ALLETE INC
Form 10-Q
May 07, 2015

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

FORM 10-Q

(Mark One)

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended March 31, 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 1-3548

ALLETE, Inc.
(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	41-0418150 (IRS Employer Identification No.)

30 West Superior Street
Duluth, Minnesota 55802-2093
(Address of principal executive offices)
(Zip Code)

(218) 279-5000
(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. x Yes ¨ 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). x Yes ¨ 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 x	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller Reporting Company ¨

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

Common Stock, without par value,
48,751,109 shares outstanding
as of March 31, 2015

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to "we," "us" and "our" are to ALLETE, Inc., and its subsidiaries, collectively.

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction – the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc. and its subsidiaries
ALLETE Properties	ALLETE Properties, LLC, and its subsidiaries
ATC	American Transmission Company LLC
Bison Wind Energy Center	Bison 1, 2, 3 & 4 Wind Facilities
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CO_2	Carbon Dioxide
Company	ALLETE, Inc., and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
IBEW	International Brotherhood of Electrical Workers
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
Item ___	Item ___ of this Form 10-Q
kV	Kilovolt(s)
kWh	Kilowatt-hour
Laskin	Laskin Energy Center
LIBOR	London Interbank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, LLC
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent System Operator, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss

Abbreviation or Acronym	Term
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Note ___	Note ___ to the Consolidated Financial Statements in this Form 10-Q
NPDES	National Pollutant Discharge Elimination System
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Thomson	Thomson Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
U.S.	United States of America
U.S. Water Services	U.S. Water Services, Inc.
USS Corporation	United States Steel Corporation

Forward-Looking Statements

Statements in this report that are not statements of historical facts are considered "forward-looking" and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there can be no assurance that the expected results will be achieved. Any statements that express, or involve discussions as to, future expectations, risks, beliefs, plans, objectives, assumptions, events, uncertainties, financial performance, or growth strategies (often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "projects," "likely," "will continue," "could," "may," "potential," "target," "outlook" or words of similar m not statements of historical facts and may be forward-looking.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-Q, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- global and domestic economic conditions affecting us or our customers;
- wholesale power market conditions;
- federal and state regulatory and legislative actions that impact regulated utility economics, including our allowed rates of return, capital structure, ability to secure financing, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities and utility infrastructure, recovery of purchased power, capital investments and other expenses, including present or prospective environmental matters;
- changes in and compliance with laws and regulations;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- changes in tax rates or policies or in rates of inflation;
- the impacts on our Regulated Operations segment of climate change and future regulation to restrict the emissions of greenhouse gases;
- the impacts of laws and regulations related to renewable and distributed generation;
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements;
- weather conditions, natural disasters and pandemic diseases;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures and our ability to recover these costs;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such commodities;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel;
- effects of emerging technology;
- war, acts of terrorism and cyber attacks;
- our ability to manage expansion and integrate acquisitions;
- our current and potential industrial and municipal customers' ability to execute announced expansion plans;
- population growth rates and demographic patterns; and
- zoning and permitting of land held for resale, real estate development or changes in the real estate market.

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 29 of ALLETE’s Annual Report on Form 10-K for the year ended December 31, 2014 and in “Item 1A. Risk Factors” in this Form 10-Q beginning on page 54. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can we assess the impact of each of these factors on our businesses or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-Q and in our other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect our business.

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ALLETE
CONSOLIDATED BALANCE SHEET
Millions – Unaudited

	March 31, 2015	December 31, 2014
Assets		
Current Assets		
Cash and Cash Equivalents	$72.1	$145.8
Accounts Receivable (Less Allowance of $1.1 and $1.1)	111.8	103.0
Inventories	102.7	80.5
Prepayments and Other	88.5	82.0
Deferred Income Taxes	14.9	7.5
Total Current Assets	390.0	418.8
Property, Plant and Equipment – Net	3,319.2	3,284.8
Regulatory Assets	358.0	357.3
Investment in ATC	122.3	121.1
Other Investments	114.7	114.4
Goodwill and Intangible Assets – Net	214.3	4.8
Other Non-Current Assets	61.6	59.6
Total Assets	$4,580.1	$4,360.8
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$98.9	$134.1
Accrued Taxes	47.4	38.7
Accrued Interest	14.5	18.0
Long-Term Debt Due Within One Year	122.3	100.7
Notes Payable	0.3	3.7
Other	118.6	120.8
Total Current Liabilities	402.0	416.0
Long-Term Debt	1,253.8	1,272.8
Deferred Income Taxes	559.5	510.7
Regulatory Liabilities	101.2	94.2
Defined Benefit Pension and Other Postretirement Benefit Plans	190.4	190.9
Other Non-Current Liabilities	302.3	265.0
Total Liabilities	2,809.2	2,749.6
Commitments, Guarantees and Contingencies (Note 16)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 48.8 and 45.9 Shares Outstanding	1,249.7	1,107.6
Unearned ESOP Shares	(5.3)	(7.2)
Accumulated Other Comprehensive Loss	(20.6)	(21.1)
Retained Earnings	545.1	530.1
Total ALLETE Equity	1,768.9	1,609.4
Non-Controlling Interest in Subsidiaries	2.0	1.8
Total Equity	1,770.9	1,611.2

Total Liabilities and Equity	$4,580.1	$4,360.8

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF INCOME
Millions Except Per Share Amounts – Unaudited

	Three Months Ended March 31, 2015	2014
Operating Revenue	$320.0	$296.5
Operating Expenses		
Fuel and Purchased Power	86.0	96.2
Transmission Services	14.9	10.8
Cost of Sales	31.2	23.5
Operating and Maintenance	79.7	74.3
Depreciation and Amortization	39.0	32.2
Taxes Other than Income Taxes	12.8	11.2
Total Operating Expenses	263.6	248.2
Operating Income	56.4	48.3
Other Income (Expense)		
Interest Expense	(15.1)	(12.8)
Equity Earnings in ATC	3.9	5.1
Other	1.1	2.0
Total Other Expense	(10.1)	(5.7)
Income Before Non-Controlling Interest and Income Taxes	46.3	42.6
Income Tax Expense	6.2	8.8
Net Income	40.1	33.8
Less: Non-Controlling Interest in Subsidiaries	0.2	0.3
Net Income Attributable to ALLETE	$39.9	$33.5
Average Shares of Common Stock		
Basic	46.9	41.4
Diluted	47.1	41.6
Basic Earnings Per Share of Common Stock	$0.85	$0.81
Diluted Earnings Per Share of Common Stock	$0.85	$0.80
Dividends Per Share of Common Stock	$0.505	$0.49

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Millions – Unaudited

Comprehensive Income	Three Months Ended March 31, 2015	2014
Net Income	$40.1	$33.8
Other Comprehensive Income		
Unrealized Gain on Securities		
Net of Income Taxes of $0.1 and $–	0.1	—
Unrealized Gain on Derivatives		
Net of Income Taxes of $– and $0.1	0.1	—
Defined Benefit Pension and Other Postretirement Benefit Plans		
Net of Income Taxes of $0.2 and $0.2	0.3	0.3
Total Other Comprehensive Income	0.5	0.3
Total Comprehensive Income	40.6	34.1
Less: Non-Controlling Interest in Subsidiaries	0.2	0.3
Comprehensive Income Attributable to ALLETE	$40.4	$33.8

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Three Months Ended March 31, 2015	2014
Operating Activities		
Net Income	$40.1	$33.8
Allowance for Funds Used During Construction – Equity	(0.9)	(1.8)
Income from Equity Investments, Net of Dividends	(0.8)	(0.8)
Depreciation Expense	38.4	32.2
Amortization of Intangible Assets and Other Assets	0.8	0.3
Amortization of Power Purchase Agreements	(4.9)	(2.3)
Deferred Income Tax Expense	6.1	8.8
Share-Based Compensation Expense	0.6	0.8
ESOP Compensation Expense	2.4	2.2
Defined Benefit Pension and Postretirement Benefit Expense	3.8	3.2
Bad Debt Expense	0.2	0.2
Changes in Operating Assets and Liabilities		
Accounts Receivable	7.8	2.9
Inventories	(8.8)	(6.5)
Prepayments and Other	(0.7)	2.2
Accounts Payable	(14.0)	0.1
Other Current Liabilities	(1.7)	1.6
Changes in Regulatory and Other Non-Current Assets	(4.1)	(4.0)
Changes in Regulatory and Other Non-Current Liabilities	7.5	2.0
Cash from Operating Activities	71.8	74.9
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	0.2	0.6
Payments for Purchase of Available-for-sale Securities	(0.4)	(0.7)
Acquisitions of Subsidiaries – Net of Cash Acquired	(166.9)	(23.1)
Investment in ATC	(0.4)	(1.2)
Changes to Other Investments	—	30.0
Additions to Property, Plant and Equipment	(88.2)	(216.2)
Construction Costs for Development Project	(0.2)	—
Cash in Escrow for Acquisition	—	6.0
Cash for Investing Activities	(255.9)	(204.6)
Financing Activities		
Proceeds from Issuance of Common Stock	141.5	24.8
Proceeds from Issuance of Long-Term Debt	—	100.0
Changes in Restricted Cash	(0.8)	—
Changes in Notes Payable	(3.4)	—
Reductions of Long-Term Debt	(2.0)	(19.8)
Acquisition of Non-Controlling Interest	—	(6.0)
Debt Issuance Costs	—	(0.9)
Dividends on Common Stock	(24.9)	(21.1)
Cash from Financing Activities	110.4	77.0
Change in Cash and Cash Equivalents	(73.7)	(52.7)
Cash and Cash Equivalents at Beginning of Period	145.8	97.3

Cash and Cash Equivalents at End of Period	$72.1	$44.6

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited Consolidated Financial Statements have been prepared in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X and do not include all of the information and notes required by GAAP for complete financial statements. Similarly, the December 31, 2014, Consolidated Balance Sheet was derived from audited financial statements, but does not include all disclosures required by GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Operating results for the three months ended March 31, 2015, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2015. For further information, refer to the Consolidated Financial Statements and notes included in our 2014 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Reclassifications. As a result of recent acquisitions, certain financial statement captions have been added and as a result we have reclassified certain prior-period amounts in our Consolidated Balance Sheet, Consolidated Statement of Income, and Consolidated Statement of Cash Flows to conform to the presentation for the current period.

Consolidated Balance Sheet. In conformity with the current presentation of Goodwill and Intangible Assets - Net on the Consolidated Balance Sheet, we have reclassified our December 31, 2014 Consolidated Balance Sheet to include \$1.6 million and \$3.2 million of goodwill and intangible assets previously disclosed in Property, Plant and Equipment - Net and Other Non-Current Assets, respectively, under Goodwill and Intangible Assets - Net. There was no impact to Total Assets as a result of the reclassification.

Consolidated Statement of Income. In conformity with the current presentation of Cost of Sales on the Consolidated Statement of Income, we have reclassified \$23.5 million from Operating and Maintenance Expenses to Cost of Sales for the three months ended March 31, 2014. Cost of Sales includes purchased gas at SWL&P, expenses incurred to deliver coal at BNI Coal, and the cost of land and other sales at ALLETE Properties. There was no impact to Operating Income, Net Income, or Net Income Attributable to ALLETE as a result of the reclassification. Cost of Sales also includes costs associated with the manufacture and delivery of inventories at U.S. Water Services, our integrated water management company which was acquired February 10, 2015. (See Note 4. Acquisitions.) In addition to the presentation of Cost of Sales, we have created new captions on the Consolidated Statement of Income to provide additional detail for Transmission Services and Taxes Other than Income Taxes. Transmission Services are MISO-related costs incurred for the transmission of electricity. In conformity with the current presentation, \$10.8 million of Transmission Services and \$11.2 million of Taxes Other than Income Taxes have been reclassified from Operating and Maintenance Expenses for the three months ended March 31, 2014.

Consolidated Statement of Cash Flows. In conformity with the current presentation of the Amortization of Power Purchase Agreements on the Consolidated Statement of Cash Flows, we have reclassified \$2.3 million from Changes in Regulatory and Other Non-Current Liabilities to Amortization of Power Purchase Agreements for the three months ended March 31, 2014. There was no impact on cash from (for) Operating Activities, Investing Activities, and Financing Activities as a result of the reclassifications.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventories in our Regulated Operations segment are recorded on an average cost basis. Amounts removed from inventories in our Investments and Other segment are recorded on an average cost, first-in, first-out or specific identification basis.

Inventories	March 31, 2015	December 31, 2014
Millions		
Regulated Operations Inventories		
Fuel	$38.0	$29.0
Materials and Supplies	34.6	35.2
Total Regulated Operations Inventories	72.6	64.2
Investments and Other Inventories (a)		
Materials and Supplies	16.3	16.3
Raw Materials	3.1	—
Work in Progress	1.0	—
Finished Goods	10.2	—
Reserve for Obsolescence	(0.5)	—
Total Investments and Other Inventories	30.1	16.3
Total Inventories	$102.7	$80.5

(a) Raw materials, Work in Progress, Finished Goods, and Reserve for Obsolescence presented are attributable to U.S. Water Services which was acquired February 10, 2015.

Prepayments and Other Current Assets	March 31, 2015	December 31, 2014
Millions		
Deferred Fuel Adjustment Clause	$15.6	$16.3
Construction Costs for Development Project (a)	48.4	48.2
Restricted Cash (b)	5.6	2.7
Other	18.9	14.8
Total Prepayments and Other Current Assets	$88.5	$82.0

(a) Construction Costs for Development Project relate to ALLETE Clean Energy’s acquisition in November 2014 of a project to develop and construct a wind energy facility in 2015. (See Other Current Liabilities table and Note 4. Acquisitions.)

(b) Restricted Cash related to ALLETE Clean Energy’s wind energy facilities operating expense and capital distribution reserve requirements and cash pledged as collateral by U.S. Water Services for stand-by letters of credit.

Goodwill and Intangible Assets.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with U.S. GAAP, goodwill is not amortized. The Company assesses whether there has been an impairment of goodwill annually in the third quarter and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit’s net assets exceeds the estimated fair value of the reporting unit. The estimated fair value is generally determined using a discounted future cash flow analysis.

