ALLETE INC
Form 10-Q
November 04, 2016

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 September 30, 2016

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	41-0418150
(State or other jurisdiction of incorporation or organization)	(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,
49,462,700 shares outstanding
as of September 30, 2016

Index

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
ALLETE Transmission Holdings	ALLETE Transmission Holdings, Inc.
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
BNI Energy	BNI Energy, Inc. and its subsidiary
Boswell	Boswell Energy Center
Cliffs	Cliffs Natural Resources Inc.
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
Essar	Essar Steel Minnesota LLC
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	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
IBEW	International Brotherhood of Electrical Workers
IRP	Integrated Resource Plan
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
Item ___	Item ___ of this Form 10-Q
kV	Kilovolt(s)
kW / kWh	Kilowatt(s) / Kilowatt-hour(s)
Laskin	Laskin Energy Center
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.
Montana-Dakota Utilities	Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.
MPCA	Minnesota Pollution Control Agency

Abbreviation or Acronym	Term
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
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Northshore Mining	Northshore Mining Company, a wholly-owned subsidiary of Cliffs
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 District	Palm Coast Park Community Development District in Florida
PolyMet	PolyMet Mining Corp.
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
Shell Energy	Shell Energy North America (US), L.P.
Silver Bay Power	Silver Bay Power Company, a wholly-owned subsidiary of Cliffs
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative, a North Dakota cooperative corporation
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Thomson	Thomson Energy Center
Town Center District	Town Center at Palm Coast Community Development District in Florida
United Taconite	United Taconite LLC, a wholly-owned subsidiary of Cliffs
U.S.	United States of America
U.S. Water Services	U.S. Water Services Holding Company and its subsidiaries
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;
- changes in and compliance with laws and regulations;
- changes in tax rates or policies, or in rates of inflation;
- 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;
- changes in operating expenses and capital expenditures, and our ability to raise revenues from our customers in regulated rates or sales price increases at our Energy Infrastructure and Related Services businesses;
- the impacts of commodity prices on ALLETE and our customers;
- our ability to attract 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;
- population growth rates and demographic patterns;
- 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;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- the impacts on our Regulated Operations segment of climate change and future regulation to restrict the emissions of greenhouse gases;
- effects of increased deployment of distributed low-carbon electricity generation resources;
- the impacts of laws and regulations related to renewable and distributed generation;

- pricing, availability and transportation of fuel and other commodities, and the ability to recover the costs of such commodities;
- our current and potential industrial and municipal customers' ability to execute announced expansion plans;
- real estate market conditions where our legacy Florida real estate investment is located may not improve;
- the success of efforts to realize value from, invest in, and develop new opportunities in, our Energy Infrastructure and Related Services businesses; and
- factors affecting our Energy Infrastructure and Related Services businesses, including fluctuations in the volume of customer orders, unanticipated cost increases, changes in legislation and regulations impacting the industries in which the customers served operate, the effects of weather, creditworthiness of customers, ability to obtain materials required to perform services, and changing market conditions.

Forward-Looking Statements (Continued)

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Part 1, Item 1A, under the heading “Risk Factors” beginning on page 25 of our 2015 Form 10-K. 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 it assess the impact of each of these factors on the businesses of ALLETE 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 ALLETE in this Form 10-Q and in other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect ALLETE’s business.

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

	September 30, 2016	December 31, 2015
Assets		
Current Assets		
Cash and Cash Equivalents	$107.2	$97.0
Accounts Receivable (Less Allowance of $1.8 and $1.0)	108.1	121.2
Inventories	107.4	117.1
Prepayments and Other	38.9	35.7
Total Current Assets	361.6	371.0
Property, Plant and Equipment – Net	3,644.5	3,669.1
Regulatory Assets	358.9	372.0
Investment in ATC	133.8	124.5
Other Investments	58.1	74.6
Goodwill and Intangible Assets – Net	211.4	215.2
Other Non-Current Assets	106.5	68.1
Total Assets	$4,874.8	$4,894.5
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$72.6	$88.8
Accrued Taxes	36.7	44.0
Accrued Interest	14.8	18.6
Long-Term Debt Due Within One Year	186.6	35.7
Notes Payable	—	1.6
Other	93.6	86.1
Total Current Liabilities	404.3	274.8
Long-Term Debt	1,358.9	1,556.7
Deferred Income Taxes	582.1	579.8
Regulatory Liabilities	122.9	105.0
Defined Benefit Pension and Other Postretirement Benefit Plans	197.7	206.8
Other Non-Current Liabilities	335.9	349.0
Total Liabilities	3,001.8	3,072.1
Commitments, Guarantees and Contingencies (Note 13)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 49.5 and 49.1 Shares Outstanding	1,289.4	1,271.4
Accumulated Other Comprehensive Loss	(23.7)	(24.5)
Retained Earnings	607.3	573.3
Total ALLETE Equity	1,873.0	1,820.2
Non-Controlling Interest in Subsidiaries	—	2.2
Total Equity	1,873.0	1,822.4

Total Liabilities and Equity	$4,874.8	$4,894.5

The accompanying notes are an integral part of these statements.

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

	Quarter Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
Operating Revenue	$349.6	$462.5	$998.2	$1,105.8
Operating Expenses				
Fuel and Purchased Power	91.0	76.8	246.0	242.9
Transmission Services	16.6	13.9	49.5	40.1
Cost of Sales	46.4	149.8	113.1	233.3
Operating and Maintenance	80.8	81.3	240.9	246.4
Depreciation and Amortization	48.9	43.2	145.7	123.5
Taxes Other than Income Taxes	12.5	12.3	40.6	38.5
Total Operating Expenses	296.2	377.3	835.8	924.7
Operating Income	53.4	85.2	162.4	181.1
Other Income (Expense)				
Interest Expense	(18.7)	(17.7)	(53.0)	(49.0)
Equity Earnings in ATC	6.1	5.5	15.0	14.1
Other	1.2	1.7	2.8	3.5
Total Other Expense	(11.4)	(10.5)	(35.2)	(31.4)
Income Before Non-Controlling Interest and Income Taxes	42.0	74.7	127.2	149.7
Income Tax Expense	1.7	14.4	15.7	27.0
Net Income	40.3	60.3	111.5	122.7
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	0.5	(0.1)
Net Income Attributable to ALLETE	$40.3	$60.4	$111.0	$122.8
Average Shares of Common Stock				
Basic	49.4	48.8	49.3	48.0
Diluted	49.5	48.9	49.4	48.1
Basic Earnings Per Share of Common Stock	$0.82	$1.24	$2.25	$2.56
Diluted Earnings Per Share of Common Stock	$0.81	$1.23	$2.25	$2.55
Dividends Per Share of Common Stock	$0.52	$0.505	$1.56	$1.515

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Millions – Unaudited

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income	$40.3	$60.3	$111.5	$122.7
Other Comprehensive Income (Loss)				
Unrealized Gain (Loss) on Securities				
Net of Income Tax Expense (Benefit) of $0.2, $(0.4), $0.2, and $(0.3)	0.3	(0.7)	0.3	(0.6)
Unrealized Gain on Derivatives				
Net of Income Tax Expense of $–, $–, $–, and $0.1	—	—	—	0.1
Defined Benefit Pension and Other Postretirement Benefit Plans				
Net of Income Tax Expense of $0.1, $0.3, $0.3, and $0.7	0.2	0.3	0.5	1.0
Total Other Comprehensive Income (Loss)	0.5	(0.4)	0.8	0.5
Total Comprehensive Income	40.8	59.9	112.3	123.2
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	0.5	(0.1)
Total Comprehensive Income Attributable to ALLETE	$40.8	$60.0	$111.8	$123.3

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Nine Months Ended September 30,	
	2016	2015
Operating Activities		
Net Income	$111.5	$122.7
Allowance for Funds Used During Construction – Equity	(1.7)	(2.6)
Income from Equity Investments – Net of Dividends	(5.8)	(3.7)
Gain on Sales of Investments and Property, Plant and Equipment	(5.3)	(0.2)
Depreciation Expense	141.8	120.7
Amortization of Power Purchase Agreements	(16.7)	(17.1)
Amortization of Other Intangible Assets and Other Assets	8.1	5.0
Deferred Income Tax Expense	15.5	26.5
Share-Based Compensation Expense	2.0	2.1
ESOP Compensation Expense	1.6	7.3
Defined Benefit Pension and Postretirement Benefit Expense	3.9	11.5
Bad Debt Expense	2.5	0.8
Changes in Operating Assets and Liabilities		
Accounts Receivable	10.6	11.6
Inventories	9.7	(24.1)
Prepayments and Other	(0.7)	(0.4)
Accounts Payable	0.6	—
Other Current Liabilities	(23.0)	(0.8)
Cash Contributions to Defined Benefit Pension Plans	(6.3)	—
Changes in Regulatory and Other Non-Current Assets	(18.3)	(6.2)
Changes in Regulatory and Other Non-Current Liabilities	7.8	1.5
Cash from Operating Activities	237.8	254.6
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	6.8	0.7
Payments for Purchase of Available-for-sale Securities	(7.2)	(1.1)
Acquisitions of Subsidiaries – Net of Cash Acquired	—	(324.8)
Investment in ATC	(3.5)	(1.2)
Changes to Other Investments	2.5	—
Additions to Property, Plant and Equipment	(119.5)	(208.2)
Proceeds from Sale of Property, Plant and Equipment	0.2	0.3
Cash for Investing Activities	(120.7)	(534.3)
Financing Activities		
Proceeds from Issuance of Common Stock	27.0	155.2
Proceeds from Issuance of Long-Term Debt	2.2	240.0
Changes in Restricted Cash	2.1	2.2
Changes in Notes Payable	(1.6)	(3.7)
Repayments of Long-Term Debt	(50.7)	(81.8)
Acquisition of Non-Controlling Interest	(8.0)	—
Acquisition-Related Contingent Consideration Payments	(0.8)	—

Debt Issuance Costs	(0.1)	(1.0)
Dividends on Common Stock	(77.0)	(74.0)
Cash from (for) Financing Activities	(106.9)	236.9
Change in Cash and Cash Equivalents	10.2	(42.8)
Cash and Cash Equivalents at Beginning of Period	97.0	145.8
Cash and Cash Equivalents at End of Period	$107.2	$103.0

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF EQUITY
Millions – Unaudited

	Total Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock	Non-Controlling Interest in Subsidiaries
Balance as of December 31, 2015	$1,822.4	$573.3	$(24.5)	$1,271.4	$2.2
Comprehensive Income					
Net Income	111.5	111.0			0.5
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities	0.3		0.3		
Defined Benefit Pension and Other Postretirement Plans	0.5		0.5		
Total Comprehensive Income	112.3				
Common Stock Issued	30.0			30.0	
Common Stock Retired	(8.0)			(8.0)	
Dividends Declared	(77.0)	(77.0)			
Acquisition of Non-Controlling Interest	(6.7)			(4.0)	(2.7)
Balance as of September 30, 2016	$1,873.0	$607.3	$(23.7)	$1,289.4	—

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – UNAUDITED

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, 2015, Consolidated Balance Sheet was derived from audited financial statements, but does not include all disclosures required by GAAP. In management's opinion, these unaudited financial statements include all adjustments necessary for a fair statement of financial results. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Operating results for the nine months ended September 30, 2016, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2016. For further information, refer to the Consolidated Financial Statements and notes included in our 2015 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Inventories. Inventories are stated at the lower of cost or market. Inventories in our Regulated Operations and ALLETE Clean Energy segments are carried at an average cost or first-in, first-out basis. Inventories in our U.S. Water Services and Corporate and Other segments are carried at an average cost, first-in, first-out or specific identification basis.

Inventories	September 30, 2016	December 31, 2015
Millions		
Fuel (a)	$45.9	$58.1
Materials and Supplies	49.8	49.1
Raw Materials	3.3	2.7
Work in Progress	1.1	—
Finished Goods	7.8	7.5
Reserve for Obsolescence	(0.5)	(0.3)
Total Inventories	$107.4	$117.1

(a) Fuel consists primarily of coal inventory at Minnesota Power.

Prepayments and Other Current Assets	September 30, 2016	December 31, 2015
Millions		
Deferred Fuel Adjustment Clause	$16.8	$10.6
Restricted Cash (a)	7.0	5.6
Other	15.1	19.5
Total Prepayments and Other Current Assets	$38.9	$35.7

(a) Restricted Cash includes collateral deposits required under ALLETE Clean Energy's loan agreements and cash pledged as collateral for U.S. Water Services' standby letters of credit.

Other Non-Current Assets	September 30, 2016	December 31, 2015
Millions		
Contract Payment (a)	$30.1	—
Finance Receivable (b)	11.6	—
Restricted Cash (c)	4.6	$8.1
Other	60.2	60.0
Total Other Non-Current Assets	$106.5	$68.1

(a)

Contract Payment includes a $31.0 million payment made to Cliffs as part of a long-term power sales agreement between Minnesota Power and Silver Bay Power. The contract payment will be amortized over the term of the sales agreement. (See Note 13. Commitments, Guarantees and Contingencies.)

(b) On September 22, 2016, ALLETE Properties sold its Ormond Crossings project and Lake Swamp wetland mitigation bank for consideration of approximately $21 million. The consideration included a down payment in the form of 0.1 million shares of ALLETE common stock with a value of $8.0 million. The remaining purchase price will be paid under the terms of a finance receivable due over a five-year period which bears interest at market rates and is collateralized by the property sold.

(c) Restricted Cash includes collateral deposits required under ALLETE Clean Energy’s loan agreements and PPAs.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Current Liabilities	September 30, 2016	December 31, 2015
Millions		
Customer Deposits	$9.0	$15.1
Power Purchase Agreements	24.3	23.3
Other	60.3	47.7
Total Other Current Liabilities	$93.6	$86.1

Other Non-Current Liabilities	September 30, 2016	December 31, 2015
Millions		
Asset Retirement Obligation	$136.5	$131.4
Power Purchase Agreements	119.8	138.1
Contingent Consideration (a)	37.9	36.6
Other	41.7	42.9
Total Other Non-Current Liabilities	$335.9	$349.0

(a) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 3. Acquisitions and Note 5. Fair Value.)

Supplemental Statement of Cash Flows Information.

Nine Months Ended September 30,	2016	2015
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$54.9	$46.6
Cash Paid During the Period for Income Taxes	$0.5	$0.1
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(19.5)	$(26.8)
Capitalized Asset Retirement Costs	$3.7	$7.8
AFUDC–Equity	$1.7	$2.6
Contingent Consideration	—	$35.7
ALLETE Common Stock Received for Land Inventory	$8.0	—
Long-Term Finance Receivable for Land Inventory	$12.0	—

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

New Accounting Standards.

Amendments to the Consolidation Analysis. In February 2015, the FASB issued revised guidance which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. The new standard affects (1) limited partnerships and similar legal entities, (2) evaluating fees paid to a decision maker or a service provider as a variable interest, (3) the effect of fee arrangements on the primary beneficiary determination, (4) the effect of related parties on the primary beneficiary determination, and (5) certain investment funds. This guidance was adopted in the first quarter of 2016 and did not have a material impact on our Consolidated Financial Statements.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). In May 2015, the FASB issued an accounting standard update which removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share (or its equivalent) practical expedient. The guidance applies to investments for which there is not a readily determinable fair value (market quote) or the investment is in a mutual fund without a publicly available net asset value. This guidance was adopted in the first quarter of 2016 and did not have a material impact on our Consolidated Financial Statements.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
New Accounting Standards (Continued)

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 on the Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability. This guidance was adopted in the first quarter of 2016 resulting in the reclassification of unamortized debt issuance costs from Other Non-Current Assets to Long-Term Debt on the Consolidated Balance Sheet. The effect of the adoption decreased Total Assets and Total Liabilities on the Consolidated Balance Sheet by $12.6 million as of December 31, 2015.

