Summary of Significant Accounting Policies - Debt Acquisition Costs" for discussion of debt issuance costs reclassification upon adoption of ASU 2015-03, Interest—Imputation of Interest.

Regal Cinemas Seventh Amended and Restated Credit Agreement— On April 2, 2015, Regal Cinemas entered into a seventh amended and restated credit agreement (the “Amended Senior Credit Facility”), with Credit Suisse AG as Administrative Agent (“Credit Suisse AG”) and the lenders party thereto which amended, restated and refinanced the sixth amended and restated credit agreement (the “Prior Senior Credit Facility”). The Amended Senior Credit Facility consisted of a term loan facility (the “Term Facility”) in an aggregate principal amount of $965.8 million with a final maturity date in April 2022 and a revolving credit facility (the “Revolving Facility”) in an aggregate principal amount of $85.0 million with a final maturity date in April 2020. The Term Facility amortized in equal quarterly installments in an aggregate annual amount equal to 1.0% of the original principal amount of the Term Facility, with the balance payable on the Term Facility maturity date. Proceeds from the Term Facility (approximately $963.3 million, net of debt discount) were applied to refinance the term loan under the Prior Senior Credit Facility, which had an aggregate outstanding principal balance of approximately $963.2 million. As a result of the amendment, the Company recorded a loss on debt extinguishment of approximately $5.7 million during the quarter ended June 30, 2015.

On June 1, 2016, Regal Cinemas entered into a permitted secured refinancing agreement with REH, the guarantors party thereto, Credit Suisse AG and the lenders party thereto (the "June 2016 Refinancing Agreement"). Pursuant to the June 2016 Refinancing Agreement, Regal Cinemas consummated a permitted secured refinancing of the Term Facility under the Amended Senior Credit Facility, which had an aggregate principal balance of approximately $958.5 million, and in accordance therewith, received term loans in an aggregate principal amount of approximately $958.5 million with a final maturity date in April 2022. Together with other amounts provided by Regal Cinemas, proceeds of the term loans were applied to repay all of the outstanding principal and accrued and unpaid interest on the Term Facility under the Amended Senior Credit Facility. In connection with the execution of the June 2016 Refinancing Agreement, the Company recorded a loss on debt extinguishment of approximately $1.5 million during the quarter ended June 30, 2016.

On December 2, 2016, Regal Cinemas entered into a permitted secured refinancing agreement (the “December 2016 Refinancing Agreement”) with REH, the guarantors party thereto, Credit Suisse AG and the lenders party thereto. The December 2016 Refinancing Agreement further amends the Amended Senior Credit Facility, which was amended by the June 2016 Refinancing Agreement. Pursuant to the December 2016 Refinancing Agreement, Regal Cinemas consummated a permitted secured refinancing of the Term Facility, which had an aggregate principal balance of approximately $956.1 million, and in accordance therewith, and received term loans in an aggregate principal amount of approximately $956.1 million with a final maturity date in April 2022 (the “New Term Loans”). Together with other amounts provided by Regal Cinemas, proceeds of the New Term Loans were applied to repay all of the outstanding principal and accrued and unpaid interest on the existing term facility under the Amended Senior Credit Facility in effect immediately prior to the making of the New Term Loans. The New Term Loans amortize in equal quarterly installments in an aggregate annual amount equal to 1.0% of the original principal amount of the New Term Loans, with the balance payable on the maturity date of the New Term Loans. The December 2016 Refinancing Agreement also amends the Amended Senior Credit Facility by reducing the interest rate on the New Term Loans, by providing, at Regal Cinemas' option, either a base rate or an adjusted LIBOR rate (as defined in the Amended Senior Credit Facility) plus, in each case, an applicable margin. Such applicable margin will be either 1.50% in the case of base rate loans or 2.50% in the case of LIBOR rate loans. The December 2016 Refinancing Agreement also provides for a 1% prepayment premium applicable in the event that Regal Cinemas enters into a refinancing or amendment of the New Term Loans on or prior to the sixth-month anniversary of the closing of the December 2016 Refinancing Agreement that, in either case, has the effect of reducing the interest rate on the New Term Loans. In connection with the execution of the December 2016 Refinancing Agreement, the Company recorded a loss on debt extinguishment of approximately $1.4 million during the quarter ended December 31, 2016.

No amounts have been drawn on the Revolving Facility. The Amended Senior Credit Facility also permits Regal Cinemas to borrow additional term loans thereunder in an amount of up to $200.0 million, plus additional amounts as would not cause the consolidated total leverage ratio of Regal Cinemas to exceed 3.00:1.00, in each case, subject to lenders providing additional commitments for such amounts and the satisfaction of certain other customary conditions. The obligations of Regal Cinemas are secured by, among other things, a lien on substantially all of its tangible and intangible personal property (including but not limited to accounts receivable, inventory, equipment, general intangibles, investment property, deposit and securities accounts, and intellectual property) and certain owned real property. The obligations under the Amended Senior Credit Facility are also guaranteed by certain subsidiaries of Regal Cinemas and secured by a lien on all or substantially all of such subsidiaries' personal property and certain owned real property pursuant to that certain second amended and restated guaranty and collateral agreement, dated as of May 19, 2010, among Regal Cinemas, certain subsidiaries of Regal Cinemas party thereto and Credit Suisse AG (the "Amended Guaranty Agreement"). The obligations are further guaranteed by Regal Entertainment Holdings, Inc., on a limited recourse basis, with such guaranty being secured by a lien on the capital stock of Regal Cinemas.

Borrowings under the Amended Senior Credit Facility bear interest, at Regal Cinemas' option, at either a base rate or an adjusted LIBOR rate (as defined in the Amended Senior Credit Facility) plus, in each case, an applicable margin of 1.50% in the case of base rate loans or 2.50% in the case of LIBOR rate loans. Interest is payable (a) in the case of base rate loans, quarterly in arrears, and (b) in the case of LIBOR rate loans, at the end of each interest period, but in no event less often than every 3 months. If, at any time, with respect to the New Term Loans, the adjusted LIBOR rate as defined in the Amended Senior Credit Facility would otherwise be lower than 0.75% per annum, the adjusted LIBOR rate with respect to the New Term Loans shall be deemed to be 0.75% per annum at such time.

Regal Cinemas may prepay borrowings under the Amended Senior Credit Facility, in whole or in part, in minimum amounts and subject to other conditions set forth in the Amended Senior Credit Facility. Regal Cinemas is required to make mandatory prepayments with:

- 50% of excess cash flow in any fiscal year (as reduced by voluntary repayments of the New Term Loans), with elimination based upon achievement and maintenance of a leverage ratio of 3.75:1.00 or less;
- 100% of the net cash proceeds of all asset sales or other dispositions of property by Regal Cinemas and its subsidiaries, subject to certain exceptions (including reinvestment rights); and
-

100% of the net cash proceeds of issuances of funded debt of Regal Cinemas and its subsidiaries, subject to exceptions for most permitted debt issuances.

The above-described mandatory prepayments are required to be applied pro rata to the remaining amortization payments under the New Term Loans. When there are no longer outstanding loans under the New Term Loans, mandatory prepayments are to be applied to prepay outstanding loans under the Revolving Facility with no corresponding permanent reduction of commitments under the Revolving Facility.

The Amended Senior Credit Facility includes the following financial maintenance covenants, which are applicable only in certain circumstances where usage of the revolving credit commitments exceeds 30% of such commitments. Such financial covenants are limited to the following:

- maximum adjusted leverage ratio, determined by the ratio of (i) the sum of funded debt (net of unencumbered cash) plus the product of eight (8) times lease expense to (ii) consolidated EBITDAR (as defined in the Amended Senior Credit Facility), of 6.0 to 1.0; and
- maximum total leverage ratio, determined by the ratio of funded debt (net of unencumbered cash) to consolidated EBITDA, of 4.0 to 1.0.

The Amended Senior Credit Facility requires that Regal Cinemas and its subsidiaries comply with covenants relating to customary matters, including with respect to incurring indebtedness and liens, making investments and acquisitions, effecting mergers and asset sales, prepaying indebtedness, and paying dividends. The Amended Senior Credit Facility also limits capital expenditures to an amount not to exceed 35% of consolidated EBITDA for the prior fiscal year plus a one-year carryforward for unused amounts from the prior fiscal year. Among other things, such limitations will restrict the ability of Regal Cinemas to fund the operations of Regal or any subsidiary of Regal that is not a subsidiary of Regal Cinemas which guarantees the obligations under Amended Senior Credit Facility.

The Amended Senior Credit Facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross default and cross acceleration with respect to indebtedness in an aggregate principal amount of $25.0 million or more; bankruptcy; judgments involving liability of $25.0 million or more that are not paid; ERISA events; actual or asserted invalidity of guarantees or security documents; and change of control.

As of December 31, 2016 and December 31, 2015, borrowings of $954.7 million (net of debt discount) and $958.8 million (net of debt discount), respectively, were outstanding under the New Term Loans and term facility under the Prior Senior Credit Facility at an effective interest rate of 3.56% (as of December 31, 2016) and 4.17% (as of December 31, 2015), after the impact of the interest rate swaps is taken into account.

Regal $5^{3}/_{4}$% Senior Notes Due 2022—On March 11, 2014, Regal issued $775.0 million in aggregate principal amount of its $5^{3}/_{4}$% senior notes due 2022 (the "$5^{3}/_{4}$% Senior Notes Due 2022") in a registered public offering. The net proceeds from the offering were approximately $760.1 million, after deducting underwriting discounts and offering expenses. Regal used a portion of the net proceeds from the offering to purchase approximately $222.3 million aggregate principal amount of its then outstanding $9^{1}/_{8}$% Senior Notes for an aggregate purchase price of approximately $240.5 million pursuant to a cash tender offer for such notes, and $355.8 million aggregate principal amount of Regal Cinemas' then outstanding $8^{5}/_{8}$% Senior Notes for an aggregate purchase price of approximately $381.0 million pursuant to a cash tender offer for such notes as described further below. As a result of the tender offers, the Company recorded a $51.9 million loss of extinguishment of debt during the year ended January 1, 2015.

Also on March 11, 2014, the Company and Regal Cinemas each announced their intention to redeem all $9^{1}/_{8}$% Senior Notes and $8^{5}/_{8}$% Senior Notes that remained outstanding following the consummation of the tender offers at a price equal to 100% of the principal amount thereof plus a "make-whole" premium and accrued and unpaid interest payable thereon up to, but not including, the redemption date, in accordance with the terms of the indentures governing the $9^{1}/_{8}$% Senior Notes and $8^{5}/_{8}$% Senior Notes. On April 10, 2014, the remaining $9^{1}/_{8}$% Senior Notes and $8^{5}/_{8}$% Senior Notes were fully redeemed by the Company and Regal Cinemas for an aggregate purchase price of $144.9 million (including accrued and unpaid interest) using the remaining net proceeds from the $5^{3}/_{4}$% Senior Notes Due 2022 and available cash on hand. As a result of the redemptions, the Company recorded an additional $10.5 million loss on extinguishment of debt during the year ended January 1, 2015.

The $5^3/_4$% Senior Notes Due 2022 bear interest at a rate of 5.75% per year, payable semiannually in arrears on March 15 and September 15 of each year, beginning September 15, 2014. The $5^3/_4$% Senior Notes Due 2022 will mature on March 15, 2022. The $5^3/_4$% Senior Notes Due 2022 are the Company's senior unsecured obligations and rank equal in right of payment with all of the Company's existing and future senior unsecured indebtedness and prior to all of the Company's future subordinated indebtedness. The $5^3/_4$% Senior Notes Due 2022 are effectively subordinated to all of the Company's future secured indebtedness to the extent of the value of the collateral securing that indebtedness and structurally subordinated to all existing and future indebtedness and other liabilities of the Company's subsidiaries. None of the Company's subsidiaries guaranty any of the Company's obligations with respect to the $5^3/_4$% Senior Notes Due 2022.