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements and trademarks and trade names. Intangible assets with definite lives consist of customer relationships, patents and non-compete agreements, which are amortized on a straight-line or accelerated basis with estimated useful lives ranging from less than 1 year to 23 years. We review other definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and trade names, which are tested for impairment annually in the third quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset's carrying amount over its fair value. Fair value is generally determined using a discounted future cash flow analysis.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Non-Current Assets.

Restricted Cash. Included in Other Non-Current Assets on the Consolidated Balance Sheet was restricted cash of $5.3 million as of March 31, 2015 and December 31, 2014, related to ALLETE Clean Energy's wind energy facilities debt service and other requirements.

Other Current Liabilities	March 31, 2015	December 31, 2014
Millions		
Customer Deposits	$20.0	$19.7
Power Purchase Agreements (a)	18.9	19.4
Construction Deposits Received for Development Project (b)	54.3	54.3
Other	25.4	27.4
Total Other Current Liabilities	$118.6	$120.8

(a) Power Purchase Agreements were acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisitions in 2014. (See Note 4. Acquisitions.)

(b) Construction Deposits Received for Development Project relate to ALLETE Clean Energy's project to develop and construct a wind energy facility in 2015. (See Prepayments and Other Current Assets table and Note 4. Acquisitions.)

Other Non-Current Liabilities	March 31, 2015	December 31, 2014
Millions		
Asset Retirement Obligation	$111.6	$109.2
Power Purchase Agreements (a)	106.3	110.7
Contingent Consideration (b)	35.8	—
Other	48.6	45.1
Total Other Non-Current Liabilities	$302.3	$265.0

(a) Power Purchase Agreements were acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisitions in 2014. (See Note 4. Acquisitions.)

(b) Contingent Consideration relates to the estimated fair value of the earnings-based payment to acquire the remaining ownership interest in U.S. Water Services. (See Note 4. Acquisitions and Note 7. Fair Value.)

Supplemental Statement of Cash Flows Information.

Three Months Ended March 31,	2015	2014
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$15.3	$12.4
Cash Paid During the Period for Income Taxes	$0.1	$0.2
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(32.2)	$(22.6)
Capitalized Asset Retirement Costs	$1.2	$0.6
AFUDC–Equity	$0.9	$1.8
ALLETE Common Stock Contributed to the Pension Plan	—	$19.5
Contingent Consideration	$35.7	—

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

New Accounting Standards.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. In April 2014, the FASB issued an accounting standard update modifying the criteria for determining which disposals should be presented as discontinued operations and modifying the related disclosure requirements. Additionally, the new guidance requires that a business which qualifies as held for sale upon acquisition should be reported as discontinued operations. The new guidance is effective beginning in the first quarter of 2015, and applies prospectively to new disposals and new classifications of disposal groups as held for sale. This guidance is not expected to have a material impact on our consolidated financial position, results of operations or cash flows.

Revenue from Contracts with Customers. In May 2014, the FASB issued amended revenue recognition guidance to clarify the principles for recognizing revenue from contracts with customers. The guidance requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. The guidance also requires expanded disclosures relating to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. Additionally, qualitative and quantitative disclosures are required regarding customer contracts, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. This accounting guidance was to have been effective for the Company beginning in the first quarter of 2017 using one of two prescribed retrospective methods. Early adoption is not permitted for public companies. On April 1, 2015, the FASB voted to propose a deferral of the effective date of the standard by one year which would make the guidance effective for the Company beginning in the first quarter of 2018. The FASB is expected to issue updated accounting guidance regarding the deferred effective date, subject to a 30-day comment period, in the second quarter of 2015. The Company is evaluating the impact of the amended revenue recognition guidance on the Company's consolidated financial statements.

Presentation of Debt Issuance Costs. In April 2015, the FASB issued revised guidance addressing the presentation requirements for debt issuance costs. Under the revised guidance, all costs incurred to issue debt are to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The revised guidance is effective for interim and annual reporting periods beginning after December 15, 2015. We are evaluating the impact of the adoption of this standard.

NOTE 2. BUSINESS SEGMENTS

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Investments and Other is comprised primarily of our Energy Infrastructure and Related Services businesses: ALLETE Clean Energy, our business aimed at acquiring or developing capital projects that create energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations, U.S. Water Services, our integrated water management company which was acquired on February 10, 2015, and BNI Coal, our coal mining operations in North Dakota. Investments and Other also includes ALLETE Properties, our Florida real estate investment, and other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments. Future acquisitions or growth may impact segment reporting.

Millions	Consolidated	Regulated Operations	Investments and Other
Three Months Ended March 31, 2015			
Operating Revenue	$320.0	$262.8	$57.2
Fuel and Purchased Power	86.0	86.0	—
Transmission Services	14.9	14.9	—
Cost of Sales	31.2	4.5	26.7
Operating and Maintenance	79.7	58.7	21.0
Depreciation and Amortization	39.0	32.1	6.9
Taxes Other than Income Taxes	12.8	11.6	1.2
Operating Income	56.4	55.0	1.4
Interest Expense	(15.1)	(13.0)	(2.1)
Equity Earnings in ATC	3.9	3.9	—
Other Income	1.1	0.9	0.2
Income (Loss) Before Non-Controlling Interest and Income Taxes	46.3	46.8	(0.5)
Income Tax Expense	6.2	5.4	0.8
Net Income (Loss)	40.1	41.4	(1.3)
Less: Non-Controlling Interest in Subsidiaries	0.2	—	0.2
Net Income (Loss) Attributable to ALLETE	$39.9	$41.4	$(1.5)
As of March 31, 2015			
Total Assets	$4,580.1	$3,748.4	$831.7
Property, Plant and Equipment – Net	$3,319.2	$3,025.3	$293.9
Accumulated Depreciation	$1,367.0	$1,286.9	$80.1
Capital Additions	$57.3	$54.9	$2.4

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
Three Months Ended March 31, 2014			
Operating Revenue	$296.5	$264.2	$32.3
Fuel and Purchased Power	96.2	96.2	—
Transmission Services	10.8	10.8	—
Cost of Sales	23.5	8.7	14.8
Operating and Maintenance	74.3	60.5	13.8
Depreciation and Amortization	32.2	28.8	3.4
Taxes Other than Income Taxes	11.2	10.2	1.0
Operating Income (Loss)	48.3	49.0	(0.7)
Interest Expense	(12.8)	(11.5)	(1.3)
Equity Earnings in ATC	5.1	5.1	—
Other Income	2.0	1.8	0.2
Income (Loss) Before Non-Controlling Interest and Income Taxes	42.6	44.4	(1.8)
Income Tax Expense (Benefit)	8.8	10.5	(1.7)
Net Income (Loss)	33.8	33.9	(0.1)
Less: Non-Controlling Interest in Subsidiaries	0.3	—	0.3
Net Income (Loss) Attributable to ALLETE	$33.5	$33.9	$(0.4)
As of March 31, 2014			
Total Assets	$3,749.2	$3,335.5	$413.7
Property, Plant and Equipment – Net	$2,905.1	$2,671.3	$233.8
Accumulated Depreciation	$1,266.7	$1,202.9	$63.8
Capital Additions	$195.2	$193.5	$1.7

NOTE 3. INVESTMENTS

Investments. At March 31, 2015, our investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held in other postretirement plans to fund employee benefits, the cash equivalents within these plans, and other assets consisting primarily of land in Minnesota.

Other Investments	March 31, 2015	December 31, 2014
Millions		
ALLETE Properties	$88.3	$88.2
Available-for-sale Securities (a)	19.3	18.9
Cash Equivalents	2.8	2.9
Other	4.3	4.4
Total Other Investments	$114.7	$114.4

(a) As of March 31, 2015, the aggregate amount of available-for-sale corporate debt securities maturing in one year or less was $0.4 million, in one year to less than three years was $1.7 million, in three years to less than five years was $3.0 million, and in five or more years was $5.9 million.

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NOTE 3. INVESTMENTS (Continued)

ALLETE Properties	March 31, 2015	December 31, 2014
Millions		
Land Inventory Beginning Balance	$83.8	$85.4
Cost of Sales	—	(2.2)
Other	0.1	0.6
Land Inventory Ending Balance	83.9	83.8
Long-Term Finance Receivables (net of allowances of $0.6 and $0.6)	1.2	1.2
Other	3.2	3.2
Total Real Estate Assets	$88.3	$88.2

Land Inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to fair value. Land values are reviewed for indicators of impairment on a quarterly basis and no impairments were recorded for the three months ended March 31, 2015 (none for the year ended December 31, 2014).

Long-Term Finance Receivables. As of March 31, 2015, long-term finance receivables were $1.2 million net of an allowance ($1.2 million net of an allowance as of December 31, 2014). Long-term finance receivables are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. As of March 31, 2015, the allowance for doubtful accounts amounted to $0.6 million ($0.6 million as of December 31, 2014).

Available-For-Sale Securities

Millions		Gross Unrealized		
	Cost	Gain	Loss	Fair Value
March 31, 2015	$19.8	$0.3	$0.8	$19.3
December 31, 2014	$19.6	$0.2	$0.9	$18.9

NOTE 4. ACQUISITIONS

The acquisitions below are consistent with ALLETE’s stated strategy of investing in energy infrastructure and related services businesses to complement its core regulated utility, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. The pro forma impact of the following acquisitions was not significant either individually or in the aggregate, to the results of the Company for the three months ended March 31, 2015 and year ended December 31, 2014.

2015 Acquisition Activity.

U.S. Water Services. On February 10, 2015, ALLETE acquired U.S. Water Services. Total consideration for the transaction was $202.3 million, which included payment of $166.6 million for an 87 percent ownership interest in the company, and an estimated fair value of earnings-based contingent consideration of $35.7 million to be paid in 2019. The contingent consideration is presented within Other Non-Current Liabilities on the Consolidated Balance Sheet. The Consolidated Statement of Income reflects 100 percent of the results of operations of U.S. Water Services since the acquisition date as the Company has effectively acquired 100 percent of U.S. Water Services. U.S. Water Services, an integrated industrial water management company headquartered in St. Michael, Minnesota, provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage and improve efficiency. U.S. Water Services helps customers achieve efficient and sustainable use of their energy systems, is a leading provider to the biofuels industry, and has a growing presence in the power generation and midstream oil and gas industries.

NOTE 4. ACQUISITIONS (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The allocation of the purchase price is subject to judgment and the preliminary estimated fair value of the assets acquired and the liabilities assumed may be adjusted when the valuation analysis is completed in subsequent periods. Preliminary estimates subject to adjustment in subsequent periods relate primarily to customer relationships, developed technologies, trademarks and trade names, and current and deferred income taxes; subsequent adjustments could impact the amount of goodwill recorded. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.9
Accounts Receivable	16.8
Inventories (a)	13.4
Other Current Assets (b)	5.3
Property, Plant and Equipment	10.6
Goodwill (c)	127.1
Intangible Assets (d)	83.0
Other Non-Current Assets	0.2
Total Assets Acquired	$257.3
Liabilities Assumed	
Other Current Liabilities	$18.7
Other Non-Current Liabilities	36.3
Total Liabilities Assumed	$55.0
Net Identifiable Assets Acquired	$202.3

(a) Included in Inventories was $2.7 million of fair value adjustments relating to work in process and finished goods inventories which will be recognized as Cost of Sales within one year from the acquisition date.

(b) Included in Other Current Assets was $1.6 million relating to the fair value of sales backlog. Sales backlog will be recognized as Cost of Sales within one year from the acquisition date. Also included in Other Current Assets was restricted cash of $2.1 million relating to cash pledged as collateral for stand-by letters of credit.

(c) Goodwill is largely attributable to strategic opportunities for growing U.S. Water Services and the benefits of the existing workforce. Goodwill of $3.2 million is deductible for tax purposes.

(d) Intangible Assets include customer relationships, patents, non-compete agreements and trademarks and trade names. (See Note 5. Goodwill and Intangible Assets.)

ALLETE incurred a $3.0 million after-tax expense of acquisition-related costs during the three months ended March 31, 2015, which were expensed when incurred and were recorded in Operating and Maintenance on the Consolidated Statement of Income.

Chanarambie/Viking. On April 15, 2015, ALLETE Clean Energy acquired wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Energy Holdings Limited for $47.5 million, subject to a working capital adjustment. We are currently in the process of accounting for the acquisition, therefore, certain disclosures, including the allocation of the purchase price, will be included in the Form 10-Q for the period ending June 30, 2015.

The facilities have 97.5 MW of generating capability and are located near our Lake Benton facility. The wind facilities began commercial operations in 2003 and have PPAs in place for the entire output, which expire in 2018 (12 MW) and 2023 (85.5 MW).

Armenia Mountain. On April 30, 2015, ALLETE Clean Energy signed purchase agreements to acquire 100 percent of a wind energy facility located near Troy, Pennsylvania (Armenia Mountain) from The AES Corporation (AES) and a non-controlling interest from a minority shareholder for $108.0 million, plus the assumption of existing debt. The agreement with AES is subject to a purchase price adjustment. The acquisition is expected to close in July 2015.

The facility has 100.5 MW of generating capability, began commercial operations in 2009, and has PPAs in place for the entire output, which expire in 2025.

NOTE 4. ACQUISITIONS (Continued)

2014 Acquisition Activity.

ACE Wind Acquisition. In January 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake II) and Condon, Oregon (Condon) from AES for $26.9 million.

Lake Benton, Storm Lake II and Condon have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake II began commercial operations in 1998, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032.

ALLETE Clean Energy acquired a controlling interest in the limited liability company (LLC) which owns Lake Benton and Storm Lake II, and a controlling interest in the LLC that owns Condon. The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$3.8
Other Current Assets	14.3
Property, Plant and Equipment	156.9
Other Non-Current Assets (a)	7.5
Total Assets Acquired	$182.5
Liabilities Assumed	
Other Current Liabilities (b)	$15.2
Long-Term Debt Due Within One Year	2.2
Long-Term Debt	21.1
Power Purchase Agreements	99.4
Other Non-Current Liabilities	10.6
Non-Controlling Interest (c)	7.1
Total Liabilities and Non-Controlling Interest Assumed	$155.6
Net Identifiable Assets Acquired	$26.9

(a) Included in Other Non-Current Assets was $0.3 million for the option to purchase Armenia Mountain in 2015, and goodwill of $2.9 million; for tax purposes, the purchase price allocation resulted in no allocation to goodwill.