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. The guidance is effective for the Company beginning in the first quarter of 2018 with early adoption permitted. The Company is evaluating the impact of the amended revenue recognition guidance on the Company’s Consolidated Financial Statements.

Leases. In February 2016, the FASB issued an accounting standard update which revises the existing guidance for leases. Under the revised guidance, lessees will be required to recognize a “right-of-use” asset and a lease liability for all leases with a term greater than 12 months. The new standard also requires additional quantitative and qualitative disclosures by lessees and lessors to enable users of the financial statements to assess the amount, timing and uncertainty of cash flows arising from leases. The accounting for leases by lessors and the recognition, measurement and presentation of expenses and cash flows from leases are not expected to significantly change as a result of the updated guidance. The revised guidance is effective for the Company beginning in the first quarter of 2019 with early adoption permitted. The Company is evaluating the impact of the amended lease guidance on the Company’s Consolidated Financial Statements.

Improvements to Employee Share-Based Payment Accounting. In March 2016, the FASB issued guidance to simplify the accounting for share-based payment transactions by requiring all excess tax benefits and deficiencies to be recognized in income tax expense or benefit in earnings; thus, eliminating the requirement to classify the excess tax benefit and deficiencies as additional paid-in capital. Under the new guidance, an entity makes an accounting policy election to either estimate the expected forfeiture awards or account for forfeitures as they occur. This accounting guidance is effective for the Company beginning in the first quarter of 2017. The Company is evaluating the impact of the share-based payment guidance on the Company’s Consolidated Financial Statements.

Classification of Certain Cash Receipts and Cash Payments. In August 2016, the FASB issued an accounting standard update which addresses the following eight specific cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. This accounting guidance is effective for the Company beginning in the first quarter of 2018. The Company does not believe the guidance will have a material impact on its Consolidated Financial

Statements.

NOTE 2. INVESTMENTS

Investments. As of September 30, 2016, the investment portfolio included the legacy 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	September 30, 2016	December 31, 2015
Millions		
ALLETE Properties (a)	$32.9	$50.1
Available-for-sale Securities (b)	19.4	18.5
Cash Equivalents	2.0	2.0
Other	3.8	4.0
Total Other Investments	$58.1	$74.6

(a) On September 22, 2016, ALLETE Properties sold its Ormond Crossings project and Lake Swamp wetland mitigation bank for consideration of approximately $21 million. The consideration included a down payment in the form of 0.1 million shares of ALLETE common stock with a value of $8.0 million, with the remaining purchase price to be paid under the terms of a finance receivable due over a five-year period which bears interest at market rates. The finance receivable is collateralized by the property sold.

(b) As of September 30, 2016, the aggregate amount of available-for-sale corporate and governmental debt securities maturing in one year or less was $0.2 million, in one year to less than three years was $2.7 million, in three years to less than five years was $5.5 million, and in five or more years was $3.3 million.

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 estimated fair value. Land values are reviewed for indicators of impairment on a quarterly basis and no impairments were recorded for the quarter and nine months ended September 30, 2016.

NOTE 3. ACQUISITIONS

The following acquisitions are consistent with ALLETE’s stated strategy of investing in energy infrastructure and related services businesses to complement its regulated businesses, 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 nine months ended September 30, 2016 and 2015.

2016 Activity.

Acquisition of Non-Controlling Interest. On April 15, 2016, ALLETE Clean Energy acquired the non-controlling interest in the limited liability company that owns its Condon wind energy facility for $8.0 million. This transaction was accounted for as an equity transaction, and no gain or loss was recognized in net income or other comprehensive income. As a result of the acquisition, the Condon wind energy facility is now a wholly-owned subsidiary of ALLETE Clean Energy.

WEST. On October 11, 2016, U.S. Water Services acquired 100 percent of Water & Energy Systems Technology of Nevada, Inc. (WEST). Total consideration for the transaction was $6.5 million, subject to a working capital adjustment. Consideration of $5.9 million was paid in cash on the acquisition date and a $0.6 million payment is due in April 2018. WEST, similar to U.S. Water Services, is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southwestern United States. 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-K for the year ended December 31, 2016.

2015 Activity.

U.S. Water Services. In February 2015, ALLETE acquired U.S. Water Services. Total consideration for the transaction was $202.3 million, which included payment of $166.6 million in cash and an estimated fair value of earnings-based contingent consideration of $35.7 million, as estimated at the date of acquisition, to be paid through 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 for U.S. Water Services since the acquisition date as the Company has acquired 100 percent of U.S. Water Services.

NOTE 3. ACQUISITIONS (Continued)
2015 Activity (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 purchase price accounting, which was finalized in 2015, is reflected in the following table. 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
Intangible Assets (c)	83.0
Goodwill (d)	122.9
Other Non-Current Assets	0.2
Total Assets Acquired	$253.1
Liabilities Assumed	
Current Liabilities	$19.2
Non-Current Liabilities	31.6
Total Liabilities Assumed	$50.8
Net Identifiable Assets Acquired	$202.3

(a) Included in Inventories was $2.7 million of fair value adjustments relating to work in progress and finished goods inventories which were 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 was 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 standby letters of credit.
(c) Intangible Assets include customer relationships, patents, non-compete agreements, and trademarks and trade names. (See Note 4. Goodwill and Intangible Assets.)
(d) For tax purposes, the purchase price allocation resulted in $2.9 million of deductible goodwill.

Acquisition-related costs of $3.0 million after-tax were expensed as incurred during the first quarter of 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

Chanarambie/Viking. In April 2015, ALLETE Clean Energy acquired 100 percent of wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Renewable Energy, Inc. for $48.0 million.

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

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

NOTE 3. ACQUISITIONS (Continued)
2015 Activity (Continued)

Millions	
Assets Acquired	
Current Assets	$4.8
Property, Plant and Equipment	103.0
Other Non-Current Assets (a)	1.0
Total Assets Acquired	$108.8
Liabilities Assumed	
Current Liabilities (b)	$6.7
Power Purchase Agreements	49.0
Non-Current Liabilities	5.1
Total Liabilities Assumed	$60.8
Net Identifiable Assets Acquired	$48.0

(a) Included in Other Non-Current Assets was $0.3 million of goodwill. For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

(b) Current Liabilities included $5.9 million related to the current portion of PPAs.

Acquisition-related costs of $0.2 million after-tax were expensed as incurred during the second quarter of 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

Armenia Mountain. In July 2015, ALLETE Clean Energy acquired 100 percent of a wind energy facility located near Troy, Pennsylvania (Armenia Mountain) from The AES Corporation (AES) and a minority shareholder for $111.1 million, plus the assumption of existing debt.

The facility has 100.5 MW of generating capability, began commercial operations in 2009, and has PPAs in place for its entire output, which expire in 2024.

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets (a)	$9.0
Property, Plant and Equipment	156.2
Other Non-Current Assets (b)	14.4
Total Assets Acquired	$179.6
Liabilities Assumed	
Current Liabilities	$2.9
Long-Term Debt Due Within One Year	5.9
Long-Term Debt	55.0
Other Non-Current Liabilities	4.7
Total Liabilities Assumed	$68.5
Net Identifiable Assets Acquired	$111.1

(a) Included in Current Assets was $1.0 million related to the current portion of PPAs and $6.0 million of restricted cash related to collateral deposits required under its loan agreement.

(b) Included in Other Non-Current Assets was $8.2 million related to the non-current portion of PPAs, $6.1 million of restricted cash related to collateral deposits required under its loan agreements, and an immaterial amount of goodwill. For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

NOTE 3. ACQUISITIONS (Continued)
2015 Activity (Continued)

Acquisition-related costs of $1.6 million after-tax were expensed as incurred throughout the second and third quarters of 2015, and recorded in Operating and Maintenance on the Consolidated Statement of Income.

A and W Technologies. In November 2015, U.S. Water Services acquired 100 percent of A and W Technologies, Inc. (AWT). Total consideration for the transaction was $9.3 million, which included payment of $8.3 million in cash and a $1.0 million payment due in April 2017. AWT, similar to U.S. Water Services, is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southeastern United States.

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets	$1.0
Property, Plant and Equipment	0.1
Intangible Assets (a)	3.9
Goodwill (b)	4.4
Total Assets Acquired	$9.4
Liabilities Assumed	
Current Liabilities	$0.1
Total Liabilities Assumed	$0.1
Net Identifiable Assets Acquired	$9.3

(a) Intangible Assets include customer relationships and non-compete agreements. (See Note 4. Goodwill and Intangible Assets.)
(b) For tax purposes, the purchase price allocation resulted in $4.4 million of deductible goodwill.

Acquisition-related costs were immaterial, expensed as incurred during the fourth quarter of 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

NOTE 4. GOODWILL AND INTANGIBLE ASSETS

The aggregate carrying amount of goodwill was $130.6 million as of September 30, 2016, and December 31, 2015. There have been no changes to goodwill by reportable segment for the nine months ended September 30, 2016.

Balances of intangible assets, net, excluding goodwill as of September 30, 2016, are as follows:

	December 31, 2015	Amortization	September 30, 2016
Millions			
Intangible Assets			
Definite-Lived Intangible Assets			
Customer Relationships	$60.8	$(3.2)	$57.6
Developed Technology and Other (a)	7.2	(0.6)	6.6
Total Definite-Lived Intangible Assets	68.0	(3.8)	64.2

Indefinite-Lived Intangible Assets			
Trademarks and Trade Names	16.6	n/a	16.6
Total Intangible Assets	$84.6	$(3.8)	$80.8

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

NOTE 4. GOODWILL AND INTANGIBLE ASSETS (Continued)

Customer relationships have a remaining useful life of approximately 21 years, and developed technology and other have remaining useful lives ranging from approximately 2 years to approximately 12 years (weighted average of approximately 8 years). The weighted average remaining useful life of all definite-lived intangible assets as of September 30, 2016, is approximately 20 years.

Amortization expense of intangible assets for the nine months ended September 30, 2016, was $3.8 million. Accumulated amortization was $7.9 million as of September 30, 2016 ($4.1 million as of December 31, 2015). The estimated amortization expense for definite-lived intangible assets for the remainder of 2016 is $1.3 million. Estimated annual amortization expense for definite-lived intangible assets is $5.0 million in 2017, $4.7 million in 2018, $4.4 million in 2019, $4.2 million in 2020 and $44.6 million thereafter.

NOTE 5. 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 2015 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 September 30, 2016, and December 31, 2015. 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 following tables.

	Fair Value as of September 30, 2016			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets				
Investments (a)				
Available-for-sale – Equity Securities	$7.7	—	—	$7.7
Available-for-sale – Corporate and Governmental Debt Securities	—	$11.7	—	11.7
Cash Equivalents	2.0	—	—	2.0
Total Fair Value of Assets	$9.7	$11.7	—	$21.4
Liabilities (b)				

Deferred Compensation	—	$16.0	—	$16.0
U.S. Water Services Contingent Consideration	—	—	$37.9	37.9
Total Fair Value of Liabilities	—	$16.0	$37.9	$53.9
Total Net Fair Value of Assets (Liabilities)	$9.7	$(4.3)	$(37.9)	$(32.5)

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

NOTE 5. FAIR VALUE (Continued)

Recurring Fair Value Measures	Fair Value as of December 31, 2015			
	Level 1	Level 2	Level 3	Total
Millions				
Assets				
Investments (a)				
Available-for-sale – Equity Securities	$7.6	—	—	$7.6
Available-for-sale – Corporate Debt Securities	—	$10.9	—	10.9
Cash Equivalents	2.0	—	—	2.0
Total Fair Value of Assets	$9.6	$10.9	—	$20.5
Liabilities (b)				
Deferred Compensation	—	$16.1	—	$16.1
U.S. Water Services Contingent Consideration	—	—	$36.6	36.6
Total Fair Value of Liabilities	—	$16.1	$36.6	$52.7
Total Net Fair Value of Assets (Liabilities)	$9.6	$(5.2)	$(36.6)	$(32.2)

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

The Level 3 liability in the preceding tables is the result of the February 2015 acquisition of U.S. Water Services. Changes in the U.S. Water Services Contingent Consideration can result from changes in discount rates, timing of milestones that trigger payment, and the timing and amount of earnings estimates. Changes in the fair value of U.S. Water Services' Contingent Consideration for the nine months ended September 30, 2016, are primarily due to accretion expense. Management analyzes the fair value of the contingent liability on a quarterly basis and makes adjustments as appropriate.

For the nine months ended September 30, 2016, and the year ended December 31, 2015, 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 Long-Term Debt Due Within One Year		
September 30, 2016	$1,556.9	$1,721.8
December 31, 2015	$1,605.0	$1,676.0

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. For the nine months ended September 30, 2016, and the year ended December 31, 2015, there were no indicators of impairment for these non-financial assets.

NOTE 6. REGULATORY MATTERS

Regulatory matters are summarized in Note 5. Regulatory Matters to our Consolidated Financial Statements in our 2015 Form 10-K, with additional disclosure provided in the following paragraphs.

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 that allows for a 10.38 percent return on common equity and a 54.29 percent equity ratio. Subsequent to this order, and as authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for environmental, renewable and transmission investments. (See Transmission Cost Recovery Rider, Renewable Cost Recovery Rider and Environmental Improvement Rider.) Revenue from cost recovery riders was $73.9 million for the nine months ended September 30, 2016 ($67.8 million for the nine months ended September 30, 2015).

2016 Minnesota Rate Case. On November 2, 2016, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 9 percent for retail customers. The rate filing seeks a return on equity of 10.25 percent, and a capital structure consisting of 53.8 percent equity and 46.2 percent debt. On an annualized basis, the requested rate increase would generate approximately $55 million in additional revenue. Once the filing is accepted as complete, interim rates of approximately $49 million are expected to be implemented within 60 days, subject to MPUC adjustment and authorization. We cannot predict the level of interim or final rates that may be authorized by the MPUC.

Energy-Intensive Trade-Exposed (EITE) Customer Rates. The state of Minnesota enacted an EITE customer ratemaking law in June 2015 which established that it is the energy policy of the state to have competitive rates for certain industries such as mining and forest products. In November 2015, Minnesota Power filed a rate schedule petition for EITE customers and a corresponding rider for EITE cost recovery with the MPUC. The rate proposal was revenue and cash flow neutral to Minnesota Power. In an order dated March 23, 2016, the MPUC dismissed the petition without prejudice, providing Minnesota Power the option to refile the petition with additional information or file a new petition. On June 30, 2016, Minnesota Power filed a revised EITE petition with the MPUC, which includes additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. On September 15, 2016, the MPUC approved a reduction in rates for EITE customers and determined that cost recovery will be addressed in a subsequent proceeding. Minnesota Power provided additional information on cost recovery allocation alternatives in a compliance filing made on October 13, 2016.

FERC-Approved Wholesale Rates. Minnesota Power has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. All of the wholesale contracts include a termination clause requiring a three-year notice to terminate.

In April 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 SWL&P and one other municipal customer are effective through June 30, 2019. The rates included in these three 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 Minnesota Power's 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.