Prior to March 15, 2017, the Company may redeem all or any part of the $5^3/_4$% Senior Notes Due 2022 at its option at 100% of the principal amount, plus accrued and unpaid interest to the redemption date and a make-whole premium. The Company may redeem the $5^3/_4$% Senior Notes Due 2022 in whole or in part at any time on or after March 15, 2017 at the redemption prices specified in the indenture. In addition, prior to March 15, 2017, the Company may redeem up to 35% of the original aggregate principal amount of the $5^3/_4$% Senior Notes Due 2022 from the net proceeds of certain equity offerings at the redemption price specified in the indenture. The Company has not separated the make-whole premium from the underlying debt instrument to account for it as a derivative instrument, as the economic characteristics and risks of this embedded derivative are clearly and closely related to the economic characteristics and risks of the underlying debt.

If the Company undergoes a change of control (as defined in the indenture), holders may require the Company to repurchase all or a portion of their $5^3/_4$% Senior Notes Due 2022 at a price equal to 101% of the principal amount of the notes being repurchased, plus accrued and unpaid interest, if any, to the date of purchase.

The indenture contains covenants that limit the Company's (and its restricted subsidiaries') ability to, among other things: (i) incur additional indebtedness; (ii) pay dividends on or make other distributions in respect of its capital stock, purchase or redeem capital stock, or purchase, redeem or otherwise acquire or retire certain subordinated obligations; (iii) enter into certain transactions with affiliates; (iv) permit, directly or indirectly, it to create, incur, or suffer to exist any lien, except in certain circumstances; (v) create or permit encumbrances or restrictions on the ability of its restricted subsidiaries to pay dividends or make distributions on their capital stock, make loans or advances to other subsidiaries or the Company, or transfer any properties or assets to other subsidiaries or the Company; and (vi) merge or consolidate with other companies or transfer all or substantially all of its assets. These covenants are, however, subject to a number of important limitations and exceptions. The indenture contains other customary terms, including, but not limited to, events of default, which, if any of them occurs, would permit or require the principal, premium, if any, interest and any other monetary obligations on all the then outstanding notes to be due and payable immediately.

Regal $5^3/_4$% Senior Notes Due 2025—On January 17, 2013, Regal issued $250.0 million in aggregate principal amount of its $5^3/_4$% senior notes due 2025 (the "$5^3/_4$% Senior Notes Due 2025") in a registered public offering. The net proceeds from the offering were approximately $244.5 million, after deducting underwriting discounts and offering expenses. Regal used approximately $194.4 million of the net proceeds from the offering to fund the acquisition of Hollywood Theaters.

The $5^3/_4$% Senior Notes Due 2025 bear interest at a rate of 5.75% per year, payable semiannually in arrears on February 1 and August 1 of each year, beginning August 1, 2013. The $5^3/_4$% Senior Notes Due 2025 will mature on February 1, 2025. The $5^3/_4$% Senior Notes Due 2025 are the Company's senior unsecured obligations. They rank equal in right of payment with all of the Company's existing and future senior unsecured indebtedness and prior to all of the Company's future subordinated indebtedness. The $5^3/_4$% Senior Notes Due 2025 are effectively subordinated to all of the Company's future secured indebtedness to the extent of the value of the collateral securing that indebtedness and structurally subordinated to all existing and future indebtedness and other liabilities of the Company's subsidiaries. None of the Company's subsidiaries guaranty any of the Company's obligations with respect to the $5^3/_4$% Senior Notes Due 2025.

Prior to February 1, 2018, the Company may redeem all or any part of the $5^3/_4$% Senior Notes Due 2025 at its option at 100% of the principal amount, plus accrued and unpaid interest to the redemption date and a make-whole premium. The Company may redeem the $5^3/_4$% Senior Notes Due 2025 in whole or in part at any time on or after February 1, 2018 at the redemption prices specified in the indenture governing the $5^3/_4$% Senior Notes Due 2025. In addition, prior to February 1, 2016, the Company may redeem up to 35% of the original aggregate principal amount of the

$5^3/_4$% Senior Notes Due 2025 from the net proceeds from certain equity offerings at the redemption price specified in the indenture. The Company has not separated the make-whole premium from the underlying debt instrument to account for it as a derivative instrument, as the economic characteristics and risks of this embedded derivative are clearly and closely related to the economic characteristics and risks of the underlying debt.

If the Company undergoes a change of control (as defined in the indenture), holders may require the Company to repurchase all or a portion of their notes at a price equal to 101% of the principal amount of the notes being repurchased, plus accrued and unpaid interest, if any, to the date of purchase.

The indenture contains covenants that limit the Company's (and its restricted subsidiaries') ability to, among other things: (i) incur additional indebtedness; (ii) pay dividends on or make other distributions in respect of its capital stock, purchase or redeem capital stock, or purchase, redeem or otherwise acquire or retire certain subordinated obligations; (iii) enter into certain transactions with affiliates; (iv) permit, directly or indirectly, it to create, incur, or suffer to exist any lien, except in certain circumstances; (v) create or permit encumbrances or restrictions on the ability of its restricted subsidiaries to pay dividends or make distributions on their capital stock, make loans or advances to other subsidiaries or the Company, or transfer any properties or assets to other subsidiaries or the Company; and (vi) merge or consolidate with other companies or transfer all or substantially all of its assets. These covenants are, however, subject to a number of important limitations and exceptions. The indenture contains other customary terms, including, but not limited to, events of default, which, if any of them occurs, would permit or require the principal, premium, if any, interest and any other monetary obligations on all the then outstanding notes to be due and payable immediately.

Regal $5^3/_4$% Senior Notes Due 2023—On June 13, 2013, Regal issued $250.0 million in aggregate principal amount of its $5^3/_4$% senior notes due 2023 (the "$5^3/_4$% Senior Notes Due 2023") in a registered public offering. The net proceeds from the offering were approximately $244.4 million, after deducting underwriting discounts and offering expenses. Regal used the net proceeds from the offering to purchase approximately $213.6 million aggregate principal amount of its outstanding $9^1/_8$% Senior Notes for an aggregate purchase price of approximately $244.3 million pursuant to a cash tender offer for such notes as described further above.

The $5^3/_4$% Senior Notes Due 2023 bear interest at a rate of 5.75% per year, payable semiannually in arrears on June 15 and December 15 of each year, beginning December 15, 2013. The $5^3/_4$% Senior Notes Due 2023 will mature on June 15, 2023. The $5^3/_4$% Senior Notes Due 2023 are the Company’s senior unsecured obligations. They rank equal in right of payment with all of the Company’s existing and future senior unsecured indebtedness and prior to all of the Company’s future subordinated indebtedness. The $5^3/_4$% Senior Notes Due 2023 are effectively subordinated to all of the Company’s future secured indebtedness to the extent of the value of the collateral securing that indebtedness and structurally subordinated to all existing and future indebtedness and other liabilities of the Company’s subsidiaries. None of the Company’s subsidiaries will guaranty any of the Company’s obligations with respect to the $5^3/_4$% Senior Notes Due 2023.

Prior to June 15, 2018, the Company may redeem all or any part of the $5^3/_4$% Senior Notes Due 2023 at its option at 100% of the principal amount, plus accrued and unpaid interest to the redemption date and a make-whole premium. The Company may redeem the $5^3/_4$% Senior Notes Due 2023 in whole or in part at any time on or after June 15, 2018 at the redemption prices specified in the indenture. In addition, prior to June 15, 2016, the Company may redeem up to 35% of the original aggregate principal amount of the $5^3/_4$% Senior Notes Due 2023 from the net proceeds of certain equity offerings at the redemption price specified in the indenture. The Company has not separated the make-whole premium from the underlying debt instrument to account for it as a derivative instrument, as the economic characteristics and risks of this embedded derivative are clearly and closely related to the economic characteristics and risks of the underlying debt.

If the Company undergoes a change of control (as defined in the indenture), holders may require the Company to repurchase all or a portion of their $5^3/_4$% Senior Notes Due 2023 at a price equal to 101% of the principal amount of the notes being repurchased, plus accrued and unpaid interest, if any, to the date of purchase.

The indenture contains covenants that limit the Company's (and its restricted subsidiaries') ability to, among other things: (i) incur additional indebtedness; (ii) pay dividends on or make other distributions in respect of its capital stock, purchase or redeem capital stock, or purchase, redeem or otherwise acquire or retire certain subordinated obligations; (iii) enter into certain transactions with affiliates; (iv) permit, directly or indirectly, it to create, incur, or suffer to exist any lien, except in certain circumstances; (v) create or permit encumbrances or restrictions on the ability of its restricted subsidiaries to pay dividends or make distributions on their capital stock, make loans or advances to other subsidiaries or the Company, or transfer any properties or assets to other subsidiaries or the Company; and (vi) merge or consolidate with other companies or transfer all or substantially all of its assets. These covenants are, however, subject to a number of important limitations and exceptions. The indenture contains other customary terms, including, but not limited to, events of default, which, if any of them occurs, would permit or require the principal, premium, if any, interest and any other monetary obligations on all the then outstanding notes to be due and payable immediately.

Lease Financing Arrangements—These obligations primarily represent lease financing obligations resulting from the requirements of ASC Subtopic 840-40. In connection with the acquisition of Hollywood Theaters, the Company assumed approximately $40.4 million of lease financing obligations associated with 14 acquired theatres. As of December 31, 2016, such obligations have a weighted average interest rate of approximately 10.9% and mature in various installments through November 2028. In addition, as a result of certain lease transactions effected during the years ended December 31, 2016 and December 31, 2015, the Company increased the carrying amount of its lease financing obligations by approximately $18.5 million and $5.1 million, respectively.

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Maturities of Debt Obligations—The Company's long-term debt and future minimum lease payments for its capital lease obligations and lease financing arrangements are scheduled to mature as follows:

	Long-Term Debt and Other	Capital Leases	Lease Financing Arrangements	Total
	(in millions)			
2017	$10.9	$ 3.1	$ 21.8	$35.8
2018	10.9	0.9	21.9	33.7
2019	10.9	0.9	20.1	31.9
2020	9.6	0.9	14.4	24.9
2021	9.6	1.0	10.5	21.1
Thereafter	2,181.9	9.0	54.9	2,245.8
Less: interest on capital leases and lease financing arrangements	—	(6.6)	(46.5)	(53.1)
Totals	$2,233.8	$ 9.2	$ 97.1	$2,340.1

Covenant Compliance—As of December 31, 2016, we are in full compliance with all agreements, including all related covenants, governing our outstanding debt obligations.

6. LEASES

The Company accounts for a majority of its leases as operating leases. Minimum rentals payable under all non-cancelable operating leases with terms in excess of one year as of December 31, 2016, are summarized for the following fiscal years (in millions):

2017	$426.9
2018	409.4
2019	363.1
2020	311.8
2021	272.4
Thereafter	1,128.0
Total	$2,911.6

Rent expense under such operating leases amounted to $427.6 million, $421.5 million and $423.4 million for the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively. Contingent rent expense was $23.5 million, $22.7 million and $23.7 million for the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively.