(b) Other Current Liabilities included $12.4 million related to the current liabilities portion of the Power Purchase Agreements.

(c) The purchase price accounting valued the non-controlling interest relating to Lake Benton, Storm Lake II and Condon at fair value using the discounted cash flow method. The non-controlling interest related to Lake Benton and Storm Lake II was subsequently purchased by ALLETE Clean Energy.

In February 2014, ALLETE Clean Energy purchased the non-controlling interest related to Lake Benton and Storm Lake II for $6.0 million. This was accounted for as an equity transaction, and no gain or loss was recognized in net income or other comprehensive income.

Montana-Dakota Utilities. In November 2014, ALLETE Clean Energy acquired a business for $27.0 million to develop a wind facility near Hettinger, North Dakota. ALLETE Clean Energy is developing and constructing a 107 MW wind facility consisting of 43 turbines, which will be sold to Montana-Dakota Utilities Co., a division of MDU

Resources Group, Inc., for approximately $200 million. Construction is expected to be completed in December 2015, and the sale is subject to regulatory approval from the NDPSC. If regulatory approval is not obtained for the sale of the wind facility, ALLETE Clean Energy would then own and operate the facility and sell the entire output to Montana-Dakota Utilities Co. under a long-term PPA.

NOTE 4. ACQUISITIONS (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition. Fair value measurements were valued primarily using the replacement cost method and determined that the assets acquired amounted to cash of approximately $3.6 million and construction in process of approximately $23.4 million. There were no liabilities assumed and no recognition of goodwill.

As of March 31, 2015, $48.4 million of construction costs incurred (including the construction costs acquired) and $54.3 million of construction deposits received from Montana-Dakota Utilities Co. have been classified on the Consolidated Balance Sheet as Prepayments and Other Current Assets and Other Current Liabilities, respectively ($48.2 million and $54.3 million of costs incurred and deposits received as of December 31, 2014, respectively). ALLETE expects revenue to be recognized under the percentage of completion method of accounting as progress toward completion of the project is achieved. Until it becomes probable that regulatory approval from the NDPSC for the sale of the facility will be obtained, we expect no impact from the project on the Consolidated Statement of Income. Costs to construct the wind facility and deposits received from Montana-Dakota Utilities Co. are reported as Construction Costs for Development Project in investing activities and Construction Deposits Received for Development Project in financing activities on the Consolidated Statement of Cash Flows, respectively. On April 15, 2015, we received an additional construction deposit from Montana-Dakota Utilities Co. of approximately $50 million.

Storm Lake I Acquisition. In December 2014, ALLETE Clean Energy acquired a wind energy facility in Storm Lake, Iowa (Storm Lake I) from NRG Energy, Inc. for $15.1 million.

Storm Lake I has 108 MW of generating capability and is located adjacent to Storm Lake II. The wind generation facility began commercial operations in 1999 and has a PPA in place for its entire output which expires in 2018.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. In connection with finalizing purchase price accounting, the Company recorded minor adjustments during the first quarter of 2015 to certain assets and liabilities, which are reflected in the table below. The result of these adjustments had no impact on the results of operations for the period ended March 31, 2015. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.4
Other Current Assets	4.7
Property, Plant and Equipment	47.3
Other Non-Current Assets (a)	11.4
Total Assets Acquired	$63.8
Liabilities Assumed	
Other Current Liabilities (b)	$8.2
Power Purchase Agreements	23.5
Other Non-Current Liabilities	17.0
Total Liabilities Assumed	$48.7
Net Identifiable Assets Acquired	$15.1

(a) Included in Other Non-Current Assets was $0.4 million of restricted cash and an immaterial amount of goodwill; for tax purposes, the purchase price allocation resulted in no allocation to goodwill.

(b)

Other Current Liabilities included $7.5 million related to the current liabilities portion of the Power Purchase Agreements.

NOTE 5. GOODWILL AND INTANGIBLE ASSETS

The following table summarizes changes to goodwill by business segment for the three months ended March 31, 2015:

Millions	Investments and Other
Balance as of December 31, 2014	$2.9
Acquired Goodwill	127.1
Balance as of March 31, 2015	$130.0

Balances of intangible assets, net, excluding goodwill as of March 31, 2015 are as follows:

Millions	December 31, 2014	Additions as a Result of Acquisitions	Amortization	March 31, 2015
Intangible Assets				
Definite-Lived Intangible Assets				
Customer Relationships	—	$60.1	$0.5	$59.6
Developed Technology and Other (a)	$1.9	6.3	0.1	8.1
Total Definite-Lived Intangible Assets	1.9	66.4	0.6	67.7
Indefinite-Lived Intangible Assets				
Trademarks and Trade Names	—	16.6	n/a	16.6
Total Intangible Assets	$1.9	$83.0	$0.6	$84.3

(a) Developed Technology and Other includes patents, non-compete agreements, and land easements.

Customer relationships have a useful life of approximately 23 years and developed technology and other have useful lives ranging from less than 1 year to approximately 14 years (weighted average of approximately 9 years). The weighted average useful life of all definite-lived intangible assets as of March 31, 2015 is approximately 21 years.

Amortization expense of intangible assets for the three months ended March 31, 2015 was $0.6 million.

The estimated amortization expense for definite-lived intangible assets for the remainder of 2015 is $3.6 million. Estimated annual amortization expense for definite-lived intangible assets is $4.3 million in 2016, $4.2 million in 2017, $4.1 million in 2018, $4.0 million in 2019, $3.9 million in 2020 and $43.6 million thereafter.

NOTE 6. DERIVATIVES

We have one variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with a $75.0 million term loan which represents approximately 5 percent of the Company's outstanding long-term debt, including long-term debt due within one year, as of March 31, 2015. (See Note 10. Short-Term and Long-Term Debt.) The Swap has an effective date of August 26, 2014, and matures on August 25, 2015. The Swap involves the receipt of the one-month LIBOR in exchange for fixed interest payments over the life of the agreement at 0.75 percent without an exchange of the underlying notional amount. Cash flows from the Swap are expected to be highly effective. If it is determined that the Swap ceases to be effective, we will prospectively discontinue hedge accounting. When applicable, we use the shortcut method to assess hedge effectiveness. If the shortcut method is not applicable, we assess effectiveness using the "change-in-variable-cash-flows" method. Our assessment of hedge effectiveness resulted in no ineffectiveness recorded for the three months ended March 31, 2015. As of March 31, 2015, the fair value of the Swap was a $0.2 million liability ($0.3 million liability as of December 31, 2014) which was included in Other Current Liabilities on the Consolidated Balance Sheet. Changes in the fair value of the Swap were recorded in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheet. Cash flows from the Swap are presented in the same category as the hedged item on the Consolidated Statement of Cash Flows. Amounts recorded in Other Comprehensive Income related to the Swap will be recorded in earnings when the hedged transaction occurs or when it is probable it will not occur. Gains or losses on the interest rate hedging transaction are reflected as a component of Interest Expense on the Consolidated Statement of Income.

NOTE 7. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Descriptions of the three levels of the fair value hierarchy are discussed in Note 10. Fair Value to the Consolidated Financial Statements in our 2014 Form 10-K.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2015, and December 31, 2014. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy levels. The estimated fair value of Cash and Cash Equivalents listed on the Consolidated Balance Sheet approximates the carrying amount and therefore is excluded from the recurring fair value measures in the tables below.

NOTE 7. FAIR VALUE (Continued)

	Fair Value as of March 31, 2015			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments (a)				
Available-for-sale – Equity Securities	$8.3	—	—	$8.3
Available-for-sale – Corporate Debt Securities	—	$11.0	—	11.0
Cash Equivalents	2.8	—	—	2.8
Total Fair Value of Assets	$11.1	$11.0	—	$22.1
Liabilities:				
Deferred Compensation (b)	—	$15.4	—	$15.4
Derivatives – Interest Rate Swap (c)	—	0.2	—	0.2
U.S. Water Services Contingent Consideration (b)	—	—	$35.8	35.8
Total Fair Value of Liabilities	—	$15.6	$35.8	$51.4
Total Net Fair Value of Assets (Liabilities)	$11.1	$(4.6)	$(35.8)	$(29.3)

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Current Liabilities - Other on the Consolidated Balance Sheet.

	Fair Value as of December 31, 2014			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments (a)				
Available-for-sale – Equity Securities	$8.1	—	—	$8.1
Available-for-sale – Corporate Debt Securities	—	$10.8	—	10.8
Cash Equivalents	2.9	—	—	2.9
Total Fair Value of Assets	$11.0	$10.8	—	$21.8
Liabilities:				
Deferred Compensation (b)	—	$16.2	—	$16.2
Derivatives – Interest Rate Swap (c)	—	0.3	—	0.3
Total Fair Value of Liabilities	—	$16.5	—	$16.5
Total Net Fair Value of Assets (Liabilities)	$11.0	$(5.7)	—	$5.3

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Current Liabilities - Other on the Consolidated Balance Sheet.

The following table provides a reconciliation of the beginning and ending balances of the U.S. Water Services Contingent Consideration measured at fair value using Level 3 measurements as of March 31, 2015. The acquisition contingent consideration is recorded at the acquisition date at the estimated fair value of the acquisition contingent consideration. The acquisition date fair value is measured based on the consideration expected to be transferred, discounted to present value. The discount rate is determined at the time of measurement in accordance with accepted valuation methods. The fair value of the acquisition contingent consideration is remeasured to arrive at estimated fair value each reporting period with the change in fair value recognized as income or expense in our Consolidated Statement of Income. Changes to the fair value of the acquisition contingent consideration can result from changes in discount rates, or in the timing and amount of earnings estimates. Using different valuation assumptions including earnings projections or discount rates result in different fair value measurements and expense (or income) in the current or future periods. The acquisition contingent consideration was measured at $35.8 million as of March 31, 2015.

NOTE 7. FAIR VALUE (Continued)

Recurring Fair Value Measures	
Activity in Level 3	
Millions	
Balance at December 31, 2014	—
Recognition of U.S. Water Services Contingent Consideration	$35.7
Accretion Expense	0.1
Balance at March 31, 2015	$35.8

The Level 3 activity above is the result of the February 10, 2015 acquisition of U.S. Water Services; there was no activity in Level 3 during the year ended December 31, 2014.

For the three months ended March 31, 2015 and the year ended December 31, 2014, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed in the table below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed below was based on quoted market prices for the same or similar instruments (Level 2).

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
March 31, 2015	$1,376.1	$1,525.4
December 31, 2014	$1,373.5	$1,484.5

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-financial assets such as equity method investments, goodwill, intangible assets, and property, plant and equipment are measured at fair value when there is an indicator of impairment and recorded at fair value only when an impairment is recognized.

Equity Method Investment. Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. (See Note 9. Investment in ATC.) The aggregate carrying amount of the investment was $122.3 million as of March 31, 2015 and $121.1 million as of December 31, 2014. The Company assesses our investment in ATC for impairment whenever events or changes in circumstances indicate that the carrying amount of our investment in ATC may not be recoverable. For the three months ended March 31, 2015 and the year ended December 31, 2014, there were no indicators of impairment.

Goodwill. The Company assesses the impairment of goodwill annually in the third quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Substantially all of the Company’s goodwill is a result of the U.S. Water Services acquisition on February 10, 2015. The aggregate carrying amount of goodwill was $130.0 million and $2.9 million as of March 31, 2015 and December 31, 2014, respectively.

Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit’s net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. The Company calculated the excess of each reporting unit's fair value over its carrying amount, including goodwill, utilizing a discounted cash flow analysis. As of March 31, 2015, there have been no events or changes in circumstance which would indicate impairment of our goodwill.

NOTE 7. FAIR VALUE (Continued)

Intangible Assets. The Company assesses indefinite-lived intangible assets for impairment annually in the third quarter. The Company also assesses indefinite-lived and definite-lived intangible assets whenever events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable. Substantially all of the Company’s intangible assets are a result of the U.S. Water Services acquisition on February 10, 2015. The aggregate carrying amount of intangible assets was $84.3 million as of March 31, 2015 ($1.9 million as of December 31, 2014). When events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable, the Company calculates the excess of an intangible asset's carrying value over its undiscounted future cash flows. If the carrying value is not recoverable, an impairment loss is recorded based on the amount by which the carrying value exceeds the fair value. The inputs used in the fair value analysis fall within Level 3 of the fair value hierarchy due to the use of significant unobservable inputs to determine fair value. As of March 31, 2015, there have been no events or changes in circumstance which would indicate impairment of our intangible assets.

Property, Plant and Equipment. The Company assesses the impairment of property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of property, plant, and equipment assets may not be recoverable. For the three months ended March 31, 2015 and the year ended December 31, 2014, there were no indicators of impairment.

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allows for the recovery of the remaining book value of retired plant assets. We will retire Taconite Harbor Unit 3 and convert Laskin to natural gas in the second quarter of 2015, which actions were included in our 2013 Integrated Resource Plan approved by the MPUC in a November 2013 order. Accordingly, we do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3 or conversion of Laskin.

NOTE 8. REGULATORY MATTERS

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, the FERC or the PSCW.

2010 Minnesota Rate Case. Minnesota Power’s current retail rates are based on a 2011 MPUC retail rate order, effective June 1, 2011, that allows for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

FERC-Approved Wholesale Rates. Minnesota Power has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a customer of Minnesota Power. On April 21, 2015, Minnesota Power amended its formula-based wholesale electric sales contract with the Nashwauk Public Utilities Commission, extending the term through June 30, 2028. The electric service agreements with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (currently 10.38 percent). The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the Nashwauk Public Utilities Commission agreement, no termination notice may be given prior to June 30, 2025. Under the agreements with the remaining 15 municipal customers and SWL&P, no termination notices may be given prior to June 30, 2016.

2012 Wisconsin Rate Case. SWL&P’s current retail rates are based on a 2012 PSCW retail rate order, effective January 1, 2013, that allows for a 10.9 percent return on common equity.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. In an order dated February 23, 2015, the MPUC approved Minnesota Power's updated billing factor which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested.

NOTE 8. REGULATORY MATTERS (Continued)

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for investments and expenditures related to the 497 MW Bison Wind Energy Center in North Dakota. Customer billing rates for our Bison 1, 2, & 3 wind facilities were approved by the MPUC in a December 2013 order. In April 2014 and November 2014, we filed renewable resources factor filings which include updated costs associated with the Bison Wind Energy Center. Upon approval of the filings, we will be authorized to include updated billing rates on customer bills.