In September 2015, Minnesota Power amended its wholesale electric contracts with 14 municipal customers, extending the contract terms through December 31, 2024. These contracts include fixed capacity charges through

2018; beginning in 2019, the capacity charge will not increase by more than two percent or decrease by more than one percent from the previous year's capacity charge and will be determined using a cost-based formula methodology. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and will also be determined using a cost-based formula methodology.

In January 2016, one of Minnesota Power's municipal customers provided notice of its intent to terminate its contract effective June 30, 2019. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. Under the Nashwauk Public Utilities Commission agreement, no termination notice may be given prior to June 30, 2025. Under the agreement with SWL&P, no termination notice may be given prior to October 31, 2016. The remaining 14 municipal customers may not give termination notices prior to December 31, 2021.

NOTE 6. REGULATORY MATTERS (Continued)

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 3, 2016, 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. As a result of the MPUC approval of the certificate of need for the GNTL in June 2015, the project is eligible for cost recovery under the existing transmission cost recovery rider. Minnesota Power anticipates including its portion of the investments and expenditures for the GNTL in future transmission factor filings to include updated billing rates on customer bills.

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 and the restoration and repair of Thomson. Updated customer billing rates for the renewable cost recovery rider were approved by the MPUC in an order dated March 9, 2016, allowing Minnesota Power to charge retail customers on a current basis for the costs of constructing certain renewable investments plus a return on the capital invested. While approving the updated customer billing rates for the renewable cost recovery rider, the MPUC also allowed Minnesota Power additional time to submit support for its position on its utilization of North Dakota investment tax credits.

Minnesota Power accounts for North Dakota investment tax credits based on long-standing regulatory precedents of stand-alone allocation methodology of accounting for income taxes. The stand-alone method provides that income taxes (and credits) are calculated as if Minnesota Power was the only entity included in ALLETE's consolidated federal and unitary state income tax returns. Minnesota Power has recorded a regulatory liability for North Dakota investment tax credits generated by its jurisdictional activity and expected to be realized in the future. North Dakota investment tax credits attributable to ALLETE's apportionment and income of ALLETE's other subsidiaries are included in the ALLETE consolidated group. The Minnesota Department of Commerce (Department) has inquired about our use of the North Dakota investment tax credits, taking the position that all North Dakota investment tax credits realized from the Bison Wind Energy Center should be credited to Minnesota Power regulated retail customers. The MPUC did not come to a decision on this issue in its order dated March 9, 2016, but requested that Minnesota Power provide further support on its position which was submitted on April 8, 2016.

On October 18, 2016, the MPUC held a hearing in which it decided Minnesota Power should attribute all North Dakota investment tax credits realized from the Bison Wind Energy Center to Minnesota Power regulated retail customers. As a result of the adverse regulatory outcome, Minnesota Power has created a regulatory liability, and recorded a reduction in operating revenue for $15.0 million. The North Dakota investment tax credits previously recognized as income tax credits in Corporate and Other were reversed in the third quarter of 2016 resulting in an $8.8 million charge to net income. Minnesota Power will seek reconsideration with the MPUC, and if not successful, will consider all available avenues of appeal.

Minnesota Power also has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. (See Minnesota Solar Energy Standard.) Currently, there is no approved customer billing rate for solar costs, but Minnesota Power expects to file its first solar factor filing in 2017 for recovery of costs related to the Camp Ripley solar project and community solar garden project.

Environmental Improvement Rider. Minnesota Power has an approved environmental improvement rider in place for investments and expenditures related to the implementation of the Boswell Unit 4 mercury emissions reduction plan completed in 2015. Customer billing rates for the environmental improvement rider were approved by the MPUC in August 2015. In September 2015, Minnesota Power filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of the filing, Minnesota Power will be authorized to include updated billing rates on customer bills.

Boswell Remaining Life Petition. In November 2015, Minnesota Power filed a petition with the MPUC for approval to extend Boswell's remaining life to 2050 for all units and utilize the existing environmental improvement rider to credit a portion of the depreciation expense savings to customers. The extension request was based on the significant multi-emissions retrofit work done at Boswell Unit 3 and Boswell Unit 4. In an order dated September 23, 2016, the MPUC approved Minnesota Power's request to withdraw the petition. Minnesota Power intends to address Boswell's remaining life and the environmental improvement rider in the upcoming general rate case. (See 2016 Minnesota Rate Case.)

NOTE 6. REGULATORY MATTERS (Continued)

Annual Automatic Adjustment (AAA) of Charges. In an order dated June 2, 2016, the MPUC approved Minnesota Power's AAA filings made in 2012 and 2013. The MPUC deferred action for 90 days on the AAA filing made in 2014 to review and confirm coal transportation costs and terms of service, which was subsequently completed on September 6, 2016, resulting in final approval of the filing.

2016 Wisconsin Rate Case. SWL&P's current retail rates are based on a 2012 PSCW retail rate order that allows for a 10.9 percent return on common equity. On June 28, 2016, SWL&P filed a rate increase request with the PSCW requesting an average overall increase of 3.1 percent for retail customers (a 3.5 percent increase in electric rates, a 1.3 percent decrease in natural gas rates and a 7.8 percent increase in water rates). The rate filing seeks an overall return on equity of 10.9 percent, based on a capital structure consisting of approximately 55 percent equity and 45 percent debt. On an annualized basis, the requested rate increase would generate approximately $2.7 million in additional revenue. Hearings are expected to be scheduled in late 2016. The Company anticipates new rates will take effect during the first quarter of 2017. We cannot predict the level of rates that may be approved by the PSCW.

Integrated Resource Plan (IRP). In a November 2013 order, the MPUC approved Minnesota Power's 2013 IRP which detailed its EnergyForward strategic plan. Significant elements of the EnergyForward plan include major wind investments in North Dakota completed in 2014, the installation of emissions control technology at Boswell Unit 4 completed in December 2015, planning for the proposed GNTL, the conversion of Laskin from coal to natural gas completed in June 2015 and the retirement of Taconite Harbor Unit 3 completed in May 2015. In September 2015, Minnesota Power filed its 2015 IRP with the MPUC which included an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. The 2015 IRP also contained the next steps in Minnesota Power's EnergyForward plan including the economic idling of Taconite Harbor Units 1 and 2 which was completed in September 2016, the ceasing of coal-fired operations at Taconite Harbor in 2020, and the addition of between 200 MW and 300 MW of natural gas-fired generation in the next decade.

In an order dated July 18, 2016, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepts Minnesota Power's plans for Taconite Harbor, directs Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, requires an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal and requires Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. On October 19, 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as the latest step in its EnergyForward strategic plan. Minnesota Power's next IRP must be filed by February 1, 2018.

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 which was approved in a June 2015 order. Based on this order, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In a December 2015 order, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. 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 an order dated April 11, 2016, the MPUC approved the route permit which largely follows Minnesota Power's preferred route, including the international border crossing. Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is expected to begin by 2017 and to be completed in 2020.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of net gross operating revenues from service provided in the state on energy CIPs each year. On June 1, 2016, Minnesota Power submitted its CIP triennial filing for 2017 through 2019 with the Minnesota Department of Commerce, which outlines Minnesota Power's CIP spending and energy-saving goals for 2017 through 2019. A decision on the CIP triennial filing by the Minnesota Department of Commerce is expected in the fourth quarter of 2016.

NOTE 6. REGULATORY MATTERS (Continued)

On April 1, 2016, Minnesota Power submitted its 2015 CIP consolidated filing, which detailed Minnesota Power's CIP program results and requested a CIP financial incentive of $7.5 million based upon MPUC procedures. In an order dated July 19, 2016, the MPUC approved Minnesota Power's CIP consolidated filing, including the requested CIP financial incentive which was recorded as revenue and as a regulatory asset. The approved financial incentive will be recovered through customer billing rates in 2016 and 2017. In 2015, the CIP financial incentive of $6.2 million was also recognized in the third quarter. CIP financial incentives are recognized in the period in which the MPUC approves the filing.

MISO Return on Equity Complaints. In November 2013, several customer groups located within the MISO service area filed complaints with the FERC requesting, among other things, a reduction in the base return on equity used by MISO transmission owners, including ALLETE and ATC, to 9.15 percent. In December 2015, a federal administrative law judge ruled on the November 2013 complaint proposing a reduction in the base return on equity to 10.32 percent. On September 28, 2016, the FERC issued an order affirming the administrative law judge's recommendation.

In February 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity to 8.67 percent. On June 30, 2016, a federal administrative law judge ruled on the February 2015 complaint proposing a further reduction in the base return on equity to 9.70 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is expected in 2017.

In January 2015, the FERC approved an incentive adder of up to 50 basis points on the allowed base return on equity for our participation in a regional transmission organization upon the resolution of each individual return on equity complaint.

Minnesota Solar Energy Standard. In 2013, legislation was enacted by the state of Minnesota requiring at least 1.5 percent of total retail electric sales, excluding sales to certain 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 kW or less. Minnesota Power has two solar projects under development. In August 2015, Minnesota Power filed for MPUC approval of a 10 MW utility scale solar project at Camp Ripley, a Minnesota Army National Guard base and training facility near Little Falls, Minnesota. In an order dated February 24, 2016, the MPUC approved the Camp Ripley solar project as eligible to meet the solar energy standard and for current cost recovery, subject to certain compliance requirements. In September 2015, Minnesota Power filed for MPUC approval of a community solar garden project in Duluth, Minnesota, which is comprised of a 1 MW solar array to be owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that will be owned and operated by Minnesota Power. In an order dated July 27, 2016, the MPUC approved the community solar garden project and cost recovery, subject to certain compliance requirements. Minnesota Power believes these projects will meet approximately one-third of the overall mandate. Additionally, on June 1, 2016, Minnesota Power filed a proposal with the MPUC to increase the amount of solar rebates available for customer-sited solar installations and recover costs of the program through Minnesota Power's renewable cost recovery rider. If approved, the Minnesota Power projects would meet part of the mandate related to solar photovoltaic devices with a nameplate capacity of 20 kW or less.

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 of 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 6. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities	September 30, 2016	December 31, 2015
Millions		
Current Regulatory Assets (a)		
Deferred Fuel Adjustment Clause	$16.8	$10.6
Total Current Regulatory Assets	16.8	10.6
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	213.9	219.3
Income Taxes (c)	65.1	64.2
Cost Recovery Riders (d)	39.9	58.0
Asset Retirement Obligations (e)	24.8	21.6
PPACA Income Tax Deferral	5.0	5.0
Other	10.2	3.9
Total Non-Current Regulatory Assets	358.9	372.0
Total Regulatory Assets	$375.7	$382.6
Non-Current Regulatory Liabilities		
Wholesale and Retail Contra AFUDC (f)	$56.9	$58.0
North Dakota Investment Tax Credits (g)	27.9	12.8
Income Taxes (c)	20.0	6.1
Plant Removal Obligations	15.6	22.1
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	—	0.9
Other	2.5	5.1
Total Non-Current Regulatory Liabilities	$122.9	$105.0

(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 as actuarial gains and losses as well as prior service costs and credits, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. (See Note 12. Pension and Other Postretirement Benefit Plans.)

(c) These assets and liabilities are offsets to deferred income taxes recognized on certain regulatory temporary differences, which will reverse over the remaining lives of those temporary differences.

(d) The cost recovery rider regulatory assets are revenues not yet collected from our customers primarily due to capital expenditures related to the 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. The cost recovery rider regulatory assets as of September 30, 2016, will be recovered over the next two years.

(e) Asset retirement obligations will accrete and be amortized over the lives of the related property with asset retirement obligations.

(f) Wholesale and Retail Contra AFUDC represents the regulatory offset to AFUDC Equity and Debt recorded during the construction period of our cost recovery rider projects prior to placing the projects in service. The regulatory liability will decrease over the remaining depreciable lives of the related assets.

(g) North Dakota investment tax credits expected to be realized from the Bison Wind Energy Center that will be credited to Minnesota Power's regulated retail customers over the remaining life of the Bison Wind Energy Center through future renewable cost recovery rider filings.

NOTE 7. INVESTMENT IN ATC

Our wholly-owned subsidiary, ALLETE Transmission Holdings, 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. We account for our investment in ATC under the equity method of accounting. As of September 30, 2016, our equity investment in ATC was $133.8 million ($124.5 million at December 31, 2015). In the first nine months of 2016, we invested $3.5 million in ATC, and on October 28, 2016, we invested an additional $1.9 million. We do not expect to make any additional investments in 2016.

ALLETE’s Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2015	$124.5
Cash Investments	3.5
Equity in ATC Earnings	15.0
Distributed ATC Earnings	(9.2)
Equity Investment Balance as of September 30, 2016	$133.8

NOTE 7. INVESTMENT IN ATC (Continued)

On September 28, 2016, the FERC issued an order reducing ATC's authorized return on equity to 10.82 percent, including an incentive adder for participation in a regional transmission organization. Prior to this order, ATC had been allowed a return on equity of 12.2 percent which had been impacted by reductions for estimated refunds related to complaints filed with the FERC by several customers located within the MISO service area.

On June 30, 2016, a federal administrative law judge ruled on an additional complaint proposing a further reduction in the base return on equity to 9.70 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is expected in 2017. (See Note 6. Regulatory Matters.) 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 after-tax ($0.9 million pre-tax).

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

The following tables present ALLETE's short-term and long-term debt as of September 30, 2016 and December 31, 2015.

September 30, 2016	Principal	Unamortized Debt Issuance Costs	Total
Millions			
Short-Term Debt (a)	$187.2	$(0.6)	$186.6
Long-Term Debt	1,369.7	(10.8)	1,358.9
Total Debt	$1,556.9	$(11.4)	$1,545.5

(a) Consisted of long-term debt due within one year.

December 31, 2015	Principal	Unamortized Debt Issuance Costs	Total
Millions			
Short-Term Debt (a)	$37.9	$(0.6)	$37.3
Long-Term Debt	1,568.7	(12.0)	1,556.7
Total Debt	$1,606.6	$(12.6)	$1,594.0

(a) Consisted of long-term debt due within one year and notes payable.

No material long-term debt was issued in the first nine months of 2016.

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 September 30, 2016, our ratio was approximately 0.45 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 September 30, 2016, ALLETE was in compliance with its financial covenants.

26

NOTE 9. INCOME TAX EXPENSE

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Millions				
Current Tax Expense (a)				
Federal	—	—	—	—
State	—	$0.2	$0.2	$0.5
Total Current Tax Expense	—	$0.2	$0.2	$0.5
Deferred Tax Expense				
Federal	$0.4	$14.8	$7.1	$23.5
State	1.4	(0.4)	8.9	3.6
Investment Tax Credit Amortization	(0.1)	(0.2)	(0.5)	(0.6)
Total Deferred Tax Expense	$1.7	$14.2	$15.5	$26.5
Total Income Tax Expense	$1.7	$14.4	$15.7	$27.0

(a) For the nine months ended September 30, 2016, and 2015, the federal and state current tax expense was minimal due to NOLs which resulted from the bonus depreciation provisions of the Protecting Americans from Tax Hikes Act of 2015, the Tax Increase Prevention Act of 2014 and the American Taxpayer Relief Act of 2012.

The Company's tax provision for interim periods is determined using an estimate of its annual effective tax rate, adjusted for discrete items arising in that quarter. In each quarter, the Company updates its estimate of the annual effective tax rate, and if the estimated annual effective tax rate changes, the Company would make a cumulative adjustment in that quarter.

