ALLETE INC
Form 10-Q
August 02, 2017

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 June 30, 2017
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, a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer”, “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller Reporting Company ¨
	Emerging Growth Company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the

Exchange Act. ¨

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,
50,956,836 shares outstanding
as of June 30, 2017

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 regulated 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.
ASC	Accounting Standards Codification
ATC	American Transmission Company LLC
Bison	Bison Wind Energy Center
BNI Energy	BNI Energy, Inc. and its subsidiary
Boswell	Boswell Energy Center
Camp Ripley	Camp Ripley Solar Array
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CIP	Conservation Improvement Program
Cliffs	Cliffs Natural Resources Inc.
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
ERP Iron Ore	ERP Iron Ore, LLC
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
IRP	Integrated Resource 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
Mesabi Metallics	Mesabi Metallics Company, LLC (formerly Essar Steel Minnesota, LLC)
Minnesota Power	An operating division of ALLETE, Inc.

Minnkota Power	Minnkota Power Cooperative, Inc.

Abbreviation or Acronym	Term
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
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
Northern States Power	Northern States Power Company, a subsidiary of Xcel Energy Inc.
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/PSA	Power Purchase Agreement / Power Sales Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
Silver Bay Power	Silver Bay Power Company, a wholly-owned subsidiary of Cliffs Natural Resources Inc.
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
Tenaska	Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC
Thomson	Thomson Energy Center
Town Center District	Town Center at Palm Coast Community Development District in Florida
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 ALLETE’s 2016 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. CONSOLIDATED FINANCIAL STATEMENTS

ALLETE
CONSOLIDATED BALANCE SHEET
Unaudited

	June 30, 2017	December 31, 2016
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$84.2	$27.5
Accounts Receivable (Less Allowance of $2.4 and $3.1)	120.1	122.5
Inventories – Net	103.4	104.2
Prepayments and Other	38.8	40.3
Total Current Assets	346.5	294.5
Property, Plant and Equipment – Net	3,745.6	3,741.2
Regulatory Assets	324.5	330.1
Investment in ATC	143.1	135.6
Other Investments	56.2	55.6
Goodwill and Intangible Assets – Net	210.8	213.4
Other Non-Current Assets	104.8	106.5
Total Assets	$4,931.5	$4,876.9
Liabilities and Shareholders' Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$61.0	$74.0
Accrued Taxes	39.1	46.5
Accrued Interest	17.5	17.6
Long-Term Debt Due Within One Year	117.7	187.7
Other	70.1	73.7
Total Current Liabilities	305.4	399.5
Long-Term Debt	1,401.4	1,370.4
Deferred Income Taxes	577.0	554.6
Regulatory Liabilities	125.8	125.8
Defined Benefit Pension and Other Postretirement Benefit Plans	195.8	210.9
Other Non-Current Liabilities	309.1	322.7
Total Liabilities	2,914.5	2,983.9
Commitments, Guarantees and Contingencies (Note 13)		
Shareholders' Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 51.0 and 49.6 Shares Issued and Outstanding	1,386.5	1,295.3
Accumulated Other Comprehensive Loss	(27.3)	(28.2)
Retained Earnings	657.8	625.9
Total Shareholders' Equity	2,017.0	1,893.0
Total Liabilities and Shareholders' Equity	$4,931.5	$4,876.9

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF INCOME
Unaudited

	Quarter Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Millions Except Per Share Amounts				
Operating Revenue				
Utility	$264.9	$234.9	$546.5	$487.2
Non-utility	88.4	79.9	172.4	161.4
Total Operating Revenue	353.3	314.8	718.9	648.6
Operating Expenses				
Fuel, Purchased Power and Gas – Utility	93.1	79.0	189.7	158.9
Transmission Services – Utility	17.6	16.1	34.2	32.9
Cost of Sales – Non-utility	38.4	32.5	70.0	62.8
Operating and Maintenance	84.9	82.0	168.2	160.1
Depreciation and Amortization	50.1	48.7	100.6	96.8
Taxes Other than Income Taxes	14.2	14.3	28.6	28.1
Total Operating Expenses	298.3	272.6	591.3	539.6
Operating Income	55.0	42.2	127.6	109.0
Other Income (Expense)				
Interest Expense	(16.7)	(17.4)	(33.9)	(34.3)
Equity Earnings in ATC	5.3	4.1	11.4	8.9
Other	0.6	0.6	1.2	1.6
Total Other Expense	(10.8)	(12.7)	(21.3)	(23.8)
Income Before Non-Controlling Interest and Income Taxes	44.2	29.5	106.3	85.2
Income Tax Expense	7.3	4.7	20.4	14.0
Net Income	36.9	24.8	85.9	71.2
Less: Non-Controlling Interest in Subsidiaries	—	—	—	0.5
Net Income Attributable to ALLETE	$36.9	$24.8	$85.9	$70.7
Average Shares of Common Stock				
Basic	50.9	49.3	50.5	49.2
Diluted	51.1	49.5	50.7	49.3
Basic Earnings Per Share of Common Stock	$0.73	$0.50	$1.70	$1.44
Diluted Earnings Per Share of Common Stock	$0.72	$0.50	$1.69	$1.43
Dividends Per Share of Common Stock	$0.535	$0.52	$1.07	$1.04

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Unaudited

	Quarter Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Millions				
Net Income	$36.9	$24.8	$85.9	$71.2
Other Comprehensive Income (Loss)				
Currency Translation Adjustments	(0.2)	—	(0.2)	—
Unrealized Gain on Securities				
Net of Income Tax Expense of $0.2, $0.3, $0.5, and $–	0.4	0.4	0.7	—
Defined Benefit Pension and Other Postretirement Benefit Plans				
Net of Income Tax Expense of $0.2, $0.1, $0.3, and $0.2	0.2	0.1	0.4	0.3
Total Other Comprehensive Income	0.4	0.5	0.9	0.3
Total Comprehensive Income	37.3	25.3	86.8	71.5
Less: Non-Controlling Interest in Subsidiaries	—	—	—	0.5
Total Comprehensive Income Attributable to ALLETE	$37.3	$25.3	$86.8	$71.0

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Unaudited

	Six Months Ended June 30,	
	2017	2016
Millions		
Operating Activities		
Net Income	$85.9	$71.2
AFUDC – Equity	(0.4)	(1.2)
Income from Equity Investments – Net of Dividends	(2.5)	(2.9)
Change in Fair Value of Contingent Consideration	(0.4)	—
Depreciation Expense	97.9	94.2
Amortization of PSAs	(11.8)	(11.1)
Amortization of Other Intangible Assets and Other Assets	5.3	5.0
Deferred Income Tax Expense	20.2	13.8
Share-Based and ESOP Compensation Expense	3.3	2.2
Defined Benefit Pension and Postretirement Benefit Expense	5.0	2.6
Bad Debt Expense	—	1.1
Changes in Operating Assets and Liabilities		
Accounts Receivable	2.4	6.5
Inventories	0.8	6.7
Prepayments and Other	4.3	(0.8)
Accounts Payable	(12.6)	1.3
Other Current Liabilities	(12.8)	(18.5)
Cash Contributions to Defined Benefit Pension Plans	(1.7)	—
Changes in Regulatory and Other Non-Current Assets	6.7	(21.0)
Changes in Regulatory and Other Non-Current Liabilities	(5.2)	(2.9)
Cash from Operating Activities	184.4	146.2
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	1.0	1.4
Payments for Purchase of Available-for-sale Securities	(1.6)	(1.2)
Investment in ATC	(5.0)	(1.6)
Changes to Other Investments	1.3	2.1
Additions to Property, Plant and Equipment	(81.1)	(74.8)
Proceeds from Sale of Property, Plant and Equipment	0.7	0.2
Cash for Investing Activities	(84.7)	(73.9)
Financing Activities		
Proceeds from Issuance of Common Stock	74.4	15.2
Proceeds from Issuance of Long-Term Debt	86.2	2.2
Changes in Restricted Cash	(1.5)	(2.0)
Changes in Notes Payable	—	(0.7)
Repayments of Long-Term Debt	(127.0)	(32.1)
Acquisition of Non-Controlling Interest	—	(8.0)
Acquisition-Related Contingent Consideration Payments	(19.7)	(0.7)
Dividends on Common Stock	(54.0)	(51.2)
Other Financing Activities	(1.4)	(0.1)

Cash for Financing Activities	(43.0)	(77.4)
Change in Cash and Cash Equivalents	56.7	(5.1)
Cash and Cash Equivalents at Beginning of Period	27.5	97.0
Cash and Cash Equivalents at End of Period	$84.2	$91.9

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
Unaudited

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Loss	Common Stock
Balance as of December 31, 2016	$1,893.0	$625.9	$(28.2)	$1,295.3
Comprehensive Income				
Net Income	85.9	85.9	—	—
Other Comprehensive Income – Net of Tax				
Currency Translation Adjustments	(0.2)	—	(0.2)	—
Unrealized Gain on Securities	0.7	—	0.7	—
Defined Benefit Pension and Other Postretirement Plans	0.4	—	0.4	—
Total Comprehensive Income	86.8			
Common Stock Issued	91.2	—	—	91.2
Dividends Declared	(54.0)	(54.0)	—	—
Balance as of June 30, 2017	$2,017.0	$657.8	$(27.3)	$1,386.5

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, 2016, 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 six months ended June 30, 2017, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2017. For further information, refer to the Consolidated Financial Statements and notes included in our 2016 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Inventories – Net. Inventories are stated at the lower of cost or net realizable value. 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 segment and Corporate and Other operations are carried at an average cost, first-in, first-out or specific identification basis.