On February 13, 2015, Minnesota Power supplemented its November 2014 renewable resources factor filing to include costs associated with the restoration and repair of Thomson. In an order dated March 5, 2015, the MPUC approved our petition seeking cost recovery for investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider.

Integrated Resource Plan. In a November 2013 order, the MPUC approved Minnesota Power’s 2013 Integrated Resource Plan which details our “EnergyForward” strategic plan and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. Significant elements of the “EnergyForward” plan include major wind investments in North Dakota which were completed in the fourth quarter of 2014, installation of emissions control technology at Boswell Unit 4, planning for the proposed GNTL, conversion of Laskin from coal to natural gas in the second quarter of 2015 and retiring Taconite Harbor Unit 3 in the second quarter of 2015. We are required to submit our 2015 Integrated Resource Plan with the MPUC no later than September 1, 2015.

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be approximately $260 million of which $162 million was spent through March 31, 2015. In a November 2013 order, the MPUC approved the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. Customer billing rates for the environmental improvement rider were approved by the MPUC in a July 2014 order. In November 2014, we filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of this filing, we will be authorized to include updated billing rates on customer bills.

Great Northern Transmission Line (GNTL). Minnesota Power and Manitoba Hydro have proposed construction of the GNTL, an approximately 220-mile 500 kV transmission line, between Manitoba and Minnesota’s Iron Range. The GNTL is subject to various federal and state regulatory approvals. In October 2013, a Certificate of Need application was filed with the MPUC with respect to the GNTL. In a January 2014 order, the MPUC determined the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. On March 16, 2015, the administrative law judge recommended the MPUC grant a Certificate of Need for construction of the GNTL. In April 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. In a July 2014 order, the MPUC determined the route permit application to be complete. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. Construction of Manitoba Hydro’s hydroelectric generation facility commenced in the third quarter of 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is anticipated to begin in 2016 and to be completed in 2020.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to accounting guidance for the effect of certain types of regulation. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. No regulatory assets or liabilities are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable regulatory authority or over the corresponding period related to the asset or liability.

NOTE 8. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities	March 31, 2015	December 31, 2014
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	$15.6	$16.3
Total Current Regulatory Assets	15.6	16.3
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	220.0	223.9
Cost Recovery Riders (c)	63.4	59.7
Income Taxes	46.8	46.6
Asset Retirement Obligations	18.6	17.8
PPACA Income Tax Deferral	5.0	5.0
Other	4.2	4.3
Total Non-Current Regulatory Assets	358.0	357.3
Total Regulatory Assets	$373.6	$373.6
Non-Current Regulatory Liabilities		
Wholesale and Retail Contra AFUDC	$46.9	$42.9
Plant Removal Obligations	22.0	22.8
Income Taxes	13.5	13.4
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	2.9	3.5
Other	15.9	11.6
Total Non-Current Regulatory Liabilities	$101.2	$94.2

(a) Current regulatory assets are included in Prepayments and Other on the Consolidated Balance Sheet.

(b) Defined benefit pension and other postretirement items included in our Regulated Operations, which are otherwise required to be recognized in accumulated other comprehensive income, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. (See Note 15. Pension and Other Postretirement Benefit Plans.)

(c) The cost recovery rider regulatory assets are due to capital expenditures related to our Bison Wind Energy Center, investment in CapX2020 projects, and the Boswell Unit 4 environmental upgrade and are recognized in accordance with the accounting standards for alternative revenue programs.

NOTE 9. INVESTMENT IN ATC

Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC rates are based on a FERC-approved 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of March 31, 2015, our equity investment in ATC was $122.3 million ($121.1 million at December 31, 2014). In the first three months of 2015, we invested $0.4 million in ATC, and on April 29, 2015, we invested an additional $0.4 million. We expect to make additional investments of approximately $1.1 million in 2015.

ALLETE’s Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2014	$121.1
Cash Investments	0.4
Equity in ATC Earnings	3.9

Distributed ATC Earnings	(3.1)
Equity Investment Balance as of March 31, 2015	$122.3

NOTE 9. INVESTMENT IN ATC (Continued)

ATC's summarized financial data for the three months ended March 31, 2015 and 2014, is as follows:

ATC Summarized Financial Data	Three Months Ended March 31,	
Income Statement Data	2015	2014
Millions		
Revenue	$152.4	$163.3
Operating Expense	80.0	78.6
Other Expense	24.4	21.6
Net Income	$48.0	$63.1
ALLETE's Equity in Net Income	$3.9	$5.1

Our equity earnings in ATC for the three months ended March 31, 2015 were $3.9 million and reflected a $1.4 million reduction related to complaints filed with the FERC by several customer groups located within the MISO service area; of the $1.4 million reduction, $1.1 million was attributable to ATC's change in estimate of a refund liability recorded in a previous period. The groups requested, among other things, a reduction in the base return on equity used by MISO transmission owners, including ATC, to 9.15 percent. ATC's current authorized return on equity is 12.2 percent. On February 12, 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity to 8.67 percent. We own approximately 8 percent of ATC and estimate that for every 50 basis point reduction in ATC's allowed return on equity our equity earnings in ATC would be impacted annually by approximately $0.5 million on an after-tax basis ($0.9 million pre-tax).

NOTE 10. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of March 31, 2015, total short-term debt outstanding was $122.6 million ($104.4 million as of December 31, 2014) and consisted of long-term debt due within one year and notes payable.

Long-Term Debt. No long-term debt was issued in the first three months of 2015. As of March 31, 2015, total long-term debt outstanding was $1,253.8 million ($1,272.8 million as of December 31, 2014).

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive financial covenant requires ALLETE to maintain a ratio of indebtedness to total capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00, measured quarterly. As of March 31, 2015, our ratio was approximately 0.44 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of March 31, 2015, ALLETE was in compliance with its financial covenants.

NOTE 11. OTHER INCOME (EXPENSE)

	Three Months Ended March 31,	
	2015	2014
Millions		
AFUDC–Equity	$0.9	$1.8

Investments and Other Income	0.2	0.2
Total Other Income	$1.1	$2.0

NOTE 12. INCOME TAX EXPENSE

	Three Months Ended March 31,	
	2015	2014
Millions		
Current Tax Expense		
Federal (a)	—	—
State (a)	$0.1	—
Total Current Tax Expense	$0.1	—
Deferred Tax Expense		
Federal	$4.8	$6.3
State	1.5	2.7
Investment Tax Credit Amortization	(0.2)	(0.2)
Total Deferred Tax Expense	6.1	8.8
Total Income Tax Expense	$6.2	$8.8

(a) For the three months ended March 31, 2015 and 2014, the federal and state current tax expense was minimal due to the utilization of NOL carryforwards from prior periods. The NOL carryforwards resulted from the bonus depreciation provisions of the Tax Increase Prevention Act of 2014 and the American Taxpayer Relief Act of 2012.

For the three months ended March 31, 2015, the effective tax rate was 13.4 percent (20.7 percent for the three months ended March 31, 2014). The decrease in the effective tax rate from March 31, 2014, was primarily due to increased production tax credits. The effective rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC–Equity, investment tax credits, production tax credits and depletion.

Uncertain Tax Positions. As of March 31, 2015, we had gross unrecognized tax benefits of $2.0 million ($2.0 million as of December 31, 2014). Of the total gross unrecognized tax benefits, $0.3 million represents the amount of unrecognized tax benefits included in the Consolidated Balance Sheet that, if recognized, would favorably impact the effective income tax rate. The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on the Consolidated Balance Sheet.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE is no longer subject to federal examination for years before 2011, or state examination for years before 2010.

NOTE 13. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in accumulated other comprehensive loss, net of tax, for the three months ended March 31, 2015 and 2014, were as follows:

	Unrealized Gains and Losses on Available-for-sale Securities	Defined Benefit Pension, Other Postretirement Items	Gains and Losses on Cash Flow Hedge	Total
Millions				
Three Months Ended March 31, 2015				
Beginning Accumulated Other Comprehensive Loss	$(0.3)	$(20.7)	$(0.1)	$(21.1)
Other Comprehensive Income Before Reclassifications	0.2	—	0.1	0.3
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.1)	0.3	—	0.2
Net Other Comprehensive Income	0.1	0.3	0.1	0.5
Ending Accumulated Other Comprehensive Loss	$(0.2)	$(20.4)	—	$(20.6)
Three Months Ended March 31, 2014				
Beginning Accumulated Other Comprehensive Loss	$(0.1)	$(16.7)	$(0.3)	$(17.1)
Other Comprehensive Income Before Reclassifications	—	—	—	—
Amounts Reclassified From Accumulated Other Comprehensive Loss	—	0.3	—	0.3
Net Other Comprehensive Income	—	0.3	—	0.3
Ending Accumulated Other Comprehensive Loss	$(0.1)	$(16.4)	$(0.3)	$(16.8)

Reclassifications from accumulated other comprehensive loss for the three months ended March 31, 2015 and 2014, were as follows:

Amount Reclassified from Accumulated Other Comprehensive Loss	Three Months Ended March 31, 2015	March 31, 2014
Millions		
Unrealized Gains on Available-for-sale Securities	—	—
Income Taxes (a)	$0.1	—
Total, Net of Income Taxes	$0.1	—
Amortization of Defined Benefit Pension and Other Postretirement Items		
Prior Service Costs (b)	$0.1	$0.1
Actuarial Gains and Losses (b)	(0.6)	(0.6)
Total	(0.5)	(0.5)
Income Taxes (a)	0.2	0.2
Total, Net of Income Taxes	$(0.3)	$(0.3)
Total Reclassifications	$(0.2)	$(0.3)

(a) Included in Income Tax Expense on our Consolidated Statement of Income.

(b) Defined benefit pension and other postretirement items excluded from our Regulated Operations are recognized in accumulated other comprehensive loss and are subsequently reclassified out of accumulated other comprehensive loss as components of net periodic pension and other postretirement benefit expense. (See Note 15. Pension and Other Postretirement Benefit Plans.)

NOTE 14. EARNINGS PER SHARE AND COMMON STOCK

We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units, performance share awards granted under our Executive Long-Term Incentive Compensation Plan and common shares under the forward sale agreement (described below). For the three months ended March 31, 2015 and 2014, no options to purchase shares of common stock were excluded from the computation of diluted earnings per share.

Reconciliation of Basic and Diluted Earnings Per Share	Basic	2015 Dilutive Securities	Diluted	Basic	2014 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
Three months ended March 31,						
Net Income Attributable to ALLETE	$39.9		$39.9	$33.5		$33.5
Average Common Shares	46.9	0.2	47.1	41.4	0.2	41.6
Earnings Per Share	$0.85		$0.85	$0.81		$0.80

Forward Sale Agreement and Issuance of Common Stock. In February 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock.

Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock from third parties and sold them to the underwriters. The forward sale price was $48.01 per share, subject to adjustment as provided in the Agreement. In September 2014, ALLETE physically settled a portion of its obligations under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.0 million and on February 4, 2015, ALLETE physically settled the remaining portion of its obligation under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.4 million.

In connection with the public offering of the 2.8 million shares, ALLETE granted the underwriters an option to purchase up to an additional 0.4 million shares of ALLETE common stock (the option shares). The underwriters exercised the option in full and in March 2014, the Company issued and sold the option shares to the underwriters at a price to ALLETE equal to the initial forward sale price for proceeds of $20.2 million.

Contributions to Pension. No contributions were made to the pension plan for the three months ended March 31, 2015. For the three months ended March 31, 2014, ALLETE contributed 0.4 million shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended, and had an aggregate value of $19.5 million when contributed.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Components of Net Periodic Benefit Expense (Income)	Pension 2015	Pension 2014	Other Postretirement 2015	Other Postretirement 2014
Millions				
Three months ended March 31,				
Service Cost	$2.5	$2.1	$1.1	$0.9

Interest Cost	7.5	7.4	1.8	1.8
Expected Return on Plan Assets	(10.2)	(9.6)	(2.7)	(2.6)
Amortization of Prior Service Costs (Credits)	—	0.1	(0.8)	(0.6)
Amortization of Net Loss	4.5	3.6	0.1	0.1
Net Periodic Benefit Expense (Income)	$4.3	$3.6	$(0.5)	$(0.4)

Employer Contributions. For the three months ended March 31, 2015, no contributions were made to our defined benefit pension plan ($19.5 million for the three months ended March 31, 2014); we do not expect to make any contributions to our defined benefit pension plan in 2015. For the three months ended March 31, 2015 and 2014, we made no contributions to our other postretirement benefit plan; we do not expect to make any contributions to our other postretirement benefit plan in 2015.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Power Purchase Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPAs or, where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our capacity and energy payments.

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). It provides a long-term supply of energy to customers in our electric service territory and enables Minnesota Power to meet reserve requirements. Square Butte, a North Dakota cooperative corporation, owns a 455 MW coal-fired generating unit (Unit) near Center, North Dakota. The Unit is adjacent to a generating unit owned by Minnkota Power, a North Dakota cooperative corporation whose Class A members are also members of Square Butte. Minnkota Power serves as the operator of the Unit and also purchases power from Square Butte.

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the Agreement, subject to the provisions of the Minnkota Power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of March 31, 2015, Square Butte had total debt outstanding of $390.9 million. Annual debt service for Square Butte is expected to be approximately $45 million in each of the next five years, 2015 through 2019, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during the three months ended March 31, 2015, was $19.2 million ($16.8 million for the three months ended March 31, 2014). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $2.5 million during the three months ended March 31, 2015 ($2.5 million for the three months ended March 31, 2014). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Minnkota Power Sales Agreement. In December 2009, Minnesota Power entered into a power sales agreement with Minnkota Power, which commenced in June 2014. Under the power sales agreement, Minnesota Power is selling a portion of its output from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025. In 2015, Minnesota Power's portion of output sold to Minnkota Power is approximately 28 percent (23 percent commencing on June 1, 2014).

Minnkota Power PPA. In December 2012, Minnesota Power entered into a long-term PPA with Minnkota Power. Under this agreement, Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity from June 2016 through May 2020. The agreement includes a fixed capacity charge and energy pricing that escalates at a fixed rate annually over the term.