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7. INCOME TAXES

The components of the provision for income taxes for income from operations are as follows (in millions):

	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Federal:			
Current	$ 89.2	$ 91.1	$ 53.8
Deferred	3.3	(8.1)	4.4
Total Federal	92.5	83.0	58.2
State:			
Current	19.6	19.9	13.0
Deferred	(0.9)	(2.8)	2.2
Total State	18.7	17.1	15.2
Total income tax provision	$ 111.2	$ 100.1	$ 73.4

During the years ended December 31, 2016, December 31, 2015 and January 1, 2015, a current tax benefit of $0.9 million, $1.8 million and $1.6 million, respectively, was allocated directly to stockholders' equity for compensation expense for tax purposes in excess of amounts recognized for financial reporting purposes.

A reconciliation of the provision for income taxes as reported and the amount computed by multiplying the income before taxes and extraordinary item by the U.S. federal statutory rate of 35% was as follows (in millions):

	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Provision calculated at federal statutory income tax rate	$ 98.6	$ 88.7	$ 62.5
State and local income taxes, net of federal benefit	12.2	11.1	9.7
Other	0.4	0.3	1.2
Total income tax provision	$ 111.2	$ 100.1	$ 73.4

Significant components of the Company's net deferred tax asset consisted of the following at (in millions):

	December 31, 2016	December 31, 2015
Deferred tax assets:		
Net operating loss carryforward	$ 46.6	$ 52.7
Excess of tax basis over book basis of fixed assets	55.2	36.8
Deferred revenue	176.5	176.9
Deferred rent	86.6	64.5
Other	14.3	16.0
Total deferred tax assets	379.2	346.9
Valuation allowance	(34.5)	(34.9)
Total deferred tax assets, net of valuation allowance	344.7	312.0
Deferred tax liabilities:		
Excess of book basis over tax basis of intangible assets	(58.7)	(42.5)

Excess of book basis over tax basis of investments	(219.1)	(201.4)
Other	(10.6)	(9.7)
Total deferred tax liabilities	(288.4)	(253.6)
Net deferred tax asset	$ 56.3	$ 58.4

At December 31, 2016, the Company had net operating loss carryforwards for federal income tax purposes of approximately $84.1 million with expiration commencing in 2018. The Company's net operating loss carryforwards were generated by the entities of United Artists, Edwards and Hollywood Theaters. The Tax Reform Act of 1986 imposed substantial restrictions on the utilization of net operating losses in the event of an "ownership change" of a corporation. Accordingly, the Company's ability to utilize the net operating losses acquired from United Artists, Edwards and Hollywood Theaters may be impaired as a result of the "ownership change" limitations. The Company’s state net operating losses may be carried forward for various periods, between seven and 20 years, with expiration commencing in 2017. The Company also has net operating losses in U.S. territorial jurisdictions with expirations commencing in 2019.

In assessing the realizable value of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which these temporary differences become deductible. The Company has recorded a valuation allowance against deferred tax assets of $34.5 million and $34.9 million as of December 31, 2016 and December 31, 2015, respectively, as management believes it is more likely than not that certain deferred tax assets will not be realized in future tax periods. Future reductions in the valuation allowance associated with a change in management's determination of the Company's ability to realize these deferred tax assets will result in a decrease in the provision for income taxes. During the year ended December 31, 2016, the valuation allowance was increased by $0.6 million related to management's determination that it was more likely than not that certain state net operating losses created in the current year would not be realized, decreased by $0.8 million related to the expiration of federal net operating losses during the current year, and decreased by $0.2 million related to management's determination that it was more likely than not that certain state net operating losses created in prior years would be realized.

In accordance with the provisions of ASC Subtopic 740-10, a reconciliation of the change in the amount of unrecognized tax benefits during the years ended December 31, 2016 and December 31, 2015 was as follows (in millions):

	Year Ended December 31, 2016	Year Ended December 31, 2015
Beginning balance	$ 13.1	$ 13.6
Decreases related to prior year tax positions	—	(0.5)
Increases related to current year tax positions	0.4	0.2
Lapse of statute of limitations	(2.6)	(0.2)
Ending balance	$ 10.9	$ 13.1

Exclusive of interest and penalties, it is reasonably possible that gross unrecognized tax benefits associated with state tax positions will decrease between $3.0 million and $6.0 million within the next 12 months primarily due to the expiration of the statute of limitations, settlement of tax disputes with taxing authorities and the resolution of other state tax matters.

The total net unrecognized tax benefits that would affect the effective tax rate if recognized at December 31, 2016 and December 31, 2015 was $5.4 million and $6.8 million, respectively. Additionally, the total net unrecognized tax benefits that would result in an increase to the valuation allowance if recognized at December 31, 2016 and

December 31, 2015 was approximately $1.7 million.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. As of December 31, 2016 and December 31, 2015, the Company has accrued gross interest and penalties of approximately $1.8 million and $2.2 million, respectively. The total amount of interest and penalties recognized in the statement of income for the years ended December 31, 2016, December 31, 2015 and January 1, 2015 was $(0.2) million, $0.3 million and $0.2 million, respectively.

The Company and its subsidiaries collectively file income tax returns in the U.S. federal jurisdiction and various state and U.S. territory jurisdictions. The Company is not subject to U.S. federal examinations before 2013, U.S. Territory examinations for years before 2012, and with limited exceptions, state examinations before 2012. However, the taxing authorities still have the ability to review the propriety of tax attributes created in closed tax years if such tax attributes are utilized in an open tax year. During the year ended December 31, 2015, the Internal Revenue Service (“IRS”) closed an examination of the Company’s 2010 and 2012 federal income tax returns and notified the Company that no items were being disputed. In April 2016, the Company was notified that the IRS would examine its 2014 federal tax return. The Company is in the process of providing information requested by the IRS with respect to such tax year. Management believes that it has provided adequate provision for income taxes relative to the tax year under examination.

8. LITIGATION AND CONTINGENCIES

The Company is presently involved in various judicial, administrative, regulatory and arbitration proceedings concerning matters arising in the ordinary course of business operations, including but not limited to, personal injury claims, landlord-tenant, antitrust, vendor and other third party disputes, tax disputes, employment and other contractual matters, some of which are described below. Many of these proceedings are at preliminary stages, and many of these cases seek an indeterminate amount of damages. The Company's theatre operations are also subject to federal, state and local laws governing such matters as wages, working conditions, citizenship and health and sanitation and environmental protection requirements.

On October 9, 2012, staff at the San Francisco Regional Water Quality Board (the "Regional Board") notified United Artists Theatre Circuit, Inc. (“UATC”), an indirect, wholly owned subsidiary of the Company, that the Regional Board was contemplating issuing a cleanup and abatement order to UATC with respect to a property in Santa Clara, California that UATC owned and then leased during the 1960s and 1970s. On June 25, 2013, the Regional Board issued a tentative order to UATC setting out proposed site clean-up requirements for UATC with respect to the property. According to the Regional Board, the property in question has been contaminated by dry-cleaning facilities that operated at the property in question from approximately 1961 until 1996. The Regional Board also issued a tentative order to the current property owner, who has been conducting site investigation and remediation activities at the site for several years. UATC submitted comments to the Regional Board on July 28, 2013, objecting to the tentative order. The Regional Board considered the matter at its regular meeting on September 11, 2013 and adopted the tentative order with only minor changes. On October 11, 2013, UATC filed a petition with the State Water Resources Control Board (“State Board”) for review of the Regional Board’s order. The State Board failed to act on the petition and hence by operation of law it was deemed denied, and UATC filed a petition for writ of mandamus with the California Superior Court seeking review and modification of the order. The Superior Court dismissed UATC's claims against the State Board and the City of Santa Clara. Briefing on UATC's claims against the Regional Board is scheduled to be completed during the first half of 2017. UATC is cooperating with the Regional Board while its petition remains pending before the State Board. To that end, UATC and the current property owner jointly submitted, and on October 27, 2015, the Regional Board approved, a Remedial Action Plan (“RAP”) to remediate the dry-cleaner contamination. UATC intends to vigorously defend this matter. We believe that we are, and were during the period in question described in this paragraph, in compliance with such applicable laws and regulations.

On January 28, 2016, Regional Board staff contacted UATC’s counsel in the Santa Clara matter to ascertain whether he would be representing UATC in connection with the cleanup of a drycleaner-impacted property located in Millbrae, California that the Regional Board believes UATC or related entities formerly owned during the dry-cleaning operations. Counsel subsequently responded in the affirmative. The Company has received no further communications from the Regional Board on this matter.

On May 5, 2014, NCM, Inc. announced that it had entered into a merger agreement to acquire Screenvision, LLC ("Screenvision"). On November 3, 2014, the United States Department of Justice ("DOJ") filed an antitrust lawsuit seeking to enjoin the proposed merger between NCM, Inc. and Screenvision. On March 16, 2015, NCM, Inc. announced that it had agreed with Screenvision to terminate the merger agreement. On March 17, 2015, the Company was notified by the DOJ that it had opened an investigation into potential anticompetitive conduct by and coordination among NCM, Inc., National CineMedia, Regal, AMC and Cinemark (the “DOJ Notice”). In addition, the DOJ Notice requested that the Company preserve all documents and information since January 1, 2011 relating to movie clearances or communications or cooperation between and among AMC, Regal and Cinemark or their participation in NCM. On May 28, 2015, the Company received a civil investigative demand (the “CID”) from the DOJ as part of an investigation into potentially anticompetitive conduct under Sections 1 and 2 of the Sherman Act, 15 U.S.C. § 1 and § 2. The Company has also received investigative demands from the antitrust sections of various state attorneys general regarding movie clearances and Regal's various joint venture investments, including National CineMedia. The CID and various state investigative demands require the Company to produce documents and answer interrogatories. The Company may receive additional investigative demands from the DOJ and state attorneys general regarding these or related matters. The Company continues to cooperate with these investigations and any other related Federal or state investigations to the extent any are undertaken. The DOJ and various state investigations may also give rise to additional lawsuits filed against the Company related to clearances and the Company’s investments in its various joint ventures. While we do not believe that the Company has engaged in any violation of Federal or state antitrust or competition laws during its participation in NCM and other joint ventures, we can provide no assurances as to the scope, timing or outcome of the DOJ's or any other state or Federal governmental reviews of the Company's conduct.

On June 17, 2014, Starlight Cinemas, Inc. ("Starlight") filed a complaint and demand for jury trial in the Superior Court of the State of California, County of Los Angeles, Central District against Regal alleging various violations by Regal of California antitrust and unfair competition laws and common law. On July 14, 2014, Regal removed the action to the United States District Court for the Central District of California. Starlight alleges, among other things, that Regal has adversely affected Starlight's ability to exhibit first-run, feature-length motion pictures at its Corona, California theatre. Starlight is seeking, among other things, compensatory, treble and punitive damages and equitable relief enjoining Regal from engaging in future anticompetitive conduct. Regal filed a motion to dismiss all claims. The United States District Court for the Central District of California granted the motion on October 23, 2014. Starlight's subsequent attempts to file an amended complaint were struck and denied. On February 5, 2015, Starlight filed a notice of appeal with the United States Court of Appeals for the Ninth Circuit. The parties' briefing of the case is complete and the case was submitted without oral argument on November 7, 2016. Management believes that the allegations and claims are without merit and intends to vigorously defend against Starlight's claims through the appellate process.