Inventories – Net	June 30, 2017	December 31, 2016
Millions		
Fuel (a)	$45.0	$43.9
Materials and Supplies	48.0	48.7
Raw Materials	2.8	2.9
Work in Progress	0.3	1.0
Finished Goods	8.3	8.6
Reserve for Obsolescence	(1.0)	(0.9)
Total Inventories – Net	$103.4	$104.2

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

Prepayments and Other Current Assets	June 30, 2017	December 31, 2016
Millions		
Deferred Fuel Adjustment Clause	$16.7	$18.6
Restricted Cash	3.7	2.2
Other	18.4	19.5
Total Prepayments and Other Current Assets	$38.8	$40.3

Other Non-Current Assets	June 30, 2017	December 31, 2016
Millions		
Contract Payment	$28.4	$29.6
Finance Receivable	11.5	11.5
Restricted Cash	8.6	8.6
Other	56.3	56.8
Total Other Non-Current Assets	$104.8	$106.5

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Current Liabilities	June 30, 2017	December 31, 2016
Millions		
PSAs	$24.7	$24.6
Other	45.4	49.1
Total Other Current Liabilities	$70.1	$73.7

Other Non-Current Liabilities	June 30, 2017	December 31, 2016
Millions		
Asset Retirement Obligation	$158.2	$136.6
PSAs	101.5	113.8
Contingent Consideration (a)	5.5	25.0
Other	43.9	47.3
Total Other Non-Current Liabilities	$309.1	$322.7

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

Supplemental Statement of Cash Flows Information.

Six Months Ended June 30,	2017	2016
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$32.5	$32.9
Cash Paid During the Period for Income Taxes	$0.3	$0.4
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(0.4)	$(24.4)
Capitalized Asset Retirement Costs	$19.7	$2.3
AFUDC–Equity	$0.4	$1.2
ALLETE Common Stock Contributed to the Pension Plans	$13.5	—

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

New Accounting Pronouncements.

Recently Adopted Pronouncements

Simplifying the Measurement of Inventory. In 2015, the FASB issued an accounting standards update which requires entities that measure inventory using the first-in, first-out or average cost methods to measure inventory at the lower of cost or net realizable value. Net realizable value is defined as estimated selling price in the ordinary course of business less reasonably predictable costs of completion, disposal and transportation. This accounting guidance was adopted in the first quarter of 2017 and did not have a material impact on our 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 was adopted in the first quarter of 2017. The adoption of this guidance is expected to result in a less than $1 million impact to income tax expense (benefit) annually.

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

Clarifying the Definition of a Business. In January 2017, the FASB issued clarifying guidance on the definition of a business and provided additional guidance to assist with evaluating whether transactions are to be accounted for as an acquisition or disposal of a group of assets or a business. The clarifying guidance will also impact other areas including the accounting for goodwill and consolidation. This accounting guidance was adopted in the first quarter of 2017 and did not have an impact on our Consolidated Financial Statements.

Stock Compensation: Scope of Modification Accounting. In May 2017, the FASB issued additional clarifying guidance regarding circumstances where changes to the terms or conditions of share-based payment awards require an entity to apply modification accounting under ASC 718. The guidance provides specific situations that would be excluded from effects of a modification including if the fair value, vesting conditions, and classification are the same before and after modification. The amendments in this update will be applied prospectively to awards modified on or after adoption. This accounting guidance was adopted by the Company in the second quarter of 2017 and did not have an impact on our Consolidated Financial Statements.

Recently Issued Pronouncements

Simplifying the Test for Goodwill Impairment. In January 2017, the FASB issued updated guidance which simplifies the measurement of goodwill impairment by removing step two of the goodwill impairment test that requires the determination of the fair value of individual assets and liabilities of a reporting unit. The updated guidance requires goodwill impairment to be measured as the amount by which a reporting unit’s carrying value exceeds its fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for the Company beginning in the first quarter of 2020, with early adoption permitted on a prospective basis.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. In March 2017, the FASB issued guidance to improve the presentation of net periodic pension and postretirement benefit costs. Under the revised guidance of ASC 715, an entity shall present the service cost component of the net periodic benefit cost in the same income statement line as other employee compensation costs arising from services rendered during the period. The guidance also allows only the service cost component of the periodic cost to be eligible for capitalization. The standard will be applied retrospectively for income statement presentation, and prospectively for capitalization of service cost components. Although the non-service components of pension and other postretirement benefit costs are excluded from capitalization, they are considered allowable costs for ratemaking and will be recorded as regulatory assets or liabilities for the regulated portion of the Company. We do not expect there to be a material impact on the Consolidated Financial Statements with the adoption of the updated guidance which is effective for the Company beginning in the first quarter of 2018.

Revenue from Contracts with Customers. In 2014, the FASB issued amended revenue recognition guidance that clarifies the principles for recognizing revenue from contracts with customers by providing a single comprehensive model to determine the measurement of revenue and timing of recognition. The guidance requires an entity to recognize revenue in a manner that depicts 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. As of June 30, 2017, the Company has reviewed nearly all of its revenue streams and contracts for its regulated businesses, completing the preliminary evaluations of the impact of this guidance. Additional review and analysis is being performed on the Company's energy infrastructure and related services businesses. The Company does not expect the update to significantly affect results of its regulated operations, which represent the majority of revenue, or the remaining revenue from its energy infrastructure and related services businesses. Management continues to monitor and evaluate the unresolved industry related issues, primarily around step versus strip pricing, long-term contract minimums and principal versus agent considerations. The Company currently expects to implement the new standard on a modified retrospective basis which requires application of standards to contracts with customers effective January 1, 2018, with the cumulative impact on contracts not yet completed as of December 31, 2017, recognized as an adjustment to retained earnings on the Consolidated Balance Sheet. The Company will adopt this guidance for our fiscal year beginning January 1, 2018.

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

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. We are currently evaluating the impact of the revised lease guidance on our Consolidated Financial Statements.

Financial Instruments. In January 2016, the FASB issued an accounting standard update which requires entities to measure their investments at fair value and recognize any changes in fair value in net income unless the investments qualify for the new practicability exception. The practicability exception will be available for equity investments that do not have readily determinable fair values. The updated guidance is effective for the Company beginning in the first quarter of 2018 and will result in a cumulative effect adjustment to retained earnings on the Consolidated Balance Sheet in the fiscal year of adoption. We have performed a preliminary evaluation of the impact of this update, and based on that evaluation, we do not expect the adoption of the update to have a material impact on our 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. We do not expect the update to have a material impact on our Consolidated Statement of Cash Flows.

Statement of Cash Flows: Restricted Cash. In November 2016, the FASB issued an accounting standard update related to the presentation of restricted cash in the Company’s Consolidated Statement of Cash Flows. The update requires that the Consolidated Statement of Cash Flows explain the change during the period in cash, cash equivalents and restricted cash. Restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. This accounting guidance is effective for the Company beginning in the first quarter of 2018 and will be applied retrospectively to all periods presented. The guidance will result in changes to the Company’s Consolidated Statement of Cash Flows such that restricted cash amounts will be included in the beginning-of-period and end-of-period cash and cash equivalents totals when adopted for our fiscal year beginning January 1, 2018.

Revision of Prior Balance Sheet. During the first quarter of 2017, the Company identified an error related to the deferred income tax treatment associated with its Wholesale and Retail Contra AFUDC Regulatory Liability. The Company evaluated the materiality of the error and concluded that it was not material to any previously issued historical financial statements. The Company has revised its Consolidated Balance Sheet as of December 31, 2016, by decreasing Regulatory Assets and Deferred Income Taxes by $29.5 million. The correction had no impact on our Consolidated Statement of Income.