Oliver Wind I and II PPAs. Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW)—wind facilities located near Center, North Dakota that expire in 2031 and 2032, respectively. Each agreement provides for the purchase of all output from the facilities at fixed energy prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Manitoba Hydro PPAs. Minnesota Power has a long-term PPA with Manitoba Hydro that expires in May 2020. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index. In addition, Minnesota Power has a separate long-term PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only agreement primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro for 15 years beginning in 2020. The agreement is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

In July 2014, Minnesota Power and Manitoba Hydro signed a long-term PPA that provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro for 20 years beginning in 2020. The pricing under this PPA is based on forward market prices. The agreement was approved by the MPUC in an order dated January 30, 2015, and is subject to the construction of the GNTL. (See Great Northern Transmission Line.)

Great River Energy PPAs. In August 2014 and January 2015, Minnesota Power and Great River Energy signed long-term PPAs that provide for Minnesota Power to purchase 50 MW of capacity and energy under the first PPA and 50 MW of capacity only under the second PPA. The PPAs commence in June 2016 and expire in May 2020. Both contracts have fixed capacity pricing. The energy price in the first PPA is based on a formula that includes an annual fixed price component adjusted for changes in a natural gas index as well as market prices.

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements with expiration dates through December 2015. Minnesota Power is currently in discussions regarding the extension of our coal supply contracts beyond 2015. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through December 2018. Our minimum annual payment obligation under these supply and transportation agreements is $42.3 million for the remainder of 2015, $27.0 million in 2016, $27.6 million in 2017, and $28.4 million in 2018. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term, which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We also lease other properties and equipment under operating lease agreements with terms expiring through 2022. The aggregate amount of minimum lease payments for all operating leases is $13.4 million in 2015, $11.4 million in 2016, $10.6 million in 2017, $9.5 million in 2018, $8.3 million in 2019 and $27.3 million thereafter.

Transmission. We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include the GNTL and the CapX2020 initiative, as well as investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others), and our investment in ATC.

Transmission Investments. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. In an order dated February 23, 2015, the MPUC approved Minnesota Power's updated billing factor which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives and municipal and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Transmission (Continued)

On April 2, 2015, the CapX2020 transmission line project from Fargo, North Dakota to St. Cloud, Minnesota was completed and placed into service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed into service in 2011 and 2012.

Minnesota Power invested approximately $100 million to complete the three transmission line projects. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.
Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220-mile 500 kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

The GNTL is subject to various federal and state regulatory approvals. In October 2013, a Certificate of Need application was filed with the MPUC with respect to the GNTL. In a January 2014 order, the MPUC determined the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. On March 16, 2015, the administrative law judge recommended the MPUC grant a Certificate of Need for construction of the GNTL. In April 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. In a July 2014 order, the MPUC determined the route permit application to be complete. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is anticipated to begin in 2016 and to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, depending on the final route of the line. Minnesota Power is expected to have majority ownership of the transmission line.

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements are under consideration by both Congress and the EPA. Minnesota Power's fossil fuel facilities will likely be subject to regulation under these proposals. Our intention is to reduce our exposure to these requirements by reshaping our generation portfolio over time to reduce our reliance on coal.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to expected future restrictive environmental requirements imposed through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to project power supply trends and impacts on customers.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, baghouses and low NO_X technologies. Under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

New Source Review (NSR). In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin Unit 2 between the years of 1981 to 2001. Minnesota Power received an additional NOV in April 2011 alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power reached a settlement with the EPA regarding these NOVs and entered into a Consent Decree which was approved by the U.S. District Court for the District of Minnesota (Court) in September 2014. The Consent Decree provided for, among other requirements, more stringent emissions limits at all affected units, the option of refueling, retrofits or retirements at certain small coal units, and the addition of 200 MW of wind energy. Provisions of the Consent Decree require that, by no later than December 31, 2018, Boswell Units 1 and 2 must be retired, refueled, repowered, or emissions rerouted to an existing Boswell scrubber. Minnesota Power estimates that if the units are not retired, capital expenditures could range between $20 million and $40 million. We are evaluating our options with regard to Boswell Units 1 and 2 to comply with the Consent Decree and future anticipated environmental regulations. We are required to notify the EPA no later than December 31, 2016, whether we will retire, refuel, repower or reroute Boswell Units 1 and 2. We believe that future capital expenditures or costs to retire would likely be eligible for recovery in rates over time subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). In April 2014, the U.S. Supreme Court issued an opinion reversing an August 2012 U.S. Court of Appeals for the D.C. Circuit decision that had vacated the CSAPR. The EPA filed a motion with the U.S. Court of Appeals for the D.C. Circuit in June 2014, to have the stay of CSAPR lifted and the CSAPR compliance deadlines tolled by three years. In October 2014, the U.S. Court of Appeals for the D.C. Circuit granted the EPA's motion, allowing the first compliance period, Phase I, to begin on January 1, 2015, with Phase II beginning in 2017.

CSAPR requires five states in the eastern half of the United States, including Minnesota, to significantly improve air quality by reducing power plant emissions that contribute to ozone or fine particulate pollution in other states. These states are required to make summertime NO_x reductions under the CSAPR ozone season control program. CSAPR does not require installation of controls; rather it requires that facilities have sufficient allowances to cover their emissions on an annual basis. These allowances will be allocated to facilities from each state's annual budget and can be bought and sold.

In December 2014, the EPA distributed the CSAPR allowances to CSAPR-subject units for the Phase I years (2015 and 2016). Phase II allowances (2017-2020) have not been distributed. Based on our initial accounting of the NO_x and SO_2 Phase I allowances already issued, and our review of the CSAPR Phase II allowances not yet issued, we currently expect projected generation levels and emission rates will be in compliance in both Phase I and Phase II.

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA published the final MATS rule in the Federal Register in February 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 187 listed HAPs that the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources must be in compliance with the rule by April 2015. States have the authority to grant sources a one-year extension. Minnesota Power was notified by the MPCA that it has approved Minnesota Power's request for an additional year extending the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016. Compliance at

Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures of approximately $260 million through 2016, of which $162 million was spent through March 31, 2015. Boswell Unit 3 is also subject to the MATS rule; however, the emission reduction investments completed in 2009 at our Boswell Unit 3 generating unit substantially meet the requirements of the MATS rule. Our "EnergyForward" plan, which was approved as part of our 2013 Integrated Resource Plan by the MPUC in a November 2013 order, also includes the conversion of Laskin Units 1 and 2 to natural gas in 2015 to position the Company for MATS compliance. In January 2014, the MPCA approved Minnesota Power's application to extend the deadline for Taconite Harbor Unit 3 to comply with MATS to June 1, 2015, in order to align the Unit 3 retirement with MISO's resource planning year.

Minnesota Mercury Emissions Reduction Act/Rule. In order to comply with the 2006 Minnesota Mercury Emissions Reduction Act, which was incorporated into rules promulgated by the MPCA in September 2014, Minnesota Power must implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above, which is required to be completed by April 1, 2016 (see Mercury and Air Toxics Standards (MATS) Rule), will fulfill the requirements of the Minnesota Mercury Emissions Reduction Act.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. A final rule issued by the EPA for Industrial Boiler Maximum Achievable Control Technology (Industrial Boiler MACT) became effective in December 2012. Major existing sources have until January 31, 2016, to achieve compliance with the final rule. Minnesota Power's Hibbard Renewable Energy Center and Rapids Energy Center are subject to this rule. We expect compliance to consist largely of adjustments to our operating practices; therefore costs for complying with the final rule are not expected to be material at this time.

Proposed and Finalized National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants than the NAAQS. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

Ozone NAAQS. The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. In November 2014, the EPA proposed a 65 to 70 parts per billion (ppb) NAAQS for ground level ozone. The EPA is proposing to update both the primary ozone standard and the secondary standard. Both standards would be 8-hour standards set within a range of 65 to 70 ppb. The EPA is also seeking comment on levels for the primary standard as low as 60 ppb. The EPA has announced it will accept comments on all aspects of the proposal, including retaining the existing standard. A final rule is expected to be issued in the fourth quarter of 2015. The costs for complying with the final ozone NAAQS cannot be estimated at this time.

Particulate Matter NAAQS. The EPA finalized the Particulate Matter NAAQS in September 2006. Since then, the EPA has established more stringent 24-hour and annual average fine particulate matter ($PM_{2.5}$) standards; the 24-hour coarse particulate matter standard has remained unchanged. In December 2012, the EPA issued a final rule implementing a more stringent annual $PM_{2.5}$ standard, while retaining the current 24-hour $PM_{2.5}$ standard. To implement the new annual $PM_{2.5}$ standard, the EPA is also revising aspects of relevant monitoring, designation and permitting requirements. New projects and permits must comply with the new standard, which is generally demonstrated by modeling at the facility level.

Under the final rule, states will be responsible for additional $PM_{2.5}$ monitoring, which will likely be accomplished by relocating or repurposing existing monitors. The EPA asked states to submit attainment designations by December 2013, based on already available monitoring data. The EPA issued designations of 2012 fine particulate attainment status in December 2014. Minnesota retained attainment status; however, Minnesota sources may ultimately be required to reduce their emissions to assist with attainment in neighboring states. Accordingly, the costs for complying with the final Particulate Matter NAAQS cannot be estimated at this time.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized one-hour NAAQS for SO_2 and NO_2. Ambient monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also may require the EPA to evaluate modeling data to determine attainment. In April 2012, the MPCA notified Minnesota Power that modeling had been suspended as a result of the EPA's announcement that the SIP submittals would not require modeling demonstrations for states, such as Minnesota, where ambient monitors indicate compliance with the new standard. The EPA notified states that their infrastructure SIPs for maintaining attainment of the standard were required to be submitted to the EPA for approval by June 2013. However, the State of Minnesota has delayed completing the documents pending EPA guidance to states for preparing the SIP submittal. The MPCA has indicated it will communicate with affected sources once it has more information on how the state will meet the

EPA's SIP requirements. Guidance was expected in 2013 but has been delayed. Currently, compliance with these new NAAQS is expected to be required as early as 2017. The costs for complying with the final standards cannot be estimated at this time.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

In July 2014, the Fond du Lac Band of Lake Superior Chippewa (Band) announced that it had petitioned the EPA to redesignate its reservation air shed from Class II to Class I air quality pursuant to Section 164(c) of the Clean Air Act. The Band does not currently possess authority to directly regulate air quality. Federal Class I air shed status, if granted, would allow the Band to impose more stringent Clean Air Act protections within the boundaries of the Fond du Lac reservation, including the reservation air shed, near Cloquet, Minnesota. Five other reservations across the U.S. have applied for and received Class I status. A public hearing was held by the Band in October 2014, and the public comment period on the petition expired in November 2014. After the Band prepares responses to the comments, the Band will make a formal submittal request to the EPA. There is no deadline for the approval, denial, or modification of the request by the EPA. The Company has requested additional clarification from the Band and the MPCA on the final regulatory structure that may arise from a Class I redesignation. We are unable to determine the impact of potential Class I status on the Company’s operations at this time.

Climate Change. The scientific community generally accepts that emissions of GHG are linked to global climate change which creates physical and financial risks. Physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and changes in the intensity and frequency of extreme weather events. These all have the potential to affect the Company’s business and operations. We are addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers’ requirements:

- Expanding our renewable energy supply;
- Providing energy conservation initiatives for our customers and engaging in other demand side efforts;
- Improving efficiency of our energy generating facilities;
- Supporting research of technologies to reduce carbon emissions from generation facilities and carbon sequestration efforts; and
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas generating facilities.

President Obama’s Climate Action Plan. In June 2013, President Obama announced a Climate Action Plan (CAP) that calls for implementation of measures that reduce GHG emissions in the U.S., emphasizing means such as expanded deployment of renewable energy resources, energy and resource conservation, energy efficiency improvements and a shift to fuel sources that have lower emissions. Certain portions of the CAP directly address electric utility GHG emissions.

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, existing facilities that undergo major modifications and other facilities characterized as major sources under the Clean Air Act’s Title V program. For our existing facilities, the rule does not require amending our existing Title V operating permits to include GHG requirements. However, GHG requirements are likely to be added to our existing Title V operating permits by the MPCA as these permits are renewed or amended.

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific, top-down Best Available Control Technology (BACT) determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible that these control technologies could be determined to be BACT on a project-by-project basis.

In June 2014, the U.S. Supreme Court invalidated the aspect of the Tailoring Rule that established lower permitting thresholds for GHG than for other pollutants subject to PSD. However, the court also upheld the EPA's power to require BACT for GHG from sources already subject to regulation under PSD. Minnesota Power's coal-fired generating facilities are already subject to regulation under PSD, so we anticipate that ultimately PSD for GHG will apply to our facilities, but the timing of the promulgation of a replacement for the Tailoring Rule is uncertain. The PSD applies to existing facilities only when they undertake a major modification that increases emissions. At this time, we are unable to predict the compliance costs that we might incur.

In March 2012, the EPA announced a proposed rule to apply CO_2 emission New Source Performance Standards (NSPS), under Section 111(b) of the Clean Air Act, to new fossil fuel-fired electric generating units. The proposed NSPS would have applied only to new or re-powered units. Based on the volume of comments received, the EPA announced its intent to re-propose the rule. In September 2013, the EPA retracted its March 2012 proposal and announced the release of a revised NSPS for new or re-powered utility CO_2 emissions.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

In June 2014, the EPA announced a proposed rule under Section 111(d) of the Clean Air Act for existing power plants entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units" (CPP). The EPA is expected to finalize such rules by the summer of 2015. In the CPP, the EPA proposes to set state-specific goals for CO_2 emissions from the power sector. The EPA maintains such goals are achievable if a state undertakes a combination of measures across its power sector that constitute the EPA's guideline for a Best System of Emission Reductions (BSER).

The EPA proposed that BSER is comprised of four building blocks: 1) improved fossil fuel power plant efficiency, 2) increased reliance on low-emitting power sources by generating more electricity from existing natural gas combined cycle units, 3) building more or preserving existing zero- and low-emitting power sources, including renewable and nuclear energy, and 4) more efficient electricity use by consumers.