On July 23, 2015, Regal accepted service of a complaint filed by Cinema Village, Cinemart ("Cinemart"), which was filed in the U.S. District Court for the Southern District of New York. Cinemart filed an amended complaint on October 20, 2015. Cinemart alleges among other things, that as a result of a clearance, the Company adversely affected the plaintiff's ability to exhibit first-run, feature-length motion pictures at its Forest Hills, New York theatre. Cinemart is seeking, among other things, compensatory, treble and punitive damages and equitable relief enjoining the Company from engaging in future anticompetitive conduct. On December 18, 2015, the Company filed a motion to dismiss all claims. On September 29, 2016, the district court granted Regal's motion to dismiss. Cinemart filed a notice of appeal with the United States Court of Appeals for the Second Circuit on October 11, 2016. Management believes that the allegations and claims are without merit, and intends to vigorously defend the Company against the claims.

On November 17, 2015, iPic-Gold Class Entertainment LLC ("iPic") filed a petition in the District Court of Harris County, Texas. iPic filed an amended petition on December 4, 2015, that claims, among other things, that the Company adversely affected the plaintiff's ability to exhibit first-run motion pictures at its theatre in Houston, Texas. The petition also names AMC Entertainment Holdings, Inc., AMC, and American Multi-Cinema, Inc. (together, the "AMC Companies") and alleges that the Company and the AMC Companies conspired together to coordinate their respective positions with distributors regarding the distribution of film to iPic's theatre in Houston, and a proposed iPic theatre in Frisco, Texas. iPic is seeking under Texas antitrust law and common law, among other things, actual and treble damages and equitable relief enjoining the Company from engaging in future anticompetitive conduct. On January 21, 2016, after an evidentiary hearing, the district court entered a Temporary Injunction Order ("TIO") which prohibits the Company from (i) requesting that movie studios grant it exclusive film licenses that would exclude iPic from licensing the same film at its Houston theatre; (ii) indicating to a studio that it will not play a film at any of its theatres if the studio licenses the film to iPic's Houston theatre; and (iii) communicating with the AMC Companies or coordinating their respective communications with any studio, with regard to preventing iPic from receiving licenses to first-run films to exhibit at iPic's Houston theatre. On February 4, 2016, Regal filed a notice of appeal regarding the TIO, and on September 29, 2016, the Texas First Court of Appeals affirmed the district court's order. The district court has scheduled trial for March 27, 2017. Management believes that the allegations and claims are without merit, and intends to vigorously defend the Company.

In situations where management believes that a loss arising from proceedings described herein is probable and can reasonably be estimated, the Company records the amount of the loss, or the minimum estimated liability when the loss is estimated using a range and no amount within the range is more probable than another. As additional information becomes available, any potential liability related to these proceedings is assessed and the estimates are revised, if necessary. The amounts reserved for such proceedings totaled approximately $3.5 million and $4.0 million as of December 31, 2016 and December 31, 2015, respectively. Management believes any additional liability with respect to these claims and disputes will not be material in the aggregate to the Company’s consolidated financial position, results of operations or cash flows. Under ASC Topic 450, Contingencies—Loss Contingencies, an event is "reasonably possible" if "the chance of the future event or events occurring is more than remote but less than likely" and an event is "remote" if "the chance of the future event or events occurring is slight." Thus, references to the upper end of the range of reasonably possible loss for cases in which the Company is able to estimate a range of reasonably possible loss mean the upper end of the range of loss for cases for which the Company believes the risk of loss is more than slight. Management is unable to estimate a range of reasonably possible loss for cases described herein in which damages have not been specified and (i) the proceedings are in early stages, (ii) there is uncertainty as to the likelihood of a class being certified or the ultimate size of the class, (iii) there is uncertainty as to the outcome of pending appeals or motions, (iv) there are significant factual issues to be resolved, and/or (v) there are novel legal issues presented. However, for these cases, management does not believe, based on currently available information, that the outcomes of these proceedings will have a material adverse effect on the Company's financial condition, though the outcomes could be material to the Company's operating results for any particular period, depending, in part, upon the operating results for such period.

Our theatres must comply with Title III of the Americans with Disabilities Act of 1990 (the "ADA") to the extent that such properties are "public accommodations" and/or "commercial facilities" as defined by the ADA. Compliance with the ADA requires that public accommodations "reasonably accommodate" individuals with disabilities and that new construction or alterations made to "commercial facilities" conform to accessibility guidelines unless "structurally impracticable" for new construction or technically infeasible for alterations. Non-compliance with the ADA could result in the imposition of injunctive relief, fines, awards of damages to private litigants and additional capital expenditures to remedy such non-compliance. The Company believes that it is in substantial compliance with all current applicable regulations relating to accommodations for the disabled. The Company intends to comply with future regulations in this regard and except as set forth above, does not currently anticipate that compliance will require the Company to expend substantial funds.

The Company has entered into employment contracts (the "employment contracts"), with four of its current executive officers, Ms. Miles and Messrs. Dunn, Ownby, and Brandow, to whom we refer as the "executive" or "executives." Under each of the employment contracts, the Company must indemnify each executive from and against all liabilities with respect to such executive's service as an officer, and as a director, to the extent applicable. In addition, under the employment contracts, each executive is entitled to severance payments in connection with the termination by the Company of the executive without cause, the termination by the executive for good reason, or the termination of the executive under circumstances in connection with a change in control of the Company (as defined within each employment contract).

Pursuant to each employment contract, the Company provides for severance payments if the Company terminates an executive's employment without cause or if an executive terminates his or her employment for good reason; provided, however, such executive must provide written notification to the Company of the existence of a condition constituting good reason within 90 days of the initial existence of such condition and the resignation must occur within two (2) years of such existence date. Under these circumstances, the executive shall be entitled to receive severance payments equal to (i) the actual bonus, pro-rated to the date of termination, that executive would have received with respect to the fiscal year in which the termination occurs; (ii) two times the executive's annual base salary plus one times the executive's target bonus; and (iii) continued coverage under any medical, health and life insurance plans for a 24-month period following the date of termination.

If the Company terminates any executive's employment, or if any executive resigns for good reason, within three (3)months prior to, or one (1) year after, a change of control of the Company (as defined within each employment contract), the executive shall be entitled to receive severance payments equal to: (i) the actual bonus, pro-rated to the date of termination, that executive would have received with respect to the fiscal year in which the termination occurs; and (ii)(a) in the case of Ms. Miles, two and one-half times the executive's annual base salary plus two times the executive's target bonus; and (b) in the case of Messrs. Dunn, Ownby, and Brandow, two times the executive's annual salary plus one and one-half times the executive's target bonus; and (iii) continued coverage under any medical, health and life insurance plans for a 30-month period following the date of termination.

Pursuant to the employment contracts, the maximum amount of payments and benefits payable to Ms. Miles and Messrs. Dunn, Ownby and Brandow, in the aggregate, if such executives were terminated (in the event of a change of control), would be approximately $13.0 million.

Each employment contract contains standard provisions for non-competition and non-solicitation of the Company's employees (other than the executive's secretary or other administrative employee who worked directly for executive) that are effective during the term of the executive's employment and shall continue for a period of one year following the executive's termination of employment with the Company. Each Executive is also subject to a permanent covenant to maintain confidentiality of the Company's confidential information.

9. CAPITAL STOCK AND SHARE-BASED COMPENSATION

Capital Stock

As of December 31, 2016, the Company's authorized capital stock consisted of:

- 500,000,000 shares of Class A common stock, par value $0.001 per share;
- 200,000,000 shares of Class B common stock, par value $0.001 per share; and
- 50,000,000 shares of preferred stock, par value $0.001 per share.

Of the authorized shares of Class A common stock, 18.0 million shares were sold in connection with the Company's initial public offering in May 2002. The Company's Class A common stock is listed on the New York Stock Exchange under the trading symbol "RGC." As of December 31, 2016, 133,080,279 shares of Class A common stock were outstanding. Of the authorized shares of Class B common stock, 23,708,639 shares were outstanding as of December 31, 2016, all of which are beneficially owned by The Anschutz Corporation and its affiliates (collectively, "Anschutz"). Each share of Class B common stock converts into a single share of Class A common stock at the option of the holder or upon certain transfers of a holder's Class B common stock. Each holder of Class B common stock is entitled to ten votes for each outstanding share of Class B common stock owned by that stockholder on every matter properly submitted to the stockholders for their vote. Of the authorized shares of the preferred stock, no shares were issued and outstanding as of December 31, 2016. The Class A common stock is entitled to a single vote for each outstanding share of Class A common stock on every matter properly submitted to the stockholders for a vote. Except as required by law, the Class A and Class B common stock vote together as a single class on all matters submitted to the stockholders. The material terms and provisions of the Company's certificate of incorporation affecting the relative rights of the Class A common stock and the Class B common stock are described below.

On August 2, 2016, the Company entered into an underwriting agreement with Merrill Lynch, Pierce, Fenner & Smith Incorporated and The Anschutz Corporation and certain of its affiliates named therein (the “Selling Stockholders”). Pursuant to the underwriting agreement, the Selling Stockholders agreed to sell 13,000,000 shares of the Company’s Class A common stock, par value $0.001 per share, to Merrill Lynch, Pierce, Fenner & Smith Incorporated at a price of $21.60 per share. In addition, on November 17, 2016, the Company entered into an underwriting agreement with UBS Securities LLC and the Selling Stockholders. Pursuant to the underwriting agreement, the Selling Stockholders agreed to sell 13,000,000 shares of the Company’s Class A common stock, par value $0.001 per share, to UBS Securities LLC at a price of $22.95 per share. The Company did not receive any proceeds from the sales of the shares by the Selling Stockholders. The offerings were made pursuant to two prospectus supplements, dated August 3, 2016 and November 17, 2016, respectively, to the prospectus dated August 28, 2015 that was included in the Company’s effective shelf registration statement (Reg. No. 333-206656) relating to shares of the Company’s Class A common stock.

The Selling Stockholders owned 18,440,000 shares of our issued and outstanding Class A Common Stock, representing approximately 13.9% of our Class A common stock issued and outstanding as of December 31, 2016, which together with the 23,708,639 shares of our Class B common stock owned by the Selling Stockholders, represents approximately 69.0% of the combined voting power of the outstanding shares of Class A common stock and Class B common stock as of December 31, 2016.

Common Stock

The Class A common stock and the Class B common stock are identical in all respects, except with respect to voting and except that each share of Class B common stock will convert into a single share of Class A common stock at the option of the holder or upon a transfer of the holder's Class B common stock, other than to certain transferees. Each holder of Class A common stock will be entitled to a single vote for each outstanding share of Class A common stock owned by that stockholder on every matter properly submitted to the stockholders for their vote. Each holder of Class B common stock will be entitled to ten votes for each outstanding share of Class B common stock owned by that stockholder on every matter properly submitted to the stockholders for their vote. Except as required by law, the Class A common stock and the Class B common stock will vote together on all matters. Subject to the dividend rights of holders of any outstanding preferred stock, holders of common stock are entitled to any dividend declared by the Board of Directors out of funds legally available for this purpose, and, subject to the liquidation preferences of any outstanding preferred stock, holders of common stock are entitled to receive, on a pro rata basis, all the Company's remaining assets available for distribution to the stockholders in the event of the Company's liquidation, dissolution or winding up. No dividend can be declared on the Class A or Class B common stock unless at the same time an equal dividend is paid on each share of Class B or Class A common stock, as the case may be. Dividends paid in shares of common stock must be paid, with respect to a particular class of common stock, in shares of that class.

Holders of common stock do not have any preemptive right to become subscribers or purchasers of additional shares of any class of the Company's capital stock. The outstanding shares of common stock are, when issued and paid for, fully paid and nonassessable. The rights, preferences and privileges of holders of common stock may be adversely affected by the rights of the holders of shares of any series of preferred stock that the Company may designate and issue in the future.