Reclassification of Prior Income Statement. Beginning with the second quarter of 2017, the Company enhanced its presentation of Operating Revenue and certain Operating Expenses on the Consolidated Statement of Income by presenting the caption Operating Revenue separately as Operating Revenue – Utility and Operating Revenue – Non-utility. In conformity with the current presentation, we now present $234.9 million and $487.2 million of Operating Revenue as Operating Revenue – Utility for the quarter and six months ended June 30, 2016, respectively, as it is generated from our regulated utility operations. Non-utility revenue of $79.9 million and $161.4 million for the quarter and six months ended June 30, 2016, respectively, is now presented as Operating Revenue – Non-utility. In addition, the captions Fuel and Purchased Power and Cost of Sales have been updated to Fuel, Purchased Power and Gas – Utility and Cost of Sales – Non-utility. As a result, we have reclassified $0.9 million relating to the cost of gas sales at SWL&P from Cost of Sales – Non-utility to Fuel, Purchased Power and Gas – Utility for the quarter ended June 30, 2016, and $3.9 million for the six months ended June 30, 2016.

NOTE 2. INVESTMENTS

Investments. As of June 30, 2017, 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	June 30, 2017	December 31, 2016
Millions		
ALLETE Properties	$29.5	$31.7
Available-for-sale Securities (a)	20.6	18.8
Cash Equivalents	2.4	1.3
Other	3.7	3.8
Total Other Investments	$56.2	$55.6

(a) As of June 30, 2017, the aggregate amount of available-for-sale corporate and governmental debt securities maturing in one year or less was $0.6 million, in one year to less than three years was $2.7 million, in three years to less than five years was $6.8 million and in five or more years was $2.9 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 impairment was recorded for the quarter and six months ended June 30, 2017, and 2016.

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits.

Gross realized and unrealized gains and losses on our available-for-sale investments were immaterial for the quarter and six months ended June 30, 2017, and 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 six months ended June 30, 2016.

2016 Activity.

Acquisition of Non-Controlling Interest. In April 2016, ALLETE Clean Energy acquired the non-controlling interest in the limited liability company that owns the 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 became a wholly-owned subsidiary of ALLETE Clean Energy.

WEST. In October 2016, U.S. Water Services acquired 100 percent of Water & Energy Systems Technology of Nevada, Inc. (WEST). Total consideration for the transaction was $6.7 million. Consideration of $5.9 million was paid in cash on the acquisition date, working capital adjustments of $0.2 million were paid in the first six months of 2017 and a $0.6 million payment is due in April 2018. WEST is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southwestern 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 the second quarter of 2017, is shown in the following table. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis.

NOTE 3. ACQUISITIONS (Continued)

2016 Activity (Continued)

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.1
Other Current Assets	1.0
Customer Relationships (a)	2.8
Goodwill (a)(b)	4.2
Other Non-Current Assets	0.1
Total Assets Acquired	$8.2
Liabilities Assumed	
Current Liabilities	$0.3
Non-Current Liabilities	1.2
Total Liabilities Assumed	$1.5
Net Identifiable Assets Acquired	$6.7

(a) Presented within Goodwill and Intangible Assets – Net on the Consolidated Balance Sheet. (See Note 4. Goodwill and Intangible Assets.)

(b) For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

Acquisition-related costs were immaterial, expensed as incurred during 2016 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 $131.4 million as of June 30, 2017, and $131.2 million as of December 31, 2016. Changes to goodwill for the six months ended June 30, 2017, relate to the finalization of purchase price accounting for U.S. Water Services' acquisition of WEST.

Balances of intangible assets, net, excluding goodwill as of June 30, 2017, are as follows:

	December 31, 2016	Amortization	June 30, 2017
Millions			
Intangible Assets			
Definite-Lived Intangible Assets			
Customer Relationships	$59.3	$(2.3)	$57.0
Developed Technology and Other (a)	6.3	(0.5)	5.8
Total Definite-Lived Intangible Assets	65.6	(2.8)	62.8
Indefinite-Lived Intangible Assets			
Trademarks and Trade Names	16.6	n/a	16.6
Total Intangible Assets	$82.2	$(2.8)	$79.4

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

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 June 30, 2017, is approximately 19 years.

NOTE 4. GOODWILL AND INTANGIBLE ASSETS (Continued)

Amortization expense of intangible assets was $1.4 million and $2.8 million for the quarter and six months ended June 30, 2017, respectively ($1.2 million and $2.5 million for the quarter and six months ended June 30, 2016, respectively). Accumulated amortization was $12.1 million as of June 30, 2017 ($9.3 million as of December 31, 2016). The estimated amortization expense for definite-lived intangible assets for the remainder of 2017 is $2.7 million. Estimated annual amortization expense for definite-lived intangible assets is $5.1 million in 2018, $4.8 million in 2019, $4.5 million in 2020, $4.4 million in 2021 and $41.3 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 9. Fair Value to the Consolidated Financial Statements in our 2016 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 June 30, 2017, and December 31, 2016. 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 June 30, 2017			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets				
Investments (a)				
Available-for-sale – Equity Securities	$7.6	—	—	$7.6
Available-for-sale – Corporate and Governmental Debt Securities	—	$13.0	—	13.0
Cash Equivalents	2.4	—	—	2.4
Total Fair Value of Assets	$10.0	$13.0	—	$23.0
Liabilities (b)				
Deferred Compensation	—	$17.6	—	$17.6
U.S. Water Services Contingent Consideration	—	—	$5.5	5.5
Total Fair Value of Liabilities	—	$17.6	$5.5	$23.1
Total Net Fair Value of Assets (Liabilities)	$10.0	$(4.6)	$(5.5)	$(0.1)

(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, 2016			
	Level 1	Level 2	Level 3	Total
Millions				
Assets				
Investments (a)				
Available-for-sale – Equity Securities	$7.1	—	—	$7.1
Available-for-sale – Corporate and Governmental Debt Securities	—	$11.7	—	11.7
Cash Equivalents	1.3	—	—	1.3
Total Fair Value of Assets	$8.4	$11.7	—	$20.1
Liabilities (b)				
Deferred Compensation	—	$16.0	—	$16.0
U.S. Water Services Contingent Consideration	—	—	$25.0	25.0
Total Fair Value of Liabilities	—	$16.0	$25.0	$41.0
Total Net Fair Value of Assets (Liabilities)	$8.4	$(4.3)	$(25.0)	$(20.9)

(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 2015 acquisition of U.S. Water Services. Changes in the U.S. Water Services Contingent Consideration can result from modifications to the shareholder agreement, changes in discount rates, timing of milestones that trigger payment, or the timing and amount of earnings estimates. The following table provides a reconciliation of the beginning and ending balances of the U.S. Water Services Contingent Consideration measured at fair value using Level 3 measurements as of June 30, 2017. Management analyzes the fair value of the contingent liability on a quarterly basis and makes adjustments as appropriate.

Recurring Fair Value Measures	
Activity in Level 3	
Millions	
Balance as of December 31, 2016	$25.0
Accretion	0.6
Payments (a)	(19.7)
Changes in Cash Flow Projections (a)	(0.4)
Balance as of June 30, 2017	$5.5

(a) Payments and changes in cash flow projections reflect the impact of a modification to the shareholder agreement in the first quarter of 2017 which provided participants a one-time election to sell shares at a determined price. Participants representing approximately half of the outstanding contingent consideration shares made the election, which were paid in the first six months of 2017.

For the six months ended June 30, 2017, and the year ended December 31, 2016, 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 following table, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed in the following table 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		
June 30, 2017	$1,529.6	$1,634.6
December 31, 2016	$1,569.1	$1,653.8

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 quarter and six months ended June 30, 2017, and the year ended December 31, 2016, there were no triggering events or indicators of impairment for these non-financial assets.

NOTE 6. REGULATORY MATTERS

Regulatory matters are summarized in Note 4. Regulatory Matters to our Consolidated Financial Statements in our 2016 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, FERC or PSCW.

2010 Minnesota General 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. As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission, renewable, and environmental investments and expenditures. (See Transmission Cost Recovery Rider, Renewable Cost Recovery Rider and Environmental Improvement Rider.) Revenue from cost recovery riders was $24.4 million and $48.6 million for the quarter and six months ended June 30, 2017, respectively ($23.5 million and $48.9 million for the quarter and six months ended June 30, 2016, respectively).

2016 Minnesota General Rate Case. In November 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 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $55 million in additional revenue. In December 2016, Minnesota Power filed a request to modify its original interim rate proposal reducing its requested interim rate increase to $34.7 million from the original request of approximately $49 million due to a change in its electric sales forecast. In December 2016 orders, the MPUC accepted the November 2016 filing as complete and authorized an annual interim rate increase of $34.7 million beginning January 1, 2017.

On February 23, 2017, Minnesota Power filed an additional request to further reduce its requested interim rate increase. In an order dated April 13, 2017, the MPUC approved Minnesota Power's updated retail rate request resulting in a reduction in the annual interim rate increase to $32.2 million beginning May 1, 2017. As a result of working with intervenors and further developments as the rate review has progressed, Minnesota Power now expects its final rate request to be approximately $49 million on an annualized basis. Management has evaluated the need for a reserve for interim rate refunds and concluded that a reserve is not necessary as of June 30, 2017. Management evaluates the need for reserves for interim rates each reporting period.