	Quarter Ended		Nine Months Ended	
Reconciliation of Taxes from Federal Statutory	September 30,		September 30,	
Rate to Total Income Tax Expense	2016	2015	2016	2015
Millions				
Income Before Non-Controlling Interest and Income Taxes	$42.0	$74.7	$127.2	$149.7
Statutory Federal Income Tax Rate	35 %	35 %	35 %	35 %
Income Taxes Computed at 35 percent Statutory Federal Rate	$14.7	$26.1	$44.5	$52.4
Increase (Decrease) in Tax Due to:				
State Income Taxes – Net of Federal Income Tax Benefit	0.9	(0.2)	5.9	2.6
Production Tax Credits	(14.0)	(11.0)	(34.5)	(31.8)
Regulatory Differences for Utility Plant	—	(0.3)	(0.1)	(0.7)
Other	0.1	(0.2)	(0.1)	4.5
Total Income Tax Expense	$1.7	$14.4	$15.7	$27.0

For the nine months ended September 30, 2016, the effective tax rate was 12.3 percent (18.0 percent for the nine months ended September 30, 2015).

Uncertain Tax Positions. As of September 30, 2016, we had gross unrecognized tax benefits of $2.0 million ($2.4 million as of December 31, 2015). Of the total gross unrecognized tax benefits, $0.6 million represents the amount of unrecognized tax benefits included on 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 2013, or state examination for years before 2012.

NOTE 10. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in Accumulated Other Comprehensive Loss. Comprehensive income (loss) is the change in shareholders' equity during a period from transactions and events from non-owner sources, including net income. The amounts recorded to accumulated other comprehensive loss include unrealized gains and losses on available-for-sale securities, defined benefit pension and other postretirement items, consisting of deferred actuarial gains or losses and prior service costs or credits, and gains and losses on derivatives accounted for as cash flow hedges.

For the quarter and nine months ended September 30, 2016 and 2015, reclassifications out of accumulated other comprehensive income for the Company were not material. Changes in accumulated other comprehensive loss for the nine months ended September 30, 2016, are presented on the Consolidated Statement of Equity.

NOTE 11. 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 entered into in 2014, a portion of which were issued in 2015. For the nine months ended September 30, 2016, and 2015, 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	2016 Dilutive Securities	Diluted	Basic	2015 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
Quarter ended September 30,						
Net Income Attributable to ALLETE	$40.3		$40.3	$60.4		$60.4
Average Common Shares	49.4	0.1	49.5	48.8	0.1	48.9
Earnings Per Share	$0.82		$0.81	$1.24		$1.23
Nine Months Ended September 30,						
Net Income Attributable to ALLETE	$111.0		$111.0	$122.8		$122.8
Average Common Shares	49.3	0.1	49.4	48.0	0.1	48.1
Earnings Per Share	$2.25		$2.25	$2.56		$2.55

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Expense (Income)	2016	2015	2016	2015
Millions				
Quarter Ended September 30,				
Service Cost	$2.0	$2.6	$1.0	$1.0
Interest Cost	8.2	7.5	1.9	1.8
Expected Return on Plan Assets	(10.7)	(10.2)	(2.8)	(2.7)
Amortization of Prior Service Credits	—	—	(0.7)	(0.7)
Amortization of Net Loss	2.4	4.4	—	0.1
Net Periodic Benefit Expense (Income)	$1.9	$4.3	$(0.6)	$(0.5)

Nine Months Ended September 30,				
Service Cost	$6.1	$7.6	$3.0	$3.2
Interest Cost	24.4	22.4	5.6	5.4
Expected Return on Plan Assets	(32.0)	(30.5)	(8.4)	(8.2)
Amortization of Prior Service Costs (Credits)	—	0.1	(2.2)	(2.2)
Amortization of Net Loss	7.3	13.4	0.1	0.3
Net Periodic Benefit Expense (Income)	$5.8	$13.0	$(1.9)	$(1.5)

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Employer Contributions. For the nine months ended September 30, 2016, we contributed $6.3 million in cash to our defined benefit pension plan (none for the nine months ended September 30, 2015); we do not expect to make additional contributions to our defined benefit pension plan in 2016. For the nine months ended September 30, 2016, and 2015, 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 2016.

NOTE 13. 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.

Our PPAs are summarized in Note 12. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in our 2015 Form 10-K, with additional disclosure provided in the following paragraphs.

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). Minnesota Power is obligated to pay its pro rata share of Square Butte’s costs based on its entitlement to the output of Square Butte’s 455 MW coal-fired generating unit. Minnesota Power’s 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. Square Butte’s costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of September 30, 2016, Square Butte had total debt outstanding of $329.7 million. Fuel expenses are recoverable through Minnesota Power’s fuel adjustment clause and include the cost of coal purchased from BNI Energy under a long-term contract.

Minnesota Power’s cost of power purchased from Square Butte during the nine months ended September 30, 2016, was $56.8 million ($57.6 million for the nine months ended September 30, 2015). 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 $7.2 million during the nine months ended September 30, 2016 ($7.6 million for the nine months ended September 30, 2015). 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. Minnesota Power has a power sales agreement with Minnkota Power, which commenced in 2014. Under the power sales agreement, Minnesota Power is selling a portion of its entitlement 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. Of Minnesota Power’s 50 percent output entitlement, it sold to Minnkota Power approximately 28 percent in 2016 and in 2015.

Silver Bay Power Sales Agreement. On May 23, 2016, Minnesota Power and Silver Bay Power entered into a long-term PPA through 2031. Silver Bay Power supplies approximately 90 MW of load to Northshore Mining which has been served predominately through self-generation by Silver Bay Power. In the years 2016 through 2019, Minnesota Power will supply Silver Bay Power with at least 50 MW of energy and Silver Bay Power will have the option to purchase additional energy from Minnesota Power as it transitions away from self-generation. On

December 31, 2019, Silver Bay Power will cease self-generation and Minnesota Power will supply the entire energy requirements for Silver Bay Power.

Shell Energy PPA. In June 2016, Minnesota Power and Shell Energy signed a PPA that provides for Minnesota Power to purchase 50 MW of energy at fixed prices. The PPA begins in January 2017 and expires in December 2019.

Coal, Rail and Shipping Contracts. Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2016 and a portion of its coal requirements through December 2021. Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2018. The minimum annual payment obligation under these supply and transportation agreements is $7.9 million for the remainder of 2016, $27.9 million in 2017, $27.0 million in 2018, $1.8 million in 2019 and none thereafter. The delivered costs of fuel for Minnesota Power’s generation are recoverable from Minnesota Power’s utility customers through the fuel adjustment clause.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Leasing Agreements. BNI Energy is obligated to make lease payments for a dragline totaling $2.8 million annually during the lease term, which expires in 2027. BNI Energy 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 $3.5 million for the remainder of 2016, $12.6 million in 2017, $11.1 million in 2018, $9.9 million in 2019, $6.9 million in 2020 and $23.2 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, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others) and our investment in ATC.

Our transmission investments are summarized in Note 12. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in our 2015 Form 10-K, with additional disclosure provided in the following paragraphs.

Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in 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 which was approved in a June 2015 order. Based on this order, Minnesota Power’s portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. (See Note 6. Regulatory Matters.) In a December 2015 order, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power’s wholesale customers. 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 an order dated April 11, 2016, the MPUC approved the route permit which largely follows Minnesota Power’s preferred route, including the international border crossing. Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro’s hydroelectric generation facility commenced in 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is expected to begin by 2017 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. 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. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have recently been promulgated by both the EPA and state authorities. Minnesota Power’s facilities are subject to additional regulation under many of these regulations. In response to these regulations, Minnesota Power is reshaping its generation portfolio over time to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

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. We anticipate that with many state and federal environmental regulations finalized, or to be finalized in the near future, potential expenditures for future environmental matters may be material and may require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of 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 become 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.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 emission requirements.

New Source Review (NSR). In 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 and Laskin Unit 2 between the years of 1981 and 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 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 through existing emission control technology at Boswell. On October 19, 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as the latest step in its EnergyForward strategic plan. We believe that costs to retire would be eligible for recovery in rates over time subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). The CSAPR requires a total of 28 states in the eastern half of the United States, including Minnesota, to reduce power plant emissions that contribute to ozone or fine particulate pollution in other states. The 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 are allocated to facilities from each state's annual budget and can be bought and sold.

In 2014, the EPA distributed the CSAPR allowances to CSAPR-subject units for the Phase I years (2015 and 2016). Phase II allowances (2017 and beyond) for 2017 and 2018 were distributed on June 29, 2016. Based on our review of the NO_x and SO_2 Phase I and Phase II allowances already issued, and Phase II allowances not yet issued, we currently expect projected generation levels and emission rates will result 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 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 were required to be in compliance with the rule by April 2015. States had the authority to grant sources a one-year extension. The MPCA approved Minnesota Power's request for an extension of the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan was completed in 2015. Boswell Unit 3 is also subject to the MATS rule; however, investments and compliance work completed at Boswell Unit 3, including the emission reduction investments completed in 2009, meet the requirements of the MATS rule. The conversion of Laskin Units 1 and 2 to natural gas in

June 2015 positioned those units for MATS compliance.

In June 2015, the U.S. Supreme Court reversed and remanded an earlier U.S. Court of Appeals for the D.C. Circuit decision on the MATS rule. The U.S. Supreme Court ruled that it was unreasonable for the EPA to deem cost of compliance irrelevant in determining that regulation of emissions of hazardous air pollutants from power plants was “appropriate and necessary” under Section 112 of the Clean Air Act. The MATS rule remains in effect until the U.S. Court of Appeals for the D.C. Circuit acts on the remand. In December 2015, the U.S. Court of Appeals for the D.C. Circuit rejected a motion by utilities and states to vacate the MATS rule, instead ordering the rule to remain in effect while the EPA completes its review. On April 15, 2016, the EPA announced its determination that the MATS rule is appropriate and necessary, even after considering cost of compliance. The outcome of these proceedings is not expected to have a material impact on Minnesota Power generation due to emission reduction obligations under the Minnesota Mercury Emissions Reduction Act and the Consent Decree. (See New Source Review.)

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 was required to implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above (see Mercury and Air Toxics Standards (MATS) Rule) fulfills the requirements of the Minnesota Mercury Emissions Reduction Act.

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 MACT became effective in 2012. Major existing sources had until January 31, 2016, to achieve compliance with the final rule and July 29, 2016, to perform initial compliance demonstrations. Minnesota Power’s Hibbard Renewable Energy Center and Rapids Energy Center are subject to this rule and are currently in compliance. Compliance consists largely of adjustments to our operating practices; therefore the costs for complying with the final rule are not expected to be material.

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 the 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 more stringent control related to emissions that result in ground level ozone. In 2010, the EPA proposed to revise the 2008 eight-hour ozone standard of 75 parts per billion (ppb) and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. In October 2015, the EPA published the final rule in the Federal Register revising the eight-hour ozone standard to 70 ppb with a secondary standard also set at 70 ppb. All areas of Minnesota currently meet the new standard based on the most recent available ambient monitoring data; however, some areas in the metropolitan Twin Cities and southwest portion of the state are close to exceeding the standard. As a result, voluntary efforts to reduce ozone continue in the state. No additional costs for compliance are anticipated at this time.

Particulate Matter NAAQS. The EPA finalized the Particulate Matter NAAQS in 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 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 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 2013, based on already available monitoring data, and issued designations of the 2012 revised primary annual fine particulate attainment status in 2014. The EPA designated the entire state of Minnesota as unclassifiable/attainment; however, Minnesota sources may ultimately be required to reduce their emissions to assist with attainment in neighboring states. On September 27, 2016, environmental groups filed a lawsuit against the EPA in the United States District Court for the Northern District of California alleging the EPA had failed to fully implement the $PM_{2.5}$ standards in 24 states, including Minnesota, by not enforcing states’ submittals of required infrastructure SIPs for the 2012 $PM_{2.5}$ NAAQS. The outcome of this litigation is uncertain, and as such any 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 is likely in compliance with these standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate additional modeling and monitoring considerations to determine attainment. In 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 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 2013. However, the State of Minnesota delayed completing the documents pending EPA guidance to states for preparing the SIP submittal.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

In 2013, the EPA provided guidance to states regarding implementation of the one-hour NO_2 NAAQS and in 2014, as clarified in February 2015, the MPCA submitted a SIP revision to the EPA addressing the infrastructure requirements of Sections 110(a)(1) and 110(a)(2) of the Clean Air Act in regards to the one-hour NO_2 and SO_2 NAAQS, among other standards. The SIP stated that since the EPA determined in 2012 that no area in the country is in violation of the one-hour NO_2 NAAQS, there are no nonattainment areas in the country for this pollutant, and therefore Minnesota's NO_2 emissions cannot be significantly contributing to nonattainment in any other state. In October 2015, the EPA published in the Federal Register an approval and partial disapproval of the 2014 SIP revision. According to the MPCA, the partial disapproval is regarding state delegation of a program unrelated to the one-hour NAAQS for SO_2 and NO_2, and is not expected to require further action. As such, additional compliance costs for the one-hour NO_2 NAAQS are not expected at this time.

In August 2015, the EPA finalized the SO_2 data requirements rule (DRR) for the 2010 one-hour NAAQS to assist the states in implementing the standard. The rule sets emissions thresholds and exemptions for facilities that trigger modeling requirements. On January 8, 2016, the MPCA informed the EPA of the Minnesota sources subject to the rule, confirming that Boswell and Taconite Harbor are the only Minnesota Power generating facilities subject to the DRR. The MPCA was required to notify the EPA how each source will evaluate air quality by July 1, 2016. Compliance options include ambient monitoring, modeling existing enforceable emission limits, or modeling actual emissions. The MPCA initially informed Minnesota Power that compliant SO_2 modeling recently completed at these facilities would satisfy the DRR obligations, and no further modeling would be required. However, the DRR also requires facilities have federally-enforceable permit limits at which the one-hour SO_2 NAAQS compliance was modeled by January 13, 2017. Taconite Harbor was issued an amended air permit on September 1, 2016 containing the new modeling limits at that facility. The MPCA informed Minnesota Power that the MPCA will not meet the January 13, 2017 deadline to amend the Boswell permit. However, the MPCA is in discussions with the EPA on alternate compliance pathways to use existing completed modeling at current limits. Compliance costs for the one-hour SO_2 NAAQS are not expected to be material.

Class I Air Quality Petitions and Requests. In 2014, the Fond du Lac Band of Lake Superior Chippewa (Fond du Lac Band) announced its intent to petition 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 Fond du Lac Band does not currently possess authority to directly regulate air quality. Class I air shed status, if granted, would allow the Fond du Lac 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 received Class I status. A public hearing was held by the Fond du Lac Band in October 2014, and the extended public comment period on the petition expired in November 2014. After the Fond du Lac Band prepares responses to the comments, it is anticipated to make a formal submittal request to the EPA.

In 2013, the Bad River Band of Lake Superior Chippewa (Bad River Band) announced its intent to petition the EPA to redesignate its reservation air shed, which is located approximately 100 miles east of Duluth, Minnesota, from Class II to Class I air quality pursuant to Section 164(c) of the Clean Air Act. The Class I analysis report was issued by the Bad River Band in January 2015 which was followed by public hearings in March 2015 and a public comment period ending in May 2015. After the Bad River Band prepares responses to the comments, it is also anticipated to make a formal submittal request to the EPA.