Preferred Stock

The Company's certificate of incorporation allows the Company to issue, without stockholder approval, preferred stock having rights senior to those of the common stock. The Company's Board of Directors is authorized, without further stockholder approval, to issue up to 50,000,000 shares of preferred stock in one or more series and to fix the rights, preferences, privileges and restrictions of any series of preferred stock, including dividend rights, conversion rights, voting rights, terms of redemption and liquidation preferences, and to fix the number of shares constituting any series and the designations of these series. The issuance of preferred stock could decrease the amount of earnings and assets available for distribution to the holders of common stock or could adversely affect the rights and powers, including voting rights, of the holders of common stock. The issuance of preferred stock could also have the effect of decreasing the market price of the Class A common stock. As of December 31, 2016, no shares of preferred stock are outstanding.

Warrants

No warrants to acquire the Company's Class A or Class B common stock were outstanding as of December 31, 2016.

Dividends

Regal paid four quarterly cash dividends of $0.22 per share on each outstanding share of the Company's Class A and Class B common stock, or approximately $138.9 million in the aggregate, during the year ended December 31, 2016. Regal paid four quarterly cash dividends of $0.22 per share on each outstanding share of the Company's Class A and Class B common stock, or approximately $139.1 million in the aggregate, during the year ended December 31, 2015. Regal paid four quarterly cash dividends of $0.22 per share on each outstanding share of the Company's Class A and Class B common stock, or approximately $138.6 million in the aggregate, during the year ended January 1, 2015. In addition, on December 15, 2014, Regal paid an extraordinary cash dividend of $1.00 per share on each outstanding share of our Class A and Class B common stock, or approximately $156.2 million in the aggregate.

Share-Based Compensation

In 2002, the Company established the Regal Entertainment Group Stock Incentive Plan (as amended, the "Incentive Plan"), which provides for the granting of incentive stock options and non-qualified stock options to officers, employees and consultants of the Company. As described below under "Restricted Stock" and "Performance Share Units," the Incentive Plan also provides for grants of restricted stock and performance shares that are subject to restrictions and risks of forfeiture.

On May 9, 2012, the stockholders of Regal approved amendments to the the Incentive Plan increasing the number of Class A common stock authorized for issuance under the Incentive Plan by a total of 5,000,000 shares and extending the term of the Plan to May 9, 2022. As of December 31, 2016, 4,003,781 shares remain available for future issuance under the Incentive Plan.

Stock Options

As of December 31, 2016, there were no options to purchase shares of Class A common stock outstanding under the Incentive Plan. There were no stock options granted during the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively, and no compensation expense related to stock options was recorded during such periods.

Restricted Stock

The Incentive Plan also provides for restricted stock awards to officers, directors and key employees. Under the Incentive Plan, shares of Class A common stock of the Company may be granted at nominal cost to officers, directors and key employees, subject to a continued employment/service restriction. The restriction is fulfilled upon continued employment or service (in the case of directors) for a specified number of years (typically one to four years after the award date) and as such restrictions lapse, the award immediately vests. In addition, we will receive a tax deduction when restricted stock vests. The Incentive Plan participants are entitled to cash dividends and to vote their respective shares, although the sale and transfer of such shares is prohibited during the restricted period. The shares are also subject to the terms and conditions of the Incentive Plan.

On January 8, 2014, 227,447 restricted shares were granted under the Incentive Plan at nominal cost to officers, directors and key employees. On January 28, 2015, 228,116 restricted shares were granted under the Incentive Plan at nominal cost to officers, directors and key employees. On January 13, 2016, 261,119 restricted shares were granted under the Incentive Plan at nominal cost to officers, directors and key employees. These awards vest 25% at the end of each year for 4 years (in the case of officers and key employees) and vest 100% at the end of one year (in the case of directors). The closing price of the Company's Class A common stock was $19.08 on January 8, 2014, $20.99 on January 28, 2015, and $17.74 per share on January 13, 2016. The Company assumed forfeiture rates ranging from 4% to 6% for such restricted stock awards.

During the years ended December 31, 2016, December 31, 2015 and January 1, 2015, the Company withheld approximately 177,769 shares, 204,540 shares and 194,675 shares, respectively, of restricted stock at an aggregate cost of approximately $3.2 million, $4.3 million and $3.8 million, respectively, as permitted by the applicable equity award agreements, to satisfy employee tax withholding requirements related to the vesting of restricted stock awards. On January 9, 2016, 262,476 performance shares (originally granted on January 9, 2013) were effectively converted to shares of restricted common stock. As of the calculation date, which was January 9, 2016, threshold performance goals for these awards were satisfied, and therefore, all 262,476 outstanding performance shares were converted to restricted shares as of January 9, 2016. These awards fully vested on January 9, 2017, the one year anniversary of the calculation date. In addition, on January 11, 2015, 306,696 performance shares (originally granted on January 11, 2012) were effectively converted to shares of restricted common stock. These awards fully vested on January 11, 2016, the one year anniversary of the calculation date. Finally, on January 12, 2014, 330,750 performance share awards (originally granted on January 12, 2011) were effectively converted to shares of restricted common stock. These awards fully vested on January 12, 2015.

During the fiscal years ended December 31, 2016, December 31, 2015 and January 1, 2015, the Company recognized approximately $4.1 million, $4.0 million and $4.0 million, respectively, of share-based compensation expense related to restricted share grants. Such expense is presented as a component of "General and administrative expenses." The compensation expense for these awards was determined based on the market price of the Company's stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest. As of December 31, 2016, we have unrecognized compensation expense of $4.2 million associated with restricted stock awards, which is expected to be recognized through January 13, 2020.

The following table represents the restricted stock activity for the years ended December 31, 2016, December 31, 2015 and January 1, 2015:

	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Unvested at beginning of year:	773,643	885,365	927,261
Granted during the year	261,119	228,116	227,447
Vested during the year	(520,258)	(596,639)	(576,921)

Forfeited during the year	(11,028)	(49,895)	(23,172)
Conversion of performance shares during the year	262,476	306,696	330,750
Unvested at end of year	765,952	773,643	885,365

During the year ended December 31, 2016, the Company paid four cash dividends of $0.22 on each share of outstanding restricted stock totaling approximately $0.7 million.

Performance Share Units

The Incentive Plan also provides for grants in the form of performance share units to officers, directors and key employees. Performance share agreements are entered into between the Company and each grantee of performance share units. In 2009, the Company adopted an amended and restated form of performance share agreement (each, a "Performance Agreement" and collectively, the "Performance Agreements"). Pursuant to the terms and conditions of the Performance Agreements, grantees will be issued shares of restricted common stock of the Company in an amount determined by the attainment of Company performance criteria set forth in each Performance Agreement. The shares of restricted common stock received upon attainment of the performance criteria will be subject to further vesting over a period of time, provided the grantee remains a service provider to the Company during such period. Under the Performance Agreement, which is described further in the section entitled "Compensation Discussion and Analysis—Elements of Compensation—Performance Shares," of our 2016 proxy statement filed with the Commission on April 6, 2016, each performance share represents the right to receive from 0% to 150% of the target numbers of shares of restricted Class A common stock.

On January 8, 2014, 226,471 performance shares were granted under the Incentive Plan at nominal cost to officers and key employees. In addition, on January 28, 2015, 234,177 performance shares were granted under the Incentive Plan at nominal cost to officers and key employees. Finally, on January 13, 2016, 280,374 performance shares were granted under the Incentive Plan at nominal cost to officers and key employees. The number of shares of restricted common stock earned will be determined based on the attainment of specified performance goals by January 8, 2017 (the third anniversary of the grant date for the January 8, 2014 grant), January 28, 2018 (the third anniversary of the grant date for the January 28, 2015 grant), and January 13, 2019 (the third anniversary of the grant date for the January 13, 2016 grant), as set forth in the applicable Performance Agreement. Such performance shares vest on the fourth anniversary of their respective grant dates. The shares are subject to the terms and conditions of the Incentive Plan. The closing price of the Company's Class A common stock on the date of grant was $19.08 on January 8, 2014, $20.99 on January 28, 2015, and $17.74 on January 13, 2016, which approximates the respective grant date fair value of the awards. The Company assumed forfeiture rates ranging from 8% to 9% for such performance share awards.

As of the respective grant dates, the aggregate grant date fair value of performance share awards outstanding as of December 31, 2016 was determined to be $15.2 million, which includes related dividends on shares estimated to be earned and paid on the third anniversary of the respective grant dates. The fair value of the performance share awards are amortized as compensation expense over the expected term of the awards of four years. During the years ended December 31, 2016, December 31, 2015 and January 1, 2015, the Company recognized approximately $4.7 million, $4.3 million and $5.4 million, respectively, of share-based compensation expense related to performance share grants. Such expense is presented as a component of "General and administrative expenses." As of December 31, 2016, we have unrecognized compensation expense of $6.2 million associated with performance share units, which is expected to be recognized through January 13, 2020.

The following table summarizes information about the Company's number of performance shares for the years ended December 31, 2016, December 31, 2015 and January 1, 2015:

	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Unvested at beginning of year:	696,849	812,927	940,767
Granted (based on target) during the year	280,374	234,177	226,471
Cancelled/forfeited during the year	(16,038)	(43,559)	(23,561)
Conversion to restricted shares during the year	(262,476)	(306,696)	(330,750)
Unvested at end of year	698,709	696,849	812,927

In connection with the conversion of the above 262,476 performance shares, during the year ended December 31, 2016, the Company paid cumulative cash dividends of $3.60 (representing the sum of all cash dividends paid from January 9, 2013 through January 9, 2016) on each performance share converted, totaling approximately $0.9 million. In connection with the conversion of the above 306,696 performance shares, during the year ended December 31, 2015, the Company paid cumulative cash dividends of $4.56 (representing the sum of all cash dividends paid from January 11, 2012 through January 11, 2015) and $4.58 (representing the sum of all cash dividends paid from June 25, 2012 through June 25, 2015) on each performance share converted, totaling approximately $1.4 million. In connection with the conversion of the above 330,750 performance shares, during the year ended January 1, 2015, the Company paid cumulative cash dividends totaling approximately $1.2 million. The above table does not reflect the maximum or minimum number of shares of restricted stock contingently issuable. An additional 0.3 million shares of restricted stock could be issued if the performance criteria maximums are met.

10. RELATED PARTY TRANSACTIONS

During the years ended December 31, 2016, December 31, 2015 and January 1, 2015, Regal Cinemas received approximately $0.2 million. $0.1 million, and $0.1 million, respectively, from an Anschutz affiliate for rent and other expenses related to a theatre facility.

During each of the years ended December 31, 2016, December 31, 2015 and January 1, 2015, in connection with an agreement with an Anschutz affiliate, Regal received various forms of advertising in exchange for on-screen advertising provided in certain of its theatres. The value of such advertising was approximately $0.1 million.

During each of the years ended December 31, 2016, December 31, 2015 and January 1, 2015, the Company received approximately $0.5 million from an Anschutz affiliate for management fees related to a theatre site in Los Angeles, California.

Please also refer to Note 4—"Investments" for a discussion of other related party transactions associated with our various investments in non-consolidated entities.