The EPA then established state goals, expressed as a carbon intensity target in CO_2 tons per megawatt hour, by estimating the achievability of the building blocks in each state. Using 2012 emissions data, the EPA derived interim goals for states to be met over the years 2020-2029, as well as a final goal to be met in 2030 and thereafter. Under the CPP, each state would be required to develop a state implementation plan by June 30, 2016. Minnesota Power is currently evaluating the CPP as it relates to the State of Minnesota and its potential impact on the Company. We submitted comments on the CPP to the EPA.

Minnesota has already initiated several measures consistent with those called for under the CAP and CPP. Minnesota Power is implementing its "EnergyForward" strategic plan that provides for significant emission reductions and diversifying its electricity generation mix to include more renewable and natural gas energy. (See Note 8. Regulatory Matters.)

We are unable to predict the GHG emission compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Minnesota's Next Generation Energy Act of 2007. In April 2014, a U.S. District Court for the District of Minnesota ruled that part of Minnesota's Next Generation Energy Act of 2007 violated the Commerce Clause of the U.S. Constitution. The portions of the law which were ruled unconstitutional prohibited the importation of power from a new CO_2-producing facility outside of Minnesota and prohibited the entry into new long-term power purchase agreements that would increase CO_2 emissions in Minnesota. The State of Minnesota appealed the decision to the U.S. Court of Appeals for the Eighth Circuit in May 2014.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations.

Clean Water Act - Aquatic Organisms. In April 2011, the EPA announced proposed regulations under Section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes, and have a design intake flow of greater than 2 million gallons per day, to limit the number of aquatic organisms that are impacted by the facility's intake structure or cooling system. The Section 316(b) rule was published in the Federal Register in August 2014, with an effective date in October 2014. The Section 316(b) standards will be implemented through NPDES permits issued to the covered facilities with compliance timing dependent on individual NPDES renewal schedules. No NPDES permits have been re-issued containing Section 316(b) requirements since the final rule was published, so at this time we are unable to determine the final cost of compliance; however, our preliminary assessment suggests costs of compliance could be up to approximately $15 million. We would seek recovery of any additional costs through a general rate case.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Steam Electric Power Generating Effluent Guidelines. In April 2013, the EPA announced proposed revisions to the federal effluent guidelines for steam electric power generating stations under the Clean Water Act. The proposed revisions would set limits on the level of toxic materials in wastewater discharged from seven waste streams: flue gas desulfurization wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, non-chemical metal cleaning wastes, coal gasification wastewater, and wastewater from flue gas mercury control systems. As part of this proposed rulemaking, the EPA is considering imposing rules to address “legacy” wastewater currently residing in ponds as well as rules to impose stringent best management practices for discharges from active coal combustion residual surface impoundments. The EPA’s proposed rulemaking would base effluent limitations on what can be achieved by available technologies. The proposed rule was published in the Federal Register in June 2013, and public comments were due in September 2013. The EPA is expected to issue the final rule by September 30, 2015. Compliance with the final rule, as proposed, would be required no later than July 1, 2022. We are reviewing the proposed rule and evaluating its potential impacts on our operations. We are unable to predict the compliance costs we might incur related to these or other potential future water discharge regulations; however, the costs could be material, including costs associated with retrofits for bottom ash handling, pond dewatering, pond closure, and wastewater treatment and/or reuse. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals (CCR) generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash under Subtitle D of Resource Conservation and Recovery Act (RCRA) (non-hazardous) or Subtitle C of RCRA (hazardous).

The EPA issued the final CCR rule in December 2014 under Subtitle D (non-hazardous) of RCRA with a final publication date of April 27, 2015. The rule includes additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. The final rule also includes provisions that could incentivize early closure of existing impoundments within a three-year window. Costs of compliance, primarily for Boswell and Laskin, could be up to approximately $130 million. The Company continues to work on minimizing costs on behalf of customers through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. We would seek recovery of any additional costs through a general rate case.

Other Matters.

ALLETE Clean Energy. In January 2014, ALLETE Clean Energy acquired three wind energy facilities–Lake Benton, Storm Lake II and Condon. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032. In December 2014, ALLETE Clean Energy acquired a wind facility, Storm Lake I, which has a PPA in place for its entire output which expires in 2018. On April 15, 2015, ALLETE Clean Energy acquired wind facilities in southern Minnesota with PPAs in place for the entire output, which expire in 2018 and 2023. (See Note 4. Acquisitions.)

U.S. Water Services. As of March 31, 2015, U.S. Water Services has $3.2 million outstanding in stand-by letters of credit.

BNI Coal. As of March 31, 2015, BNI Coal had surety bonds outstanding of $49.5 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit for an additional $0.6 million to provide for BNI Coal’s total reclamation liability, which is currently estimated at $49.3 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Other Matters (Continued)

ALLETE Properties. As of March 31, 2015, ALLETE Properties, through its subsidiaries, had surety bonds outstanding and letters of credit to governmental entities totaling $10.2 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is approximately $7.1 million. ALLETE Properties does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and are secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006 for Town Center and November 2007 for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At March 31, 2015, we owned 72 percent of the assessable land in the Town Center District (72 percent at December 31, 2014) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2014). At these ownership levels, our annual assessments are approximately $1.4 million for Town Center and $2.1 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. In accordance with accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, and compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

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

OVERVIEW

The following discussion should be read in conjunction with our Consolidated Financial Statements and notes to those statements, Management’s Discussion and Analysis of Financial Condition and Results of Operations from the 2014 Form 10-K and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-Q contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-Q under the headings: “Forward-Looking Statements” located on page 5, “Risk Factors” located in Part I, Item 1A, beginning on page 29 of our 2014 Form 10-K, and in “Item 1A. Risk Factors” in this Form 10-Q beginning on page 54. The risks and uncertainties described in this Form 10-Q and our 2014 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the risks are realized.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

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

Investments and Other is comprised primarily of our Energy Infrastructure and Related Services businesses: ALLETE Clean Energy, U.S. Water Services and BNI Coal. ALLETE Clean Energy is our business aimed at acquiring or developing capital projects that create energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations. U.S. Water Services is our integrated water management company which was acquired February 10, 2015. BNI Coal is our coal mining operations in North Dakota. Investments and Other also includes ALLETE Properties, our Florida real estate investment, and other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of March 31, 2015, unless otherwise indicated. All subsidiaries are wholly-owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

Financial Overview

The following net income discussion summarizes a comparison of the three months ended March 31, 2015, to the three months ended March 31, 2014.

Net income attributable to ALLETE for the three months ended March 31, 2015, was $39.9 million, or $0.85 per diluted share, compared to $33.5 million, or $0.80 per diluted share, for the same period of 2014. Net income for 2015 reflected a $3.0 million after-tax expense, or $0.06 per share, of acquisition costs for the February 10, 2015 acquisition of U.S. Water Services. Net income in 2014 reflected a $1.4 million after-tax expense, or $0.03 per share, of acquisition costs for ALLETE Clean Energy's wind energy facilities acquisition in January 2014. Net income for 2015 reflected higher net income at Minnesota Power and ALLETE Clean Energy. Earnings per share dilution was $0.11 due to additional shares of common stock outstanding as of March 31, 2015.

Regulated Operations net income attributable to ALLETE was $41.4 million for the three months ended March 31, 2015, compared to $33.9 million for the same period of 2014. Net income for 2015 reflected higher net income at Minnesota Power primarily due to higher cost recovery rider revenue, production tax credits, and power marketing sales as the Minnkota Power sales agreement commenced June 1, 2014. These increases were partially offset by higher depreciation and interest expenses. Our equity earnings in ATC for the three months ended March 31, 2015 reflected a $0.8 million after-tax reduction related to complaints filed with the FERC.

Investments and Other net loss attributable to ALLETE was $1.5 million for the three months ended March 31, 2015, compared to a net loss of $0.4 million for the same period of 2014. The net loss for 2015 reflected a $3.0 million after-tax expense of acquisition costs for the February 10, 2015 acquisition of U.S. Water Services. The net loss in 2014 reflected a $1.4 million after-tax expense of acquisition costs for ALLETE Clean Energy's wind energy facilities acquisition in January 2014. Net income at ALLETE Clean Energy increased $1.4 million over 2014 primarily due to operations of the wind energy facilities which were acquired in 2014.

COMPARISON OF THE THREE MONTHS ENDED MARCH 31, 2015 AND 2014

(See Note 2. Business Segments for financial results by segment.)

Regulated Operations

Operating Revenue decreased $1.4 million, or 1 percent, from 2014 primarily due to lower fuel adjustment clause recoveries and gas sales, partially offset by higher cost recovery rider revenues, transmission revenues, and kilowatt-hour sales.

Fuel adjustment clause recoveries decreased $10.0 million due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Gas sales at SWL&P decreased $4.8 million from 2014 as a result of unseasonably cold weather during the first quarter of 2014. (See Cost of Sales.)

COMPARISON OF THE THREE MONTHS ENDED MARCH 31, 2015 AND 2014 (Continued)
Regulated Operations (Continued)

Cost recovery rider revenue increased $8.2 million primarily due to the completion of our Bison Wind Energy Center and CapX2020 projects and higher capital expenditures related to our Boswell Unit 4 environmental upgrade.

Transmission revenue increased $2.9 million primarily due to higher MISO related revenues.

Revenue from Regulated Operations increased $2.2 million due to a 7.4 percent increase in kWh sales. Although total kWh sales for the first quarter of 2015 were 7.4 percent higher than the same period in 2014, market prices for sales to Other Power Suppliers were lower than residential and commercial rates, resulting in proportionally lower revenues. Sales to our residential, commercial, and municipal customers decreased 10.6 percent, 2.8 percent, and 3.7 percent, respectively, primarily due to unseasonably cold temperatures during the first quarter of 2014 compared to the same period in 2015. Heating degree days in Duluth, Minnesota were approximately 14 percent lower in the first quarter of 2015 compared to the same period in 2014. Sales to our industrial customers increased 7.4 percent primarily due to the unseasonably cold temperatures in 2014 adversely affecting our taconite customers operations. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations, and increased 27.3 percent in 2015 compared to 2014 due to the commencement of the Minnkota Power sales agreement on June 1, 2014. (See Note 16. Commitments, Guarantees and Contingencies.)

Kilowatt-hours Sold Three months ended March 31,	2015	2014	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	356	398	(42)	(10.6)%
Commercial	384	395	(11)	(2.8)%
Industrial	1,950	1,816	134	7.4%
Municipal	233	242	(9)	(3.7)%
Total Retail and Municipal	2,923	2,851	72	2.5%
Other Power Suppliers	891	700	191	27.3%
Total Regulated Utility Kilowatt-hours Sold	3,814	3,551	263	7.4%

Revenue from electric sales to taconite/iron concentrate customers accounted for 20 percent of consolidated operating revenue in 2015 (22 percent in 2014). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 6 percent of consolidated operating revenue in 2015 (7 percent in 2014). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2015 (6 percent in 2014).

Operating Expenses decreased $7.4 million, or 3 percent, from 2014.

Fuel and Purchased Power expense decreased $10.2 million, or 11 percent, from 2014 primarily due to lower prices for purchased power in 2015 compared to 2014 which was partially offset by increased quantities of purchased power resulting from a 7.4 percent increase in kWh sales. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue.)

Transmission Services expense increased $4.1 million, or 38 percent, from 2014 primarily due to higher MISO related expenses.

Cost of Sales decreased $4.2 million, or 48 percent, from 2014 due to lower purchased gas at SWL&P. (See Operating Revenue.)

Depreciation and Amortization expense increased $3.3 million, or 11 percent, from 2014 primarily reflecting additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $1.4 million, or 14 percent, from 2014 primarily due to higher property tax expenses resulting from higher taxable plant and rates.

Interest Expense increased $1.5 million, or 13 percent, from 2014 primarily due to higher average long-term debt balances.

COMPARISON OF THE THREE MONTHS ENDED MARCH 31, 2015 AND 2014 (Continued)
Regulated Operations (Continued)

Equity Earnings in ATC decreased $1.2 million, or 24 percent, from 2014 primarily due to a $1.4 million expense related to complaints filed with the FERC; of the $1.4 million expense, $1.1 million was attributable to ATC’s change in estimate of a refund liability recorded in a previous period.

Other Income decreased $0.9 million, or 50 percent, from 2014 primarily due to lower AFUDC–Equity.

Income Tax Expense decreased $5.1 million, or 49 percent, from 2014 primarily due to increased production tax credits as a result of the completion of the Bison Wind Energy Center in December 2014.

Investments and Other

Operating Revenue increased $24.9 million, or 77 percent, from 2014 primarily due to an increase in revenue from U.S. Water Services which was acquired February 10, 2015. Also contributing to the increase was increased revenue at ALLETE Clean Energy primarily due to operations of the wind energy facilities which were acquired in 2014, and an increase in revenue at BNI Coal, which operates under cost-plus fixed fee contracts, as a result of higher expenses in 2015. (See Cost of Sales.)

Operating Expenses increased $22.8 million, or 69 percent, from 2014.

Cost of Sales increased $11.9 million, or 80 percent, from 2014 primarily due to the acquisition of U.S. Water Services and higher expenses at BNI Coal primarily due to increased contractor services and repair expenses, which are recovered through cost-plus fixed fee contracts. (See Operating Revenue.) Cost of sales also included $0.6 million of expense relating to fair value adjustments for inventories and sales backlog which resulted from the U.S. Water Services acquisition. Purchase accounting requires inventories and sales backlog at the date of acquisition to be recognized at fair value. The total estimated fair value adjustment to inventories and sales backlog of $4.3 million will be reflected in Cost of Sales over approximately one year from the date of acquisition. (See Note 4. Acquisitions.)

Operating and Maintenance expense increased $7.2 million, or 52 percent, from 2014 primarily due to operating expenses and $3.2 million of acquisition costs relating to the acquisition of U.S. Water Services. These increases were partially offset by ALLETE Clean Energy’s acquisition costs of $1.6 million in 2014 resulting from the January 2014 acquisition of three wind energy facilities.

Depreciation and Amortization expense increased $3.5 million, or 103 percent, from 2014 reflecting additional property, plant and equipment in service due primarily to recent acquisitions. Also contributing to the increase was the amortization of intangibles acquired through the U.S. Water Services acquisition.

Taxes Other than Income Taxes increased $0.2 million, or 20 percent, from 2014 primarily due to higher property taxes at ALLETE Clean Energy resulting from the wind facilities acquisitions in 2014.

