ALLETE INC
Form 10-Q
November 03, 2009

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

FORM 10-Q

(Mark One)

T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2009

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. T 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). £ Yes £ No

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

Large Accelerated Filer T	Accelerated Filer £
Non-Accelerated Filer £	Smaller Reporting Company £

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

Common Stock, no par value,
34,891,615 shares outstanding
as of September 30, 2009

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Definitions

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

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction – consisting of the cost of both the debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Bison I	Bison I Wind Project
BNI Coal	BNI Coal, Ltd.
BNSF	BNSF Railway Company
Boswell	Boswell Energy Center
Company	ALLETE, Inc. and its subsidiaries
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
FTR	Financial Transmission Rights
GAAP	United States Generally Accepted Accounting Principles
GHG	Greenhouse Gases
IBEW Local 31	International Brotherhood of Electrical Workers Local 31
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
kV	Kilovolt(s)
Laskin	Laskin Energy Center
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NDPSC	North Dakota Public Service Commission
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NOX	Nitrogen Oxide
Note ___	Note ___ to the consolidated financial statements in this Form 10-Q
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center

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Definitions (Continued)

Abbreviation or Acronym	Term
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
WDNR	Wisconsin Department of Natural Resources

Safe Harbor Statement
Under the Private Securities Litigation Reform Act of 1995

Statements in this report that are not statements of historical facts may be 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 is 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,” “will likely result,” “will continue,” “could,” “may,” “potential,” “target,” “outlo similar meaning) are 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 hereby filing cautionary statements identifying important factors that could cause our actual results to differ materially from those projected, or expectations suggested, in forward-looking statements made by or on behalf of ALLETE in this Quarterly Report on 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:

- our ability to successfully implement our strategic objectives;
- our ability to manage expansion and integrate acquisitions;
- prevailing governmental policies, regulatory actions, and legislation including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, and various local and county regulators, and city administrators, about allowed rates of return, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated Operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and regulations;
- weather conditions;
- natural disasters and pandemic diseases;
- war and acts of terrorism;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses, capital and land development expenditures;
- global and domestic economic conditions affecting us or our customers;

- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements that affect the business and profitability of ALLETE.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 20 of our 2008 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 us in this Form 10-Q and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

ALLETE
CONSOLIDATED BALANCE SHEET
Millions – Unaudited

	September 30, 2009	December 31, 2008
Assets		
Current Assets		
Cash and Cash Equivalents	$54.3	$102.0
Accounts Receivable (Less Allowance of $0.9 at September 30, 2009 and $0.7 at December 31, 2008)	79.3	76.3
Inventories	54.4	49.7
Prepayments and Other	24.5	24.3
Total Current Assets	212.5	252.3
Property, Plant and Equipment - Net	1,530.5	1,387.3
Investment in ATC	85.1	76.9
Other Investments	138.8	136.9
Other Assets	288.2	281.4
Total Assets	$2,255.1	$2,134.8
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$54.8	$75.7
Accrued Taxes	15.9	12.9
Accrued Interest	9.9	8.9
Long-Term Debt Due Within One Year	12.0	10.4
Notes Payable	5.3	6.0
Other	44.2	36.8
Total Current Liabilities	142.1	150.7
Long-Term Debt	628.4	588.3
Deferred Income Taxes	217.5	169.6
Other Liabilities	352.0	389.3
Total Liabilities	1,340.0	1,297.9
Commitments and Contingencies (Note 14)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 34.9 and 32.6 Shares Outstanding	601.4	534.1
Unearned ESOP Shares	(46.9)	(54.9)
Accumulated Other Comprehensive Loss	(30.4)	(33.0)
Retained Earnings	381.5	380.9
Total ALLETE's Equity	905.6	827.1

Non-Controlling Interest in Subsidiaries	9.5	9.8
Total Equity	915.1	836.9
Total Liabilities and Equity	$2,255.1	$2,134.8

The accompanying notes are an integral part of these statements.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Operating Revenue				
Operating Revenue	$178.8	$201.7	$550.7	$604.9
Prior Year Rate Refunds	–	–	(7.6)	–
Total Operating Revenue	178.8	201.7	543.1	604.9
Operating Expenses				
Fuel and Purchased Power	69.8	81.0	199.4	242.3
Operating and Maintenance	67.5	74.0	224.7	241.5
Depreciation	16.1	13.5	46.8	39.1
Total Operating Expenses	153.4	168.5	470.9	522.9
Operating Income	25.4	33.2	72.2	82.0
Other Income (Expense)				
Interest Expense	(8.3)	(6.9)	(25.4)	(19.5)
Equity Earnings in ATC	4.4	4.2	12.9	11.2
Other	0.8	2.8	3.8	13.9
Total Other Income (Expense)	(3.1)	0.1	(8.7)	5.6
Income Before Non-Controlling Interest and Income Taxes	22.3	33.3	63.5	87.6
Income Tax Expense	6.5	8.4	21.5	28.3
Net Income	15.8	24.9	42.0	59.3
Less: Non-Controlling Interest in Subsidiaries	(0.2)	0.2	(0.3)	0.3
Net Income Attributable to ALLETE	$16.0	$24.7	$42.3	$59.0
Average Shares of Common Stock				
Basic	32.8	29.1	31.8	28.9
Diluted	32.9	29.3	31.9	29.0
Basic and Diluted Earnings Per Share of Common Stock	$0.49	$0.85	$1.33	$2.04
Dividends Per Share of Common Stock	$0.44	$0.43	$1.32	$1.29

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions - Unaudited

	Nine Months Ended September 30, 2009	2008
Operating Activities		
Net Income	$42.0	$59.3
Allowance for Funds Used During Construction	(4.5)	(2.6)
Income from Equity Investments, Net of Dividends	(0.2)	(2.4)
Gain on Sale of Assets	(0.1)	(4.7)
Gain on Sale of Available-for-Sale Securities	–	(6.5)
Depreciation Expense	46.8	39.1
Amortization of Debt Issuance Costs	0.7	0.6
Deferred Income Tax Expense	38.9	18.4
Stock Compensation Expense	1.6	1.3
Bad Debt Expense	1.2	0.9
Changes in Operating Assets and Liabilities		
Accounts Receivable	(4.1)	13.6
Inventories	(4.7)	(10.4)
Prepayments and Other	(0.3)	20.2
Accounts Payable	(4.4)	(13.0)
Other Current Liabilities	11.4	1.5
Other Assets	(7.0)	(10.2)
Other Liabilities	(11.0)	(3.3)
Cash from Operating Activities	106.3	101.8
Investing Activities		
Proceeds from Sale of Available-for-Sale Securities	1.0	58.5
Payments for Purchase of Available-for-Sale Securities	(1.8)	(45.1)
Investment in ATC	(5.4)	(5.2)
Changes to Other Investments	(0.5)	(0.7)
Additions to Property, Plant and Equipment	(200.1)	(210.0)
Proceeds from Sale of Assets	0.3	20.3
Other	–	1.9
Cash for Investing Activities	(206.5)	(180.3)
Financing Activities		
Proceeds from Issuance of Common Stock	53.7	35.2
Proceeds from Issuance of Long-Term Debt	44.7	140.1
Reductions of Long-Term Debt	(3.0)	(8.4)
Debt Issuance Costs	(0.5)	(1.1)
Dividends on Common Stock	(41.7)	(38.5)
Changes in Notes Payable	(0.7)	6.0
Cash from Financing Activities	52.5	133.3
Change in Cash and Cash Equivalents	(47.7)	54.8

Cash and Cash Equivalents at Beginning of Period	102.0	23.3
Cash and Cash Equivalents at End of Period	$54.3	$78.1

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X and do not include all of the information and notes required by GAAP for complete financial statements. Similarly, the December 31, 2008 consolidated balance sheet was derived from audited financial statements but does not include all disclosures required by GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Certain prior year amounts within operating activities in our consolidated statement of cash flows have been reclassified between line items for comparative purposes. The reclassifications did not affect our net income or cash flows from operating activities. In the opinion of management, the accompanying unaudited consolidated financial statements contain all normal and recurring adjustments necessary to make a fair statement of the consolidated financial position, results of operations and cash flows of ALLETE for the interim periods presented. Operating results for the period ended September 30, 2009, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2009. For further information, refer to the consolidated financial statements and notes included in our 2008 Form 10-K and Form 10-K/A.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of issuing the financial statements on November 3, 2009.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventory are recorded on an average cost basis.

Inventories	September 30, 2009	December 31, 2008
Millions		
Fuel	$21.8	$16.6
Materials and Supplies	32.6	33.1
Total Inventories	$54.4	$49.7

Other Assets and Other Liabilities.

Other Assets	September 30, 2009	December 31, 2008
Millions		
Deferred Regulatory Assets	$256.5	$249.3
Other	31.7	32.1
Total Other Assets	$288.2	$281.4
Other Liabilities		
Millions		

Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Plans (a)	$211.8	$251.8
Deferred Regulatory Liabilities	46.0	50.0
Asset Retirement Obligation	43.9	39.5
Other	50.3	48.0
Total Other Liabilities	$352.0	$389.3

(a) Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Plans declined primarily due to contributions. See Note 13. Pension and Other Postretirement Benefit Plans.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Supplemental Statement of Cash Flows Information.

For the Nine Months Ended September 30, Millions	2009	2008
Cash Paid During the Period for		
Interest – Net of Amounts Capitalized	$23.7	$20.1
Income Taxes	$1.1	$4.9
Noncash Investing and Financing Activities		
Change in Accounts Payable for Capital Additions to Property Plant and Equipment	$(16.5)	$(1.1)
ALLETE Common Stock contributed to the Pension Plan	$(12.0)	–

New Accounting Standards.

Codification. In June 2009, the FASB approved the FASB Accounting Standards Codification (Codification) as the single source of authoritative nongovernmental GAAP. The Codification is an online research system that reorganizes the thousands of GAAP pronouncements into a topical structure. The Codification was launched on July 1, 2009, at which time all existing accounting standards documents were superseded and all existing accounting literature not included in the Codification was considered non-authoritative, except for guidance issued by the SEC, which remains a source of authoritative GAAP. The Codification was effective September 30, 2009.

Subsequent Events. In May 2009, the FASB issued guidance on accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Entities are required to disclose the date through which subsequent events have been evaluated and the basis for that date. The guidance on subsequent events was adopted on June 30, 2009, and did not have a material impact on our consolidated financial position, results of operations, or cash flows.

Non-controlling Interests. In December 2007, the FASB issued amended guidance to improve the relevance, comparability, and transparency of the financial information a reporting entity provides in its consolidated financial statements with regards to non-controlling interests. Non-controlling interest in a subsidiary is defined as an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. The amended guidance changes the presentation of the consolidated income statement by requiring consolidated net income to include amounts attributable to the parent and the non-controlling interest. A single method of accounting was established for changes in a parent's ownership interest in a subsidiary which do not result in deconsolidation. Expanded disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners of a subsidiary are also required. The guidance for non-controlling interests was adopted on January 1, 2009. ALLETE Properties does have certain non-controlling interests in consolidated subsidiaries. The presentation of our consolidated financial statements was impacted, but the adoption of the guidance for non-controlling interests did not have a material impact on our consolidated financial position, results of operations or cash flows.