As part of its 2016 general rate case and through its 2017 remaining life depreciation petition filed on February 1, 2017, Minnesota Power is seeking an extension of the recovery period for Boswell to better reflect recent environmental investments at the facility and mitigate rate increases for our customers. If approved, annual depreciation expense will be reduced by approximately $25 million. If the requested recovery period extension is not approved, we would expect final rates to be increased by a similar amount, subject to regulatory approval. We cannot predict the level of final rates that may be authorized by the MPUC.

Energy-Intensive Trade-Exposed (EITE) Customer Rates. The Minnesota Legislature enacted EITE customer ratemaking law in 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 2015, Minnesota Power filed a rate schedule petition with the MPUC for EITE customers and a corresponding rider for EITE cost recovery. In a March 2016 order, the MPUC dismissed the petition without prejudice, providing Minnesota Power the option to refile the petition with additional information or file a new petition. In June 2016, Minnesota Power filed a revised EITE petition with the MPUC which included additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an order dated April 20, 2017. The rate adjustments are intended to be revenue and cash flow neutral to Minnesota Power.

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 wholesale contracts include a termination clause requiring a three-year notice to terminate.

In 2015, Minnesota Power amended its formula-based wholesale electric sales contract with the Nashwauk Public Utilities Commission, extending the term through June 30, 2028. No termination notice may be given for this contract prior to June 30, 2025. The electric service agreements with SWL&P and another municipal customer are effective through July 31, 2020, and June 30, 2019, respectively. Under the agreement with SWL&P, no termination notice may be given prior to July 31, 2017. The other municipal customer provided termination notice for its contract in June 2016. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. 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.

NOTE 6. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

Also in 2015, Minnesota Power amended its wholesale electric contracts with 14 municipal customers, extending the contract terms through December 31, 2024. No termination notices may be given prior to December 31, 2021. 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.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. In a February 2016 order, the MPUC approved Minnesota Power's updated customer billing rates 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 2015, the project is eligible for cost recovery under the existing transmission cost recovery rider. Minnesota Power is funding the construction of the GNTL with a subsidiary of Manitoba Hydro (see Great Northern Transmission Line.), and anticipates including its portion of the investments and expenditures for the GNTL in future transmission cost recovery filings.

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for investments and expenditures related to Bison and the restoration and repair of Thomson. Updated customer billing rates for the renewable cost recovery rider were approved by the MPUC in a December 2016 order, which allows 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. The approval is on a provisional basis pending the outcome of Minnesota Power's 2016 general rate case. (See 2016 Minnesota General Rate Case.)

In a November 2016 order, the MPUC directed Minnesota Power to attribute all North Dakota investment tax credits realized from Bison to Minnesota Power regulated retail customers. As a result of the adverse regulatory outcome, Minnesota Power recorded a regulatory liability and a reduction in operating revenue of $15.0 million in 2016. The North Dakota investment tax credits previously recognized as income tax credits in Corporate and Other were reversed in 2016 resulting in an $8.8 million charge to net income for the year ended December 31, 2016. In December 2016, Minnesota Power submitted a request for reconsideration with the MPUC. In an order dated February 14, 2017, the MPUC decided to reconsider its November 2016 order and provided for a comment period which expired on June 30, 2017.

Prior to the November 2016 MPUC order, Minnesota Power accounted for North Dakota investment tax credits based on the 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 had 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 were included in the ALLETE consolidated group.

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.

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. Updated customer billing rates for the environmental improvement rider were approved by the MPUC in a December 2016 order; however, in an order dated March 22, 2017, the MPUC approved a request by Minnesota Power to delay implementation of the updated rates until resolution of its 2016 general rate case. (See 2016 Minnesota General Rate Case.)

2016 Wisconsin General 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. In June 2016, SWL&P filed a rate increase request with the PSCW requesting an average increase of 3.1 percent for retail customers (3.5 percent increase in electric rates; 1.3 percent decrease in natural gas rates; and 7.8 percent increase in water rates). The filing seeks an overall return on equity of 10.9 percent and a 55 percent equity ratio. At a hearing on July 13, 2017, the PSCW approved a return on common equity of 10.5 percent and a 55 percent equity ratio. On an annualized basis, we expect additional revenue of approximately $2.5 million. An order from the PSCW detailing the effective date of final rates is expected in the third quarter of 2017.

NOTE 6. REGULATORY MATTERS (Continued)

Integrated Resource Plan. In 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 steps in Minnesota Power's EnergyForward strategic plan including the economic idling of Taconite Harbor Units 1 and 2 which occurred 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 a July 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepted Minnesota Power's plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. In October 2016, Minnesota Power announced Boswell Units 1 and 2 will be retired in 2018. On July 28, 2017, Minnesota Power submitted a resource package to the MPUC requesting approval of PPAs for the output of a 250 MW wind energy facility and a 10 MW solar energy facility as well as approval of a 250 MW natural gas energy PPA. These agreements will be subject to MPUC approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE. Minnesota Power would purchase approximately 50 percent of the facility's output starting in 2025. This resource package is the next step in Minnesota Power's EnergyForward strategic plan. Minnesota Power's next IRP is required to be filed by February 1, 2018; however, Minnesota Power filed a request with the MPUC on June 8, 2017, to delay the filing deadline until at least February 1, 2019.

Great Northern Transmission Line. 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. In 2015, a certificate of need was approved by the MPUC. Based on this approval, 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 cost recovery filings. (See Transmission Cost Recovery Rider.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In an April 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in November 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected 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, of which Minnesota Power's portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as contributions in aid of construction. Total project costs of $61.1 million have been incurred through June 30, 2017, of which $31.6 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In 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.

Conservation Improvement Program. Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year. On April 3, 2017, Minnesota Power submitted its 2016 CIP consolidated filing, which detailed Minnesota Power's CIP program results and requested a CIP financial incentive of $5.5 million based upon MPUC procedures. In an order dated June 22, 2017, 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 in the second quarter of 2017. The approved financial incentive will be recovered through customer billing rates in 2017 and 2018. In 2016, the CIP financial incentive of $7.5 million was 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 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 2015, a federal administrative law judge ruled on the complaint proposing a reduction in the base return on equity to 10.32 percent, or 10.82 percent including an incentive adder for participation in a regional transmission organization. In September 2016, the FERC issued an order affirming the administrative law judge's recommendation.

NOTE 6. REGULATORY MATTERS (Continued)
MISO Return on Equity Complaints (Continued)

In 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity to 8.67 percent. In June 2016, a federal administrative law judge ruled on the additional complaint proposing a further reduction in the base return on equity to 9.70 percent, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge’s recommendation is pending. The final decision from the FERC is not expected to have a material impact on our Consolidated Financial Statements.

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 40 kW or less. In a February 2016 order finalized in December 2016, the MPUC approved Camp Ripley, a 10 MW utility scale solar project at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, as eligible to meet the solar energy standard and for current cost recovery. Camp Ripley was completed in the fourth quarter of 2016. In a July 2016 order, the MPUC approved a community solar garden project in northeastern 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 is owned and operated by Minnesota Power. Minnesota Power believes Camp Ripley and the community solar garden project will meet approximately one-third of the overall mandate. Additionally, in an order dated February 10, 2017, the MPUC approved Minnesota Power’s proposal 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. This proposal to incentivize customer-sited solar installations is expected to meet a portion of the required mandate related to solar photovoltaic devices with a nameplate capacity of 40 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 for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. No regulatory assets or liabilities are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable regulatory authority or over the corresponding period related to the asset or liability.

Regulatory Assets and Liabilities	June 30, 2017	December 31, 2016
Millions		
Current Regulatory Assets		
Deferred Fuel Adjustment Clause	$16.7	$18.6
Total Current Regulatory Assets	16.7	18.6
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans	223.4	226.1
Income Taxes (a)	35.0	33.8
Asset Retirement Obligations	28.4	26.0
Cost Recovery Riders	13.8	30.5
Conservation Improvement Program	7.1	4.0
PPACA Income Tax Deferral	5.0	5.0
Other	11.8	4.7

Total Non-Current Regulatory Assets	324.5	330.1
Total Regulatory Assets	$341.2	$348.7
Non-Current Regulatory Liabilities		
Wholesale and Retail Contra AFUDC	$56.9	$56.8
North Dakota Investment Tax Credits	27.7	28.2
Plant Removal Obligations	19.0	19.1
Income Taxes	18.8	19.1
Other	3.4	2.6
Total Non-Current Regulatory Liabilities	$125.8	$125.8

(a) See Note 1. Operations and Significant Accounting Policies – Revision of Prior Balance Sheet.