Interest Expense increased $0.8 million, or 62 percent, from 2014 primarily due to higher average long-term debt balances.

Income Tax Expense increased $2.5 million, or 147 percent, from 2014 primarily due to a decrease in pretax losses.

Income Taxes – Consolidated

For the three months ended March 31, 2015, the effective tax rate was 13.4 percent (20.7 percent for the three months ended March 31, 2014). The decrease in the effective tax rate from March 31, 2014, was primarily due to increased production tax credits. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC–Equity, investment tax credits, production tax credits and depletion. (See Note 12. Income Tax Expense.)

CRITICAL ACCOUNTING POLICIES

Certain accounting measurements under U.S. GAAP involve management’s judgment about subjective factors and estimates, the effects of which are inherently uncertain. Accounting measurements that we believe are most critical to our reported results of operations and financial condition include: regulatory accounting, pension and postretirement health and life actuarial assumptions, impairment of long-lived assets and taxation. These policies are reviewed with the Audit Committee of our Board of Directors on a regular basis and summarized in Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations of our 2014 Form 10-K. As a result of our acquisition of U.S. Water Services on February 10, 2015, the valuation of intangible assets and goodwill are considered critical accounting policies.

Valuation of Goodwill and Intangible Assets

When we acquire a business, the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition date. Determining the fair value of intangible assets acquired as part of a business combination requires us to make significant estimates. These estimates include the amount and timing of projected future cash flows, the discount rate used to discount those cash flows to present value, the assessment of the asset’s life cycle, and the consideration of legal, technical, regulatory, economic, and competitive risks. The fair value assigned to intangible assets is determined by estimating the future cash flows of each project and discounting the net cash flows back to their present values. The discount rate used is determined at the time of measurement in accordance with accepted valuation standards.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with U.S. GAAP, goodwill is not amortized. The Company assesses whether there has been an impairment of goodwill annually in the third quarter and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit’s net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. Our estimates associated with the goodwill impairment test are considered critical due to the amount of goodwill recorded on our Consolidated Balance Sheet and the judgment required in determining fair value, including projected future cash flows. The results of our annual impairment test are discussed in Note 7. Fair Value to the Consolidated Financial Statements in this Form 10-Q. Goodwill was $130.0 million and $2.9 million as of March 31, 2015 and December 31, 2014, respectively.

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements and trademarks and trade names. Intangible assets with definite lives consist of customer relationships, patents, and non-compete agreements, which are amortized on a straight-line or accelerated basis with estimated useful lives ranging from less than 1 year to 23 years. We review definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and trade names, which are tested for impairment annually in the third quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset’s carrying amount over its fair value. Our impairment reviews are based on an estimated future cash flow approach that requires significant judgment with respect to future revenue and expense growth rates, selection of appropriate discount rate, and other assumptions and estimates. We use estimates that are consistent with our business plans and a market participant view of the assets being evaluated. The results of our annual impairment test are discussed in Note 7. Fair Value to the Consolidated Financial Statements in this Form 10-Q. Actual results may differ from our estimates due to a number of risk factors, including those which are discussed in Item 1A, "Risk Factors" in this Form 10-Q. Intangible assets, net of accumulated amortization, were $84.3 million and $1.9 million as of March 31, 2015 and December 31, 2014, respectively.

OUTLOOK

For additional information see our 2014 Form 10-K.

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has long-term objectives of achieving average earnings per share growth of 5 percent per year and providing a dividend payout competitive with our industry.

ALLETE is predominantly a regulated utility through Minnesota Power, SWL&P and an investment in ATC. Minnesota Power believes it is well positioned for the future as it executes on its EnergyForward initiative and serves a potentially growing industrial customer base. Minnesota Power will continue to pursue customer growth opportunities and cost recovery rider approval for environmental, renewable and transmission investments, as well as work with regulators to earn a fair rate of return. We believe that ATC is poised for future growth both organically and through its partnership with Duke Energy.

In February 2015, ALLETE acquired U.S. Water Services, consistent with ALLETE's stated strategy of investing in energy infrastructure and related services to complement its core regulated utility, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. ALLETE will now focus its energy infrastructure and related service efforts on ALLETE Clean Energy, U.S. Water Services and BNI Coal. ALLETE Clean Energy has a growing portfolio of wind generating facilities, and U.S. Water Services provides integrated water management to a growing base of industrial and commercial customers. ALLETE's Energy Infrastructure and Related Services businesses primarily have contracted or recurring revenues.

ALLETE is focused on providing sustainable solutions to our customers, as exemplified by the EnergyForward and Power of One initiatives at Minnesota Power, renewable energy investments at ALLETE Clean Energy, and investment in U.S. Water Services.

Regulated Operations. Minnesota Power's long-term strategy is to be the leading electric energy provider in northeastern Minnesota by providing safe, reliable and cost-competitive electric energy, while complying with environmental permit conditions and renewable energy requirements. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain customer viability. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. (See Regulated Operations – EnergyForward.) We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. Minnesota Power will continue to pursue customer growth opportunities and cost recovery rider approval for environmental, renewable and transmission investments, as well as work with regulators to earn a fair rate of return. We project that Minnesota Power will not earn its allowed rate of return in 2015.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC, the PSCW or the NDPSC. See Note 8. Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, Wisconsin and North Dakota jurisdictions.

Industrial Customers and Prospective Additional Load

Industrial Customers. Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and wood products, and pipeline industries. Approximately 48 percent of our Regulated Utility kWh sales in the three months ended March 31, 2015 (51 percent in the three months ended March 31, 2014) were made to our industrial customers in these industries.

Minnesota Power provides electric service to five taconite customers capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute (AISI), an association of North American steel producers, reported that U.S. raw steel production operated at approximately 73 percent of capacity during the first three months of 2015 compared to 77 percent in the first three months of 2014. Many steel producers have reduced production this year, citing high levels of imports and lower prices. Some Minnesota taconite and iron concentrate producers have reduced production in response to declining U.S. taconite demand primarily resulting from the higher level of imports and lower prices.

OUTLOOK (Continued)
Industrial Customers and Prospective Additional Load (Continued)

USS Corporation. USS Corporation announced on March 12, 2015 that it will temporarily idle its Minnesota Ore Operations - Keetac plant in Keewatin, MN, effective May 13, 2015. In addition, USS Corporation announced on March 31, 2015 that it will adjust operations and temporarily idle a portion of its Minnesota Ore Operations - Minntac plant in Mountain Iron, MN, effective June 1, 2015. These actions are due to its current inventory levels and ongoing adjustment of its steel producing operations throughout North America. USS Corporation has stated that it will continue to operate the Minntac plant at reduced capacity in order to meet customer demand, and stated the ongoing operational adjustments are a result of challenging market conditions that reflect the cyclical nature of the industry. Global influences in the market, including a high level of imports, unfairly traded products and reduced steel prices, were cited as having an impact. Both facilities are Large Power Customers of Minnesota Power. USS Corporation reported that its Keetac and Minntac plants produced approximately 5 million tons and 16 million tons of taconite, respectively, in 2014.

Minnesota Power's Large Power taconite customers, subject to demand nomination requirements, have nominated at full demand levels through August 31, 2015, including USS Corporation's Minnesota Ore Operations. Nominations for the subsequent four-month period are due August 1, 2015. We are unable to predict the level of demand nominations for periods subsequent to August 31, 2015. If there are reductions in demand nominations, we will market available power to Other Power Suppliers in an effort to mitigate the earnings impact. Sales to Other Power Suppliers are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. We can make no assurances that our power marketing efforts would fully offset any reduction in earnings resulting from lower demand nominations from our industrial customers.

Our taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in our taconite customers' production would impact our annual earnings per share by approximately $0.03, net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead us to file a rate case to recover lost revenues.

Magnetation. On May 5, 2015 Magnetation announced that it had reached an agreement with holders of more than 70 percent of its 11.0 percent senior secured notes due 2018 to restructure its balance sheet and provide liquidity to support long-term operations. To implement this restructuring, Magnetation announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Minnesota, citing the significant decrease in global iron ore prices and existing capital structure.

Magnetation stated that it intends to continue to pay suppliers and vendors in full under normal terms for goods and services provided after the bankruptcy filing date of May 5, 2015. Magnetation stated that it expects its mining and pelletizing operations and customer shipments to continue in the ordinary course throughout the reorganization.

Magnetation is a Large Power Customer of Minnesota Power. On January 27, 2014 Minnesota Power and Magnetation entered into a ten-year electric service agreement for its new concentrate facility near Coleraine, Minnesota. Minnesota Power received full demand nominations on March 1 for the May-August period indicating full production, consistent with the operating expectations that Magnetation communicated in their May 5 announcement. Minnesota Power's pre-petition amounts due from Magnetation as of May 5, 2015 are less than $1 million.

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource based projects that represent long-term growth potential and load diversity for Minnesota Power. We cannot predict the outcome of these projects.

Nashwauk Public Utilities Commission. On April 21, 2015, the Company amended its formula-based wholesale electric sales agreement with the Nashwauk Public Utilities Commission for all of its electric service requirements, extending the term through June 30, 2028. A new Essar taconite facility is currently under construction in the city of Nashwauk, and the Nashwauk Public Utilities Commission also amended and extended its electric service agreement with Essar. Upon completion, this facility would result in approximately 110 MW of additional load for Minnesota Power. Essar announced the completion of project financing in October 2014 and has stated that it expects to achieve full production capability in 2016.

OUTLOOK (Continued)

EnergyForward. In January 2013, Minnesota Power announced “EnergyForward”, a strategic plan for assuring reliability, protecting affordability and further improving environmental performance. The plan includes completed and planned investments in wind and hydroelectric power, the addition of natural gas as a generation fuel source, and the installation of emissions control technology. Significant elements of the “EnergyForward” plan include:

- Major wind investments in North Dakota. Our Bison Wind Energy Center added 205 MW of capacity in the fourth quarter of 2014, bringing total capacity to 497 MW. (See Renewable Energy.)
- Planned installation of approximately $260 million in emissions control technology at Boswell Unit 4 to further reduce emissions of SO_2, particulates and mercury. (See Boswell Mercury Emission Reduction Plan.)
- Planning for the proposed GNTL to deliver hydroelectric power from northern Manitoba by 2020. (See Transmission.)
- The conversion of Laskin from coal to cleaner-burning natural gas in the second quarter of 2015.
- Retiring Taconite Harbor Unit 3, one of three coal-fired units at Taconite Harbor, in the second quarter of 2015.

Integrated Resource Plan. In a November 2013 order, the MPUC approved Minnesota Power’s 2013 Integrated Resource Plan which details our “EnergyForward” strategic plan and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. We are required to submit our 2015 Integrated Resource Plan with the MPUC no later than September 1, 2015.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power’s total retail and municipal energy sales in Minnesota to be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power met the 2012 milestone and has developed a plan to meet the future renewable milestones which is included in its 2013 Integrated Resource Plan. Minnesota Power’s 2013 Integrated Resource Plan, which was approved by the MPUC in a November 2013 order, included an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See EnergyForward.)

Minnesota Power continues to execute its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate at the lowest cost for customers. We expect 28 percent of the Company’s total retail and municipal energy sales will be supplied by renewable energy sources in 2015.

Minnesota Solar Energy Standard. In May 2013, legislation was enacted by the state of Minnesota requiring at least 1.5 percent of total retail electric sales, excluding sales to certain industrial customers, to be generated by solar energy by the end of 2020. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Minnesota Power is in the process of evaluating the potential impact of this legislation on our operations; however, any costs are expected to be recovered in customer rates.

Wind Energy. Our wind energy facilities consist of the 497 MW Bison Wind Energy Center located in North Dakota, which was placed in service in various phases between 2010 and 2014, and the 25 MW Taconite Ridge Energy Center located in northeastern Minnesota. We also have two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) located in North Dakota.

Customer billing rates for our Bison 1, 2, & 3 wind facilities were approved by the MPUC in a December 2013 order. In April 2014 and November 2014, we filed renewable resources factor filings which included updated costs associated with the Bison Wind Energy Center. Upon approval of the filings, we will be authorized to include updated billing rates on customer bills.

Minnesota Power uses the 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte’s lignite coal-fired generating unit. The DC transmission line capacity can be increased if renewable energy or transmission needs justify investments to upgrade the line.

OUTLOOK (Continued)
Energy Forward (Continued)

Manitoba Hydro. Minnesota Power has a long-term PPA with Manitoba Hydro that expires in May 2020. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index. In addition, Minnesota Power has a separate long-term PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only agreement primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term.

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro for 15 years beginning in 2020. The agreement is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

In July 2014, Minnesota Power and Manitoba Hydro signed a long-term PPA that provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro for 20 years beginning in 2020. The pricing under this PPA is based on forward market prices. The agreement was approved by the MPUC in an order dated January 30, 2015, and is subject to the construction of the GNTL. (See Transmission.)

Hydro Operations. On February 13, 2015, Minnesota Power supplemented its November 2014 renewable resources factor filing to include costs associated with the restoration and repair of Thomson. In an order dated March 5, 2015, the MPUC approved our petition seeking cost recovery of investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider.

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be approximately $260 million, of which $162 million was spent through March 31, 2015. In a November 2013 order, the MPUC approved the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. Customer billing rates for the environmental improvement rider were approved by the MPUC in a July 2014 order. In November 2014, we filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of this filing, we will be authorized to include updated billing rates on customer bills.

Transmission. We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include the GNTL and the CapX2020 initiative, as well as investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others), and our investment in ATC.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives and municipal and investor-owned utilities, including Minnesota’s largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020.

On April 2, 2015, the CapX2020 transmission line project from Fargo, North Dakota to St. Cloud, Minnesota was completed and placed into service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed into service in 2011 and 2012.

Minnesota Power invested approximately $100 million to complete the three transmission line projects. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

OUTLOOK (Continued)
Regulated Operations (Continued)

Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220-mile 500 kV transmission line, between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

The GNTL is subject to various federal and state regulatory approvals. In October 2013, a Certificate of Need application was filed with the MPUC with respect to the GNTL. In a January 2014 order, the MPUC determined the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. On March 16, 2015, the administrative law judge recommended the MPUC grant a Certificate of Need for construction of the GNTL. In April 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. In a July 2014 order, the MPUC determined the route permit application to be complete. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is anticipated to begin in 2016 and to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, depending on the final route of the line. Minnesota Power is expected to have majority ownership of the transmission line.