Derivative Instruments and Hedging Activities. In March 2008, the FASB issued guidance that amends and expands the disclosure requirements for derivative instruments and hedging activities. The guidance requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. Qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements are also required. The guidance on derivative instruments and hedging activities was adopted on January 1, 2009. As the amended guidance provides only disclosure requirements, the adoption of this standard did not have an impact on our consolidated financial position, results of operations or cash flows. (See Note 4. Derivatives.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Financial Instruments. In April 2009, the FASB issued amended guidance to require disclosure about fair value of financial instruments for interim reporting periods of publicly traded companies in addition to annual financial statements. This amended guidance was adopted on June 30, 2009. As the amended guidance provided only disclosure requirements, the adoption of this standard did not have a material impact on our consolidated financial position, results of operations or cash flows. (See Note 5. Fair Value.)

Fair Value. In April 2009, the FASB issued additional guidance for applying the provisions of fair value. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants under current market conditions. This guidance requires an evaluation of whether there has been a significant decrease in the volume and level of activity for the asset or liability in relation to normal market activity for the asset or liability. If there has, transactions or quoted prices may not be indicative of fair value and a significant adjustment may need to be made to those prices to estimate fair value. Additionally, an entity must consider whether the observed transaction was orderly (that is, not distressed or forced). If the transaction was orderly, the obtained price can be considered a relevant observable input for determining fair value. If the transaction is not orderly, other valuation techniques must be used when estimating fair value. This additional guidance on fair value was adopted on June 30, 2009, and did not have a material impact on our consolidated financial position, results of operations or cash flows.

In August 2009, the FASB issued an amendment to the guidance for fair value measurement and disclosure of liabilities. This amendment provides clarification for measuring the fair value of liabilities in circumstances in which a quoted price in an active market for the identical liability is not available. As the amended guidance provides only disclosure requirements, the adoption of this standard on September 30, 2009, did not have an impact on our consolidated financial position, results of operations or cash flows.

Other-Than-Temporary Impairments. In April 2009, the FASB issued amended guidance on other-than-temporary impairments. If it is more likely than not that an impaired security will be sold before the recovery of its cost basis, either due to the investor's intent to sell or because it will be required to sell the security, the entire impairment is recognized in earnings. Otherwise, only the portion of the impaired debt security related to estimated credit losses is recognized in earnings, while the remainder of the impairment is recorded in other comprehensive income and recognized over the remaining life of the debt security. In addition, the guidance expands the presentation and disclosure requirements for other-than-temporary impairments for both debt and equity securities. The amended guidance for other-than-temporary impairments was adopted on June 30, 2009, and did not have an impact on our consolidated financial position, results of operations or cash flows.

Pensions and Other Postretirement Benefits. In December 2008, the FASB issued guidance that amends employers' disclosures about pensions and other postretirement benefits. These changes provide guidance on disclosures about plan assets, investment strategies, major categories of plan assets, concentrations of risk within plan assets, and valuation techniques used to measure the fair value of plan assets. These disclosure requirements will be effective for fiscal years ending after December 15, 2009. Upon initial adoption, the requirements within this guidance are not required for earlier periods that are presented for comparative purposes. As the amended guidance provides only disclosure requirements, the adoption of this standard will not have an impact on our consolidated financial position, results of operations or cash flows.

Transfers of Financial Assets. In June 2009, the FASB issued amended guidance for the transfers of financial assets. The guidance was issued with the objective of improving the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. Key provisions of the amended guidance include (1) the removal of the concept of qualifying special purpose entities, (2) the introduction of the concept of a participating interest, in circumstances in which a portion of a financial asset has been transferred, and (3) the requirement that to qualify for sale accounting, the transferor must evaluate whether it maintains effective control over transferred financial assets either directly or indirectly. The amended guidance also requires enhanced disclosures about transfers of financial assets and a transferor's continuing involvement. The amended guidance is effective January 1, 2010, and is required to be applied prospectively. We are currently assessing the impact of the adoption on our consolidated financial position, results of operations and cash flows, but we do not believe it will have a material impact on the Company.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Variable Interest Entities. In June 2009, the FASB issued guidance amending the manner in which entities evaluate whether consolidation is required for variable interest entities (VIEs). A company must first perform a qualitative analysis in determining whether it must consolidate a VIE, and if the qualitative analysis is not determinative, must perform a quantitative analysis. The guidance requires continuous evaluation of VIEs for consolidation, rather than upon the occurrence of triggering events. Additional enhanced disclosures about how an entity's involvement with a VIE affects its financial statements and exposure to risk will also be required. This guidance is effective January 1, 2010. We are currently assessing the impact of this amended guidance on our consolidated financial position, results of operations and cash flows, but we do not believe it will have a material impact on the Company.

NOTE 2. BUSINESS SEGMENTS

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate business. This segment also includes Emerging Technology Investments, a small amount of non-rate base generation, approximately 7,000 acres of land for sale in Minnesota, and earnings on cash and short-term investments.

	Consolidated	Regulated Operations	Investments and Other
Millions			
For the Quarter Ended September 30, 2009			
Operating Revenue	$178.8	$160.1	$18.7
Fuel and Purchased Power	69.8	69.8	–
Operating and Maintenance	67.5	50.1	17.4
Depreciation Expense	16.1	15.0	1.1
Operating Income	25.4	25.2	0.2
Interest Expense	(8.3)	(7.0)	(1.3)
Equity Earnings in ATC	4.4	4.4	–
Other Income (Expense)	0.8	1.6	(0.8)
Income (Loss) Before Non-Controlling Interest and Income Taxes	22.3	24.2	(1.9)
Income Tax Expense (Benefit)	6.5	7.6	(1.1)
Net Income (Loss)	15.8	16.6	(0.8)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	–	(0.2)
Net Income (Loss) Attributable to ALLETE	$16.0	$16.6	$(0.6)

	Consolidated	Regulated Operations	Investments and Other
Millions			
For the Quarter Ended September 30, 2008			
Operating Revenue	$201.7	$179.1	$22.6
Fuel and Purchased Power	81.0	81.0	–
Operating and Maintenance	74.0	53.7	20.3
Depreciation Expense	13.5	12.4	1.1

Operating Income	33.2	32.0	1.2
Interest Expense	(6.9)	(6.1)	(0.8)
Equity Earnings in ATC	4.2	4.2	–
Other Income	2.8	0.6	2.2
Income Before Non-Controlling Interest and Income Taxes	33.3	30.7	2.6
Income Tax Expense (Benefit)	8.4	11.5	(3.1)
Net Income	24.9	19.2	5.7
Less: Non-Controlling Interest in Subsidiaries	0.2	–	0.2
Net Income Attributable to ALLETE	$24.7	$19.2	$5.5

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
For the Nine Months Ended September 30, 2009			
Operating Revenue	$550.7	$493.9	$56.8
Prior Year Rate Refunds	(7.6)	(7.6)	–
Total Operating Revenue	543.1	486.3	56.8
Fuel and Purchased Power	199.4	199.4	–
Operating and Maintenance	224.7	169.8	54.9
Depreciation Expense	46.8	43.4	3.4
Operating Income (Loss)	72.2	73.7	(1.5)
Interest Expense	(25.4)	(20.9)	(4.5)
Equity Earnings in ATC	12.9	12.9	–
Other Income (Expense)	3.8	4.5	(0.7)
Income (Loss) Before Non-Controlling Interest and Income Taxes	63.5	70.2	(6.7)
Income Tax Expense (Benefit)	21.5	25.2	(3.7)
Net Income (Loss)	42.0	45.0	(3.0)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	–	(0.3)
Net Income (Loss) Attributable to ALLETE	$42.3	$45.0	$(2.7)
As of September 30, 2009			
Total Assets	$2,255.1	$2,005.3	$249.8
Property, Plant and Equipment – Net	$1,530.5	$1,478.9	$51.6
Accumulated Depreciation	$937.0	$885.4	$51.6
Capital Additions	$186.7	$185.0	$1.7

Millions	Consolidated	Regulated Operations	Investments and Other
For the Nine Months Ended September 30, 2008			
Operating Revenue	$604.9	$535.9	$69.0
Fuel and Purchased Power	242.3	242.3	–
Operating and Maintenance	241.5	179.7	61.8
Depreciation Expense	39.1	35.6	3.5
Operating Income	82.0	78.3	3.7
Interest Expense	(19.5)	(17.5)	(2.0)
Equity Earnings in ATC	11.2	11.2	–
Other Income	13.9	2.8	11.1
Income Before Non-Controlling Interest and Income Taxes	87.6	74.8	12.8
Income Tax Expense	28.3	28.3	–
Net Income	59.3	46.5	12.8
Less: Non-Controlling Interest in Subsidiaries	0.3	–	0.3
Net Income Attributable to ALLETE	$59.0	$46.5	$12.5

As of September 30, 2008			
Total Assets	$1,847.6	$1,565.9	$281.7
Property, Plant and Equipment – Net	$1,292.4	$1,239.3	$53.1
Accumulated Depreciation	$854.2	$806.2	$48.0
Capital Additions	$211.1	$207.3	$3.8

NOTE 3. INVESTMENTS

Investments. Our long-term investment portfolio includes the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits, ARS, our Emerging Technology Investments, and land held-for-sale in Minnesota.

Investments	September 30, 2009	December 31, 2008
Millions		
ALLETE Properties	$88.9	$84.9
Available-for-Sale Securities	35.7	32.6
Emerging Technology Investments	4.8	7.4
Other	9.4	12.0
Total Investments	$138.8	$136.9

ALLETE Properties	September 30, 2009	December 31, 2008
Millions		
Land Held-for-Sale Beginning Balance	$71.2	$62.6
Additions During Period: Capitalized Improvements	2.1	10.5
Deductions During Period: Cost of Real Estate Sold	(0.6)	(1.9)
Land Held-for-Sale Ending Balance	72.7	71.2
Long-Term Finance Receivables	13.3	13.6
Other	2.9	0.1
Total Real Estate Assets	$88.9	$84.9

Land Held-for-Sale. Land held-for-sale is recorded at the lower of cost or fair value determined by the evaluation of individual land parcels. Land values are reviewed for impairment and no impairments have been recorded for the nine months ended September 30, 2009 (none in 2008).

Long-Term Finance Receivables. Long-term finance receivables, which are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts of $0.2 million at September 30, 2009 ($0.1 million at December 31, 2008). The allowance for doubtful accounts includes $0.1 million of impairments that were recorded for other receivables during the quarter ended September 30, 2009. The majority are receivables having maturities up to four years. Finance receivables totaling $7.8 million at September 30, 2009, were due from an entity which filed for voluntary Chapter 11 bankruptcy protection in June 2009. The estimated fair value of the collateral relating to these receivables was greater than the $7.8 million amount due at September 30, 2009 and no impairment was recorded on these receivables. Due to the lack of recent market activity, we estimated fair value based primarily on recent property tax assessed values. This valuation technique constitutes a Level 3 non-recurring fair value measurement.