There is no deadline for the approval, denial, or modification of these requests by the EPA. 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.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

President Obama's Climate Action Plan. In 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 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 2014, the U.S. Supreme Court invalidated the aspect of the Tailoring Rule that established higher 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.

On October 3, 2016, the EPA published a proposed rule in the Federal Register to revise its PSD and Title V regulatory provisions concerning GHG emissions. In this proposed rule, the EPA proposes to amend its regulations to clarify that a source's obligation to obtain a PSD or Title V permit is triggered only by non-GHG pollutants. If the PSD or Title V permitting requirements are triggered by non-GHG, NSR pollutants, then these programs will also apply to the source's GHG emissions. The proposed rule, as currently written, is not expected to have a material impact on the Title V permitting for current operations.

In 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 2013, the EPA retracted its 2012 proposal and announced the release of a revised NSPS for new or re-powered utility CO_2 emissions.

In 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", also referred to as the Clean Power Plan (CPP). The EPA issued the final CPP in August 2015, together with a proposed federal implementation plan and a model rule for emissions trading. Numerous petitions for review of the rule have been filed with the U.S. Court of Appeals for the District of Columbia Circuit. On February 9, 2016, the U.S. Supreme Court issued an order staying the effectiveness of the rule until after the appellate court process is complete. On September 27, 2016, the U.S. Court of Appeals for the District of Columbia heard oral arguments and is currently deliberating. The EPA is precluded from enforcing the CPP while the U.S. Supreme Court stay is in force; however, the MPCA has been holding a series of meetings on the CPP for educational and planning purposes in the interim. Minnesota Power has been actively involved in these MPCA meetings, and is closely monitoring the appeals process.

If upheld, the CPP would establish uniform CO_2 emission performance rates for existing fossil fuel-fired and natural gas-fired combined cycle generating units, setting state-specific goals for CO_2 emissions from the power sector. State goals were determined based on CPP source-specific performance emission rates and each state’s mix of power plants. The EPA maintains such goals are achievable if a state undertakes a combination of measures across its power sector that constitutes the EPA’s guideline for a Best System of Emission Reductions (BSER). BSER is comprised of three 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, and 3) building more zero- and low-emitting power sources, including renewable energy. States may also choose to include avoided CO_2 emissions from customer energy efficiency measures for credit towards meeting state goals.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

State goals under the CPP are expressed as both mass-based and rate-based, and include interim goals to be met over the years 2022 through 2029, as well as a final goal to be met in 2030 and thereafter. Under the original schedule for the CPP, each state would have been required to develop a SIP by September 6, 2016, or by September 6, 2018, if granted an extension. Due to the U.S Supreme Court order staying the effectiveness of the CPP, those SIP submittal dates are not currently in effect. If the CPP is upheld at the completion of the appellate court process, all of the CPP regulatory deadlines are expected to be reset based on the length of time that the appeals process takes.

In developing its plan, a state may choose to meet either the mass-based or the rate-based goals. Minnesota Power is currently evaluating the CPP as it relates to the State of Minnesota as well as its potential impact on the Company and is actively discussing potential compliance scenarios with regulatory agencies and in public stakeholder meetings. 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 6. Regulatory Matters.)

The EPA accepted comments through November 1, 2016, on the proposed Clean Energy Incentive Program (CEIP) that may be facilitated as part of the CPP. The CEIP would reassign CPP emission rate credits or allowances for certain early action or designated deployments of renewable energy and energy efficiency measures.

We are unable to predict the GHG emission compliance costs we might incur; however, the costs could be material. Minnesota Power 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, the U.S. District Court for the District of Minnesota ruled that part of Minnesota’s Next Generation Energy Act of 2007 (NEGA) 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 PPAs 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 2014. On June 15, 2016, the U.S. Court of Appeals for the Eighth Circuit upheld the federal district court’s decision that part of the NEGA violated the Commerce Clause of the U.S. Constitution. Minnesota Governor Dayton subsequently announced that the State of Minnesota would cease pursuing further appeals of the U.S. Court of Appeals for the Eighth Circuit’s decision.

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 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 effective in 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 for Minnesota Power generating facilities 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. Should the MPCA require significant modifications to Minnesota Power’s intake structures, its preliminary assessment suggests costs of compliance up to $15 million over the next 5 years. Minnesota Power would seek recovery of any additional costs through a general rate case.

Steam Electric Power Generating Effluent Guidelines. In 2013, the EPA announced proposed revisions to the federal effluent limit guidelines (ELG) for steam electric power generating stations under the Clean Water Act. The final ELG was issued in September 2015. It sets effluent limits and prescribes BACT for several wastewater streams, including flue gas desulphurization (FGD) water and coal combustion landfill leachate. The ELG rule also prohibits the discharge of bottom and fly ash contact waters. Compliance with the final rule is required between November 1, 2018, and December 31, 2023.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

We are reviewing the final rule and evaluating its potential impact on Minnesota Power's operations, primarily at Boswell. Boswell currently discharges bottom ash contact water through its NPDES permit, and also has a closed-loop FGD system that does not currently discharge, but may do so in the future. Under the final ELG rule, bottom ash discharge would not be allowed and bottom ash contact water would either need to be re-used in a closed-loop process, routed to a FGD scrubber, or the bottom ash handling system would need to be converted to a dry process. If the FGD wastewater is discharged in the future, it would require additional wastewater treatment. Efforts have been underway at Boswell for several years to reduce the amount of water discharged and evaluate potential re-use options in its plant processes. Additional efforts are underway to determine if land application of certain wastewater streams under a state disposal system may be feasible.

At this time, we cannot estimate what 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. Minnesota Power 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 or disposes coal ash at four of its electric generating facilities. One facility stores ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility's ash is beneficially re-used. The other 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 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 2014 under Subtitle D (non-hazardous) of RCRA and it was published in the Federal Register in April 2015. The rule includes additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. Costs of compliance for Boswell and Laskin are expected to occur primarily over the next 10 years and be between approximately $65 million and $100 million. Minnesota Power has not disposed ash onsite at Taconite Harbor since the effective date of the rule, and therefore, the CCR rule is not applicable to that generating facility. Minnesota Power continues to work on minimizing costs through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. Minnesota Power would seek recovery of any additional costs through a general rate case.

Other Matters.

ALLETE Clean Energy. ALLETE Clean Energy's wind energy facilities have PPAs in place for their entire output and expire in various years between 2018 and 2032. As of September 30, 2016, ALLETE Clean Energy has $14.6 million outstanding in standby letters of credit.

U.S. Water Services. As of September 30, 2016, U.S. Water Services has $0.8 million outstanding in standby letters of credit.

BNI Energy. As of September 30, 2016, BNI Energy had surety bonds outstanding of $49.9 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although its 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 Energy has secured a letter of credit for an additional $0.6 million to provide for BNI Energy's total reclamation liability, which is currently estimated at $47.5 million. BNI Energy does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

ALLETE Properties. As of September 30, 2016, ALLETE Properties, through its subsidiaries, had surety bonds outstanding and letters of credit to governmental entities totaling $8.6 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is approximately $5.4 million. ALLETE Properties does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Other Matters (Continued)

Community Development District Obligations. At September 30, 2016, we owned 72 percent of the assessable land in the Town Center District (72 percent at December 31, 2015) and 92 percent of the assessable land in the Palm Coast Park District (92 percent at December 31, 2015). At these ownership levels, our annual assessments related to capital improvement and special assessment bonds for the ALLETE Properties projects within these districts are approximately $1.4 million for Town Center at Palm Coast and $2.1 million for Palm Coast Park. As we sell property at these projects, 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.

NOTE 14. BUSINESS SEGMENTS

Regulated Operations includes three operating segments which consist of 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. ALLETE Clean Energy is our business focused on developing, acquiring and operating clean and renewable energy projects. U.S. Water Services is our integrated water management company which was acquired in February 2015. The ALLETE Clean Energy and U.S. Water Services reportable segments comprise our Energy Infrastructure and Related Services businesses. We also present Corporate and Other which includes two operating segments, BNI Energy, our coal mining operations in North Dakota, and ALLETE Properties, our legacy Florida real estate investment, along with 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.

	Quarter Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
Millions				
Operating Revenue				
Regulated Operations	$253.3	$250.2	$740.5	$743.0
Energy Infrastructure and Related Services				
ALLETE Clean Energy	14.7	151.1	57.1	197.5
U.S. Water Services	37.8	36.1	104.5	86.0
Corporate and Other	43.8	25.1	96.1	79.3
Total Operating Revenue	$349.6	$462.5	$998.2	$1,105.8
Net Income (Loss) Attributable to ALLETE				
Regulated Operations	$45.0	$43.8	$110.0	$108.1

Energy Infrastructure and Related Services				
ALLETE Clean Energy	1.0	13.2	9.7	18.7
U.S. Water Services	1.5	1.0	2.0	1.5
Corporate and Other	(7.2)	2.4	(10.7)	(5.5)
Total Net Income Attributable to ALLETE	$40.3	$60.4	$111.0	$122.8

NOTE 14. BUSINESS SEGMENTS (Continued)

	September 30, 2016	December 31, 2015
Millions		
Assets		
Regulated Operations (a)	$3,838.8	$3,853.1
Energy Infrastructure and Related Services		
ALLETE Clean Energy (a)	483.5	501.5
U.S. Water Services	259.4	258.3
Corporate and Other	293.1	281.6
Total Assets (a)	$4,874.8	$4,894.5

(a) As a result of revised accounting guidance adopted in the first quarter of 2016, we reclassified unamortized debt issuance costs from Other Non-Current Assets to Long-Term Debt on the Consolidated Balance Sheet. Prior period segment assets have been revised to conform to the current presentation. (See Note 1. Operations and Significant Accounting Policies.)

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 2015 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 and our 2015 Form 10-K under the headings: "Forward-Looking Statements" located on page 5 and "Risk Factors" located in Part I, Item 1A, beginning on page 25 of our 2015 Form 10 K. The risks and uncertainties described in this Form 10-Q and our 2015 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 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 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. (See Note 6. Regulatory Matters.)

ALLETE Clean Energy focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in the fourth quarter of 2015.

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.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, 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.

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

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of September 30, 2016, 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 nine months ended September 30, 2016, to the nine months ended September 30, 2015.

Net income attributable to ALLETE for the nine months ended September 30, 2016, was $111.0 million, or $2.25 per diluted share, compared to $122.8 million, or $2.55 per diluted share, for the same period in 2015. Net income for 2016 included an $8.8 million, or $0.18 per share, adverse impact for the regulatory outcome of an October 18, 2016, MPUC hearing on the allocation of North Dakota investment tax credits. (See Note 6. Regulatory Matters.) Net income for 2015 included a $4.8 million after-tax expense, or $0.10 per share, for acquisition costs related to U.S. Water Services and ALLETE Clean Energy's acquisitions. (See Note 3. Acquisitions.) In 2015, net income also included the recognition of $13.7 million after-tax estimated profit, or $0.29 per share, under percentage of completion accounting, for the construction of a wind energy facility which was sold to Montana-Dakota Utilities in the fourth quarter of 2015. Net income for 2016 also decreased due to lower net income at ALLETE Clean Energy. Earnings per share dilution was $0.06 due to additional shares of common stock outstanding as of September 30, 2016.

Regulated Operations net income attributable to ALLETE was $110.0 million for the nine months ended September 30, 2016, compared to $108.1 million for the same period in 2015. Net income for 2016 increased primarily due to higher net income at Minnesota Power resulting from lower operating and maintenance expenses, and higher FERC formula-based rates and cost recovery rider revenue. These increases were mostly offset by higher depreciation and property tax expenses, lower industrial sales and demand revenue, and impacts of warmer temperatures in 2016. Our equity earnings in ATC and earnings at SWL&P for the nine months ended September 30, 2016, were similar to the same period in 2015.

ALLETE Clean Energy net income attributable to ALLETE was $9.7 million for the nine months ended September 30, 2016, compared to $18.7 million for the same period in 2015. Net income for 2015 included the recognition of $13.7 million after-tax estimated profit under percentage of completion accounting, for the construction of a wind energy facility which was sold to Montana-Dakota Utilities in the fourth quarter of 2015. In 2015, net income also included a $1.8 million after tax expense, or $0.04 per share, for acquisition costs related to the Chanarambie/Viking and Armenia Mountain wind energy facilities. The decrease in net income for 2016 was partially offset by income generated from the operations of wind energy facilities acquired in April and July 2015. Net income in 2016 also included a $0.9 million after-tax expense related to the repayment of long-term debt.

U.S. Water Services net income attributable to ALLETE was $2.0 million for the nine months ended September 30, 2016, compared to $1.5 million for the period from the date of acquisition, February 10, 2015, through September 30, 2015. Net income for 2015 included $1.6 million of after-tax expense recognized as cost of sales related to purchase accounting for inventories and sales backlog. Net income for 2016 reflects increased investments in back office systems and support at U.S. Water Services as we create a platform for future growth.

Corporate and Other net loss attributable to ALLETE was $10.7 million for the nine months ended September 30, 2016, compared to $5.5 million for the same period in 2015. In 2016, the net loss increased primarily due to the adverse regulatory outcome of an October 18, 2016, MPUC hearing on the allocation of North Dakota investment tax credits, higher interest expense and state income tax expense. The net loss for 2016 was partially offset by a $3.3 million after-tax gain for the sale of ALLETE Properties’ Ormond Crossings project and Lake Swamp mitigation bank. In 2015, the net loss included a $3.0 million after-tax expense for acquisition costs related to U.S. Water Services.

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2016, AND 2015

(See Note 14. Business Segments for financial results by segment.)

Regulated Operations

Quarter Ended September 30,	2016	2015
Millions		
Operating Revenue	$253.3	$250.2
Fuel and Purchased Power	91.0	76.8
Transmission Services	16.6	13.9
Cost of Sales	0.7	0.5
Operating and Maintenance	52.9	54.7
Depreciation and Amortization	38.5	33.6
Taxes Other than Income Taxes	11.3	10.9
Operating Income	42.3	59.8
Interest Expense	(13.0)	(13.4)
Equity Earnings in ATC	6.1	5.5
Other Income	0.6	1.0
Income Before Non-Controlling Interest and Income Taxes	36.0	52.9
Income Tax Expense	(9.0)	9.1
Net Income Attributable to ALLETE	$45.0	$43.8

Operating Revenue increased $3.1 million, or 1 percent, from 2015 primarily due to higher kWh sales, fuel adjustment clause recoveries, cost recovery rider revenue, transmission revenue, financial incentives under the Minnesota conservation improvement program and FERC formula-based rates, partially offset by the adverse impact of a regulatory outcome related to the allocation of North Dakota investment tax credits.

Revenue increased $6.5 million primarily due to a 5.0 percent increase in kWh sales and higher pricing on our wholesale power sales agreements compared to last year. 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 8.5 percent in 2016 compared to 2015 primarily as a result of more energy available for sale. Sales to our industrial customers increased 6.2 percent primarily due to the commencement of a long-term PPA with Silver Bay Power; however, demand revenue from our industrial customers was down in 2016 as a result of lower demand nominations during the quarter. (See Note 13. Commitments, Guarantees and Contingencies.)