11. EMPLOYEE BENEFIT PLANS

Defined Contribution Plan

The Company sponsors an employee benefit plan, the Regal Entertainment Group 401(k) Plan (the "401k Plan") under section 401(k) of the Internal Revenue Code of 1986, as amended, for the benefit of substantially all employees. The 401k Plan provides that participants may contribute up to 50% of their compensation, subject to Internal Revenue Service limitations. The 401k Plan currently matches an amount equal to 100% of the first 3% of the participant's contributions and 50% of the next 2% of the participant's contributions. Employee contributions are invested in various investment funds based upon elections made by the employee. The Company made matching contributions of approximately $3.4 million, $3.3 million and $3.3 million to the 401k Plan in 2016, 2015 and 2014, respectively.

Union-Sponsored Plans

As of December 31, 2016, certain former theatre employees are covered by five insignificant union-sponsored multiemployer pension and health and welfare plans. Company contributions into those plans were determined in accordance with provisions of negotiated labor contracts and aggregated approximately $0.1 million for each of the years ended December 31, 2016, December 31, 2015 and January 1, 2015.

During fiscal 2013, the Company received a notice of a written demand for payment of a complete withdrawal liability assessment from a collectively-bargained multiemployer pension plan, Local 160, Greater Cleveland Moving Picture Projector Operator's Pension Plan ("Local 160") (Employment Identification No. 51-6115679), that covered certain of its unionized theatre employees. The Company made a complete withdrawal from Local 160 during fiscal 2012. The Company has established an estimated withdrawal liability of approximately $0.6 million related to its remaining plans, including Local 160, as of December 31, 2016.

12. EARNINGS PER SHARE

We compute earnings per share of Class A and Class B common stock using the two-class method. Basic earnings per share is computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed using the weighted average number of common shares and, if dilutive, common stock equivalents outstanding during the period. Potential common stock equivalents consist of the incremental common shares issuable upon the exercise of common stock options, or vesting of restricted stock and performance share units. The dilutive effect of outstanding restricted stock and performance share units is reflected in diluted earnings per share by application of the treasury-stock method. In addition, the computation of the diluted earnings per share of Class A common stock assumes the conversion of Class B common stock, while the diluted earnings per share of Class B common stock does not assume the conversion of those shares.

The rights, including the liquidation and dividend rights, of the holders of our Class A and Class B common stock are identical, except with respect to voting. The earnings for the periods presented are allocated based on the contractual participation rights of the Class A and Class B common shares. As the liquidation and dividend rights are identical, the earnings are allocated on a proportionate basis. Further, as we assume the conversion of Class B common stock in the computation of the diluted earnings per share of Class A common stock, the earnings are equal to net income attributable to controlling interest for that computation.

The following table sets forth the computation of basic and diluted earnings per share of Class A and Class B common stock (in millions, except share and per share data):

	Year Ended December 31, 2016		Year Ended December 31, 2015		Year Ended January 1, 2015	
	Class A	Class B	Class A	Class B	Class A	Class B
Basic earnings per share:						
Numerator:						
Allocation of earnings	$144.5	$ 25.9	$130.0	$23.4	$89.5	$ 16.1
Denominator:						
Weighted average common shares outstanding (in thousands)	132,286	23,709	131,971	23,709	131,578	23,709
Basic earnings per share	$1.09	$ 1.09	$0.99	$0.99	$0.68	$ 0.68
Diluted earnings per share:						
Numerator:						
Allocation of earnings for basic computation	$144.5	$ 25.9	$130.0	$23.4	$89.5	$ 16.1
Reallocation of earnings as a result of conversion of Class B to Class A shares	25.9	—	23.4	—	16.1	—
Reallocation of earnings to Class B shares for effect of other dilutive securities	—	—	—	(0.1)	—	—
Allocation of earnings	$170.4	$ 25.9	$153.4	$23.3	$105.6	$ 16.1
Denominator:						
Number of shares used in basic computation (in thousands)	132,286	23,709	131,971	23,709	131,578	23,709
Weighted average effect of dilutive securities (in thousands)						
Add:						
Conversion of Class B to Class A common shares outstanding	23,709	—	23,709	—	23,709	—
Restricted stock and performance shares	809	—	831	—	1,023	—
Number of shares used in per share computations (in thousands)	156,804	23,709	156,511	23,709	156,310	23,709
Diluted earnings per share	$1.09	$ 1.09	$0.98	$0.98	$0.68	$ 0.68

13. DERIVATIVE INSTRUMENTS

Regal Cinemas has entered into hedging relationships via interest rate swap agreements to hedge against interest rate exposure of its variable rate debt obligations under Regal Cinemas' Amended Senior Credit Facility. Certain of these interest rate swaps qualify for cash flow hedge accounting treatment and as such, the change in the fair values of the interest rate swaps is recorded on the Company's consolidated balance sheet as an asset or liability, with the effective portion of the interest rate swaps' gains or losses reported as a component of other comprehensive income and the ineffective portion reported in earnings. As interest expense is accrued on the debt obligation, amounts in accumulated other comprehensive income/loss related to the interest rate swaps will be reclassified into earnings. In the event that an interest rate swap is terminated or de-designated prior to maturity, gains or losses accumulated in other comprehensive income or loss remain deferred and are reclassified into earnings in the periods during which the hedged forecasted transaction affects earnings. See Note 14—"Fair Value of Financial Instruments" for discussion of the Company's interest rate swaps' fair value estimation methods and assumptions.

Below is a summary of Regal Cinemas' current interest rate swap agreements as of December 31, 2016:

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REGAL ENTERTAINMENT GROUP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
December 31, 2016, December 31, 2015 and January 1, 2015

Nominal Amount	Effective Date	Fixed Rate	Receive Rate	Expiration Date	Designated as Cash Flow Hedge	Gross Fair Value at December 31, 2016	Balance Sheet Location
$150.0 million	April 2, 2015	1.220%	1-month LIBOR*	December 31, 2016	Yes	$—	See Note 14
$200.0 million	June 30, 2015	2.165%	1-month LIBOR*	June 30, 2018	Yes	$(3.0) million	See Note 14

* Subject to a 0.75% LIBOR floor

On April 2, 2015, Regal Cinemas amended two of its existing interest rate swap agreements originally designated as cash flow hedges on $350.0 million of variable rate debt obligations. Since the terms of the interest rate swaps designated in the original cash flow hedge relationships changed with these amendments, we de-designated the original hedge relationships and re-designated the amended interest rate swaps in new cash flow hedge relationships as of the amendment date of April 2, 2015. On December 31, 2016, one of these interest rate swap agreements designated to hedge $150.0 million of variable rate debt obligations expired.

No amendments or modifications were made to two other interest swap agreements (originally designated to hedge $300.0 million of variable rate debt obligations), existing as of April 2, 2015. Since such interest rate swaps no longer met the highly effective qualification for cash flow hedge accounting, the two hedge relationships were de-designated effective April 2, 2015. Accordingly, since the interest rate swaps no longer qualified for cash flow hedge accounting treatment, the change in their fair values since de-designation was recorded on the Company's consolidated balance sheet as an asset or liability with the interest rate swaps' gains or losses reported as a component of interest expense during the period of change. On June 30, 2015, one of these interest rate swap agreements designated to hedge $200.0 million of variable rate debt obligations expired. The remaining interest rate swap agreement designated to hedge $100.0 million of variable rate debt obligations expired on December 31, 2015.

The following tables show the effective portion of gains and losses on derivative instruments designated and qualifying in cash flow hedges recognized in other comprehensive income (loss), and amounts reclassified from accumulated other comprehensive loss to interest expense for the periods indicated (in millions):

	After-tax Gain (Loss) Recognized in Other Comprehensive Income (Loss) (Effective Portion)		
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Derivatives designated as cash flow hedges:			
Interest rate swaps	$(2.3)	$ (4.3)	$(2.1)

	Pre-tax Amounts Reclassified from Accumulated Other Comprehensive Loss into Interest Expense, net		
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Derivatives designated as cash flow hedges:			
Interest rate swaps(1)	$6.0	$ 7.4	$ 5.2

(1) We estimate that $0.9 million of deferred pre-tax losses attributable to these interest rate swaps will be reclassified into earnings as interest expense during the next 12 months as the underlying hedged transactions occur.

The changes in accumulated other comprehensive loss, net associated with the Company’s interest rate swap arrangements for the years ended December 31, 2016, December 31, 2015, and January 1, 2015 were as follows (in millions):

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REGAL ENTERTAINMENT GROUP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
December 31, 2016, December 31, 2015 and January 1, 2015

	Interest Rate Swaps		
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Accumulated other comprehensive loss, net, beginning of period	$(2.7)	$ (2.9)	$(4.0)
Change in fair value of interest rate swap transactions (effective portion), net of taxes of $1.5, $2.8, and $1.3, respectively	(2.3)	(4.3)	(2.1)
Amounts reclassified from accumulated other comprehensive loss to interest expense, net of taxes of $2.4, $2.9 and $2.0, respectively	3.6	4.5	3.2
Accumulated other comprehensive loss, net, end of period	$(1.4)	$ (2.7)	$(2.9)

The following table sets forth the effect of our interest rate swap arrangements on our consolidated statements of income for the years ended December 31, 2016, December 31, 2015, and January 1, 2015 (in millions):

	Pre-tax Gain (Loss) Recognized in Interest Expense, net		
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended January 1, 2015
Derivatives designated as cash flow hedges (ineffective portion):			
Interest rate swaps(1)	$2.5	$ 1.9	$ —
Derivatives not designated as cash flow hedges:			
Interest rate swaps (2)	$—	$ 1.5	$ —

(1) Amounts represent the ineffective portion of the change in fair value of the hedging derivatives and are recorded as a reduction of interest expense in the consolidated financial statements. On December 31, 2016, one of these interest rate swap agreements designated to hedge $150.0 million of variable rate debt obligations expired.

(2) Amounts represent the change in fair value of the former hedging derivatives and are recorded as a reduction of interest expense in the consolidated financial statements from the de-designation date of April 2, 2015. On June 30, 2015, one of these interest rate swap agreements designated to hedge $200.0 million of variable rate debt obligations expired. The remaining interest rate swap agreement designated to hedge $100.0 million of variable rate debt obligations expired on December 31, 2015.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the entity transacts. The inputs used to develop these fair value measurements are established in a hierarchy, which ranks the quality and reliability of the information used to determine fair value. The fair value classification is based on levels of inputs. Assets and liabilities that are carried at fair value are classified and disclosed in one of the following categories described in ASC Topic 820, Fair Value Measurements and Disclosures:

Level 1 Inputs:	Quoted market prices in active markets for identical assets or liabilities.
Level 2 Inputs:	Observable market based inputs or unobservable inputs that are corroborated by market data.
Level 3 Inputs:	Unobservable inputs that are not corroborated by market data.