Auction Rate Securities. Included in Available-for-Sale Securities, as of September 30, 2009, are $14.3 million ($15.2 million at December 31, 2008) of three auction rate municipal bonds with stated maturity dates ranging between 14 and 27 years. One of these ARS bonds was called during the third quarter at par value of $7.0 million and payment was received on October 6, 2009. These ARS consist of guaranteed student loans insured or reinsured by the federal government. These ARS were historically auctioned every 35 days to set new rates and provided a liquidating event in which investors could either buy or sell securities. Beginning in 2008, the auctions have been unable to sustain themselves due to the overall lack of market liquidity and we have been unable to liquidate all of our ARS. As a result, we have classified the ARS as long-term investments and have the ability to hold these securities to maturity, until called by the issuer, or until liquidity returns to this market. In the meantime, these securities will pay a default rate which is above market interest rates.

The Company used a discounted cash flow model to determine the estimated fair value of its investment in the ARS as of September 30, 2009. The assumptions used in preparing the discounted cash flow model include the following: the effective interest rate, amount of cash flows, and expected holding periods of the ARS. These inputs reflect the Company's judgments about assumptions that market participants would use in pricing ARS including assumptions about risk. Based upon the results of the discounted cash flow model, the fact that these ARS consist of guaranteed student loans insured or reinsured by the federal government and recent market activity, no other-than-temporary impairment loss has been reported.

NOTE 4. DERIVATIVES

In the first nine months of 2009, we have entered into financial derivative instruments to manage price risk for certain power marketing contracts. Outstanding derivative contracts at September 30, 2009, consist of cash flow hedges for an energy sale that includes pricing based on daily natural gas prices, and FTRs purchased to manage congestion risk for forward power sales contracts. These derivative instruments are recorded on our consolidated balance sheet at fair value. As of September 30, 2009, we recorded approximately $1.1 million of derivatives in other assets on our consolidated balance sheet of which the entire balance relates to our FTRs. These derivative instruments settle monthly throughout 2009 and the first five months of 2010.

Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria is met. Favorable changes in fair value of $0.3 million were recorded in operating revenue in the first quarter, $0.1 million was recorded in the second quarter, and $0.4 was recorded in the third quarter when the corresponding energy swap contract ended. There have been no changes in fair value recorded for the FTRs to date.

The mark-to-market fluctuations on the cash flow hedge have been recorded in other comprehensive income on the consolidated balance sheet; a $0.1 million increase in fair value was recorded in the first quarter, and a decrease of $0.1 million was recorded in the second quarter. There was no mark-to-market change for the quarter ended September 30, 2009.

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). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily mutual fund investments held to fund employee benefits.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation, fixed income securities, and derivative instruments consisting of cash flow hedges.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes ARS consisting of guaranteed student loans and derivative instruments consisting of FTRs.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009 and December 31, 2008. 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, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

NOTE 5. FAIR VALUE (Continued)

	Fair Value as of September 30, 2009			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	$16.2	–	–	$16.2
Corporate Debt Securities	–	$7.3	–	7.3
Derivatives	–	–	$1.1	1.1
Debt Securities Issued by States of the United States (ARS)	–	–	14.3	14.3
Money Market Funds	4.9	–	–	4.9
Total Fair Value of Assets	$21.1	$7.3	$15.4	$43.8
Liabilities:				
Deferred Compensation	–	$14.8	–	$14.8
Total Fair Value of Liabilities	–	$14.8	–	$14.8
Total Net Fair Value of Assets (Liabilities)	$21.1	$(7.5)	$15.4	$29.0

	Fair Value as of December 31, 2008			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	$13.5	–	–	$13.5
Corporate Debt Securities	–	$3.3	–	3.3
Debt Securities Issued by States of the United States (ARS)	–	–	$15.2	15.2
Money Market Funds	10.6	–	–	10.6
Total Fair Value of Assets	$24.1	$3.3	$15.2	$42.6
Liabilities:				
Deferred Compensation	–	$13.5	–	$13.5
Total Fair Value of Liabilities	–	$13.5	–	$13.5
Total Net Fair Value of Assets (Liabilities)	$24.1	$(10.2)	$15.2	$29.1

Recurring Fair Value Measures	Derivatives		Debt Securities Issued by the States of the United States (ARS)	
Activity in Level 3	2009	2008	2009	2008
Millions				
Balance as of December 31, 2008 and December 31, 2007, respectively	–	–	$15.2	–
Purchases, Sales, Issuances and Settlements, Net	$1.1	–	(0.9)	$(5.9)
Level 3 Transfers In	–	–	–	25.2

Balance as of September 30,	$1.1	–	$14.3	$19.3

The fair value for each of the items below was based on quoted market prices for the same or similar instruments.

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
December 31, 2008	$598.7	$561.6
September 30, 2009	$640.4	$629.2

NOTE 6. REGULATORY MATTERS

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

2008 Rate Case. On May 2, 2008, Minnesota Power filed a retail rate increase request with the MPUC. On May 4, 2009, the MPUC issued its order (May Order) on the rate filing, and on June 25, 2009, the MPUC reconsidered the May Order. The reconsideration order was issued on August 10, 2009, resulting in an authorized rate increase of $20.4 million (slightly below the $21.1 million outcome in the May Order). The May Order allowing a 10.74 percent return on common equity and a capital structure consisting of 54.79 percent equity and 45.21 percent debt remains unchanged.

The reconsideration order reduced Minnesota Power's interim rates, which were in effect between August 2008 and October 31, 2009, by $6.3 million annually to approximately $15 million. This increased Minnesota Power's refunding obligation for 2008 and 2009.

As of September 30, 2009, we recorded a $20.0 million liability, including interest, for refunds anticipated to be paid to our customers as a result of the MPUC decision on our retail rate filing. Current year rate refunds totaling $11.9 million have been recorded on our consolidated statement of income and prior year rate refunds totaling $7.6 million are stated separately. Interest expense of $0.5 million was also recorded on our consolidated statement of income related to rate refunds.

On October 29, 2009, the MPUC approved the implementation of final rates to begin on November 1, 2009. Refunding of interim rates will commence in December 2009 and be completed during the first quarter of 2010.

With the May Order, the MPUC also approved the stipulation and settlement agreement that affirmed the Company's continued recovery of fuel and purchased power costs under the former base cost of fuel that was in effect prior to the retail rate filing. The transition to the former base cost of fuel will occur upon implementation of final rates. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

2010 Rate Case. Minnesota Power has previously stated its intention to file for additional revenues to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance and bring new renewable energy to northeastern Minnesota. As a result, Minnesota Power filed a retail rate increase request with the MPUC on November 2, 2009, seeking a return on equity of 11.5 percent, a capital structure consisting of 54.29 percent equity and 45.71 percent debt, and on an annualized basis, an $81.0 million net increase in electric retail revenue. We cannot predict the final level of rates that may be approved by the MPUC.

Minnesota Power's wholesale customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a wholesale customer of Minnesota Power. In 2008, Minnesota Power entered into new contracts with all of our wholesale customers with the exception of one small customer (less than 2 MW) whose contract is now in the cancellation period. The new contracts transitioned each customer to formula-based rates, which means rates can be adjusted annually based on changes in cost. The new agreements with the private utilities in Wisconsin are subject to PSCW approval. In February 2009, the FERC approved our municipal contracts, including the formula-based rate provision. A 9.5 percent rate increase for our municipal customers was implemented on February 1, 2009 under the formula-based rate provision. Incremental revenue from this rate increase is expected to be approximately $7 million on an annualized basis.

SWL&P's current retail rates are based on a December 2008 PSCW retail rate order that became effective January 1, 2009, and allows for an 11.1 percent return on equity. The new rates reflect a 3.5 percent average increase in retail utility rates for SWL&P customers (a 13.4 percent increase in water rates, a 4.7 percent increase in electric rates, and a 0.6 percent decrease in natural gas rates). On an annualized basis, the rate increase will generate approximately $3 million in additional revenue.

NOTE 7. INVESTMENT IN ATC

Our wholly-owned subsidiary Rainy River Energy owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. We account for our investment in ATC under the equity method of accounting. On October 30, 2009, we invested an additional $2.3 million in ATC.

ALLETE's Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2008	$76.9
Cash Investments	5.4
Equity in ATC Earnings	12.9
Distributed ATC Earnings	(10.1)
Equity Investment Balance as of September 30, 2009	$85.1

ATC's summarized financial data for the quarter and nine months ended September 30, 2009 and 2008, is as follows:

	Quarter Ended		Nine Months Ended	
ATC Summarized Financial Data	September 30,		September 30,	
Income Statement Data	2009	2008	2009	2008
Millions				
Revenue	$132.3	$119.9	$387.5	$345.1
Operating Expense	58.7	52.1	172.3	156.2
Other Expense	19.8	18.2	57.8	51.1
Net Income	$53.8	$49.6	$157.4	$137.8
ALLETE's Equity in Net Income	$4.4	$4.2	$12.9	$11.2

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

Long-Term Debt. In January 2009, we issued $42.0 million in principal amount of unregistered First Mortgage Bonds (Bonds) in the private placement market. The Bonds mature January 15, 2019, and carry a coupon rate of 8.17 percent. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for this type of transaction. We are using the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes. The Bonds were sold in reliance on an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

NOTE 9. OTHER INCOME (EXPENSE)

	Quarter Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
Millions				
Loss on Emerging Technology Investments	$(1.3)	$(0.1)	$(2.6)	$(0.6)

AFUDC – Equity	1.6	0.5	4.5	2.6
Investment and Other Income (a)	0.5	2.4	1.9	11.9
Total Other Income	$0.8	$2.8	$3.8	$13.9

(a) In 2008, Investment and Other Income included a gain from the sale of certain available-for-sale securities. The gain was triggered when securities were sold to reallocate investments to meet defined investment allocations based upon an approved investment strategy.

NOTE 10. INCOME TAX EXPENSE

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Millions				
Current Tax Expense (Benefit)				
Federal (a)	$(7.9)	$2.2	$(16.7)	$10.2
State	(0.5)	(3.1)	(0.7)	(0.3)
Total Current Tax Expense (Benefit)	(8.4)	(0.9)	(17.4)	9.9
Deferred Tax Expense				
Federal (a)	12.6	6.9	33.5	15.0
State	2.5	2.6	6.1	4.1
Deferred Tax Credits	(0.2)	(0.2)	(0.7)	(0.7)
Total Deferred Tax Expense	14.9	9.3	38.9	18.4
Total Income Tax Expense	$6.5	$8.4	$21.5	$28.3

(a) Due to the bonus depreciation provisions in the American Recovery and Reinvestment Act of 2009, we expect to be in a net operating loss position for the current year. The loss will be utilized by carrying it back against prior years' taxable income.

For the nine months ended September 30, 2009, the effective tax rate was 33.8 percent (32.3 percent for the nine months ended September 30, 2008). The 2009 effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for Medicare health subsidies, AFUDC-Equity, investment tax credits, wind production tax credits, and depletion.