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 June 30, 2017, our equity investment in ATC was $143.1 million ($135.6 million at December 31, 2016). In the first six months of 2017, we invested $5.0 million in ATC, and on July 31, 2017, we invested an additional $1.6 million. We expect to make additional investments of approximately $4.3 million in 2017.

ALLETE's Investment in ATC

Millions	
Equity Investment Balance as of December 31, 2016	$135.6
Cash Investments	5.0
Equity in ATC Earnings	11.4
Distributed ATC Earnings	(8.9)
Equity Investment Balance as of June 30, 2017	$143.1

In September 2016, the FERC issued an order reducing ATC's authorized return on equity to 10.32 percent, or 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.

In June 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, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending. (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.

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

The following tables present ALLETE's short-term and long-term debt as of June 30, 2017, and December 31, 2016:

June 30, 2017	Principal	Unamortized Debt Issuance Costs	Total
Millions			
Short-Term Debt	$118.2	$(0.5)	$117.7
Long-Term Debt	1,411.4	(10.0)	1,401.4
Total Debt	$1,529.6	$(10.5)	$1,519.1

December 31, 2016	Principal	Unamortized Debt Issuance Costs	Total
Millions			
Short-Term Debt	$188.3	$(0.6)	$187.7
Long-Term Debt	1,380.8	(10.4)	1,370.4
Total Debt	$1,569.1	$(11.0)	$1,558.1

On June 1, 2017, ALLETE issued $80.0 million of its senior unsecured notes (the Notes) to certain institutional buyers in the private placement market. The Notes were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors. The Notes bear interest at 3.11 percent and mature on June 1, 2027. Interest on the Notes is payable semi-annually on June 1 and December 1 of each year, commencing on December 1, 2017. ALLETE has the option to prepay all or a portion of the Notes at its discretion, subject to a make-whole provision. The Notes are subject to additional terms and conditions which are customary for these types of transactions. Proceeds from the sale of the Notes may be used to redeem debt, fund corporate growth opportunities and for general corporate purposes.

NOTE 8. SHORT-TERM AND LONG-TERM DEBT (Continued)

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 June 30, 2017, our ratio was approximately 0.43 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 June 30, 2017, ALLETE was in compliance with its financial covenants.

NOTE 9. INCOME TAX EXPENSE

	Quarter Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Millions				
Current Tax Expense (a)				
Federal	—	—	—	—
State	$0.1	$0.1	$0.2	$0.2
Total Current Tax Expense	$0.1	$0.1	$0.2	$0.2
Deferred Tax Expense				
Federal	$3.8	$2.1	$11.1	$6.7
State	3.6	2.7	9.5	7.5
Investment Tax Credit Amortization	(0.2)	(0.2)	(0.4)	(0.4)
Total Deferred Tax Expense	$7.2	$4.6	$20.2	$13.8
Total Income Tax Expense	$7.3	$4.7	$20.4	$14.0

(a) For the quarter and six months ended June 30, 2017, and 2016, 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.

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense	Quarter Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Millions				
Income Before Non-Controlling Interest and Income Taxes	$44.2	$29.5	$106.3	$85.2
Statutory Federal Income Tax Rate	35 %	35 %	35 %	35 %
Income Taxes Computed at 35 percent Statutory Federal Rate	$15.5	$10.3	$37.2	$29.8
Increase (Decrease) in Tax Due to:				
State Income Taxes – Net of Federal Income Tax Benefit	2.4	1.8	6.3	5.0

Production Tax Credits	(10.0)	(6.6)	(23.0)	(20.5)
Other	(0.6)	(0.8)	(0.1)	(0.3)
Total Income Tax Expense	$7.3	$4.7	$20.4	$14.0

For the six months ended June 30, 2017, the effective tax rate was 19.2 percent (16.4 percent for the six months ended June 30, 2016).

NOTE 9. INCOME TAX EXPENSE (Continued)

Uncertain Tax Positions. As of June 30, 2017, we had gross unrecognized tax benefits of $1.9 million ($2.0 million as of December 31, 2016). Of the total gross unrecognized tax benefits, $0.7 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 has no open federal or state audits, and 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 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 currency translation adjustments, unrealized gains and losses on available-for-sale securities and defined benefit pension and other postretirement items, consisting of deferred actuarial gains or losses and prior service costs or credits.

For the quarter and six months ended June 30, 2017, and 2016, reclassifications out of accumulated other comprehensive loss for the Company were not material. Changes in accumulated other comprehensive loss for the six months ended June 30, 2017, are presented on the Consolidated Statement of Shareholders' 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 and performance share awards granted under our Executive Long-Term Incentive Compensation Plan. For the six months ended June 30, 2017, and 2016, no options to purchase shares of ALLETE common stock were excluded from the computation of diluted earnings per share.

Reconciliation of Basic and Diluted Earnings Per Share	Basic	2017 Dilutive Securities	Diluted	Basic	2016 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
Quarter ended June 30,						
Net Income Attributable to ALLETE	$36.9		$36.9	$24.8		$24.8
Average Common Shares	50.9	0.2	51.1	49.3	0.2	49.5
Earnings Per Share	$0.73		$0.72	$0.50		$0.50
Six Months Ended June 30,						
Net Income Attributable to ALLETE	$85.9		$85.9	$70.7		$70.7
Average Common Shares	50.5	0.2	50.7	49.2	0.1	49.3
Earnings Per Share	$1.70		$1.69	$1.44		$1.43

Contributions to Pension. For the six months ended June 30, 2017, we contributed 0.2 million shares of ALLETE common stock to our defined benefit pension plans, which had an aggregate value of $13.5 million when contributed (no shares were contributed to the defined benefit pension plans for the six months ended June 30, 2016). These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended.

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Cost (Income)	2017	2016	2017	2016
Millions				
Quarter Ended June 30,				
Service Cost	$2.6	$2.1	$1.1	$1.0
Interest Cost	8.2	8.1	1.9	1.8
Expected Return on Plan Assets	(10.6)	(10.7)	(2.7)	(2.8)
Amortization of Prior Service Credits	—	—	(0.5)	(0.8)
Amortization of Net Loss	2.4	2.5	0.1	0.1
Net Periodic Benefit Cost (Income)	$2.6	$2.0	$(0.1)	$(0.7)
Six Months Ended June 30,				
Service Cost	$5.1	$4.1	$2.2	$2.0
Interest Cost	16.3	16.2	3.8	3.7
Expected Return on Plan Assets	(21.2)	(21.3)	(5.3)	(5.6)
Amortization of Prior Service Credits	—	—	(1.0)	(1.5)
Amortization of Net Loss	4.9	4.9	0.2	0.1
Net Periodic Benefit Cost (Income)	$5.1	$3.9	$(0.1)	$(1.3)

Employer Contributions. For the six months ended June 30, 2017, we contributed $1.7 million in cash and $13.5 million in ALLETE common stock to the defined benefit pension plans (none for the six months ended June 30, 2016); we do not expect to make additional contributions to our defined benefit pension plans in 2017. For the six months ended June 30, 2017, and 2016, we made no contributions to our other postretirement benefit plans; we do not expect to make any contributions to our other postretirement benefit plans in 2017.

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 11. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in our 2016 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 PSA. (See Minnkota Power PSA.) Square Butte’s costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of June 30, 2017, Square Butte had total debt outstanding of $311.6 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 six months ended June 30, 2017, was $40.7 million ($37.7 million for the six months ended June 30, 2016). 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 $4.7 million ($4.8 million for the same period in 2016). 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 PSA. Minnesota Power has a PSA with Minnkota Power, which commenced in 2014. Under the PSA, 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 2017 and in 2016.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

Tenaska PPA. On May 10, 2017, Minnesota Power and an affiliate of Tenaska signed a long-term PPA that provides for Minnesota Power to purchase the energy and associated capacity from a 250 MW wind energy facility in southwest Minnesota for a 20-year period beginning in 2020. This agreement is subject to MPUC approval of the construction of a 525 MW to 550 MW combined cycle natural gas-fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE and a wind energy facility. (See Note 6. Regulatory Matters.) The agreement provides for the purchase of output from the facility at fixed energy prices. There are no fixed capacity charges, and Minnesota Power will only pay for energy as it is delivered.

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 2018 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 $13.8 million for the remainder of 2017, $29.0 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.

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 2023. The aggregate amount of minimum lease payments for all operating leases is $6.9 million for the remainder of 2017, $12.0 million in 2018, $10.7 million in 2019, $7.5 million in 2020, $5.9 million in 2021 and $18.3 million thereafter.

Transmission. We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include the GNTL, 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. As a condition of the 250-MW long-term PPA entered into 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.