Kilowatt-hours Sold Quarter Ended September 30,	2016	2015	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	250	250	—	—
Commercial	383	391	(8)	(2.0)%
Industrial	1,633	1,538	95	6.2%
Municipal	205	209	(4)	(1.9)%
Total Retail and Municipal	2,471	2,388	83	3.5%
Other Power Suppliers	1,141	1,052	89	8.5%
Total Regulated Utility Kilowatt-hours Sold	3,612	3,440	172	5.0%

Revenue from electric sales to taconite/iron concentrate customers accounted for 17 percent of consolidated operating revenue in 2016 (12 percent in 2015). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of consolidated operating revenue in 2016 (5 percent in 2015). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2016 (5 percent in 2015).

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2016, AND 2015 (Continued)
Regulated Operations (Continued)

Fuel adjustment clause recoveries increased $6.5 million due to higher fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Cost recovery rider revenue increased $2.1 million primarily due to the completion of the Boswell Unit 4 environmental upgrade in the fourth quarter of 2015.

Transmission revenue increased $1.2 million primarily due to higher MISO-related revenue. (See Operating Expenses - Transmission Services.)

Financial incentives under the Minnesota conservation improvement program increased $1.2 million from 2015.

Revenue from our wholesale customers under formula-based rates increased $1.1 million primarily due to environmental and other investments.

Revenue decreased $15.0 million due to an adverse impact for the regulatory outcome of an October 18, 2016, MPUC hearing on the allocation of North Dakota investment tax credits. (See Note 6. Regulatory Matters.)

Operating Expenses increased $20.6 million, or 11 percent, from 2015.

Fuel and Purchased Power expense increased $14.2 million, or 18 percent, from 2015 primarily due to higher fuel costs and kWh sales compared to 2015. 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 $2.7 million, or 19 percent, from 2015 primarily due to higher MISO-related expense. (See Operating Revenue.)

Operating and Maintenance expense decreased $1.8 million, or 3 percent, from 2015 primarily due to lower salary and benefit expenses.

Depreciation and Amortization expense increased $4.9 million, or 15 percent, from 2015 primarily due to additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $0.4 million, or 4 percent, from 2015 primarily due to higher property tax expenses resulting from higher taxable plant.

Interest Expense decreased $0.4 million, or 3 percent, from 2015 primarily due to lower average interest rates. We record interest expense for Regulated Operations based on Minnesota Power’s rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC increased $0.6 million, or 11 percent, from 2015 primarily due to additional investment in ATC and period over period changes in ATC’s estimate of a refund liability related to MISO return on equity complaints.

Income Tax Expense decreased $18.1 million from 2015 due to lower pre-tax income, higher production tax credits and the impact of accounting for the adverse regulatory outcome relating to the allocation of prior period North

Dakota investment tax credits. (See Note 6. Regulatory Matters.) To account for this outcome, our Regulated Operations reduced operating revenue and recorded a corresponding regulatory liability for $15.0 million during the third quarter of 2016. In addition, and to reflect proper segment reporting, our Regulated Operations recorded a tax benefit of $8.8 million and Corporate and Other recorded an offsetting $8.8 million tax expense.

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2016, AND 2015 (Continued)

ALLETE Clean Energy

Quarter Ended September 30,	2016	2015
Millions		
Operating Revenue	$14.7	$151.1
Net Income Attributable to ALLETE	$1.0	$13.2

Operating Revenue decreased $136.4 million from 2015. Operating revenue in 2015 included the recognition under percentage of completion accounting of $135.9 million in revenue for the construction of a wind energy facility which was sold to Montana-Dakota Utilities in the fourth quarter of 2015.

	Quarter Ended September 30,			
	2016		2015	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Facilities				
Lake Benton	42.2	$2.6	48.4	$2.8
Storm Lake II	22.2	1.9	31.5	2.4
Condon	16.0	1.4	17.4	1.6
Storm Lake I	31.2	2.4	36.5	2.6
Chanarambie/Viking	45.3	2.7	46.0	3.0
Armenia Mountain	40.2	3.7	33.7	2.8
Total Wind Energy Facilities	197.1	14.7	213.5	15.2
Development Fee (a)	—	—	—	135.9
Total Production and Operating Revenue	197.1	$14.7	213.5	$151.1

(a) 2015 included the recognition of $114.9 million of cost of sales.

Net Income Attributable to ALLETE decreased $12.2 million, or 92 percent, from 2015. Net income for 2015 included the recognition under percentage of completion accounting of $12.3 million of after-tax estimated profit for the construction of a wind energy facility which was sold to Montana-Dakota Utilities in the fourth quarter of 2015. In 2015, net income also included a $0.9 million after-tax expense for acquisition costs related to the Armenia Mountain wind energy facility. Net income in 2016 included a $0.9 million after-tax expense related to the repayment of long-term debt.

U.S. Water Services

Quarter Ended September 30,	2016	2015
Millions		
Operating Revenue	$37.8	$36.1
Net Income Attributable to ALLETE	$1.5	$1.0

Operating Revenue increased $1.7 million, or 5 percent, in 2016 compared with the same period in 2015. Revenue from chemical sales and related services, which includes recurring revenue contracts for the delivery and service of chemicals, increased 11 percent to $31.1 million in 2016 compared to $27.8 million in 2015. Revenue from equipment and related services, which includes sales of water treatment equipment, was $6.7 million for 2016 compared to $8.3 million in 2015; equipment sales can fluctuate from quarter to quarter. U.S. Water Services strives to provide a full-service product offering to customers including equipment, chemicals, engineering and service.

Net Income Attributable to ALLETE increased $0.5 million from 2015. Net income in 2015 included higher cost of sales resulting from purchase accounting fair value adjustments for inventories and sales backlog of $0.6 million.

2016 earnings also reflect increased investments in back office systems and support at U.S. Water Services as we create a platform for future growth.

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2016, AND 2015 (Continued)

Corporate and Other

Operating Revenue increased $18.7 million, or 75 percent, from 2015 primarily due to an increase in land sales at ALLETE Properties, which sold its Ormond Crossings project and Lake Swamp wetland mitigation bank in 2016. The increase was partially offset by a decrease in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of lower expenses in 2016.

Net Income Attributable to ALLETE decreased $9.6 million from 2015 primarily due to an $8.8 million adverse impact for the regulatory outcome of an October 18, 2016, MPUC hearing on the allocation of North Dakota investment tax credits (see Note 6. Regulatory Matters and Regulated Operations - Income Tax Expense), higher state income tax expense and lower net income at BNI Energy, partially offset by a $3.3 million after-tax gain at ALLETE Properties resulting from the sale of its Ormond Crossings project and Lake Swamp wetland mitigation bank.

Income Taxes – Consolidated

For the quarter ended September 30, 2016, the effective tax rate was 4.0 percent (19.3 percent for the quarter ended September 30, 2015). The effective tax rate deviated from the combined statutory rate of approximately 41 percent primarily due to production tax credits. (See Note 9. Income Tax Expense.) The estimated annual effective tax rate can differ from what a quarterly effective tax rate would otherwise be on a stand-alone basis, and this may cause quarter to quarter differences in the timing of income taxes.

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015

(See Note 14. Business Segments for financial results by segment.)

Regulated Operations

Nine Months Ended September 30,	2016	2015
Millions		
Operating Revenue	$740.5	$743.0
Fuel and Purchased Power	246.0	242.9
Transmission Services	49.5	40.1
Cost of Sales	4.6	6.0
Operating and Maintenance	157.0	171.2
Depreciation and Amortization	115.1	99.4
Taxes Other than Income Taxes	36.3	34.6
Operating Income	132.0	148.8
Interest Expense	(38.8)	(40.9)
Equity Earnings in ATC	15.0	14.1
Other Income	1.8	2.6
Income Before Non-Controlling Interest and Income Taxes	110.0	124.6
Income Tax Expense	—	16.5
Net Income Attributable to ALLETE	$110.0	$108.1

Operating Revenue decreased $2.5 million from 2015 primarily due to the adverse impact of a regulatory outcome related to the allocation of North Dakota investment tax credits and lower fuel adjustment clause recoveries, conservation improvement program recoveries, and gas sales, partially offset by higher transmission revenue, cost recovery rider revenue, FERC formula based rates and kWh sales.

Revenue decreased $15.0 million due to an adverse impact for the regulatory outcome of an October 18, 2016, MPUC hearing on the allocation of North Dakota investment tax credits. (See Note 6. Regulatory Matters.)

Fuel adjustment clause recoveries decreased $3.4 million due to lower fuel and purchased power costs attributable to retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015 (Continued)
Regulated Operations (Continued)

Conservation improvement program recoveries decreased $4.8 million from 2015 primarily due to a reduction in related expenditures. (See Operating Expenses - Operating and Maintenance Expense.)

Revenue from gas sales at SWL&P decreased $1.5 million from 2015 as a result of warmer temperatures in 2016 compared to the same period in 2015. (See Cost of Sales.)

Transmission revenue increased $6.5 million primarily due to period over period changes in our estimate of a refund liability related to MISO return on equity complaints and higher MISO-related revenue. (See Operating Expenses - Transmission Services.)

Cost recovery rider revenue increased $6.1 million primarily due to the completion of the Boswell Unit 4 environmental upgrade in the fourth quarter of 2015.

Revenue from our wholesale customers under formula-based rates increased $4.0 million primarily due to additional environmental and other investments.

Despite relatively flat overall kWh sales, revenue increased $3.1 million from 2015 primarily due to higher pricing on our wholesale power sales agreements compared to last year and the commencement of a long-term PPA with Silver Bay Power. (See Note 13. Commitments, Guarantees and Contingencies.) Sales to our industrial customers decreased 6.4 percent primarily due to reduced taconite production. In addition, demand revenue from our industrial customers was down in 2016 as a result of lower demand nominations. Sales to our residential, commercial and municipal customers have been impacted by warmer temperatures in 2016 compared to the same period in 2015. Heating degree days in Duluth, Minnesota, were approximately 4 percent lower in the first nine months of 2016 compared to the same period in 2015.

Kilowatt-hours Sold Nine Months Ended September 30,	2016	2015	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	816	833	(17)	(2.0)%
Commercial	1,090	1,106	(16)	(1.4)%
Industrial	4,740	5,063	(323)	(6.4)%
Municipal	611	629	(18)	(2.9)%
Total Retail and Municipal	7,257	7,631	(374)	(4.9)%
Other Power Suppliers	3,456	3,056	400	13.1 %
Total Regulated Utility Kilowatt-hours Sold	10,713	10,687	26	0.2 %

Revenue from electric sales to taconite/iron concentrate customers accounted for 17 percent of consolidated operating revenue in 2016 (17 percent in 2015). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 6 percent of consolidated operating revenue in 2016 (6 percent in 2015). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2016 (6 percent in 2015).

Operating Expenses increased $14.3 million, or 2 percent, from 2015.

Fuel and Purchased Power expense increased $3.1 million, or 1 percent, from 2015 primarily due to higher fuel and purchased power costs attributable to sales to Other Power Suppliers, partially offset by lower fuel and purchased power costs attributable to our retail and municipal customers in 2016 compared to 2015. 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 $9.4 million, or 23 percent, from 2015 primarily due to higher MISO-related expense and period over period changes in our estimate of a refund for MISO transmission expense related to MISO return on equity complaints. (See Operating Revenue and Note 6. Regulatory Matters.)

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015 (Continued)
Regulated Operations (Continued)

Cost of Sales decreased $1.4 million, or 23 percent, from 2015 due to lower purchased gas at SWL&P. (See Operating Revenue.)

Operating and Maintenance expense decreased $14.2 million, or 8 percent, from 2015 primarily due to lower salary and benefit expenses, a $3.6 million sales tax refund received in the first quarter of 2016, and a $4.8 million decrease in conservation improvement program expenses. Conservation improvement program expenses are recovered from certain retail customers. (See Operating Revenue.)

Depreciation and Amortization expense increased $15.7 million, or 16 percent, from 2015 primarily due to additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $1.7 million, or 5 percent, from 2015 primarily due to higher property tax expenses resulting from higher taxable plant.

Interest Expense decreased $2.1 million, or 5 percent, from 2015 primarily due to lower average interest rates. We record interest expense for Regulated Operations based on Minnesota Power's rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC increased $0.9 million, or 6 percent, from 2015 primarily due to additional investment in ATC and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints.

Income Tax Expense decreased $16.5 million from 2015 due to lower pre-tax income, higher production tax credits and the impact of accounting for the adverse regulatory outcome relating to the allocation of prior period North Dakota investment tax credits. (See Note 6. Regulatory Matters.) To account for this outcome, our Regulated Operations reduced operating revenue and recorded a corresponding regulatory liability for $15.0 million during the third quarter of 2016. In addition, and to reflect proper segment reporting, our Regulated Operations recorded a tax benefit of $8.8 million and Corporate and Other recorded an offsetting $8.8 million tax expense.

ALLETE Clean Energy

Nine Months Ended September 30,	2016	2015
Millions		
Operating Revenue	$57.1	$197.5
Net Income Attributable to ALLETE	$9.7	$18.7

Operating Revenue decreased $140.4 million from 2015. Operating revenue in 2015 included the recognition under percentage of completion accounting of $156.4 million in revenue for the construction of a wind energy facility which was sold to Montana-Dakota Utilities in the fourth quarter of 2015. The decrease in operating revenue was partially offset by revenue generated from the operations of wind energy facilities acquired in April and July 2015.

	Nine Months Ended September 30,			
	2016		2015	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Facilities				

Lake Benton	175.7	$9.1	196.8	$10.1
Storm Lake II	113.8	7.5	129.6	8.4
Condon	67.0	5.7	55.1	5.1
Storm Lake I	151.5	8.4	161.4	8.8
Chanarambie/Viking	190.4	9.5	99.5	5.9
Armenia Mountain	181.0	16.9	33.7	2.8
Total Wind Energy Facilities	879.4	57.1	676.1	41.1
Development Fee (a)	—	—	—	156.4
Total Production and Operating Revenue	879.4	$57.1	676.1	$197.5

(a) 2015 included the recognition of $132.9 million of cost of sales.

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015 (Continued)
ALLETE Clean Energy (Continued)

Net Income Attributable to ALLETE decreased $9.0 million from 2015. Net income for 2015 included the recognition under percentage of completion accounting of $13.7 million of after-tax estimated profit for the construction of a wind energy facility which was sold to Montana-Dakota Utilities in the fourth quarter of 2015. In 2015, net income also included a $1.8 million after-tax expense for acquisition costs related to the Chanarambie/Viking and Armenia Mountain wind energy facilities. The decrease in net income for 2016 was partially offset by income generated from the operations of wind energy facilities acquired in April and July 2015. Net income in 2016 also included a $0.9 million after-tax expense related to the repayment of long-term debt.

U.S. Water Services

	Nine Months Ended September 30, 2016	Period February 10, 2015 Through September 30, 2015
Millions		
Operating Revenue	$104.5	$86.0
Net Income Attributable to ALLETE	$2.0	$1.5

Operating Revenue increased $18.5 million in 2016 compared to the period from February 10, 2015, to September 30, 2015. The results for 2015 reflect operations from the date of acquisition, February 10, 2015, through September 30, 2015, and therefore, do not reflect a full nine months. Revenue from chemical sales and related services, which includes recurring revenue contracts for the delivery and service of chemicals, was $84.3 million in 2016 compared to $66.6 million in 2015. Revenue from equipment and related services, which includes sales of water treatment equipment, was $20.2 million for 2016 compared to $19.4 million in 2015; equipment sales can fluctuate from quarter to quarter. U.S. Water Services strives to provide a full-service product offering to customers including equipment, chemicals, engineering and service.