Uncertain Tax Positions. As of September 30, 2009, we have gross unrecognized tax benefits of $9.6 million. Of this total, $1.5 million represents the amount of unrecognized tax benefits that, if recognized, would favorably impact the effective income tax rate.

We expect that the total amount of unrecognized tax benefits as of September 30, 2009, will change by less than $1.0 million in the next 12 months.

NOTE 11. OTHER COMPREHENSIVE INCOME

The components of total comprehensive income were as follows:

Other Comprehensive Income Net of Tax	Quarter Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Millions				
Net Income	$15.8	$24.9	$42.0	$59.3
Other Comprehensive Income				
Unrealized Gain (Loss) on Securities	1.0	(1.3)	1.9	(2.0)
Reclassification Adjustment for Losses (Gains) Included in Income (a)	0.1	–	–	(3.8)
Defined Benefit Pension and Other Postretirement Plans	0.1	0.2	0.7	1.5

Total Other Comprehensive Income (Loss)	1.2	(1.1)	2.6	(4.3)
Total Comprehensive Income	$17.0	$23.8	$44.6	$55.0
Less: Non-Controlling Interest in Subsidiaries	(0.2)	0.2	(0.3)	0.3
Comprehensive Income Attributable to ALLETE	$17.2	$23.6	$44.9	$54.7

(a) Reclassification adjustment of $3.8 million in 2008 relates to the sale of certain available-for-sale securities.

NOTE 12. EARNINGS PER SHARE AND COMMON STOCK

The difference between basic and diluted earnings per share, if any, arises from outstanding stock options and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. For the quarter and nine months ended September 30, 2009, 0.6 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices, and therefore, their effect would have been anti-dilutive. For the quarter and nine months ended September 30, 2008, 0.2 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share.

NOTE 12. EARNINGS PER SHARE AND COMMON STOCK (Continued)

Authorized Common Stock. On May 12, 2009, shareholders approved an amendment to the Company's Amended and Restated Articles of Incorporation to increase the number of authorized shares of common stock from 43.3 million to 80.0 million.

Shareholder Rights Plan. On July 25, 1996, ALLETE adopted a shareholder rights plan, which was amended and restated on July 12, 2006 (collectively, the "Rights Plan"). The amendment to the Rights Plan, among other things, extended the final expiration date of the Rights Plan to July 11, 2009. The Rights Plan expired according to its terms on July 11, 2009. As a result, ALLETE's preferred share purchase rights issued in accordance with the Rights Plan are no longer outstanding.

		2009			2008	
Reconciliation of Basic and Diluted		Dilutive			Dilutive	
Earnings Per Share	Basic	Securities	Diluted	Basic	Securities	Diluted
Millions Except Per Share Amounts						
For the Quarter Ended September 30,						
Net Income Attributable to ALLETE	$16.0	–	$16.0	$24.7	–	$24.7
Common Shares	32.8	0.1	32.9	29.1	0.2	29.3
Earnings Per Share	$0.49	–	$0.49	$0.85	–	$0.85
For the Nine Months Ended September 30,						
Net Income Attributable to ALLETE	$42.3	–	$42.3	$59.0	–	$59.0
Common Shares	31.8	0.1	31.9	28.9	0.1	29.0
Earnings Per Share	$1.33	–	$1.33	$2.04	–	$2.04

NOTE 13. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Postretirement Health and Life	
Components of Net Periodic Benefit Expense	2009	2008	2009	2008
Millions				
For the Quarter Ended September 30,				
Service Cost	$1.4	$1.5	$1.0	$1.0
Interest Cost	6.5	6.3	2.5	2.4
Expected Return on Plan Assets	(8.4)	(8.1)	(2.0)	(1.8)
Amortization of Prior Service Costs	0.1	0.2	–	–
Amortization of Net Loss	0.9	0.4	0.6	0.4
Amortization of Transition Obligation	–	–	0.6	0.6
Net Periodic Benefit Expense	$0.5	$0.3	$2.7	$2.6
For the Nine Months Ended September 30,				
Service Cost	$4.3	$4.4	$3.1	$3.0
Interest Cost	19.6	18.9	7.5	7.2
Expected Return on Plan Assets	(25.3)	(24.3)	(6.2)	(5.4)
Amortization of Prior Service Costs	0.4	0.5	–	–
Amortization of Net Loss	2.6	1.2	1.8	1.2

Amortization of Transition Obligation	–	–	1.9	1.8
Net Periodic Benefit Expense	$1.6	$0.7	$8.1	$7.8

Employer Contributions. For the nine months ended September 30, 2009, we contributed $32.9 million to our pension plan; $12.0 million was contributed through the issuance of 463,000 shares of ALLETE common stock. We also contributed $9.3 million to our postretirement health and life plan. We do not expect to make any additional contributions to our pension plan or our postretirement health and life plan in 2009.

We provide postretirement health benefits that include prescription drug benefits which qualify us for the federal subsidy under the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The expected reimbursement for Medicare health subsidies reduced our after-tax postretirement medical expense by $2.0 million for 2009 ($1.2 million for 2008). For the nine months ended September 30, 2009, we have received $0.3 million in prescription drug reimbursements.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. At September 30, 2009, Square Butte had total debt outstanding of $364.0 million. Annual debt service for Square Butte is expected to be approximately $29 million in each of the five years, 2009 through 2013. Variable operating costs include the price of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

North Dakota Wind Project. On July 7, 2009, the MPUC approved our petition seeking current cost recovery of investments and expenditures related to our Bison I and associated transmission upgrades. We anticipate filing a petition with the MPUC in the fourth quarter to establish customer billing rates for the approved cost recovery. Bison I is the first portion of several hundred MWs of our North Dakota Wind Project, which upon completion will fulfill the 2025 renewable energy supply requirement for our retail load. Bison I, which will be comprised of 33 wind turbines with a total nameplate capacity of 75.9 MWs and located near Center, North Dakota, will be phased into service in 2010 and 2011.

On September 29, 2009 the NDPSC issued a Certificate of Site Compatibility for Energy Conversion System for Bison I that authorized site construction to commence. On October 2, 2009, Minnesota Power filed a route permit application with the NDPSC for the 22 mile 230 kV Bison I transmission line that will connect Bison I to the DC transmission line at the Square Butte Substation in Center, North Dakota.

In September 2008, we signed an agreement to purchase an existing 250 kV DC transmission line for approximately $80 million to transport this wind energy to our customers while gradually reducing the supply of energy currently delivered to our system on this same transmission line from Square Butte's Unit. The transaction is subject to regulatory and board approvals. On May 14, 2009, we filed a petition with the MPUC for approval of the DC transmission line purchase and the restructuring of the power purchase agreement with Square Butte. That petition was reviewed by the MPUC through an evidentiary hearing held on September 17, 2009. The Administrative Law Judge (ALJ) takes the information from the evidentiary hearing and makes a recommendation to the MPUC. The MPUC may accept, reject, or modify the ALJ's recommendation in making their decision. On October 27, 2009, the ALJ recommended that the MPUC approve this transaction.

Wind Power Purchase Agreements. We have two wind power purchase agreements with an affiliate of NextEra Energy to purchase the output from two wind facilities, Oliver Wind I (50 MWs) and Oliver Wind II (48 MWs) located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at a fair market rental, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2016. The aggregate amount of minimum lease payments for all operating leases is $8.3 million in 2009, $8.2 million in 2010, $8.3 million in 2011, $8.2 million in 2012, $7.8 million in 2013 and $52.9 million thereafter.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Coal, Rail and Shipping Contracts. We have three primary coal supply agreements with various expiration dates ranging from December 2009 to December 2011. We also have rail and shipping agreements for the transportation of all of our coal, with various expiration dates ranging from December 2009 to January 2012. Our remaining minimum payment obligation as of September 30, 2009, under these coal, rail and shipping agreements for 2009 is $14.4 million. Annual payment obligations for 2010 and 2011 are $12.5 million and $7.6 million, respectively, with no specific commitments beyond 2011. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years.

On January 24, 2008, we received a letter from BNSF alleging that the Company defaulted on a material obligation under the Company's Coal Transportation Agreement (CTA). In the notice, BNSF claimed we underpaid approximately $1.6 million for coal transportation services in 2006 and that failure to pay such amount plus interest may result in BNSF's termination of the CTA. On April 1, 2008, to ensure that BNSF did not attempt to terminate the CTA, we paid under protest the full amount claimed by BNSF and filed a demand for arbitration of the issue. On April 22, 2008, BNSF filed a counterclaim in the arbitration disputing our position that we are entitled to a refund from BNSF of $1.5 million plus interest for amounts that we overpaid for 2007 deliveries. On March 11, 2009, the Company and BNSF resolved the disputes with no resulting associated Company liability or loss contingencies, and by an order dated March 27, 2009, the arbitrator dismissed the case. The delivered costs of fuel for the Company's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Emerging Technology Investments. We have investments in emerging technologies through minority investments in venture capital funds structured as limited liability companies, and direct investments in privately-held, start-up companies. We have committed to make $0.5 million in additional investments in certain emerging technology venture capital funds. We do not have plans to make any additional investments beyond this commitment.

Environmental Matters. Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We review environmental matters for disclosure 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. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in our consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

EPA Clean Air Interstate Rule. In March 2005, the EPA announced the Clean Air Interstate Rule (CAIR) that sought to reduce and permanently cap emissions of SO2, NOX, and particulates in the eastern United States. Minnesota was included as one of the 28 states considered as "significantly contributing" to air quality standards non-attainment in other downwind states. On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit (Court) vacated the CAIR and remanded the rulemaking to the EPA for reconsideration while also granting our petition that the EPA reconsider including Minnesota as a CAIR state. In September 2008, the EPA and others petitioned the Court for a rehearing or alternatively requested that the CAIR be remanded without a court order. In December 2008, the Court granted the request that the CAIR be remanded without a court order, effectively reinstating a January 1, 2009, compliance date for the CAIR, including Minnesota. However, in the May 12, 2009 Federal Register the EPA issued a proposed rule that would amend the CAIR to stay its effectiveness with respect to

Minnesota until completion of the EPA’s determination of whether Minnesota should be included as a CAIR state. The EPA accepted public comment through June 11, 2009 and is expected to render a final decision pending evaluation of comments received. Minnesota Power submitted comments in support of the stay.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Minnesota Regional Haze. The regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources of visibility-impairing emissions that were put in place between 1962 and 1977 are required to install emission controls, known as best available retrofit technology (BART). We have certain steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of the CAIR. However, a formal SIP was never filed due to the Court’s review of CAIR as more fully described above under “EPA Clean Air Interstate Rule.” Subsequently, the MPCA has requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which was done on Taconite Harbor Unit 3 in November 2008, in order to develop a final SIP for submission to the EPA. The retrofit work currently underway on Boswell Unit 3 meets the BART requirement for that unit. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA Clean Air Mercury Rule. In March 2005, the EPA also announced the Clean Air Mercury Rule (CAMR) that would have reduced and permanently capped electric utility mercury emissions in the continental United States through a cap and trade program. In February 2008, the Court vacated the CAMR and remanded the rulemaking to the EPA for reconsideration. In October 2008, the Department of Justice, on behalf of the EPA, petitioned the Supreme Court to review the Court’s decision in the CAMR case. In January 2009, the EPA withdrew their petition, paving the way for possible regulation of mercury emissions through Section 112 of the Clean Air Act, setting Maximum Achievable Control Technology standards for the utility sector. Cost estimates for complying with potential future mercury regulations under the Clean Air Act are premature at this time. The EPA is preparing an Information Collection Request to require numerous utilities across the United States to perform stack testing in order to develop an improved database with which to base future regulations.