In 2015, a certificate of need was approved by the MPUC. Based on this approval, 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 cost recovery filings. (See Note 6. Regulatory Matters.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In an April 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in November 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected 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, of which Minnesota Power’s portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as contributions in aid of construction. Total project costs of $61.1 million have been incurred through June 30, 2017, of which $31.6 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In 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.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

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 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 becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers.

Air. The electric utility industry is regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, baghouses and low NO_X technologies. Under currently applicable environmental regulations, these facilities are substantially compliant with 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 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 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. In October 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as part of its EnergyForward strategic plan. We believe that costs to retire Boswell Units 1 and 2 will 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 certain states in the eastern half of the U.S., 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 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.

Minnesota Power's generation levels and emission rates in 2015 and 2016 were below its allowances. Allowances for 2017 and 2018 were distributed in June 2016. Based on our review of the NO_x and SO_2 allowances issued and pending issuance, we currently expect generation levels and emission rates will result in compliance with the CSAPR.

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

Mercury and Air Toxics Standards (MATS) 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. 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, or April 2016 if granted an extension. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan was completed in 2015. Investments and compliance work previously completed at Boswell Unit 3, including 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 2015 positioned those units for MATS compliance.

In 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 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. In April 2016, the EPA announced its determination that the MATS rule is appropriate and necessary, when also 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.)

Minnesota Mercury Emissions Reduction Act/Rule. In order to comply with the 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 2016, to achieve compliance with the final rule and July 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 consisted largely of adjustments to our operating practices; therefore, the costs for complying with the final rule were not 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 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.

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

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. In September 2016, environmental groups filed a lawsuit against the EPA in the U.S. District Court for the Northern District of California alleging the EPA had failed to fully implement the $PM_{2.5}$ standards in certain 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.

In 2013, the EPA provided guidance to states regarding implementation of the one-hour NO_2 NAAQS and in 2014, as clarified in 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. In 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 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. In January 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. 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 in September 2016, containing the new modeling limits at that facility. The MPCA did not meet the January 13, 2017, deadline to amend the Boswell permit. 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. A public hearing was held by the Fond du Lac Band and the public comment period on the petition expired in 2014.

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 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 followed by public hearings and a public comment period ending in 2015.

The next step for the Fond du Lac Band and the Bad River Band would be 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.

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

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 generating facilities;
- Supporting research of technologies to reduce carbon emissions from generating facilities and carbon sequestration efforts; and
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas-fired generating facilities.

Climate Action Plan (CAP). In 2015, the Federal government announced an updated 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. On March 28, 2017, President Trump signed an Executive Order titled Promoting Energy Independence and Economic Growth that rescinded the CAP.

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 may 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 ability to require BACT for GHG from sources already subject to regulation under PSD. Minnesota Power's coal-fired generating facilities are already subject to regulation under PSD, so we anticipate that ultimately PSD for GHG will apply to our facilities, but the timing of the promulgation of a replacement for the Tailoring Rule is uncertain. The PSD applies to existing facilities only when they undertake a major modification that increases emissions. At this time, we are unable to predict the compliance costs that we might incur.

In October 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. It is uncertain how the Title V permitting requirements will be affected by the March 28, 2017, Executive Order titled Promoting Energy Independence and Economic Growth.

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

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 2015, together with a proposed federal implementation plan and a model rule for emissions trading. Petitions for review of the rule were filed with the U.S. Court of Appeals for the District of Columbia Circuit. In February 2016, the U.S. Supreme Court issued an order staying the effectiveness of the rule until after the appellate court process is complete. In September 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. The regulatory review initiated by the March 28, 2017, Executive Order titled Promoting Energy Independence and Economic Growth is directed to include Section 111(b) and 111(d) CPP provisions. In addition, the EPA has filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit to hold CPP-related litigation in abeyance while the EPA is reviewing the rule. Minnesota Power is monitoring developments with respect to the CPP rule and related matters.

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 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.)

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 additional costs through a rate proceeding.

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, a preliminary assessment indicates costs of compliance up to $15 million over the next five years. Minnesota Power would seek recovery of additional costs through a rate proceeding.

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

Steam Electric Power Generating Effluent Guidelines. In 2015, the EPA issued revised federal effluent limit guidelines (ELG) for steam electric power generating stations under the Clean Water Act. 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.

We are evaluating the final ELG rule's 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.

On April 12, 2017, the EPA published in the Federal Register the postponement of certain compliance deadlines and formally announced that it would reconsider the final ELG rule. Under the ELG rule schedule, required compliance activity deadlines could have been in place as soon as November 1, 2018. These deadlines could have included prescriptive wastewater treatment technology installation, as well as a ban on bottom ash contact water discharges. If the EPA's reconsideration results in the rule being revised or rescinded, the authority to regulate bottom ash transport water and FGD wastewater would fall under existing Effluent Guidelines Limits and state resource agency purview.

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 reuse. Minnesota Power would seek recovery of additional costs through a rate proceeding.

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 disposes or stores coal ash at four of its electric generating facilities by the following methods: storing ash in lined onsite impoundments (ash ponds), disposing of dry ash in a lined dry ash landfill which has been idled and has a temporary landfill cover in place, applying ash to land as an approved beneficial use and trucking ash to state permitted landfills.

The EPA issued the final coal combustion residuals (CCR) rule in 2014 under Subtitle D (non-hazardous) of RCRA and it was published in the Federal Register in 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. Recently, the EPA has indicated to Minnesota Power that the Taconite Harbor landfill is a CCR unit, based on the EPA's interpretation of the CCR rule language. Minnesota Power has agreed to post the required CCR information for the Taconite Harbor landfill on Minnesota Power's website while the CCR issue is resolved. Minnesota Power continues to work on minimizing costs through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. Compliance costs, if any, for CCR at Taconite Harbor are not expected to be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Other Matters.

ALLETE Clean Energy. ALLETE Clean Energy's wind energy facilities have PSAs in place for their entire output and expire in various years between 2018 and 2032. As of June 30, 2017, ALLETE Clean Energy has $15.4 million outstanding in standby letters of credit.

U.S. Water Services. As of June 30, 2017, U.S. Water Services has $0.8 million outstanding in standby letters of credit.

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

BNI Energy. As of June 30, 2017, 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 June 30, 2017, ALLETE Properties 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.

Community Development District Obligations. At June 30, 2017, we owned 70 percent of the assessable land in the Town Center District (72 percent at December 31, 2016) and 78 percent of the assessable land in the Palm Coast Park District (92 percent at December 31, 2016). At June 30, 2017, 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 $2.0 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

We present three reportable segments: Regulated Operations, ALLETE Clean Energy and U.S. Water Services. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes three operating segments which consist of our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC. 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. 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.

NOTE 14. BUSINESS SEGMENTS (Continued)

	Quarter Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Millions				
Operating Revenue				
Regulated Operations	$264.9	$234.9	$546.5	$487.2
Energy Infrastructure and Related Services				
ALLETE Clean Energy	19.6	18.8	43.3	42.4
U.S. Water Services	38.4	34.3	70.5	66.7
Corporate and Other	30.4	26.8	58.6	52.3
Total Operating Revenue	$353.3	$314.8	$718.9	$648.6
Net Income (Loss) Attributable to ALLETE				
Regulated Operations	$32.4	$22.6	$75.9	$65.0
Energy Infrastructure and Related Services				
ALLETE Clean Energy	3.8	2.6	10.5	8.7
U.S. Water Services	0.6	1.0	0.3	0.5
Corporate and Other	0.1	(1.4)	(0.8)	(3.5)
Total Net Income Attributable to ALLETE	$36.9	$24.8	$85.9	$70.7

	June 30, 2017	December 31, 2016
Millions		
Assets		
Regulated Operations	$3,824.8	$3,823.9
Energy Infrastructure and Related Services		
ALLETE Clean Energy	559.1	566.0
U.S. Water Services	267.0	264.1
Corporate and Other	280.6	222.9
Total Assets	$4,931.5	$4,876.9

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 2016 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 2016 Form 10-K under the headings: “Forward-Looking Statements” located on page 6 and “Risk Factors” located in Part I, Item 1A, beginning on page 25 of our 2016 Form 10-K. The risks and uncertainties described in this Form 10-Q and our 2016 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.

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

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 utility 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 is from PSAs under various durations. In addition, ALLETE Clean Energy constructed and sold a 107 MW wind energy facility in 2015. On January 3, 2017, ALLETE Clean Energy announced that it will develop another wind energy facility of up to 50 MW after securing a 25-year PSA with Montana-Dakota Utilities. The PSA includes an option for Montana-Dakota Utilities to purchase the facility upon completion; construction is expected to begin in 2018. On March 16, 2017, ALLETE Clean Energy announced it will build, own and operate a separate 100 MW wind energy facility pursuant to a 20-year PSA with Northern States Power; construction is expected to begin in late 2018, subject to regulatory approval.