Net Income Attributable to ALLETE increased $0.5 million for the nine months ended September 30, 2016, compared to the period from February 10, 2015, to September 30, 2015. U.S. Water Services sells certain products which are seasonal in nature, with higher demand typically realized in warmer months. The results for 2015 reflect operations from the date of acquisition, February 10, 2015, through September 30, 2015, and therefore do not reflect a full nine months. Net income for the nine months ended September 30, 2016 included $0.3 million of after-tax expense recognized as cost of sales related to fair value adjustments for inventories and sales backlog resulting from purchase accounting ($1.6 million after-tax for the period from February 10, 2015, through September 30, 2015); these purchase accounting adjustments were fully recognized as of March 31, 2016. 2016 earnings also reflect increased investments in back office systems and support at U.S. Water Services as we create a platform for future growth.

Corporate and Other

Operating Revenue increased $16.8 million, or 21 percent, from 2015 primarily due to an increase in land sales at ALLETE Properties, which sold its Ormond Crossings project and Lake Swamp wetland mitigation bank in 2016. The increase was partially offset by a decrease in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of lower expenses in 2016.

Net Loss Attributable to ALLETE increased $5.2 million from 2015 primarily due to an $8.8 million adverse impact for the regulatory outcome of an October 18, 2016, MPUC hearing on the allocation of North Dakota investment tax credits (see Note 6. Regulatory Matters and Regulated Operations - Income Tax Expense), and higher interest expense and state income tax expense, partially offset by a $3.3 million after-tax gain at ALLETE Properties resulting from the sale of its Ormond Crossings project and Lake Swamp wetland mitigation bank and a $3.0 million after-tax expense in 2015 for acquisition costs related to U.S. Water Services. Net income at BNI Energy increased to $5.4 million in 2016 compared to $5.3 million in 2015, and net income at ALLETE Properties increased to $1.1 million in 2016 compared to a net loss of $2.9 million in 2015.

Income Taxes – Consolidated

For the nine months ended September 30, 2016, the effective tax rate was 12.3 percent (18.0 percent for the nine months ended September 30, 2015). The effective rate deviated from the combined statutory rate of approximately 41 percent primarily due to production tax credits. (See Note 9. Income Tax Expense.)

CRITICAL ACCOUNTING POLICIES

Certain accounting measurements under 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, taxation and valuation of goodwill and intangible assets. 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 2015 Form 10-K.

OUTLOOK

For additional information see our 2015 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 annual earnings per share growth of a minimum of five percent and providing a dividend payout competitive with our industry.

ALLETE is predominately a regulated utility through Minnesota Power, SWL&P and an investment in ATC. ALLETE's strategy is to remain predominately a regulated utility while investing in its Energy Infrastructure and Related Services businesses to complement its regulated businesses, balance exposure to the utility's industrial customers, and provide potential long-term earnings growth. ALLETE expects net income from Regulated Operations to be approximately 85 percent to 90 percent of total consolidated net income in 2016. Over the next several years, the contribution of the Energy Infrastructure and Related Services businesses to net income is expected to increase as ALLETE grows these operations. ALLETE expects its businesses to provide regulated, contracted or recurring revenues and to support sustained growth in net income and cash flow.

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 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 2016.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC, the PSCW or the NDPSC. See Note 6. Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, Wisconsin, and North Dakota jurisdictions.

2016 Minnesota Rate Case. On November 2, 2016, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 9 percent for retail customers. The rate filing seeks a return on equity of 10.25 percent, and a capital structure consisting of 53.8 percent equity and 46.2 percent debt. On an annualized basis, the requested rate increase would generate approximately $55 million in additional revenue. Once the filing is accepted as complete, interim rates of approximately $49 million are expected to be implemented within 60 days, subject to MPUC adjustment and authorization. We cannot predict the level of interim or final rates that may be authorized by the MPUC.

2016 Wisconsin Rate Case. SWL&P's current retail rates are based on a 2012 PSCW retail rate order that allows for a 10.9 percent return on common equity. On June 28, 2016, SWL&P filed a rate increase request with the PSCW requesting an average overall increase of 3.1 percent for retail customers (a 3.5 percent increase in electric rates, a 1.3 percent decrease in natural gas rates and a 7.8 percent increase in water rates). The rate filing seeks an overall return on equity of 10.9 percent, based on a capital structure consisting of approximately 55 percent equity and 45 percent debt. On an annualized basis, the requested rate increase would generate approximately $2.7 million in additional revenue. Hearings are expected to be scheduled in late 2016. The Company anticipates new rates will take effect during the first quarter of 2017. We cannot predict the level of rates that may be approved by the PSCW.

OUTLOOK (Continued)

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 secondary wood products, and pipeline industries. Approximately 41 percent of our regulated utility kWh sales in the nine months ended September 30, 2016 (44 percent in the nine months ended September 30, 2015) 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, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 72 percent of capacity during the first nine months of 2016 compared to 73 percent in the first nine months of 2015. Many steel producers reduced production in 2015, citing higher levels of imports and lower prices. Some Minnesota taconite and iron concentrate producers reduced production in 2015 in response to declining U.S. steel production. The World Steel Association, an association of over 150 steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2016 will be consistent with 2015. There is a natural lag between U.S. steel consumption and Minnesota taconite production. The high level of imports and lower prices in 2015 continue to impact Minnesota taconite production in 2016. In 2015, petitions regarding unfairly traded cold-rolled, hot-rolled and corrosion-resistant steel products were filed by domestic steel producers with the U.S. Department of Commerce and U.S. International Trade Commission resulting in countervailing duty and antidumping investigations. The U.S. Department of Commerce has since made final affirmative determinations in these investigations. The U.S. International Trade Commission has also made affirmative rulings concluding the investigations. As a result of the affirmative determinations, cash deposits are collected on these products when imported from certain countries. According to the U.S. Census Bureau, August 2016 year-to-date imports for consumption of steel products are down approximately 22 percent compared to August 2015 year-to-date imports.

Minnesota Power’s 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 Minnesota Power’s 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 Minnesota Power to file a rate case to recover lost revenue.

Minnesota Power’s Large Power taconite customers, subject to demand nomination requirements, nominate demand levels for their energy needs each December, March, and August for four-month periods. Based on nominations received on July 29, 2016, Minnesota Power’s Large Power taconite customers nominated at approximately 90 percent of full demand levels for September through December of 2016.

Minnesota Power proactively sells power that is temporarily not required by industrial customers in the wholesale power markets to optimize the value of its generating facilities. Minnesota Power has remarketed a significant portion of the power not expected to be taken by the idled taconite facilities and is well positioned to serve the power needs for those facilities in the event they resume production sooner than currently indicated.

USS Corporation. In the second quarter of 2015, USS Corporation temporarily idled its Minnesota Ore Operations - Keetac plant in Keewatin, Minnesota, and a portion of its Minnesota Ore Operations - Minntac plant in Mountain Iron, Minnesota. These actions were due to high inventory levels and ongoing adjustment of its steel producing operations throughout North America. Global influences in the market, including a higher level of imports, unfairly traded products and reduced steel prices, were cited as having an impact. In the third quarter of 2015, USS Corporation returned its Minntac plant to full production. USS Corporation's Keetac plant remains idled. Both facilities are Large Power Customers of Minnesota Power. USS Corporation has the capability to produce approximately 5 million tons and 15 million tons of taconite annually at its Keetac and Minntac plants, respectively. On September 30, 2016, Minnesota Power extended its electric service agreement with USS Corporation through 2021 at USS Corporation's Minntac and Keetac plants, subject to regulatory approval.

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

Magnetation. In May 2015, Magnetation announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Minnesota, citing the significant decrease in global iron ore prices and its existing capital structure. On October 6, 2016, the bankruptcy court approved plans to idle Magnetation’s Plant 4 facility near Grand Rapids, Minnesota, and its pellet plant in Reynolds, Indiana, as well as terminate Magnetation’s pellet purchase agreement with A.K. Steel Corporation. The company subsequently idled the facilities and stated it is preserving the plants and their value for a potential buyer. Although, we cannot predict whether the facilities will be purchased and restarted, Minnesota Power would serve a buyer of the facilities by entering into a new electric service agreement or through the buyer assuming the existing electric service agreement with Magnetation.

United Taconite. In August 2016, Cliffs restarted operations at its United Taconite plant in Eveleth, Minnesota, following the announcements of Cliffs’ 10-year supply agreement with a major steel customer and additional business contracted with another customer in June 2016. Cliffs also held a groundbreaking ceremony at United Taconite in August 2016 to commence construction on its approximately $65 million project to produce a fully fluxed taconite pellet. The new pellet will replace a flux pellet made at Cliffs’ indefinitely idled Empire operation in Michigan. United Taconite has the capability to produce approximately 5 million tons of taconite annually. On May 23, 2016, Minnesota Power extended its electric service agreements with Cliffs for 10 years at Cliffs' United Taconite and Babbitt facilities.

Silver Bay Power. On May 23, 2016, Minnesota Power entered into multiple agreements with Cliffs and its subsidiaries. Under one of the agreements, Minnesota Power paid $31.0 million in cash as part of a long-term power sales agreement through 2031 between Minnesota Power and Silver Bay Power. Silver Bay Power provides the majority of the electric service requirements for Northshore Mining, which has the capability to produce approximately 6 million tons of taconite annually. (See Note 13. Commitments, Guarantees and Contingencies.)

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 July 8, 2016, Minnesota Governor Dayton instructed the Minnesota Department of Natural Resources to terminate Essar’s mineral lease agreements with the state. Minnesota Governor Dayton stated that Essar failed to pay full amounts owed to Minnesota contractors, fulfill its obligations under the mineral lease agreements, and demonstrate the ability to carry its current construction project through to completion, or provide reliable assurances that it will be able to do so in the foreseeable future.

Essar filed for bankruptcy protection on July 8, 2016, under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. In its filings Essar stated that it has arranged funding sources and intends to continue its project in Minnesota post-bankruptcy. Essar is a retail customer of the Nashwauk Public Utilities Commission, and Minnesota Power has a wholesale electric sales agreement with the Nashwauk Public Utilities Commission for electric service through at least June 2028. Essar also makes ongoing payments to Minnesota Power for electric transmission infrastructure costs. Essar’s pre-petition debt to Minnesota Power is not material.

Essar reached an agreement after its bankruptcy filing that continued Essar’s obligation under its agreements with the Nashwauk Public Utilities Commission and Minnesota Power. On September 8, 2016, the bankruptcy court approved the agreement, which allowed the existing agreement between Minnesota Power and Essar to remain in place through at least March 31, 2017, and allowed Minnesota Power to draw down Essar's cash deposit account to satisfy monthly take or pay commitments in full through December 2016, and in partial through March 31, 2017, at which point Essar will propose to reject, assume or modify the agreements with the Nashwauk Public Utilities Commission and Minnesota Power.

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

PolyMet. Minnesota Power has a long-term contract with PolyMet, which is planning to start a new copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. In November 2015, PolyMet announced the completion of the final EIS by state and federal agencies, which was subsequently published in the Federal Register and Minnesota Environmental Quality Board Monitor. The Minnesota Department of Natural Resources (DNR) issued its Record of Decision on March 3, 2016, finding the final EIS adequate. The 30-day period allowed by law to challenge the Record of Decision passed without any legal challenges being filed. On July 11, 2016, PolyMet submitted applications for water-related permits with the State of Minnesota, and on August 24, 2016, an application for an air quality permit was submitted to the Minnesota Pollution Control Agency. On November 3, 2016, PolyMet submitted a state permit to mine application to the DNR detailing its operational plans for the mine. The remaining state permit applications are expected to be submitted in 2016. The final EIS also requires Records of Decision by the federal agencies, which are expected in 2016, before final action can be taken on the required federal permits to construct and operate the mining operation. Minnesota Power could supply between 45 MW and 50 MW of load under a ten-year power supply contract that would begin upon start-up of the mining operations.

Enbridge. Minnesota Power has a long-term contract with Enbridge that extends through December 31, 2020. Enbridge owns and operates a crude oil and liquids transportation system in North America including in our service territories. Enbridge recently completed an expansion at two pumping stations located in Minnesota Power’s service territory in Deer River and Floodwood, Minnesota resulting in load growth of approximately 15 MW. On September 1, 2016, Enbridge announced it was withdrawing regulatory applications for its Sandpiper pipeline project which would have connected its Beaver Lodge Station, near Tioga, North Dakota, to an existing terminal in Superior, Wisconsin.

EnergyForward. In 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. The Bison Wind Energy Center added 205 MW of capacity in 2014, bringing total capacity to 497 MW. (See Renewable Energy.)
- The installation of emissions control technology at Boswell Unit 4 completed in December 2015 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 which was completed in June 2015.
- Retirement of Taconite Harbor Unit 3, one of three coal-fired units at Taconite Harbor, which was retired in May 2015.

In July 2015, Minnesota Power announced the next steps in its EnergyForward plan, which will reduce carbon emissions, increase the use of renewable resources and add natural gas to meet customer electric service needs in a balanced, reliable and cost-effective way. Significant additional elements of the plan include:

- Economic idling of Taconite Harbor Units 1 and 2 which was completed there in September 2016 and the ceasing of coal-fired operations there in 2020.
- Adding between 200 MW and 300 MW of cleaner and flexible natural gas-fired generation to Minnesota Power’s portfolio within the next decade.

- Building both large and small scale solar generation.
- Expanding the potential for additional energy efficiency savings.

OUTLOOK (Continued)
EnergyForward (Continued)

Integrated Resource Plan (IRP). In a November 2013 order, the MPUC approved Minnesota Power's 2013 IRP which detailed elements of its EnergyForward strategic plan, announced in January 2013. In September 2015, Minnesota Power filed its 2015 IRP with the MPUC which contained the next steps in its EnergyForward strategic plan, and included an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. In an order dated July 18, 2016, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepts Minnesota Power's plans for Taconite Harbor, directs Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, requires an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal and requires Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. On October 19, 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as the latest step in its EnergyForward strategic plan. Minnesota Power's next IRP must be filed by February 1, 2018.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of electric utilities' applicable 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's 2015 IRP, which was filed with the MPUC in September 2015 and approved with modifications by the MPUC in an order dated July 18, 2016, includes 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 it meets the identified state mandate at the lowest cost for customers. Minnesota Power has exceeded the interim milestone requirements to date and expects approximately 30 percent of its applicable retail and municipal energy sales will be supplied by renewable energy sources in 2016.

Minnesota Solar Energy Standard. In 2013, legislation was enacted by the state of Minnesota requiring at least 1.5 percent of total retail electric sales, excluding sales to certain 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 kW or less. Minnesota Power has two solar projects under development. In August 2015, Minnesota Power filed for MPUC approval of a 10 MW utility scale solar project at Camp Ripley, a Minnesota Army National Guard base and training facility near Little Falls, Minnesota. In an order dated February 24, 2016, the MPUC approved the Camp Ripley solar project as eligible to meet the solar energy standard and for current cost recovery, subject to certain compliance requirements. In September 2015, Minnesota Power filed for MPUC approval of a community solar garden project in Duluth, Minnesota, which is comprised of a 1 MW solar array to be owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that will be owned and operated by Minnesota Power. In an order dated July 27, 2016, the MPUC approved the community solar garden project and cost recovery, subject to certain compliance requirements. Minnesota Power believes these projects will meet approximately one-third of the overall mandate. Additionally, on June 1, 2016, Minnesota Power filed a proposal with the MPUC to increase the amount of solar rebates available for customer-sited solar installations and recover costs of the program through Minnesota Power's renewable cost recovery rider. If approved, the Minnesota Power projects would meet part of the mandate related to solar photovoltaic devices with a nameplate capacity of 20 kW or less.