EPA Greenhouse Gas Reporting Rule. On September 22, 2009, the EPA issued the final rule mandating that certain GHG emission sources, including electric generating units, are subject to the EPA’s Acid Rain Program and are required to report emission levels. The rule is intended to allow the EPA to collect accurate and timely data on GHG emissions that can be used to form future policy decisions. The rule also includes a record retention mandate requiring that written GHG monitoring plans with assignments of responsibility and quality assurance and quality control procedures be in place. The rule is effective January 1, 2010, and all GHG emissions must be reported on an annual basis by March 31 of the following year. Currently, we have the equipment necessary to track our 2010 emissions to comply with this rule.

Title V Greenhouse Gas Tailoring Rule. On October 27, 2009, the EPA issued the proposed Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring rule. This proposed regulation addresses the six primary greenhouse gases and new thresholds for when permits will be required for new facilities and existing facilities which undergo major modifications. The rule would require large industrial facilities, including power plants, emitting greater than 25,000 tons of GHGs annually, to obtain construction and operating permits that demonstrate best practices and technologies are being used at the facility to minimize GHG emissions. Best available control technologies (BACT) for criteria pollutants are already prescribed by the PSD permit program.

For our existing facilities, the proposed rule does not require amending our existing Title V operating permits to include BACT for GHGs. However, modifying or installing units with GHG emissions that trigger the PSD permitting requirements would require amending operating permits to incorporate BACT and energy efficiency measures to minimize GHG emissions.

New Source Review. On August 8, 2008, Minnesota Power received a Notice of Violation (NOV) from the United States EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1-4 and Laskin Unit 2. The NOV also asserts that the Boswell Unit 4 Title V permit was violated. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements. Minnesota Power believes the projects were in full compliance with the Clean Air Act, NSR requirements and applicable permits.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

The EPA has been conducting a nationwide enforcement initiative since 1999 relating to NSR requirements. In 2000, 2001, and 2002 Minnesota Power received requests from the EPA pursuant to Section 114(a) of the Clean Air Act seeking information regarding capital expenditures with respect to Boswell and Laskin. Minnesota Power responded to these requests; however, we had no further communications from the EPA regarding the information provided until receipt of the NOV.

We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions. Since 2006, Minnesota Power has significantly reduced, and continues to reduce, emissions at Boswell and Laskin. The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding. We are unable to predict the ultimate financial impact or the resolution of these matters at this time.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site within the City of Superior, Wisconsin and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. We have accrued a $0.5 million liability for this site as of September 30, 2009, and have recorded a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

BNI Coal. As of September 30, 2009, BNI Coal had surety bonds outstanding of $18.4 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, an additional guarantee is required by federal and state regulations. In addition to the surety bond, BNI has secured a Letter of Credit with CoBank for an additional $10.0 million to meet the requirements for BNI's total reclamation liability currently estimated at $25.1 million.

ALLETE Properties. As of September 30, 2009, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $19.1 million primarily related to performance and maintenance obligations for governmental entities to construct improvements in the Company's various projects. The cost of the remaining work to be completed on these improvements is estimated to be approximately $10.8 million, and ALLETE Properties does not believe it is likely that any of these outstanding bonds will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent Capital Improvement Revenue Bonds, Series 2005; and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent Special Assessment Bonds, Series 2006. The Capital Improvement Revenue Bonds and the Special Assessment Bonds are payable through property tax assessments on the land owners over 31 years (by May 1, 2036, and 2037, respectively). The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district, and to mitigate traffic and environmental impacts. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by each district. The assessments were billed to the landowners in November 2006, for Town Center and November 2007, for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At September 30, 2009, we owned 69 percent of the assessable land in the Town Center District (69 percent at December 31, 2008) and 86 percent of the assessable land in the Palm Coast Park District (86 percent at December 31, 2008). As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Other. 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, compliance with regulations, rate base and cost of service issues, among other things. While the resolution of such matters could have a material effect on earnings and cash flows in the year of resolution, none of these matters are expected to materially change our present liquidity position, or have a material adverse effect on our financial condition.

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

The following discussion should be read in conjunction with our consolidated financial statements, notes to those statements, Management's Discussion and Analysis of Financial Condition and Results of Operations from the 2008 Form 10-K and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-Q contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-Q under the heading: "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" located on page 5 and "Risk Factors" located in Part I, Item 1A, page 20 of our 2008 Form 10-K. The risks and uncertainties described in this Form 10-Q and our 2008 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 concerns set forth are realized.

OVERVIEW

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 144,000 retail customers and wholesale electric service to 16 municipalities. SWL&P provides regulated electric service, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate business. This segment also includes Emerging Technology Investments ($4.8 million at September 30, 2009), a small amount of non-rate base generation, approximately 7,000 acres of land for sale in Minnesota, and earnings on cash and short-term investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of September 30, 2009, 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

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

The following net income discussion summarizes a comparison of the nine months ended September 30, 2009 to the nine months ended September 30, 2008.

Net income attributable to ALLETE for 2009 was $42.3 million, or $1.33 per diluted share compared to $59.0 million, or $2.04 per diluted share for 2008. Earnings per diluted share decreased approximately $0.13 compared to 2008 as a result of additional shares of common stock outstanding in 2009. (See Note 12. Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $45.0 million in 2009 ($46.5 million in 2008). The decrease is primarily attributable to lower net income at Minnesota Power due to a 5.2 percent decrease in kilowatt-hour sales, higher depreciation and interest expense and the accrual of retail rate refunds related to 2008; these decreases were partially offset by increased retail and FERC approved wholesale rates and additional current cost recovery revenue. In addition, 2009 reflected $1.1 million in additional after-tax earnings from our investment in ATC, as a result of additional investments we have made to fund our pro-rata share of ATC's capital expansion program.

OVERVIEW (Continued)

Investments and Other reflected a net loss attributable to ALLETE of $2.7 million in 2009 ($12.5 million of net income attributable to ALLETE in 2008). The decrease is primarily attributable to a reduction in earnings at ALLETE Properties and the absence of non-recurring items recorded in 2008. For the first nine months of 2009, ALLETE Properties recorded a net loss of $3.9 million versus net income of $2.2 million in 2008; a decline of $6.1 million. In 2008, we recorded a $3.8 million non-recurring gain on the sale of certain available-for-sale securities and $5.3 million in non-recurring tax benefits and related interest due to the closing of a tax year and the completion of an IRS review.

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2009 AND 2008

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

Regulated Operations

Operating revenue decreased $19.0 million, or 11 percent, from 2008 due to lower fuel and purchased power recoveries, lower retail and municipal kilowatt-hour sales, and lower authorized interim retail electric rates. These decreases were partially offset by higher sales to Other Power Suppliers and higher wholesale rates.

Lower fuel and purchased power recoveries along with a decrease in retail and municipal kilowatt-hour sales combined for a total revenue reduction of $41.5 million. Fuel and purchased power recoveries decreased due to an $11.2 million reduction in fuel and purchased power expense. (See Fuel and Purchased Power Expense.) Total kilowatt-hour sales to retail and municipal customers decreased 33.4 percent from 2008 primarily due to idle production lines and temporary plant closures at some of our taconite customers.

The decrease in kilowatt-hour sales to retail and municipal customers was partially offset by revenue from marketing the power to Other Power Suppliers which increased $21.9 million in 2009. 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.

Authorized interim retail electric rates for Minnesota Power were $2.3 million lower in the third quarter of 2009 from 2008 as a result of final rate orders received in 2009.

Kilowatt-hours Sold Quarter Ended September 30,	2009	2008	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	240	252	(12)	(4.8) %
Commercial	352	381	(29)	(7.6) %
Industrial	984	1,854	(870)	(46.9) %
Municipals	243	243	–	– %
Total Retail and Municipals	1,819	2,730	(911)	(33.4) %
Other Power Suppliers	1,051	465	586	126.0 %
Total Regulated Utility Kilowatt-hours Sold	2,870	3,195	(325)	(10.2) %

Revenue from electric sales to taconite customers accounted for 13 percent of consolidated operating revenue in 2009 (28 percent in 2008). The decrease in revenue from our taconite customers was partially offset by revenue from electric sales to Other Power Suppliers which accounted for 24 percent of consolidated operating revenue in 2009 (10 percent in 2008). Revenue from electric sales to paper and pulp mills accounted for 10 percent of consolidated operating revenue in 2009 (10 percent in 2008). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2009 (7 percent in 2008).

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2009 AND 2008 (Continued)

Operating expenses decreased $12.2 million, or 8 percent, from 2008.

Fuel and Purchased Power Expense decreased $11.2 million, or 14 percent, from 2008 due to decreased power generation attributable to lower kilowatt-hour sales, as well as a reduction in wholesale electricity prices. Minnesota Power's coal generating fleet produced fewer kilowatt-hours of electricity compared to the third quarter of 2008 due to planned outages to implement environmental retrofits and to respond to decreased demand from our taconite customers.

Operating and Maintenance Expense decreased $3.6 million from 2008 primarily due to lower natural gas costs due to a decline in the price and quantity of natural gas, and lower compensation expense of $2.2 million mainly from the termination of an incentive compensation program. Our retail rate order requires that the expense reduction attributable to the termination of the incentive compensation program must be refunded to our retail customers to the extent it was included in retail rates.

Depreciation Expense increased $2.6 million, or 21 percent, from 2008 reflecting higher property, plant, and equipment balances placed in service.

Interest expense increased $0.9 million, or 15 percent, from 2008 primarily due to additional long-term debt issued to fund new capital investments.

Investments and Other

Operating revenue decreased $3.9 million, or 17 percent, from 2008 primarily due to a $4.2 million reduction in sales revenue at ALLETE Properties. No sales were made during the third quarter of 2009 at ALLETE Properties, due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. During the third quarter of 2008, ALLETE Properties sold one acre of property located in southwestern Florida for $0.7 million, as well as recognized $2.6 million in previously deferred revenue under percentage of completion accounting.

ALLETE Properties	2009		2008	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres (a)	–	–	1	$0.7
Contract Sales Price (b)		–		0.7
Revenue Recognized for Previously Deferred Sales				2.6
Deferred Revenue		–		–
Revenue from Land Sales		–		3.3
Other Revenue		$0.1		1.0
Total ALLETE Properties Revenue		$0.1		$4.3

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.

(b) Reflects total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method.

BNI Coal, which operates under a cost-plus contract, recorded additional revenue of $0.9 million as a result of higher expenses in 2009. (See Operating Expenses.) Revenue from non-regulated generation was down $0.7 million primarily due to a reduction in kilowatt-hour sales.