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December 31, 2016, December 31, 2015 and January 1, 2015

The following tables summarize the fair value hierarchy of the Company's financial assets and liabilities carried at fair value on a recurring basis as of December 31, 2016 and December 31, 2015:

	Balance Sheet Location	Total Carrying Value at December 31, 2016	Fair Value Measurements at December 31, 2016		
			Quoted prices in active market (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
			(in millions)		
Liabilities:					
Interest rate swap designated as cash flow hedge (2)	Accrued Expenses	$ 2.3	$ —	$ 2.3	$ —
Interest rate swap designated as cash flow hedge (2)	Other Non-Current Liabilities	$ 0.7	$ —	$ 0.7	$ —
Total liabilities at fair value		$ 3.0	$ —	$ 3.0	$ —

	Balance Sheet Location	Total Carrying Value at December 31, 2015	Fair Value Measurements at December 31, 2015		
			Quoted prices in active market (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
			(in millions)		
Assets:					
Equity securities, available for sale(1)	Other Non-Current Assets	$ 3.4	$ 3.4	$ —	$ —
Total assets at fair value		$ 3.4	$ 3.4	$ —	$ —
Liabilities:					
Interest rate swap designated as cash flow hedge (2)	Accrued Expenses	$ 3.1	$ —	$ 3.1	$ —
Interest rate swap designated as cash flow hedge (2)	Other Non-Current Liabilities	$ 1.9	$ —	$ 1.9	$ —
Total liabilities at fair value		$ 5.0	$ —	$ 5.0	$ —

(1) As of December 31, 2015, the Company held 322,780 common shares (accounted for as available for sale securities) of RealD, Inc., as described further in Note 4—"Investments." The fair value of the RealD, Inc. shares was determined using RealD, Inc.'s publicly traded common stock price (Level 1 of the valuation hierarchy) of $10.55 per share as of December 31, 2015. On February 24, 2016, RealD, Inc. stockholders approved an all-cash merger whereby Rizvi Traverse Management, LLC acquired RealD, Inc. for $11.00 per share. Under the terms of the merger agreement, RealD, Inc. shareholders received $11.00 in cash for each share of RealD, Inc.'s common stock. On March 24, 2016, the Company received approximately $3.6 million in cash consideration for its remaining 322,780 RealD, Inc. common shares. As a result of the transaction, the Company recorded a gain of approximately $1.0 million during the quarter ended March 31, 2016.

(2) The fair value of the Company's interest rate swaps described in Note 13—"Derivative Instruments" is based on Level 2 inputs, which include observable inputs such as dealer quoted prices for similar assets or liabilities, and represents the estimated amount Regal Cinemas would receive or pay to terminate the agreements taking into

consideration various factors, including current interest rates, credit risk and counterparty credit risk. The counterparties to the Company’s interest rate swaps are major financial institutions. The Company evaluates the bond ratings of the financial institutions and believes that credit risk is at an acceptably low level.

There were no changes in valuation techniques during the period. There were no transfers in or out of Level 3 during the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively.

In addition, the Company is required to disclose the fair value of financial instruments that are not recognized in the statement of financial position for which it is practicable to estimate that value. The methods and assumptions used to estimate the fair value of each class of financial instrument are as follows:

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities:

The carrying amounts approximate fair value because of the short maturity of these instruments.

Long-Lived Assets, Intangible Assets and Other Investments

As further described in Note 2—"Summary of Significant Accounting Policies," the Company regularly reviews long-lived assets (primarily property and equipment), intangible assets and investments in non-consolidated entities, for impairment whenever events or changes in circumstances indicate that the carrying amounts of the assets may not be fully recoverable. When the estimated fair value is determined to be lower than the carrying value of the asset, an impairment charge is recorded to write the asset down to its estimated fair value.

The Company's analysis relative to long-lived assets resulted in the recording of impairment charges of $9.6 million, $15.6 million and $5.6 million for the years ended December 31, 2016, December 31, 2015 and January 1, 2015, respectively. The long-lived asset impairment charges recorded were specific to theatres that were directly and individually impacted by increased competition, adverse changes in market demographics or adverse changes in the development or the conditions of the areas surrounding the theatres we deemed other than temporary.

The Company's annual goodwill impairment assessment for the year ended December 31, 2016 indicated that the carrying value of one of its reporting units exceeded its estimated fair value and as a result, the Company recorded a goodwill impairment charge of approximately $1.7 million. Based on our annual impairment assessments conducted for the years ended December 31, 2015 and January 1, 2015, we were not required to record a charge for goodwill impairment. The Company did not record an impairment of any other intangible assets during the years ended December 31, 2016, December 31, 2015 or January 1, 2015, respectively.

Finally, the Company did not record an impairment of any investments in non-consolidated subsidiaries accounted for under the equity method during the years ended December 31, 2016, December 31, 2015 or January 1, 2015.

Long term obligations, excluding capital lease obligations, lease financing arrangements and other:

The fair value of the Amended Senior Credit Facility described in Note 5—"Debt Obligations," which consists of the New Term Loans and the Revolving Facility, is estimated based on quoted prices (Level 2 inputs as described in ASC Topic 820) as of December 31, 2016 and December 31, 2015. The associated interest rates are based on floating rates identified by reference to market rates and are assumed to approximate fair value. The fair values of the $5^3/_4$% Senior Notes Due 2022, the $5^3/_4$% Senior Notes Due 2025 and the $5^3/_4$% Senior Notes Due 2023 were estimated based on quoted prices (Level 1 inputs as described in ASC Topic 820) for these issuances as of as of December 31, 2016 and December 31, 2015.

The aggregate carrying values and fair values of long-term debt at December 31, 2016 and December 31, 2015 consist of the following:

	December 31, 2016	December 31, 2015
	(in millions)	
Carrying value	$2,229.7	$2,233.8
Fair value	$2,287.1	$2,226.6

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December 31, 2016, December 31, 2015 and January 1, 2015

15. ACCUMULATED OTHER COMPREHENSIVE LOSS, NET

The following tables present for the years ended December 31, 2016 and December 31, 2015, respectively, the change in accumulated other comprehensive loss, net of tax, by component (in millions):

	Interest rate swaps	Available for sale securities	Equity method investee interest rate swaps	Total
Balance as of December 31, 2015	$(2.7)	$ 0.5	$ 0.1	$(2.1)
Other comprehensive income (loss), net of tax				
Change in fair value of interest rate swap transactions	(2.3)	—	—	(2.3)
Amounts reclassified to net income from interest rate swaps	3.6	—	—	3.6
Reclassification adjustment for gain on sale of available for sale securities recognized in net income	—	(0.5)	—	(0.5)
Total other comprehensive income (loss), net of tax	1.3	(0.5)	—	0.8
Balance as of December 31, 2016	$(1.4)	$ —	$ 0.1	$(1.3)

	Interest rate swaps	Available for sale securities	Equity method investee interest rate swaps	Total
Balance as of January 1, 2015	$(2.9)	$ 0.7	$ 0.7	$(1.5)
Other comprehensive income (loss), net of tax				
Change in fair value of interest rate swap transactions	(4.3)	—	—	(4.3)
Amounts reclassified to net income from interest rate swaps	4.5	—	—	4.5
Change in fair value of available for sale securities	—	(0.2)	—	(0.2)
Change in fair value of equity method investee interest rate swaps	—	—	(0.6)	(0.6)
Total other comprehensive income (loss), net of tax	0.2	(0.2)	(0.6)	(0.6)
Balance as of December 31, 2015	$(2.7)	$ 0.5	$ 0.1	$(2.1)

16. SUBSEQUENT EVENTS

Performance Share and Restricted Stock Activity

On January 8, 2017, 205,677 performance share awards (originally granted on January 8, 2014) were effectively converted to shares of restricted common stock. As of the calculation date, which was January 8, 2017, threshold performance goals for these awards were satisfied, and therefore, all 205,677 outstanding performance shares were converted to restricted shares as of January 8, 2017. In connection with the conversion of the above 205,677 performance shares, the Company paid a cumulative cash dividend of $3.64 (representing the sum of all cash dividends paid from January 8, 2014 through January 8, 2017) on each performance share converted, totaling approximately $0.7 million during the first fiscal quarter of 2017.

On January 11, 2017, 235,356 performance shares were granted under our Incentive Plan at nominal cost to officers and key employees. Each performance share represents the right to receive from 0% to 150% of the target numbers of shares of restricted Class A common stock. The number of shares of restricted common stock earned will be determined based on the attainment of specified performance goals by January 11, 2020 (the third anniversary of the grant date) set forth in the 2009 Performance Agreement. Such performance shares fully vest on the fourth anniversary of the grant date. The shares are subject to the terms and conditions of the Incentive Plan. The closing price of our Class A common stock on the date of this grant was $22.10 per share.

Also on January 11, 2017, 217,366 restricted shares were granted under the Incentive Plan at nominal cost to officers, directors and key employees. Under the Incentive Plan, Class A common stock of the Company may be granted at nominal cost to officers, directors and key employees, subject to a continued employment/service restriction (typically one to four years after the award date). The awards vest 25% at the end of each year for four years (in the case of officers and key employees) and vest 100% at the end of one year (in the case of directors). The plan participants are entitled to cash dividends and to vote their respective shares, although the sale and transfer of such shares is prohibited during the restricted period. The shares are subject to the terms and conditions of the Incentive Plan. The closing price of our Class A common stock on the date of this grant was $22.10 per share.

Declaration of Quarterly Dividend

On February 9, 2017, the Company declared a cash dividend of $0.22 per share on each share of the Company's Class A and Class B common stock (including outstanding restricted stock), payable on March 15, 2017, to stockholders of record on March 3, 2017.

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

None.

Item 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Commission under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to our management, including our principal executive and principal financial officers (whom we refer to in this periodic report as our Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. Our management evaluated, with the participation of our Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2016, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, our Certifying Officers concluded that, as of December 31, 2016, our disclosure controls and procedures were effective.

Management's Report on Internal Control Over Financial Reporting and Attestation of Registered Public Accounting Firm

Our management's report on internal control over financial reporting and our registered public accounting firm's audit report on the effectiveness of our internal control over financial reporting are included in Part II, Item 8 of this Form 10-K, which are incorporated herein by reference.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our fiscal quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on the Effectiveness of Controls

Management is responsible for the preparation and fair presentation of the consolidated financial statements included in this annual report. The consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and reflect management's judgments and estimates concerning effects of events and transactions that are accounted for or disclosed. The Company's internal control over financial reporting includes those policies and procedures that pertain to the Company's ability to record, process, summarize and report reliable financial data. Management recognizes that there are inherent limitations in the effectiveness of any internal control over financial reporting, including the possibility of human error and the circumvention or overriding of internal control. Accordingly, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Biographical and other information regarding our executive officers is provided in Part I of this Form 10-K under the heading "Executive Officers of the Registrant" as permitted by General Instruction G to Form 10-K. The other information required by this item is incorporated by reference to the Company's Proxy Statement on Schedule 14A for its Annual Stockholders Meeting (under the headings "Proposal 1. Election of Class III Directors," "Corporate Governance—Board and Committee Information," "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance—Code of

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Business Conduct and Ethics," "Corporate Governance—Committees" and "Corporate Governance—Audit Committee") to be held on May 3, 2017 and to be filed with the Commission within 120 days after December 31, 2016.

Item 11. EXECUTIVE COMPENSATION.

Incorporated by reference to the Company's Proxy Statement for its Annual Stockholders Meeting (under the headings "Compensation Discussion and Analysis," "Executive Compensation," "Corporate Governance—Director Compensation during Fiscal 2016" and "Compensation Committee Report") to be held on May 3, 2017 and to be filed with the Commission within 120 days after December 31, 2016.

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

Incorporated by reference to the Company's Proxy Statement on Schedule 14A for its Annual Stockholders Meeting (under the headings "Beneficial Ownership of Voting Securities" and "Executive Compensation—Equity Compensation Plan Information") to be held on May 3, 2017 and to be filed with the Commission within 120 days after December 31, 2016.

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

Incorporated by reference to the Company's Proxy Statement on Schedule 14A for its Annual Stockholders Meeting (under the headings "Certain Relationships and Related Transactions" and "Corporate Governance—Director Independence") to be held on May 3, 2017 and to be filed with the Commission within 120 days after December 31, 2016.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

Incorporated by reference to the Company's Proxy Statement on Schedule 14A for its Annual Stockholders Meeting (under the headings "Audit Committee Report—Independent Registered Public Accounting Firm" and "Audit Committee Report—Audit Committee Pre-Approval Policy") to be held on May 3, 2017 and to be filed with the Commission within 120 days after December 31, 2016.