Wind Energy. Minnesota Power's wind energy facilities consist of the 497 MW Bison Wind Energy Center located in North Dakota, and the 25 MW Taconite Ridge Energy Center located in northeastern Minnesota. Minnesota Power also has 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.

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 its system over this transmission line from Square Butte's lignite coal-fired generation unit. The DC transmission line capacity can be increased if renewable energy or transmission needs justify investments to upgrade the line.

Updated customer billing rates for the renewable cost recovery rider, which includes investments and expenditures related to the Bison Wind Energy Center, were approved by the MPUC in an order dated March 9, 2016, allowing Minnesota Power to charge retail customers on a current basis for the costs of constructing certain renewable investments plus a return on the capital invested. While approving the updated customer billing rates for the renewable cost recovery rider, the MPUC also allowed Minnesota Power additional time to submit support for its position on its utilization of North Dakota investment tax credits.

OUTLOOK (Continued)
Renewable Energy (Continued)

Minnesota Power accounts for North Dakota investment tax credits based on long-standing regulatory precedents of stand-alone allocation methodology of accounting for income taxes. The stand-alone method provides that income taxes (and credits) are calculated as if Minnesota Power was the only entity included in ALLETE's consolidated federal and unitary state income tax returns. Minnesota Power has recorded a regulatory liability for North Dakota investment tax credits generated by its jurisdictional activity and expected to be realized in the future. North Dakota investment tax credits attributable to ALLETE's apportionment and income of ALLETE's other subsidiaries are included in the ALLETE consolidated group. The Minnesota Department of Commerce (Department) has inquired about our use of the North Dakota investment tax credits, taking the position that all North Dakota investment tax credits realized from the Bison Wind Energy Center should be credited to Minnesota Power regulated retail customers. The MPUC did not come to a decision on this issue in its order dated March 9, 2016, but requested that Minnesota Power provide further support on its position which was submitted on April 8, 2016.

On October 18, 2016, the MPUC held a hearing in which it decided Minnesota Power should attribute all North Dakota investment tax credits realized from the Bison Wind Energy Center to Minnesota Power regulated retail customers. As a result of the adverse regulatory outcome, Minnesota Power has created a regulatory liability, and recorded a reduction in operating revenue for $15.0 million. The North Dakota investment tax credits previously recognized as income tax credits in Corporate and Other were reversed in the third quarter of 2016 resulting in an $8.8 million charge to net income. Minnesota Power will seek reconsideration with the MPUC, and if not successful, will consider all available avenues of appeal.

Manitoba Hydro. Minnesota Power has five long-term PPAs with Manitoba Hydro. The first PPA 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. Under the second PPA, Minnesota Power is purchasing 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 2011, Minnesota Power and Manitoba Hydro signed a third PPA. This 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. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the additional transmission capacity in Canada to Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 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 2014, Minnesota Power and Manitoba Hydro signed a fourth 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 PPA 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.)

In October 2015, Minnesota Power and Manitoba Hydro signed a fifth PPA that provides for Minnesota Power to purchase 50 MW of capacity at fixed prices. The PPA begins in June 2017 and expires in May 2020.

Environmental Improvement Rider. Minnesota Power has an approved environmental improvement rider in place for investments and expenditures related to the implementation of the Boswell Unit 4 mercury emissions reduction plan completed in 2015. Customer billing rates for the environmental improvement rider were approved by the MPUC in August 2015. In September 2015, Minnesota Power filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of the filing, Minnesota Power will be authorized to include updated billing rates on customer bills.

OUTLOOK (Continued)

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, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others), and our investment in ATC.

Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in 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 which was approved in a June 2015 order. Based on this order, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. (See Note 6. Regulatory Matters.) In a December 2015 order, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. 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 an order dated April 11, 2016, the MPUC approved the route permit which largely follows Minnesota Power's preferred route, including the international border crossing. Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is expected to begin by 2017 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. Minnesota Power is expected to have majority ownership of the transmission line.

Investment in ATC. Our wholly-owned subsidiary, ALLETE Transmission Holdings, 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. As of September 30, 2016, our equity investment in ATC was $133.8 million ($124.5 million as of December 31, 2015). In the first nine months of 2016, we invested $3.5 million in ATC, and on October 28, 2016, we invested an additional $1.9 million. We do not expect to make any additional investments in 2016. (See Note 7. Investment in ATC.)

On September 28, 2016, the FERC issued an order reducing ATC's authorized return on equity to 10.82 percent, including an incentive adder for participation in a regional transmission organization. Prior to this order, ATC had been allowed a return on equity of 12.2 percent which had been impacted by reductions for estimated refunds related to complaints filed with the FERC by several customers located within the MISO service area.

On June 30, 2016, a federal administrative law judge ruled on an additional complaint proposing a further reduction in the base return on equity to 9.70 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is expected in 2017. (See Note 6. Regulatory Matters.) 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 after-tax ($0.9 million pre-tax).

Energy Infrastructure and Related Services.

ALLETE Clean Energy.

ALLETE Clean Energy focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in the fourth quarter of 2015.

ALLETE Clean Energy believes the market for renewable energy in North America is robust, driven by several factors including environmental regulation, tax incentives, societal expectations and continual technology advances. The recent Clean Power Plan is an example of an environmental regulation that we believe will drive renewable energy development.

OUTLOOK (Continued)
ALLETE Clean Energy (Continued)

ALLETE Clean Energy's strategy includes the safe, reliable, optimal and profitable operation of its existing facilities. This includes a strong safety culture, the continuous pursuit of operational efficiencies at existing facilities, and cost controls. While ALLETE Clean Energy generally acquires facilities in liquid power markets, ALLETE Clean Energy's strategy also includes the exploration of power sales agreement extensions upon expiration of existing contracts.

ALLETE Clean Energy will pursue steady growth through acquisitions or project development for others. ALLETE Clean Energy is targeting acquisitions of existing facilities with a purchase price in the $50 million to $100 million range, and which have long-term power sales agreements in place for the facility's output. At this time, ALLETE Clean Energy expects acquisitions will be primarily wind or solar facilities in North America.

ALLETE Clean Energy will manage risk by having a diverse portfolio of assets, which will include power sales contract expiration and geographic diversity. The current mix of power sales agreement expiration and geographic location is as follows:

Wind Energy Facility	Location	Capacity MW	PPA MW %	PPA Expiration
Armenia Mountain	Pennsylvania	100.5	100%	December 2024
Chanarambie/Viking	Minnesota	97.5		
PPA 1			12%	February 2018
PPA 2			88%	February 2023
Condon	Oregon	50	100%	October 2022
Lake Benton	Minnesota	104	100%	December 2028
Storm Lake I	Iowa	108	100%	December 2019
Storm Lake II	Iowa	77		
PPA 1			90%	April 2019
PPA 2			10%	April 2032

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 is located in 49 states and Canada and has an established base of approximately 4,600 customers. U.S. Water Services differentiates itself from the competition by developing synergies between established solutions in engineering, equipment, and chemical water treatment and helping customers achieve efficient and sustainable use of their water and energy systems. U.S. Water Services is a leading provider to the biofuels industry, and also serves the food and beverage, industrial, power generation, and midstream oil and gas industries. U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers. U.S. Water Services' sells certain products which are seasonal in nature, with higher demand typically realized in warmer months. The results for 2015 reflect operations from the date of acquisition, February 10, 2015, through September 30, 2015, and therefore, do not reflect a full nine months.

Our strategy is to grow U.S. Water Services' North American presence by adding customers, products, and new geographies. We believe water scarcity and a growing emphasis on conservation will continue to drive significant growth in the industrial, commercial, and governmental sectors leading to organic revenue growth for U.S. Water Services. U.S. Water Services also expects to pursue periodic strategic tuck-in acquisitions with a purchase price in the $10 million to $50 million range. Priority will be given to acquisitions which expand its geographic reach, add new technology, or deepen its capabilities to serve its expanding customer base.

Corporate and Other.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, 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.

BNI Energy. BNI Energy anticipates selling 4.3 million tons of coal in 2016 (4.3 million tons were sold in 2015) and has sold 3.3 million tons through September 30, 2016 (3.3 million tons were sold through September 30, 2015). BNI Energy operates under cost-plus fixed fee agreements extending through December 31, 2037.

OUTLOOK (Continued)
Corporate and Other (Continued)

ALLETE Properties. ALLETE Properties represents our legacy 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. ALLETE Properties' major projects are Town Center at Palm Coast and Palm Coast Park. In addition to these two projects, ALLETE Properties has approximately 1,100 acres of other land available-for-sale.

On September 22, 2016, ALLETE Properties sold its Ormond Crossings project and Lake Swamp wetland mitigation bank for consideration of approximately $21 million. The consideration included a down payment in the form of 0.1 million shares of ALLETE common stock with a value of $8.0 million, with the remaining purchase price to be paid under the terms of a finance receivable due over a five-year period which bears interest at market rates. The finance receivable is collateralized by the property sold.

Income Taxes.

ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2016. On an ongoing basis, ALLETE has tax credits and other tax adjustments that reduce the combined 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 before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be approximately 13 percent for 2016 primarily due to federal production tax credits as a result of wind energy generation. We also expect that our effective tax rate will be lower than the combined statutory rate over the next nine years due to production tax credits attributable to our wind energy generation.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of September 30, 2016, we had cash and cash equivalents of $107.2 million, $397.8 million in available consolidated lines of credit and a debt-to-capital ratio of 45 percent.

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

	September 30, 2016	%	December 31, 2015	%
Millions				
ALLETE Equity	$1,873.0	55	$1,820.2	53
Non-Controlling Interest	—	—	2.2	—
Long-Term Debt (Including Long-Term Debt Due Within One Year)	1,556.9	45	1,605.0	47
Notes Payable	—	—	1.6	—
	$3,429.9	100	$3,429.0	100

Cash Flows. Selected information from the Consolidated Statement of Cash Flows is as follows:

For the Nine Months Ended September 30,	2016	2015
Millions		
Cash and Cash Equivalents at Beginning of Period	$97.0	$145.8

Cash Flows from (used for)		
Operating Activities	237.8	254.6
Investing Activities	(120.7)	(534.3)
Financing Activities	(106.9)	236.9
Change in Cash and Cash Equivalents	10.2	(42.8)
Cash and Cash Equivalents at End of Period	$107.2	$103.0

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Operating Activities. Cash from operating activities was $237.8 million for the nine months ended September 30, 2016 ($254.6 million for the nine months ended September 30, 2015). Cash from operating activities was lower in 2016 primarily due to a payment of $31.0 million made as part of a long-term power sales agreement between Minnesota Power and Silver Bay Power, cash contributions to our defined benefit pension plan, and non-cash items (primarily depreciation expense), partially offset by lower fuel inventory purchases and higher recoveries under cost recovery riders.

Investing Activities. Cash used for investing activities was $120.7 million for the nine months ended September 30, 2016 ($534.3 million for the nine months ended September 30, 2015). The decrease in cash used for investing activities was primarily due to $324.8 million used in 2015, net of cash acquired, for the acquisition of U.S. Water Services in February 2015 and acquisitions at ALLETE Clean Energy in April and July of 2015, as well as $88.7 million of fewer capital expenditures in 2016.

Financing Activities. Cash used for financing activities was $106.9 million for the nine months ended September 30, 2016 ($236.9 million from financing activities for the nine months ended September 30, 2015). The decrease in cash from financing activities was primarily due to $128.2 million in lower proceeds from the issuance of common stock and $206.7 million in lower proceeds from the issuance of long-term debt net of payments made.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit, the sale of securities or commercial paper. As of September 30, 2016, we had consolidated bank lines of credit aggregating $408.4 million ($408.4 million as of December 31, 2015), the majority of which expire in November 2018. We had $10.6 million outstanding in standby letters of credit and no outstanding draws under our lines of credit as of September 30, 2016 ($12.4 million in standby letters of credit and $1.6 million outstanding in draws as of December 31, 2015). In addition, as of September 30, 2016, we had 3.5 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 3.9 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 August 2016, 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 3.9 million remain available for issuance. For the nine months ended September 30, 2016, 0.1 million shares of common stock were issued under this agreement, resulting in net proceeds of $7.6 million (1.3 million shares were issued for the nine months ended September 30, 2015, resulting in net proceeds of $69.9 million). The shares issued in 2015 were offered and sold pursuant to Registration Statement No. 333-190335. On August 1, 2016, we filed Registration Statement No. 333-212794, pursuant to which the remaining shares will continue to be offered for sale, from time to time.

During the nine months ended September 30, 2016, we issued 0.4 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 $19.6 million (0.3 million shares were issued for the nine months ended September 30, 2015, resulting in net proceeds of $19.9 million). These shares of common stock were registered under Registration Statement Nos. 333-211075, 333-188315, 333-183051 and 333-162890.

Financial Covenants. See Note 8. 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. During the nine months ended September 30, 2016, we contributed $6.3 million in cash to our defined benefit pension plan. We do not expect to make additional contributions to our defined benefit pension plan in 2016 and we do not expect to make any contributions to our other postretirement benefit plan in 2016. (See Note 12. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are summarized in our 2015 Form 10-K, with additional disclosure in Note 13. Commitments, Guarantees and Contingencies.

Capital Requirements. Our capital expenditures for 2016 are expected to be approximately $175 million. For the nine months ended September 30, 2016, capital expenditures totaled $101.6 million ($184.9 million for the nine months ended September 30, 2015). 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. We anticipate that although many of the state and federal environmental regulations have been finalized, or will be finalized in the near future, potential expenditures for future environmental matters may be material and may require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 13. Commitments, Guarantees and Contingencies.

Employees.

At September 30, 2016, ALLETE had 1,965 employees, of which 1,903 were full-time.

Minnesota Power and SWL&P have an aggregate of 549 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 Energy has 176 employees, of which 130 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. As of September 30, 2016, our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits. (See Note 2. 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. SWL&P's exposure to price risk for natural gas is significantly mitigated by the current ratemaking process and regulatory framework, which allows the commodity cost to be passed through to customers. 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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Continued)

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 September 30, 2016, an increase of 100 basis points in interest rates would impact the amount of pre-tax interest expense by $1.7 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 September 30, 2016.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of September 30, 2016, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, on 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.

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.

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 our 2015 Form 10-K and Note 6. Regulatory Matters and Note 13. Commitments, Guarantees and Contingencies herein. Such information is incorporated herein by reference.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Part I, Item 1A. Risk Factors of our 2015 Form 10-K.

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

Issuer Purchases of Equity Securities.

Information regarding purchases made by ALLETE of its common stock during the quarter ended September 30, 2016, is as follows:

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 1, 2016 – July 31, 2016	—	—	—	—
August 1, 2016 – August 31, 2016	—	—	—	—
September 1, 2016 – September 30, 2016	129,722	$62.19	—	—
Total	129,722	$62.19	—	—

(a) Shares of common stock acquired as a down payment of the consideration in connection with ALLETE Properties' sale of its Ormond Crossings project and Lake Swamp wetland mitigation bank. (See Note 2. Investments.)

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 November 4, 2016, announcing 2016 third 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.

November 4, 2016	/s/ Steven Q. DeVinck Steven Q. DeVinck Senior Vice President and Chief Financial Officer
November 4, 2016	/s/ Steven W. Morris Steven W. Morris Controller