Operating expenses decreased $2.9 million, or 14 percent, from 2008 reflecting decreased expenses at ALLETE Properties due to both lower cost of land sold and reductions in general and administrative expenses. Expenses incurred as a result of planned maintenance outage at a non-regulated generating facility in the third quarter of 2008 also contributed to the decrease in 2009. Partiality offsetting this decrease was an increase in expense at BNI Coal due to permitting costs relating to mining expansion; these costs were recovered through the cost-plus contract. (See Operating Revenue.)

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2009 AND 2008 (Continued)
Investments and Other (Continued)

Interest expense increased $0.5 million from 2008 primarily due to a decrease in the proportion of ALLETE interest expense assigned to Minnesota Power. Interest Expense reflected in our Investments and Other segment consists of ALLETE interest expense not provided for in the regulatory orders for Minnesota Power and SWL&P. We record interest expense for Minnesota Power based on Minnesota Power's most recently authorized capital structure. Effective August 1, 2008, the proportion of interest expense assigned to Minnesota Power decreased to reflect the authorized capital structure inherent in interim rates that commenced on that date. Interest expense was also higher in 2009 as 2008 included a $0.6 million reversal of interest expense previously accrued due to the closing of a tax year.

Other income decreased $3.0 million from 2008 primarily due to interest income recognized in the third quarter of 2008 related to tax benefits from prior years, losses in our Emerging Technology Investments, and lower interest income due to lower average cash balances.

Income Taxes – Consolidated

For the quarter ended September 30, 2009, the effective tax rate was 29.0 percent (25.2 percent for the quarter ended September 30, 2008). The effective tax rate in both years deviated from the statutory rate (approximately 41 percent for 2009) due to deductions for Medicare health subsidies, AFUDC-Equity, investment tax credits, wind production tax credits, and depletion. In addition, the effective tax rate for the third quarter of 2009 was impacted by lower pre-tax income and the benefit of a non-recurring permanent item. The effective tax rate for the third quarter of 2008 included recognition of $4.1 million in non-recurring tax benefits due to a closing of a tax year and the completion of an IRS review. We expect the effective tax rate for the full year 2009 to be approximately 34 percent.

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2009 AND 2008

Regulated Operations

Operating revenue decreased $49.6 million, or 9 percent, from 2008 due to lower fuel and purchased power recoveries, lower retail and municipal kilowatt-hour sales, lower natural gas revenue at SWL&P, and the accrual of estimated prior year retail rate refunds related to our 2008 retail rate case. These decreases were partially offset by higher sales to Other Power Suppliers, higher rates and increased revenue from current cost recovery riders.

Lower fuel and purchased power recoveries along with a decrease in retail and municipal kilowatt-hour sales combined for a total revenue reduction of $106.8 million. Fuel and purchased power recoveries decreased due to a $42.9 million reduction in fuel and purchased power expense. (See Fuel and Purchased Power Expense.) Total kilowatt-hour sales to retail and municipal customers decreased 28.5 percent from 2008 primarily due to idled production lines and temporary plant closures at some of our taconite customers.

Estimated prior year retail rate refunds based on the MPUC May Order and the June 25, 2009, MPUC rate reconsideration decision total $7.6 million.

The decrease in kilowatt-hour sales to retail and municipal customers has been partially offset by revenue from marketing the power to Other Power Suppliers, which increased $57.9 million in 2009. 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.

Natural gas revenue at SWL&P was lower by $6.5 million due to a 54 percent decrease in the price of natural gas and a 14 percent decline in sales. Natural gas revenue is primarily a flow-through of the natural gas costs. (See Operating and Maintenance Expense.)

Higher rates resulting from the March 1, 2008, and February 1, 2009, FERC approved wholesale rate increases for our municipal customers increased revenue by $5.4 million. In addition, the August 1, 2008, interim rate increase for retail customers in Minnesota increased revenue by $3.6 million in 2009, net of estimated refunds.

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2009 AND 2008 (Continued)
Regulated Operations (Continued)

Current cost recovery rider revenue increased $5.8 million in 2009 from 2008 primarily due to increased capital expenditures related to our Boswell Unit 3 emission reduction plan.

Kilowatt-hours Sold			Quantity	%
Nine Months Ended September 30,	2009	2008	Variance	Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	857	854	3	0.4 %
Commercial	1,061	1,090	(29)	(2.7) %
Industrial	3,182	5,466	(2,284)	(41.8) %
Municipals	729	742	(13)	(1.8) %
Total Retail and Municipals	5,829	8,152	(2,323)	(28.5) %
Other Power Suppliers	3,075	1,244	1,831	147.2 %
Total Regulated Utility Kilowatt-hours Sold	8,904	9,396	(492)	(5.2) %

Revenue from electric sales to taconite customers accounted for 15 percent of consolidated operating revenue in 2009 (27 percent in 2008). The decrease in revenue from our taconite customers was partially offset by revenue from electric sales to Other Power Suppliers, which accounted for 21 percent of consolidated operating revenue in 2009 (9 percent in 2008). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2009 (9 percent in 2008). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2009 (7 percent in 2008).

Operating expenses decreased $45.0 million, or 10 percent, from 2008.

Fuel and Purchased Power Expense decreased $42.9 million, or 18 percent, from 2008 due to decreased power generation attributable to lower kilowatt-hour sales, as well as a reduction in wholesale electricity prices. Minnesota Power's coal generating fleet produced fewer kilowatt-hours of electricity due to planned outages to implement environmental retrofits and to respond to decreased demand from our taconite customers.

Operating and Maintenance Expense decreased $9.9 million from 2008 primarily due to $6.3 million in lower natural gas costs at SWL&P due to a decline in the price and quantity of natural gas purchased. In addition, lower maintenance and material costs at Minnesota Power generating facilities were partially offset by defined benefit pension and postretirement health expenses, which have increased primarily due to a decline in asset values.

Depreciation Expense increased $7.8 million, or 22 percent, from 2008 reflecting higher property, plant, and equipment balances placed in service.

Interest expense increased $3.4 million, or 19 percent, from 2008 primarily due to additional long-term debt issued to fund new capital investments and $0.5 million related to estimated retail rate refunds.

Investments and Other

Operating revenue decreased $12.2 million, or 18 percent, from 2008 primarily due to a $13.0 million reduction in sales revenue at ALLETE Properties. During the first nine months of 2009, ALLETE Properties sold approximately 19 acres of properties located outside of our three main development projects for $2.2 million; no other sales were made in 2009 due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. During the first nine months of 2008, ALLETE Properties sold approximately 52 acres of property located outside of our three main development projects for $4.6 million and recognized $2.6 million of previously deferred revenue under percentage of completion accounting. Revenue at ALLETE Properties in 2008 also included a pre-tax gain of $4.5 million resulting from the sale of a retail shopping center in Winter Haven, Florida.

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2009 AND 2008 (Continued)
Investments and Other (Continued)

ALLETE Properties	2009		2008	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres (a)	19	$2.2	52	$4.6
Contract Sales Price (b)		2.2		4.6
Revenue Recognized from Previously Deferred Sales		–		2.6
Deferred Revenue		(0.6)		–
Revenue from Land Sales		1.6		7.2
Other Revenue (c)		0.3		7.7
Total ALLETE Properties Revenue		$1.9		$14.9

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflects total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method.
(c) Included a $4.5 million pre-tax gain from the sale of a shopping center in Winter Haven, Florida in 2008.

BNI Coal, which operates under a cost-plus contract, recorded additional revenue of $2.9 million as a result of higher expenses. (See Operating Expenses.)

Operating expenses decreased $7.0 million, or 11 percent, from 2008 reflecting decreased expenses at ALLETE Properties due to both lower cost of land sold and reductions in general and administrative expenses. Expenses incurred as a result of a planned maintenance outage at a non-regulated generating facility in the third quarter of 2008 also contributed to the decrease in 2009. Partially offsetting these decreases was an increase in expense at BNI Coal due to higher permitting costs relating to mining expansion, reclamation bonding, and dragline repairs in 2009.

Interest expense increased $2.5 million from 2008 primarily due to a decrease in the proportion of ALLETE interest expense assigned to Minnesota Power. Interest Expense reflected in our Investments and Other segment consists of ALLETE interest expense not provided for in the regulatory orders for Minnesota Power and SWL&P. We record interest expense for Minnesota Power based on Minnesota Power's most recently authorized capital structure. Effective August 1, 2008, the proportion of interest expense assigned to Minnesota Power decreased to reflect the authorized capital structure inherent in interim rates that commenced on that date. Interest expense was also higher in 2009 as 2008 included a $0.6 million reversal of interest expense previously accrued due to the closing of a tax year.

Other income decreased $11.8 million from 2008 primarily due a $6.8 million gain realized from the sale of certain available-for-sale securities in the first quarter of 2008, increased losses in our Emerging Technology Investments in 2009 of $2.0 million, lower earnings on excess cash in 2009 of $1.6 million, and $1.4 million of interest income related to tax benefits recognized in the third quarter of 2008.

Income Taxes – Consolidated

For the nine months ended September 30, 2009, the effective tax rate was 33.8 percent (32.3 percent for the nine months ended September 30, 2008). The effective tax rate in each period deviated from the statutory rate (approximately 41 percent for 2009) due to deductions for Medicare health subsidies, AFUDC-Equity, investment tax credits, wind production tax credits, and depletion. In addition, the effective rate for 2009 was impacted by lower pre-tax income. The effective rate for 2008 was impacted by the recognition of a non-recurring benefit on a previously uncertain tax position for $1.7 million due to the closing of a tax year and the reversal of a state valuation allowance for $2.4 million due to the completion of an IRS review. We expect the effective tax rate for 2009 to be approximately 34 percent.

CRITICAL ACCOUNTING ESTIMATES

Certain accounting measurements under GAAP involve management's judgment about subjective factors and estimates, the effects of which are inherently uncertain. Accounting measurements that we believe are most critical to our reported results of operations and financial condition include: regulatory accounting, valuation of investments, pension and postretirement health and life actuarial assumptions, and taxation. These policies are reviewed with the Audit Committee of our Board of Directors on a regular basis and summarized in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of our 2008 Form 10-K.

OUTLOOK

ALLETE is committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. Minnesota Power's industrial customers are facing weak conditions in the markets for their products, and have and may continue to reduce the amount of energy they use; we will work to sell available energy in the wholesale markets. Our focus will be to maintain the competitively-priced production of energy, while meeting environmental requirements. Minnesota Power will also focus on maintaining competitive retail rates, as we believe this is important to the success of our customers.

Our strategy going forward is to focus on growth opportunities within our core business as we expect to continue making significant investments to comply with renewable and environmental requirements, maintain our existing competitively priced generation fleet, and strengthen and enhance the regional transmission grid. We will also look for additional transmission and renewable energy opportunities which take advantage of our geographical location between sources of renewable energy and growing energy markets. Earnings from our investment in ATC are expected to grow as we anticipate making additional investments to fund our pro-rata share of ATC's capital expansion program.

Regulated Operations. Minnesota Power expects significant rate base growth over the next several years as it continues its program to comply with renewable energy requirements and environmental mandates, as well as make significant investments in our existing generation fleet to provide for continued future operations. We anticipate our capital investments will be recovered through a combination of current cost recovery riders and anticipated increased base electric rates.