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PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Consolidated financial statements of Regal Entertainment Group:

(2) Exhibits: A list of exhibits required to be filed as part of this report on Form 10-K is set forth in the Exhibit Index, which follows the signature pages of this Form 10-K.

(3) Financial Statement Schedules: The audited financial statements of National CineMedia (the "National CineMedia Financial Statements") were not available as of the date of this annual report on Form 10-K. In accordance with Rule 3-09(b)(1) of Regulation S-X, our Form 10-K will be amended to include the National CineMedia Financial Statements within 90 days after the end of the Company's fiscal year.

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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.

	REGAL ENTERTAINMENT GROUP
February 27, 2017	By: /s/ AMY E. MILES
	Amy E. Miles
	Chief Executive Officer
	(Principal Executive Officer)

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 and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ AMY E. MILES Amy E. Miles	Chief Executive Officer (Principal Executive Officer) and Chair of the Board of Directors	February 27, 2017
/s/ DAVID H. OWNBY David H. Ownby	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 27, 2017
/s/ THOMAS D. BELL, JR. Thomas D. Bell, Jr.	Director	February 27, 2017
/s/ CHARLES E. BRYMER Charles E. Brymer	Director	February 27, 2017
/s/ MICHAEL L. CAMPBELL Michael L. Campbell	Director	February 27, 2017
/s/ STEPHEN A. KAPLAN Stephen A. Kaplan	Director	February 27, 2017
/s/ DAVID KEYTE David Keyte	Director	February 27, 2017
/s/ LEE M. THOMAS Lee M. Thomas	Director	February 27, 2017
/s/ JACK TYRRELL	Director	February 27, 2017

Jack Tyrrell

/s/ ALEX YEMENIDJIAN Alex Yemenidjian	Director	February 27, 2017

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EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (filed as Exhibit 3.1 to our Quarterly Report on Form 10-Q for the fiscal quarter ended March 28, 2002 (Commission File No. 001-31315), and incorporated herein by reference)
3.2	Amended and Restated Bylaws of the Company (filed as Exhibit 3.1 to our Quarterly Report on Form 10-Q for the fiscal quarter ended June 26, 2003 (Commission File No. 001-31315), and incorporated herein by reference)
4.1	Specimen Class A Common Stock Certificate (filed as Exhibit 4.1 to Amendment No. 2 to our Registration Statement on Form S-1 (Commission File No. 333-84096) on May 6, 2002, and incorporated herein by reference)
4.2	Specimen Class B Common Stock Certificate (filed as Exhibit 4.2 to Amendment No. 2 to our Registration Statement on Form S-1 (Commission File No. 333-84096) on May 6, 2002, and incorporated herein by reference)
4.3	Second Amended and Restated Guaranty and Collateral Agreement, dated as of May 19, 2010, among Regal Cinemas Corporation, certain subsidiaries of Regal Cinemas Corporation party thereto and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent (filed as Exhibit 4.2 to our Current Report on Form 8-K (Commission File No. 001-31315) on May 20, 2010, and incorporated herein by reference)
4.3.1	Seventh Amended and Restated Credit Agreement, dated April 2, 2015 among Regal Cinemas Corporation, Credit Suisse AG, as Administrative Agent and the lenders (filed as Exhibit 4.1 to our current report on Form 8-K (Commission File No. 001-31315) on April 7, 2015 and incorporated herein by reference)
4.3.2	Permitted Secured Refinancing Agreement, dated June 1, 2016, by and among Regal Cinemas Corporation, Regal Entertainment Holdings, Inc., the guarantors party thereto, Credit Suisse AG and the lenders party thereto (filed as Exhibit 4.1 to our current report on Form 8-K (Commission File No. 001-31315) on June 3, 2016 and incorporated herein by reference).
4.3.3	Permitted Secured Refinancing Agreement, dated December 2, 2016, by and among Regal Cinemas Corporation, Regal Entertainment Holdings, Inc., the guarantors party thereto, Credit Suisse AG and the lenders party thereto (filed as Exhibit 4.1 to our current report on Form 8-K (Commission File No. 001-31315) on December 6, 2016 and incorporated herein by reference)
4.4	Indenture, dated January 17, 2013, between Regal Entertainment Group and Wilmington Trust, National Association, as Trustee (filed as Exhibit 4.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on January 17, 2013 and incorporated herein by reference)
4.4.1	First Supplemental Indenture, dated January 17, 2013, between Regal Entertainment Group and Wilmington Trust, National Association, as Trustee, including the form of 5.750% Senior Note due 2025 (attached as Exhibit A to the Indenture) (filed as Exhibit 4.2 to our Current Report on Form 8-K (Commission File No. 001-31315) on January 17, 2013 and incorporated herein by reference)

4.4.2	Second Supplemental Indenture, dated June 13, 2013, by and between Regal Entertainment Group and Wilmington Trust, National Association, as Trustee (filed as Exhibit 4.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on June 13, 2013 and incorporated herein by reference)
4.4.3	Third Supplemental Indenture, dated March 11, 2014, by and between Regal Entertainment Group and Wilmington Trust, National Association, as Trustee (filed as Exhibit 4.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on March 11, 2014 and incorporated herein by reference)
10.1	Regal Entertainment Group Amended and Restated Stockholders' Agreement (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 26, 2002 (Commission File No. 001-31315), and incorporated herein by reference)
10.2	Lease Agreement, dated as of October 1, 1988, between United Artists Properties I Corp. and United Artists Theatre Circuit, Inc. (filed as Exhibit 10.1 to United Artists Theatre Circuit, Inc.'s Registration Statement on Form S-1 (Commission File No. 33-49598) on October 5, 1992, and incorporated herein by reference)
10.3	Contribution and Unit Holders Agreement, dated as of March 29, 2005, among Regal CineMedia Corporation, National Cinema Network, Inc. and National CineMedia, LLC (filed as Exhibit 10.1 to AMC Entertainment Inc.'s Current Report on Form 8-K (Commission File No. 001-08747) on April 4, 2005, and incorporated herein by reference)

Exhibit Number		Description
10.4		Third Amended and Restated Limited Liability Company Operating Agreement, dated as of February 13, 2007, by and among American Multi-Cinema, Inc., CineMark Media, Inc., Regal CineMedia Holdings, LLC, and National CineMedia, Inc. (filed as Exhibit 10.1 to National CineMedia, Inc.'s Current Report on Form 8-K (Commission File No. 001-33296) on February 16, 2007 and incorporated herein by reference)
10.5	†	Amended and Restated Exhibitor Services Agreement, dated December 26, 2013, by and between National CineMedia, LLC and Regal Cinemas, Inc.
10.6	*	2002 Regal Entertainment Group Stock Incentive Plan (filed as exhibit 10.2 to Amendment No. 2 to our Registration Statement on Form S-1 (Commission File No. 333-84096) on May 6, 2002, and incorporated herein by reference), as amended by Amendment to 2002 Stock Incentive Plan (filed as Appendix A to our Proxy Statement on Schedule 14A (Commission File No. 001-31315) on April 15, 2005, and incorporated herein by reference and as further amended by those amendments (filed in Appendix B to our Proxy Statement on Schedule 14A (Commission File No. 001-31315) on April 20, 2012 and incorporated herein by reference)
10.6.1	*	Form of Stock Option Agreement for use under the Regal Entertainment Group 2002 Stock Incentive Plan, as amended (filed as exhibit 10.2.1 to Amendment No. 2 to our Registration Statement on Form S-1 (Commission File No. 333-84096) on May 6, 2002, and incorporated herein by reference)
10.6.2	*	Form of Restricted Stock Agreement for use under the Regal Entertainment Group 2002 Stock Incentive Plan, as amended (filed as Exhibit 10.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on March 2, 2006, and incorporated herein by reference)
10.6.3	*	Form of Performance Share Agreement (as amended and restated) for use under the Regal Entertainment Group 2002 Stock Incentive Plan, as amended (filed as Exhibit 10.9.4 to our Annual Report on Form 10-K filed for the fiscal year ended January 1, 2009 (Commission File No. 001-31315), and incorporated herein by reference)
10.7	*	Amended and Restated Executive Employment Agreement, dated May 5, 2009, by and between Regal Entertainment Group and Amy E. Miles (filed as Exhibit 10.2 to our Current Report on Form 8-K (Commission File No. 001-31315) on May 6, 2009, and incorporated herein by reference)
10.8	*	Amended and Restated Executive Employment Agreement, dated May 5, 2009, by and between Regal Entertainment Group and Gregory W. Dunn (filed as Exhibit 10.3 to our Current Report on Form 8-K (Commission File No. 001-31315) on May 6, 2009, and incorporated herein by reference)
10.9	*	Executive Employment Agreement, dated May 5, 2009, by and between Regal Entertainment Group and David H. Ownby (filed as Exhibit 10.4 to our Current Report on Form 8-K (Commission File No. 001-31315) on May 6, 2009, and incorporated herein by reference)
10.10	*	Executive Employment Agreement, dated January 13, 2010, by and between Regal Entertainment Group and Peter B. Brandow (filed as Exhibit 10.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on January 19, 2010, and incorporated herein by reference)

10.11	*	Form of Indemnity Agreement (filed as Exhibit 10.15 to our Annual Report on Form 10-K filed for the fiscal year ended January 1, 2009 (Commission File No. 001-31315), and incorporated herein by reference)
10.12	*	Regal Cinemas, Inc. Severance Plan for Equity Compensation (filed as Exhibit 10.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on May 17, 2005, and incorporated herein by reference)
10.13	†	Equipment Contribution Agreement by and between the Company, Digital Cinema Implementation Partners, LLC, Kasima, LLC, Kasima Parent Holdings, LLC, and Kasima Holdings, LLC, dated March 10, 2010 (filed as Exhibit 10.2(1)(2) to our Quarterly Report on Form 10-Q for the fiscal quarter ended April 1, 2010 (Commission File No. 001-31315), and incorporated herein by reference)
10.14	†	Amended and Restated Limited Liability Company Agreement of Digital Cinema Implementation Partners, LLC, dated as of March 10, 2010 (filed as Exhibit 10.3(1)(2) to our Quarterly Report on Form 10-Q for the fiscal quarter ended April 1, 2010 (Commission File No. 001-31315), and incorporated herein by reference)
10.15	*	Separation and General Release Agreement with Michael L. Campbell, dated December 20, 2011 (filed as Exhibit 10.1 to our Current Report on Form 8-K (Commission File No. 001-31315) on December 22, 2011, and incorporated herein by reference)
12.1		Ratio of Earnings to Fixed Charges
21.1		Subsidiaries of the Registrant
23.1		Consent of KPMG LLP, Independent Registered Public Accounting Firm
31.1		Rule 13a-14(a) Certification of Chief Executive Officer of Regal

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Exhibit Number	Description
31.2	Rule 13a-14(a) Certification of Chief Financial Officer of Regal
32	Section 1350 Certifications
101	Financial statements from the annual report on Form 10-K of Regal Entertainment Group for the fiscal year ended December 31, 2016, filed on February 27, 2017, formatted in XBRL: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Deficit (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements tagged as detailed text

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* Identifies each management contract or compensatory plan or arrangement.

† Portions of this Exhibit have been omitted pursuant to a request for confidential treatment filed with the Commission. Omitted portions have been filed separately with the Commission.