Investment in ATC. As of March 31, 2015, our equity investment in ATC was $122.3 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. ATC's 10-year transmission assessment, which covers the years 2014 through 2023, identifies a need for between $3.3 billion and $3.9 billion in transmission system investments. These investments by ATC are expected to be funded through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC. In the first three months of 2015, we invested $0.4 million in ATC, and on April 29, 2015, we invested an additional $0.4 million. We expect to make additional investments of $1.1 million in 2015. (See Note 9. Investment in ATC.)

Our equity earnings in ATC for the three months ended March 31, 2015 were $3.9 million and reflected a $1.4 million reduction related to complaints filed with the FERC by several customer groups located within the MISO service area; of the $1.4 million reduction, $1.1 million was attributable to ATC's change in estimate of a refund liability recorded in a previous period. The groups requested, among other things, a reduction in the base return on equity used by MISO transmission owners, including ATC, to 9.15 percent. ATC's current authorized return on equity is 12.2 percent. On February 12, 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity used to 8.67 percent. We own approximately 8 percent of ATC and estimate that for every 50 basis point reduction in ATC's allowed return on equity our equity earnings in ATC would be impacted annually by approximately $0.5 million on an after-tax basis ($0.9 million pre-tax).

Investments and Other.

ALLETE Clean Energy. ALLETE Clean Energy aims to acquire or develop capital projects that create energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations. In January 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake II) and Condon, Oregon (Condon) from The AES Corporation (AES) for $26.9 million.

Lake Benton, Storm Lake II and Condon have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake II began commercial operations in 1999, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032. Armenia Mountain has 100.5 MW of generating capability, began commercial operations in 2009, and has PPAs in place for the entire output, which expire in 2025.

In November 2014, ALLETE Clean Energy acquired a business for $27.0 million to develop a wind facility near Hettinger, North Dakota. ALLETE Clean Energy is developing and constructing a 107 MW wind facility consisting of 43 turbines, which is to be sold to Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., for approximately $200 million. Construction is expected to be completed in December 2015, and the sale is subject to regulatory approval from the NDPSC. If regulatory approval is not obtained for the sale of the wind facility, ALLETE Clean Energy would then own and operate the facility and sell the entire output to Montana-Dakota Utilities Co. under a long-term PPA.

OUTLOOK (Continued)
Investments and Other (Continued)

In December 2014, ALLETE Clean Energy acquired a wind energy facility in Storm Lake, Iowa (Storm Lake I) from NRG Energy, Inc. for $15.1 million. Storm Lake I has 108 MW of generating capability and is located adjacent to Storm Lake II. The wind generation facility began commercial operations in 1999 and has a PPA in place for its entire output which expires in 2018.

On April 15, 2015, ALLETE Clean Energy acquired wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Energy Holdings Limited for $47.5 million, subject to a working capital adjustment. The facilities have 97.5 MW of generating capability and are located near our Lake Benton facility. The wind facilities began commercial operations in 2003 and have PPAs in place for the entire output, which expire in 2018 (12 MW) and 2023 (85.5 MW).

On April 30, 2015, ALLETE Clean Energy signed purchase agreements to acquire a wind energy facility located near Troy, Pennsylvania (Armenia Mountain) from The AES Corporation (AES) and a non-controlling interest from a minority shareholder for $108.0 million, plus the assumption of existing debt. The agreement with AES is subject to a purchase price adjustment. The acquisition is expected to close in July 2015. The facility has 100.5 MW of generating capability, began commercial operations in 2009, and has PPAs in place for the entire output, which expire in 2025.

U.S. Water Services. On February 10, 2015, ALLETE acquired U.S. Water Services. Headquartered in St. Michael, Minnesota, U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage and improve efficiency. U.S. Water Services helps customers achieve efficient and sustainable use of their energy systems, is a leading provider to the biofuels industry, and has a growing presence in the power generation and midstream oil and gas industries. The acquisition is not expected to have a material impact on 2015 earnings per share. (See Note 4. Acquisitions.)

BNI Coal. BNI Coal anticipates selling 4.4 million tons of coal in 2015 (4.0 million tons were sold in 2014) and has sold 1.0 million tons through March 31, 2015 (1.1 million tons were sold as of March 31, 2014). BNI Coal operates under cost-plus fixed fee agreements extending through December 31, 2037.

ALLETE Properties. ALLETE Properties represents our Florida real estate investment. Market conditions can impact land sales and could result in our inability to cover our cost basis, operating expenses or fixed carrying costs such as community development district assessments and property taxes.

Our strategy for ALLETE Properties has been to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell assets in the portfolio over time in order to optimize cash flows in support of future investment opportunities and growth initiatives. Opportunities for growth and investment in our energy infrastructure and related services strategy may impact management’s decisions to divest all or portions of the ALLETE Properties’ asset portfolio; this could impact the timing and pricing of divestitures. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings, is in the permitting stage. The City of Ormond Beach, Florida, approved a development agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

OUTLOOK (Continued)
Investments and Other (Continued)

Summary of Development Projects (100% Owned)	Acres (a)	Residential Units (b)	Non-residential Sq. Ft. (b, c)
Current Development Projects			
Town Center	958	2,359	2,236,700
Palm Coast Park	3,777	3,746	3,096,800
Total Current Development Projects	4,735	6,105	5,333,500
Planned Development Project			
Ormond Crossings	2,901	2,950	3,215,000
Other			
Lake Swamp Wetland Mitigation Project	3,050	(d)	(d)
Total of Development Projects	10,686	9,055	8,548,500

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands.
(b) Units and square footage are estimated. Density at build out may differ from these estimates.
(c) Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.
(d) The Lake Swamp wetland mitigation bank is a permitted, regionally significant wetlands mitigation bank. Wetland mitigation credits will be used at Ormond Crossings and are available-for-sale to developers of other projects that are located in the bank's service area.

In addition to the three development projects and the mitigation bank, ALLETE Properties has 1,670 acres of other land available-for-sale.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2015. On an ongoing basis, ALLETE has tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, production tax credits, AFUDC–Equity, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased federal production tax credits as a result of wind generation, we expect our effective tax rate to be approximately 15 percent for 2015. We also expect that our effective tax rate will be lower than the statutory rate over the next ten years due to production tax credits attributable to our wind generation. (See Note 12. Income Tax Expense.)

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of March 31, 2015, we had cash and cash equivalents of $72.1 million, $360.6 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent.

Capital Structure. ALLETE's capital structure is as follows:

	March 31, 2015	%	December 31, 2014	%
Millions				
ALLETE Equity	$1,768.9	56	$1,609.4	54
Non-Controlling Interest	2.0	—	1.8	—

Long-Term Debt (Including Current Maturities)	1,376.1	44	1,373.5	46
Notes Payable	0.3	—	3.7	—
	$3,147.3	100	$2,988.4	100

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Cash Flows. Selected information from ALLETE's Consolidated Statement of Cash Flows is as follows:

For the Three Months Ended March 31,	2015	2014
Millions		
Cash and Cash Equivalents at Beginning of Period	$145.8	$97.3
Cash Flows from (used for)		
Operating Activities	71.8	74.9
Investing Activities	(255.9)	(204.6)
Financing Activities	110.4	77.0
Change in Cash and Cash Equivalents	(73.7)	(52.7)
Cash and Cash Equivalents at End of Period	$72.1	$44.6

Operating Activities. Cash from operating activities was $71.8 million for the three months ended March 31, 2015 ($74.9 million for the three months ended March 31, 2014). Cash from operating activities was lower in 2015 primarily due to higher payments of accounts payable, partially offset by higher net income.

Investing Activities. Cash used for investing activities was $255.9 million for the three months ended March 31, 2015 ($204.6 million for the three months ended March 31, 2014). The increase in cash used for investing activities was primarily due to the U.S. Water Services acquisition on February 10, 2015, and a transfer of cash included in Other Investments to Cash and Cash Equivalents in 2014, partially offset by lower capital expenditures in 2015.

Financing Activities. Cash from financing activities was $110.4 million for the three months ended March 31, 2015 ($77.0 million for the three months ended March 31, 2014). The increase in cash from financing activities was primarily due to proceeds from the issuance of common stock in 2015, partially offset by proceeds from the issuance of long-term debt in 2014.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of March 31, 2015, we had available consolidated bank lines of credit aggregating $360.6 million ($401.0 million available as of March 31, 2014), the majority of which expire in November 2018. In addition, as of March 31, 2015, we had 2.1 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 4.0 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital Markets, Inc. (See Securities.) The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with Lampert Capital Markets, Inc., in 2008, as amended most recently in February 2015, with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 4.0 million remain available for issuance. For the three months ended March 31, 2015, 1.3 million shares of common stock were issued under this agreement, resulting in net proceeds of $69.9 million (no shares were issued for the three months ended March 31, 2014). The shares issued in 2015 were offered and sold pursuant to Registration Statement No. 333-190335.

During the three months ended March 31, 2015, we issued 0.1 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan, and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $6.2 million (0.2 million shares were issued for net proceeds of $4.6 million during the three months ended March 31, 2014). These shares of common stock were registered under Registration Statement Nos. 333-188315, 333-183051 and 333-162890.

In February 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock. Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock from third parties and sold them to the underwriters. The forward sale price was $48.01 per share, subject to adjustment as provided in the Agreement. In September 2014, ALLETE physically settled a portion of its obligations under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.0 million and on February 4, 2015, ALLETE physically settled the remaining portion of its obligation under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.4 million.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

In connection with the public offering of the 2.8 million shares, ALLETE granted the underwriters an option to purchase up to an additional 0.4 million shares of ALLETE common stock (the option shares). The underwriters exercised the option in full and in March 2014, the Company issued and sold the option shares to the underwriters at a price to ALLETE equal to the initial forward sale price for proceeds of $20.2 million.

Financial Covenants. See Note 10. Short-Term and Long-Term Debt for information regarding our financial covenants.

Pension and Other Postretirement Benefit Plans. Management considers various factors when making funding decisions, such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the defined benefit pension plans. We do not expect to make any contributions to our defined benefit pension plan or our other postretirement benefit plan in 2015. (See Note 15. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements.

Off-balance sheet arrangements are summarized in our 2014 Form 10-K, with additional disclosure in Note 16. Commitments, Guarantees and Contingencies.

Capital Requirements.

Our capital expenditures for 2015 are expected to be approximately $280 million. For the three months ended March 31, 2015, capital expenditures totaled $57.3 million ($195.2 million for the three months ended March 31, 2014). The expenditures were primarily made in the Regulated Operations segment.

OTHER

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Environmental Matters are summarized in our 2014 Form 10-K, with additional disclosure in Note 16. Commitments, Guarantees and Contingencies.

Employees.

Minnesota Power and SWL&P have an aggregate of 579 employees who are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The current labor agreements with IBEW Local 31 expire on January 31, 2018.

BNI Coal has 173 employees, of which 126 are members of IBEW Local 1593. The current labor agreement with IBEW Local 1593 expires on March 31, 2019.

NEW ACCOUNTING STANDARDS

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

SECURITIES INVESTMENTS

Available-for-Sale Securities. At March 31, 2015, our available-for-sale securities portfolio consisted primarily of securities established to fund certain employee benefits. (See Note 3. Investments.)

COMMODITY PRICE RISK

Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Our Minnesota regulated utility's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates. Conversely, costs below those in base rates result in a credit to our ratepayers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

POWER MARKETING

Our power marketing activities consist of: (1) purchasing energy in the wholesale market to serve our regulated service territory when energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell any excess energy to the wholesale market to optimize the value of our generating facilities.

We are exposed to credit risk primarily through our power marketing activities. We use credit policies to manage credit risk, which includes utilizing an established credit approval process and monitoring counterparty limits.

INTEREST RATE RISK

We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at March 31, 2015, and assuming no other changes to our financial structure, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by $0.6 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of March 31, 2015.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of March 31, 2015, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of ALLETE's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

ITEM 4. CONTROLS AND PROCEDURES (Continued)

Changes in Internal Controls. There has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The Company is undergoing a project with the objective of improving customer information systems. The focus of the project is the upgrade and addition of certain customer information applications; these changes are not the result of any identified deficiencies in our internal control over financial reporting. The Company expects the project to result in greater efficiencies and enhance the processes used by employees to track power consumption, invoice customers, process payments, and analyze data. Implementation is expected in the second quarter of 2015.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding material legal and regulatory proceedings, see Note 5. Regulatory Matters and Note 12. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in the 2014 Form 10-K and Note 8. Regulatory Matters and Note 16. Commitments, Guarantees and Contingencies herein. Such information is incorporated herein by reference.

ITEM 1A. RISK FACTORS

The Form 10-K includes a detailed discussion of our risk factors. The information presented below updates, and should be read in conjunction with, the risk factors and information disclosed in the Form 10-K.

ALLETE has a significant goodwill and intangible asset balance related to its acquisition of U.S. Water Service. A determination that goodwill or intangible assets have been impaired could result in a significant non-cash charge to earnings.

We had approximately $214 million of goodwill and intangible assets recorded on our Consolidated Balance Sheet as of March 31, 2015 primarily relating to our acquisition of U.S. Water Services on February 10, 2015. If we make changes in our business strategy or if market or other conditions adversely affect operations of our Investment and Other businesses, we may be required to record an impairment charge. Declines in projected operating cash flows at certain of our reported units may result in goodwill impairments. Depending on the amount of the impairment, an impairment could have a material adverse effect on our results of operations.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-Q.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	
31(a)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certification of Periodic Report by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety
99	ALLETE News Release dated May 7, 2015, announcing 2015 first quarter earnings. (This exhibit has been furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)
101.INS	XBRL Instance
101.SCH	XBRL Schema
101.CAL	XBRL Calculation
101.DEF	XBRL Definition
101.LAB	XBRL Label
101.PRE	XBRL Presentation

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.

	ALLETE, INC.
May 7, 2015	/s/ Steven Q. DeVinck Steven Q. DeVinck Senior Vice President and Chief Financial Officer
May 7, 2015	/s/ Steven W. Morris Steven W. Morris Controller