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

2008 Rate Case. On May 2, 2008, Minnesota Power filed a retail rate increase request with the MPUC. On May 4, 2009, the MPUC issued its order (May Order) on the rate filing, and on June 25, 2009, the MPUC reconsidered the May Order. The reconsideration order was issued on August 10, 2009, resulting in an authorized rate increase of $20.4 million (slightly below the $21.1 million outcome in the May Order). The May Order allowing a 10.74 percent return on common equity and a capital structure consisting of 54.79 percent equity and 45.21 percent debt remains unchanged.

The reconsideration order reduced Minnesota Power's interim rates, which were in effect between August 2008 and October 31, 2009, by $6.3 million annually to approximately $15 million. This increased Minnesota Power's refunding obligation for 2008 and 2009.

As of September 30, 2009, we recorded a $20.0 million liability, including interest, for refunds anticipated to be paid to our customers as a result of the MPUC decision on our retail rate filing. Current year rate refunds totaling $11.9

million have been recorded on our consolidated statement of income and prior year rate refunds totaling $7.6 million are stated separately. Interest expense of $0.5 million was also recorded on our consolidated statement of income related to rate refunds.

On October 29, 2009, the MPUC approved the implementation of final rates to begin on November 1, 2009. Refunding of interim rates will commence in December 2009 and be completed during the first quarter of 2010.

OUTLOOK (Continued)
Regulated Operations (Continued)

With the May Order, the MPUC also approved the stipulation and settlement agreement that affirmed the Company's continued recovery of fuel and purchased power costs under the former base cost of fuel that was in effect prior to the retail rate filing. The transition to the former base cost of fuel will occur upon implementation of final rates. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

2010 Rate Case. Minnesota Power has previously stated its intention to file for additional revenues to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance and bring new renewable energy to northeastern Minnesota. As a result, Minnesota Power filed a retail rate increase request with the MPUC on November 2, 2009, seeking a return on equity of 11.5 percent, a capital structure consisting of 54.29 percent equity and 45.71 percent debt, and on an annualized basis, an $81.0 million net increase in electric retail revenue. We cannot predict the final level of rates that may be approved by the MPUC.

Minnesota Power's wholesale customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a wholesale customer of Minnesota Power. In 2008, Minnesota Power entered into new contracts with all of our wholesale customers with the exception of one small customer (less than 2 MW) whose contract is now in the cancellation period. The new contracts transitioned each customer to formula-based rates, which means rates can be adjusted annually based on changes in cost. The new agreements with the private utilities in Wisconsin are subject to PSCW approval. In February 2009, the FERC approved our municipal contracts, including the formula-based rate provision. A 9.5 percent rate increase for our municipal customers was implemented on February 1, 2009 under the formula-based rate provision. Incremental revenue from this rate increase is expected to be approximately $7 million on an annualized basis.

SWL&P's current retail rates are based on a December 2008 PSCW retail rate order that became effective January 1, 2009, and allows for an 11.1 percent return on equity. The new rates reflect a 3.5 percent average increase in retail utility rates for SWL&P customers (a 13.4 percent increase in water rates, a 4.7 percent increase in electric rates, and a 0.6 percent decrease in natural gas rates). On an annualized basis, the rate increase will generate approximately $3 million in additional revenue.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. Approximately 35 percent of our Regulated Utility kilowatt-hour sales were made to our industrial customers through the nine months ended September 30, 2009, which includes the taconite, paper and pulp, and pipeline industries.

Strong worldwide steel demand, driven largely by extensive infrastructure development in China, resulted in very robust world iron ore demand and steel pricing for nearly a six-year period which lasted through the summer of 2008. Between 2004 and 2008, annual taconite production averaged just over 40 million tons per year from taconite mines in northeastern Minnesota. Beginning in the fall of 2008, worldwide steel makers began to dramatically cut steel production in response to reduced demand driven largely by the world credit situation. In late 2008, Minnesota taconite producers began to feel the impacts of decreased steel demand. As a result, reduced taconite production levels are occurring in 2009. Consequently, 2009 demand nominations for power from our taconite customers are lower by approximately 40 percent from 2008 levels. We continue to remarket available power to Other Power Suppliers in an effort to mitigate the earnings impact of these lower industrial sales. These sales are dependent upon the availability of generation and are sold at market based prices into the MISO market on a daily basis or through bilateral agreements of various durations. For 2009, we have successfully mitigated approximately 85 percent of the earnings impact.

Minnesota Power expects an increase in taconite production on Minnesota's Iron Range in 2010, which would result in increased electricity usage by its industrial customers compared to 2009, but less than previous years' levels.

OUTLOOK (Continued)
Regulated Operations (Continued)

Renewable Generation Sources. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota come from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016, and 20 percent by 2020. The law allows the MPUC to modify or delay a standard obligation if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a standard, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power was developing and making renewable supply additions as part of its generation planning strategy prior to the enactment of this law and this activity continues. Minnesota Power believes it will meet the requirements of this legislation.

The areas in which we operate have strong wind, water, and biomass resources and provide us with opportunities to develop a number of renewable forms of generation. Our electric service area in northeastern Minnesota is situated for delivery of renewable energy that is generated here and in adjoining regions. We intend to secure the most cost competitive and geographically advantageous renewable energy resources available. We believe that the demand for these resources is likely to grow, and the costs of the resources to generate renewable energy will continue to escalate. While we intend to maintain our disciplined approach to developing generation assets, we also believe that by acting sooner rather than later we can deliver lower cost power to our customers and maintain or improve our cost competitiveness among regional utilities. We will continue to work with our customers, our regulators and the communities we serve to develop generation options that reflect the needs of our customers as well as the environment. We believe that our location and our proactive leadership in developing renewable generation provide us with a competitive advantage.

We are executing our renewable energy strategy. In 2006 and 2007, we entered into two long-term purchase power agreements for a total of 98 MWs of wind energy constructed in North Dakota (Oliver Wind I and II). Taconite Ridge Wind I, a $50 million, 25-MW wind facility located in northeastern Minnesota became operational in 2008.

North Dakota Wind Project. On July 7, 2009, the MPUC approved our petition seeking current cost recovery of investments and expenditures related to our Bison I and associated transmission upgrades. We anticipate filing a petition with the MPUC in the fourth quarter to establish customer billing rates for the approved cost recovery. Bison I is the first portion of several hundred MWs of our North Dakota Wind Project, which upon completion will fulfill the 2025 renewable energy supply requirement for our retail load. Bison I, which will be comprised of 33 wind turbines with a total nameplate capacity of 75.9 MWs and located near Center, North Dakota, will be phased into service in 2010 and 2011.

On September 29, 2009 the NDPSC issued a Certificate of Site Compatibility for Energy Conversion System for Bison I that authorized site construction to commence. On October 2, 2009, Minnesota Power filed a route permit application with the NDPSC for the 22 mile 230 kV Bison I transmission line that will connect Bison I to the DC transmission line at the Square Butte Substation in Center, North Dakota.

In September 2008, we signed an agreement to purchase an existing 250 kV DC transmission line for approximately $80 million to transport this wind energy to our customers while gradually reducing the supply of energy currently delivered to our system on this same transmission line from Square Butte's Unit. The transaction is subject to regulatory and board approvals. On May 14, 2009, we filed a petition with the MPUC for approval of the DC transmission line purchase and the restructuring of the power purchase agreement with Square Butte. That petition was reviewed by the MPUC through an evidentiary hearing held on September 17, 2009. The Administrative Law Judge (ALJ) takes the information from the evidentiary hearing and makes a recommendation to the MPUC. The MPUC may accept, reject, or modify the ALJ's recommendation in making their decision. On October 27, 2009, the

ALJ recommended that the MPUC approve this transaction.

Hibbard Energy Center. On September 30, 2009, we purchased boilers and associated systems previously owned by the City of Duluth. This facility was initially built in the late 1940s as a coal burning power plant, and retrofitted to burn wood-based biomass fuel as well as coal. Minnesota Power intends to invest approximately $20 million over the next several years to upgrade the boilers and associated systems to increase biomass energy generation to approximately 200 MWh annually at the plant by approximately 2013. Hibbard's current generating capacity is approximately 60 MWh annually. This purchase will help us achieve Minnesota's mandate of providing 25 percent of our retail energy from renewable resources by 2025.

OUTLOOK (Continued)
Regulated Operations (Continued)

Integrated Resource Plan. On October 5, 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan (IRP), a comprehensive estimate of future capacity needs within Minnesota Power's service territory. Minnesota Power does not anticipate the need for new base load generation within the Minnesota Power service territory over the next 15 years, and plans to meet estimated future customer demand while achieving:

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily carbon dioxide); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan on reshaping our generation portfolio by adding 300 to 500 megawatts of renewable energy to our generation mix, and exploring options to incorporate peaking or intermediate resources. Our 76 MW Bison I wind project in North Dakota, expected to be in-service in 2010-2011, is part of this initiative, as is the 25 MW Taconite Ridge wind energy center in northern Minnesota that was placed in service in 2008.

We do not plan to add new coal generation or enter into long-term power purchase agreements from coal-based generation resources without a GHG solution. We project average annual long-term growth of approximately one percent in electric usage over the next 15 years. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation.

Climate Change. We believe that future regulations may restrict the emissions of GHGs from our generation facilities. Several proposals at the Federal level to "cap" the amount of GHG emissions have been made. On June 26, 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009. H.R. 2454 is a comprehensive energy bill that also includes a cap and trade program. H.R. 2454 allocates a significant number of allowances to the electric utility sector to mitigate cost impacts on consumers.

On September 30, 2009, the Senate introduced S. 1733, the Senate version of H.R. 2454. This legislation proposes a more stringent near-term greenhouse emissions reduction target in 2020 of 20 percent below 2005 levels, as compared to the 17 percent reduction proposed by H.R. 2454.

Congress may consider proposals other than cap and trade programs to address GHG emissions. We are unable to predict the outcome of H.R. 2454, S. 1733, or other efforts that Congress may make with respect to GHG emissions, and the impact that any GHG emission regulations may have on the Company.

EPA Greenhouse Gas Reporting Rule. On September 22, 2009, the EPA issued the final rule mandating that certain GHG emission sources, including electric generating units, are subject to the EPA's Acid Rain Program and are required to report emission levels. The rule is intended to allow the EPA to collect accurate and timely data on GHG emissions that can be used to form future policy decisions. The rule also includes a record retention mandate requiring that written GHG monitoring plans with assignments of responsibility and quality assurance and quality control procedures be in place. The rule is effective January 1, 2010, and all GHG emissions must be reported on an annual basis by March 31 of the following year. Currently, we have the equipment necessary to track our 2010 emissions to comply with this rule.

Title V Greenhouse Gas Tailoring Rule. On October 27, 2009, the EPA issued the proposed Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring rule. This proposed regulation addresses the six primary greenhouse gases and new thresholds for when permits will be required for new facilities and existing facilities which undergo major modifications. The rule would require large industrial facilities, including power plants, emitting greater than 25,000 tons of GHGs annually, to obtain construction and operating permits that demonstrate best practices and technologies are being used at the facility to minimize GHG emissions. Best available control technologies (BACT) for criteria pollutants are already prescribed by the PSD permit program.