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.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of June 30, 2017, 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 six months ended June 30, 2017, to the six months ended June 30, 2016.

Net income attributable to ALLETE for the six months ended June 30, 2017, was $85.9 million, or $1.69 per diluted share, compared to $70.7 million, or $1.43 per diluted share, for the same period in 2016. Earnings per share dilution was $0.05 due to additional shares of common stock outstanding as of June 30, 2017.

Regulated Operations net income attributable to ALLETE was $75.9 million for the six months ended June 30, 2017, compared to $65.0 million for the same period in 2016. Net income increased primarily due to higher net income at Minnesota Power resulting from the implementation of interim retail rates on January 1, 2017, higher kWh sales primarily due to increased industrial sales, and the recognition of a conservation improvement program financial incentive following MPUC approval in the second quarter of 2017. These increases were partially offset by higher operating and maintenance, depreciation, and interest expenses. Our equity earnings in ATC for the six months ended June 30, 2017, increased $1.5 million after-tax primarily due to a higher investment balance and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints.

ALLETE Clean Energy net income attributable to ALLETE was $10.5 million for the six months ended June 30, 2017, compared to $8.7 million for the same period in 2016. Net income increased primarily due to higher operating revenue, lower operating and maintenance expenses, and lower interest expense. Net income in 2016 included an allocation of earnings to a non-controlling interest in the limited liability company that owns the Condon wind energy facility, which was acquired by ALLETE Clean Energy in April 2016. (See Note 3. Acquisitions.)

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

U.S. Water Services net income attributable to ALLETE was $0.3 million for the six months ended June 30, 2017, compared to $0.5 million for the same period in 2016. The decrease in net income is primarily due to increased operating expenses as a result of investments for future growth in waste treatment and water safety applications, partially offset by higher operating revenue. U.S. Water Services sells certain products which are seasonal in nature, with higher demand typically realized in warmer months; generally, lower sales occur in the first quarter of each year.

Corporate and Other net loss attributable to ALLETE was $0.8 million for the six months ended June 30, 2017, compared to a net loss of $3.5 million for the same period in 2016. The net loss in 2017 decreased primarily due to lower accretion expense relating to the contingent consideration liability and lower interest expense.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2017, AND 2016

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

Regulated Operations

Quarter Ended June 30,	2017	2016
Millions		
Operating Revenue – Utility	$264.9	$234.9
Fuel, Purchased Power and Gas – Utility	93.1	79.0
Transmission Services – Utility	17.6	16.1
Operating and Maintenance	56.3	53.5
Depreciation and Amortization	39.0	38.3
Taxes Other than Income Taxes	12.7	12.8
Operating Income	46.2	35.2
Interest Expense	(14.5)	(12.7)
Equity Earnings in ATC	5.3	4.1
Other Income	0.2	0.3
Income Before Income Taxes	37.2	26.9
Income Tax Expense	4.8	4.3
Net Income Attributable to ALLETE	$32.4	$22.6

Operating Revenue - Utility increased $30.0 million, or 13 percent, from 2016 primarily due to higher fuel adjustment clause recoveries, interim retail rates, financial incentives under the Minnesota conservation improvement program, kWh sales, transmission revenue and conservation improvement program recoveries, partially offset by lower FERC formula based rates.

Fuel adjustment clause recoveries increased $8.5 million due to higher fuel and purchased power costs attributable to retail and municipal customers. (See Operating Expenses - Fuel, Purchased Power and Gas – Utility.)

Interim retail rates for Minnesota Power, subject to refund, were approved by the MPUC and became effective January 1, 2017, resulting in revenue of $7.8 million in the second quarter of 2017. (See Note 6. Regulatory Matters.)

Financial incentives under the Minnesota conservation improvement program increased $5.5 million from 2016 due to the timing of MPUC approval. The conservation improvement program financial incentive was recognized in the second quarter of 2017 upon approval by the MPUC in an order dated June 22, 2017. In 2016, the financial incentive of $7.5 million was recognized in the third quarter of 2016 following approval by the MPUC.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2017, AND 2016 (Continued)
Regulated Operations (Continued)

Revenue from kWh sales increased $4.7 million from 2016 primarily due to higher sales to Industrial customers. Sales to Industrial customers increased 20.0 percent primarily due to increased taconite production and the commencement of a long term PSA with Silver Bay Power in June 2016. Sales to Residential, Commercial and Municipal customers decreased primarily due to warmer temperatures in 2017. Heating degree days in Duluth, Minnesota, were approximately 5 percent lower in 2017 compared to the same period in 2016. Sales to Other Power Suppliers decreased 15.3 percent from 2016 as a result of increased sales to Industrial customers. 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.

Kilowatt-hours Sold Quarter Ended June 30,	2017	2016	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	229	237	(8)	(3.4)%
Commercial	328	339	(11)	(3.2)%
Industrial	1,816	1,513	303	20.0 %
Municipal	181	187	(6)	(3.2)%
Total Retail and Municipal	2,554	2,276	278	12.2 %
Other Power Suppliers	1,004	1,185	(181)	(15.3)%
Total Regulated Utility Kilowatt-hours Sold	3,558	3,461	97	2.8 %

Revenue from electric sales to taconite and iron concentrate customers accounted for 22 percent of consolidated operating revenue in 2017 (17 percent in 2016). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of consolidated operating revenue in 2017 (6 percent in 2016). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2017 (8 percent in 2016).

Transmission revenue increased $1.8 million primarily due to higher MISO-related revenue. (See Operating Expenses - Transmission Services – Utility.)

Conservation improvement program recoveries increased $1.3 million from 2016 primarily due to an increase in related expenditures. (See Operating Expenses - Operating and Maintenance.)

Revenue from wholesale customers under FERC formula-based rates decreased $1.3 million from 2016 primarily due to lower rates.

Operating Expenses increased $19.0 million, or 10 percent, from 2016.

Fuel, Purchased Power and Gas – Utility expense increased $14.1 million, or 18 percent, from 2016 primarily due to increased kWh sales and fuel costs, partially offset by lower purchased power prices. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue – Utility.)

Transmission Services – Utility expense increased $1.5 million, or 9 percent, from 2016 primarily due to higher MISO-related expense. (See Operating Revenue – Utility.)

Operating and Maintenance expense increased $2.8 million, or 5 percent, from 2016 primarily due to higher salary and benefit expenses, and a $1.3 million increase in conservation improvement program expenses in 2017. Conservation improvement program expenses are recovered from certain retail customers. (See Operating Revenue – Utility.)

Depreciation and Amortization expense increased $0.7 million, or 2 percent, from 2016 primarily due to additional property, plant and equipment in service.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2017, AND 2016 (Continued)
Regulated Operations (Continued)

Interest Expense increased $1.8 million, or 14 percent, from 2016 primarily due to higher average interest rates. We record interest expense for Regulated Operations primarily based on rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC increased $1.2 million, or 29 percent, from 2016 primarily due to additional investments in ATC and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints. (See Note 7. Investment in ATC.)

ALLETE Clean Energy

Quarter Ended June 30,	2017	2016
Millions		
Operating Revenue	$19.6	$18.8
Net Income Attributable to ALLETE	$3.8	$2.6

Operating Revenue increased $0.8 million, or 4 percent, from 2016 primarily due to higher kWh sales at Armenia Mountain, partially offset by lower kWh sales at the remaining wind energy facilities.

	Quarter Ended June 30,			
	2017		2016	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Facilities				
Lake Benton	58.4	$3.1	63.5	$3.1
Storm Lake II	35.0	2.3	39.1	2.6
Condon	20.6	1.7	22.5	1.9
Storm Lake I	49.4	3.0	56.3	2.9
Chanarambie/Viking	64.6	3.5	64.5	3.2
Armenia Mountain	62.5	6.0	48.8	5.1
Total Production and Operating Revenue	290.5	$19.6	294.7	$18.8

Net Income Attributable to ALLETE increased $1.2 million, or 46 percent, from 2016. Net income in 2017 included higher operating revenue, and lower operating and maintenance expense compared to the same period in 2016.

U.S. Water Services

Quarter Ended June 30,	2017	2016
Millions		
Operating Revenue	$38.4	$34.3
Net Income Attributable to ALLETE	$0.6	$1.0

Operating Revenue increased $4.1 million, or 12 percent, from 2016 primarily due to higher revenue from sales of chemicals and related services, and increased equipment sales; however, weather conditions in the Northern and Western U.S. negatively impacted revenue in the second quarter of 2017. Revenue from chemical sales and related services, which includes recurring revenue contracts for the delivery and service of chemicals, was $28.8 million in 2017 compared to $27.3 million in 2016. Revenue from equipment and related services, which includes sales of water treatment equipment, was $9.6 million in 2017 compared to $7.0 million in 2016; equipment sales can significantly fluctuate from period to period.

Net Income Attributable to ALLETE decreased $0.4 million from 2016 primarily due to increased operating expenses as a result of investments for future growth in waste treatment and water safety applications, partially offset by higher operating revenue.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2017, AND 2016 (Continued)

Corporate and Other

Operating Revenue increased $3.6 million, or 13 percent, from 2016 primarily due to an increase in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of higher expenses, and ALLETE Properties reflecting higher land sales in 2017 compared to the same period in 2016.

Net Income Attributable to ALLETE was $0.1 million in 2017 compared to a net loss of $1.4 million in 2016. The change from 2016 was primarily due to lower accretion expense relating to the contingent consideration liability and lower interest expense. Net income at BNI Energy was $2.0 million in 2017 compared to $1.8 million for the same period in 2016, and the net loss at ALLETE Properties was $0.4 million in 2017 compared to a net loss of $0.5 million for the same period in 2016.

Income Taxes – Consolidated

For the quarter ended June 30, 2017, the effective tax rate was 16.5 percent (15.9 percent for the quarter ended June 30, 2016). The increase from 2016 was primarily due to higher pre-tax income. We expect our annual effective tax rate in 2017 to be higher than 2016 due to higher pre-tax income. 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.) 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 SIX MONTHS ENDED JUNE 30, 2017 AND 2016

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

Regulated Operations

Six Months Ended June 30,	2017	2016
Millions		
Operating Revenue – Utility	$546.5	$487.2
Fuel, Purchased Power and Gas – Utility	189.7	158.9
Transmission Services – Utility	34.2	32.9
Operating and Maintenance	111.3	104.1
Depreciation and Amortization	78.7	76.6
Taxes Other than Income Taxes	25.9	25.0
Operating Income	106.7	89.7
Interest Expense	(28.5)	(25.8)
Equity Earnings in ATC	11.4	8.9
Other Income	0.4	1.2
Income Before Income Taxes	90.0	74.0
Income Tax Expense	14.1	9.0
Net Income Attributable to ALLETE	$75.9	$65.0

Operating Revenue – Utility increased $59.3 million, or 12 percent, from 2016 primarily due to higher fuel adjustment clause recoveries, interim retail rates, kWh sales, financial incentives under the Minnesota conservation improvement program, transmission revenue and conservation improvement program recoveries, partially offset by lower FERC formula based rates.

Fuel adjustment clause recoveries increased $18.8 million due to higher fuel and purchased power costs attributable to retail and municipal customers. (See Operating Expenses - Fuel, Purchased Power and Gas – Utility.)

Interim retail rates for Minnesota Power, subject to refund, were approved by the MPUC and became effective January 1, 2017, resulting in revenue of $16.6 million in the first six months of 2017. (See Note 6. Regulatory Matters.)

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2017 AND 2016 (Continued)
Regulated Operations (Continued)

Revenue from kWh sales increased $12.2 million from 2016 primarily due to higher sales to Industrial customers. Sales to Industrial customers increased 15.2 percent primarily due to increased taconite production and the commencement of a long term PSA with Silver Bay Power in June 2016. Sales to Residential, Commercial and Municipal customers decreased primarily due to warmer temperatures in 2017. Heating degree days in Duluth, Minnesota, were approximately 3 percent lower in 2017 compared to the same period in 2016. Sales to Other Power Suppliers decreased 11.7 percent from 2016 as a result of increased sales to industrial customers. 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.

Kilowatt-hours Sold Six Months Ended June 30,	2017	2016	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	552	566	(14)	(2.5)%
Commercial	697	707	(10)	(1.4)%
Industrial	3,578	3,107	471	15.2 %
Municipal	396	406	(10)	(2.5)%
Total Retail and Municipal	5,223	4,786	437	9.1 %
Other Power Suppliers	2,045	2,315	(270)	(11.7)%
Total Regulated Utility Kilowatt-hours Sold	7,268	7,101	167	2.4 %

Revenue from electric sales to taconite and iron concentrate customers accounted for 22 percent of consolidated operating revenue in 2017 (17 percent in 2016). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of consolidated operating revenue in 2017 (6 percent in 2016). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2017 (7 percent in 2016).

Financial incentives under the Minnesota conservation improvement program increased $5.5 million from 2016 due to the timing of MPUC approval. The conservation improvement program financial incentive was recognized in the second quarter of 2017 upon approval by the MPUC in an order dated June 22, 2017. In 2016, the financial incentive of $7.5 million was recognized in the third quarter of 2016 following approval by the MPUC.

Transmission revenue increased $3.1 million primarily due to higher MISO-related revenue. (See Operating Expenses - Transmission Services – Utility.)

Conservation improvement program recoveries increased $2.9 million from 2016 primarily due to an increase in related expenditures. (See Operating Expenses - Operating and Maintenance.)

Revenue from wholesale customers under FERC formula-based rates decreased $2.3 million from 2016 primarily due to lower rates.

Operating Expenses increased $42.3 million, or 11 percent, from 2016.

Fuel, Purchased Power and Gas – Utility expense increased $30.8 million, or 19 percent, from 2016 primarily due to increased kWh sales as well as higher purchased power prices and fuel costs. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue – Utility.)

Transmission Services – Utility expense increased $1.3 million, or 4 percent, from 2016 primarily due to higher MISO-related expense. (See Operating Revenue – Utility.)

Operating and Maintenance expense increased $7.2 million, or 7 percent, from 2016 primarily due to a $3.6 million sales tax refund received in 2016 and a $2.9 million increase in conservation improvement program expenses in 2017. Conservation improvement program expenses are recovered from certain retail customers. (See Operating Revenue – Utility.)

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2017 AND 2016 (Continued)
Regulated Operations (Continued)

Depreciation and Amortization expense increased $2.1 million, or 3 percent, from 2016 primarily due to additional property, plant and equipment in service.

Interest Expense increased $2.7 million, or 10 percent, from 2016 primarily due to higher average interest rates. We record interest expense for Regulated Operations primarily based on rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC increased $2.5 million, or 28 percent, from 2016 primarily due to additional investments in ATC and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints. (See Note 7. Investment in ATC.)

Income Tax Expense increased $5.1 million, or 57 percent, from 2016 due to higher pre-tax income. We expect our annual effective tax rate in 2017 to be higher than 2016 due to higher pre-tax income.

ALLETE Clean Energy

Six Months Ended June 30,	2017	2016
Millions		
Operating Revenue	$43.3	$42.4
Net Income Attributable to ALLETE	$10.5	$8.7

Operating Revenue increased $0.9 million, or 2 percent, from 2016 primarily due to higher kWh sales at Armenia Mountain, partially offset by lower kWh sales at the remaining wind energy facilities.

	Six Months Ended June 30,			
	2017		2016	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Facilities				
Lake Benton	134.2	$6.6	133.5	$6.5
Storm Lake II	83.2	5.2	91.6	5.6
Condon	44.8	3.7	51.0	4.3
Storm Lake I	119.1	6.4	120.3	6.0
Chanarambie/Viking	145.5	7.4	145.1	6.8
Armenia Mountain	150.2	14.0	140.8	13.2
Total Production and Operating Revenue	677.0	$43.3	682.3	$42.4

Net Income Attributable to ALLETE increased $1.8 million, or 21 percent, from 2016. Net income in 2017 included higher operating revenue, lower operating and maintenance expense, and lower interest expense compared to the same period in 2016. Net income in 2016 included an allocation of earnings to a non-controlling interest in the limited liability company that owns the Condon wind energy facility, which was acquired by ALLETE Clean Energy in April 2016. (See Note 3. Acquisitions.)

U.S. Water Services

Six Months Ended June 30,	2017	2016
Millions		
Operating Revenue	$70.5	$66.7

Net Income Attributable to ALLETE	$0.3	$0.5

Operating Revenue increased $3.8 million, or 6 percent, from 2016 primarily due to higher revenue from sales of chemicals and related services, and increased equipment sales; however, weather conditions in the Northern and Western U.S. negatively impacted revenue in the first six months of 2017. Revenue from chemical sales and related services, which includes recurring revenue contracts for the delivery and service of chemicals, was $55.9 million in 2017 compared to $53.2 million in 2016. Revenue from equipment and related services, which includes sales of water treatment equipment, was $14.6 million for 2017 compared to $13.5 million in 2016; equipment sales can significantly fluctuate from period to period.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2017 AND 2016 (Continued)
U.S. Water Services (Continued)

Net Income Attributable to ALLETE decreased $0.2 million from 2016. The decrease in net income is primarily due to increased operating expenses as a result of investments for future growth in waste treatment and water safety applications, partially offset by higher operating revenue. U.S. Water Services sells certain products which are seasonal in nature, with higher demand typically realized in warmer months; generally, lower sales occur in the first quarter of each year.