For our existing facilities, the proposed rule does not require amending our existing Title V operating permits to include BACT for GHGs. However, modifying or installing units with GHG emissions that trigger the PSD permitting requirements would require amending operating permits to incorporate BACT and energy efficiency measures to minimize GHG emissions.

OUTLOOK (Continued)
Regulated Operations (Continued)

CapX 2020. Minnesota Power is a participant in the CapX 2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX 2020, which includes Minnesota's largest transmission owners, consists of electric cooperatives, municipals and investor-owned utilities, and has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

The CapX 2020 participants filed a request for a Certificate of Need for three 345 kV lines and associated system interconnections with the MPUC in August 2007. The MPUC issued the Certificate of Need for these 345 kV lines in May 2009. The MPUC must now determine routes for the new lines in subsequent proceedings. Portions of the 345 kV lines will also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. A fourth line, a 70-mile, 230 kV line in north central Minnesota, is also among the CapX 2020 projects. A request for a Certificate of Need for this line was filed in March 2008, and a Route Permit application was filed in June 2008. The MPUC issued the Certificate of Need for the 230 kV line on July 9, 2009. The MPUC decision on the Route Permit application is expected in 2010.

Minnesota Power intends to invest in two of the lines, a 250-mile 345 kV line between Fargo, North Dakota and Monticello, Minnesota, and a 70-mile, 230 kV line between Bemidji and Grand Rapids, Minnesota. Our total investment in these two lines is expected to be approximately $80 million. We intend to include these costs in an annual filing with the MPUC for current cost recovery of the expenditures related to our investment in the lines under a Minnesota Power transmission cost recovery tariff rider mechanism authorized by Minnesota legislation. Construction of the lines is targeted to begin in 2010 and last approximately three to four years.

Boswell Unit 3 Emission Reduction Plan. We are making emission reduction investments at our Boswell Unit 3 generating unit. The investments in pollution control equipment will reduce particulates, SO2, NOX, and mercury emissions to meet future federal and state requirements. The MPUC has authorized a cash return on construction work in progress during the construction phase in lieu of AFUDC and allows for a return on investment and current cost recovery of incremental operations and maintenance expenses once the new equipment is installed and the unit is placed back in service in late 2009. We began cost recovery on January 1, 2008. Our November 2, 2009, rate request proposes to move this project from current cost recovery to base rates.

Boswell NOX Reduction Plan. In September 2008, we submitted to the MPCA and MPUC a $92 million environmental initiative proposing cost recovery for NOX emission reductions from Boswell Units 1, 2, and 4. The Boswell NOX Reduction Plan is expected to significantly reduce NOX emissions from these units. In conjunction with the NOX reduction, we plan to make an efficiency improvement to the existing turbine/generator at Boswell Unit 4, adding approximately 60 MWs of total output. Our November 2, 2009, rate request seeks recovery for this project in base rates.

Transmission. In September 2008, in connection with our existing cost recovery rider for transmission expenditures, we filed a petition with the MPUC to approve our 2009 billing factor adjustment for ongoing transmission expenditures. The annual billing factor allows us to charge our retail customers on a current basis for the costs of constructing these facilities plus a return on the capital invested. These expenditures include the Badoura and Tower transmission projects and certain statutorily authorized MISO related transmission facility charges. The Badoura and Tower transmission projects are being developed to address transmission inadequacies in northeastern Minnesota. Both projects will provide regional transmission benefits through increased voltage support and additional line capacity. The MPUC approved the 2009 billing factor adjustment in June 2009 allowing new rates to go into effect

July 1, 2009. Our November 2, 2009, rate request proposes to move completed transmission projects from current cost recovery to base rates.

Power Sales Agreement. On October 29, 2009, Minnesota Power entered into an agreement to sell Basin Electric Power Cooperative 100 MW of capacity and energy for the next ten years. The transaction is scheduled to begin in May 2010, which coincides with the expiration of two power sales contracts on April 30, 2010. (See Item 3. Power Marketing.)

OUTLOOK (Continued)
Regulated Operations (Continued)

Investment in ATC. At September 30, 2009, our equity investment was $85.1 million, representing an approximate 8 percent ownership interest. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. ATC rates, effective until 2012, are based on a 12.2 percent return on common equity dedicated to utility plant. ATC has identified $2.5 billion in future projects needed over the next 10 years to improve the adequacy and reliability of the electric transmission system in its service territory. These investments are expected to be funded through a combination of internal cash, debt and investor contributions. As additional opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro-rata ownership interest in ATC; these future capital investments are voluntary and not a long-term binding commitment. On October 30, 2009, we invested an additional $2.3 million for a total investment of $7.7 million in 2009.

Investments and Other

BNI Coal. BNI Coal anticipates selling approximately 4.5 million tons of coal in 2009 (4.5 million tons were sold in 2008) and has sold approximately 3.3 million tons through September 30, 2009 (3.4 million tons sold as of September 30, 2008).

ALLETE Properties. ALLETE Properties is our real estate business that has operated in Florida since 1991. Our current strategy is to complete and maintain key entitlements and infrastructure improvements which enhance values without requiring significant additional investment, and position the current property portfolio for a maximization of value and cash flow. Due to continued weak real estate market conditions, we anticipate a net loss of approximately $5 million for 2009.

Our two major development projects include Town Center and Palm Coast Park. A third proposed development project, Ormond Crossings, is in the permitting and planning stage. Development activities involve mainly zoning, permitting, platting, and master infrastructure construction. Development costs are financed through a combination of community development district bonds, bank loans, and internally-generated funds.

Summary of Development Projects Land Available-for-Sale	Ownership	Acres (a)	Residential Units (b)	Non-residential Sq. Ft. (b, c)
Current Development Projects				
Town Center	80%	991	2,289	2,228,200
Palm Coast Park	100%	3,436	3,239	3,116,800
Total Current Development Projects		4,427	5,528	5,345,000
Proposed Development Project				
Ormond Crossings	100%	5,968	(d)	(d)
Total of Development Projects		10,395	5,528	5,345,000

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and non-controlling interest.
(b) Estimated and includes non-controlling interest. Density at build out may differ from these estimates.
(c) Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.
(d)

A development order approved by the City of Ormond Beach includes up to 3,700 residential units and 5 million square feet of non-residential space. We estimate the first two phases of Ormond Crossings will include 2,500-3,200 residential units and 2.5 million - 3.5 million square feet of various types of non-residential space. Density of the residential and non-residential components of the project will be determined based upon market and traffic mitigation cost considerations. Approximately 2,000 acres will be devoted to a regionally significant wetlands mitigation bank.

Other Land Available-for-Sale (a)	Total	Mixed Use	Residential	Non-Residential	Agricultural
Acres (b)					
Other Land	1,327	353	114	376	484

(a) Other land available-for-sale includes land located in Palm Coast, Florida not included in development projects and land held by Lehigh Acquisition Corporation and Cape Coral Holdings, Inc.
(b) Acreage amounts are approximate and shown on a gross basis, including wetlands and non-controlling interest.

OUTLOOK (Continued)
Investments and Other (Continued)

At September 30, 2009, total pending land sales under contract were $5.6 million ($12.4 million at December 31, 2008) and are scheduled to close at various times through 2010. However, given current market conditions it may be difficult to complete these closings by 2010. We continue to have discussions with our buyers under pending contracts. Our objective is to proactively assist our buyers through this current period of weak market conditions. Our discussions sometimes result in adjustments to contract terms, and may include extending closing dates, revised pricing or termination. If a purchaser defaults on a sales contract, the legal remedy is usually limited to terminating the contract and retaining the purchaser’s deposit. The property is then available for resale. In many cases, contract purchasers incur significant costs during due diligence, planning, designing and marketing the property before the contract closes, therefore they have substantially more at risk than the deposit.

Long-term finance receivables as of September 30, 2009 were $13.3 million, which included $7.8 million due from an entity which filed for voluntary Chapter 11 bankruptcy protection in June 2009. The estimated fair value of the collateral relating to these receivables was greater than the $7.8 million amount due at September 30, 2009 and no impairment was recorded on these receivables; however, $0.1 million of impairments was recorded on other receivables.

Although weak real estate market conditions currently exist, we continue to believe the long-term prospects for our properties are favorable. In 2009, we commissioned an independent real estate advisory firm to do a study on the State of Florida, northeast Florida, and our specific major land developments (Town Center, Palm Coast Park, and Ormond Crossings) compared to the major competing developments in the region.

The study projected that northeastern Florida is expected to capture an increased portion of the state’s anticipated population growth, with the most significant growth in St. Johns and Flagler Counties (the location of our major developments). In addition, national demographic trends should have a positive impact on Florida’s long-term outlook. Based on a comparison of our three major developments compared with major competing developments in the region, the study concluded that our properties are well-positioned. Therefore, we believe our properties have long-term value and we have the ability to hold these properties, if needed, until the market improves.

Should current weak market conditions continue for an extended period of time, the impact on our future operations would be the continuation of little to no sales while still incurring operating expenses such as community development district assessments and property taxes. This could result in annual net losses for ALLETE Properties similar to 2009.

Emerging Technology. We have the potential to recognize gains or losses on the sale of investments in our Emerging Technology Investments. We plan to sell investments in our Emerging Technology Investments when publicly traded shares are distributed to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an initial public offering. We have committed to make up to $0.5 million in additional investments in certain emerging technology holdings. We do not have plans to make any additional investments beyond this commitment.

Income Taxes. ALLETE’s aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2009. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that will reduce the statutory rate to the expected effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, wind production tax credits, AFUDC-Equity, domestic manufacturer’s deduction, depletion, Medicare prescription reimbursement, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be approximately 34 percent for 2009.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Activities

ALLETE is well-positioned to meet the Company's immediate cash flow needs. With our cash balance of approximately $54 million, $160.0 million in lines-of-credit which includes a committed, syndicated, unsecured revolving line of credit of $150.0 million, and a debt-to-capital ratio of 42 percent at September 30, 2009, we project sufficient capital availability.

Operating Activities. Cash from operating activities was $106.3 million for the nine months ended September 30, 2009 ($101.8 million for the nine months ended September 30, 2008). Cash from operating activities was higher in 2009 primarily due to higher depreciation and deferred tax expense, offset by lower net income and higher working capital requirements in 2009.

Investing Activities. Cash used for investing activities was $206.5 million for the nine months ended September 30, 2009 ($180.3 million for the nine months ended September 30, 2008). Cash used for investing activities was lower in 2008 due to the proceeds from the sale of a retail shopping center in Winter Haven, Florida and available-for-sale securities.

Financing Activities. Cash from financing activities was $52.5 million for the nine months ended September 30, 2009 ($133.3 million for the nine months ended September 30, 2008). Cash from financing activities was lower in 2009 than 2008 due to less debt issuance which was partially offset by the issuance of 2.3 million shares of common stock with net proceeds of $53.7 million.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. We have consolidated bank lines of credit aggregating $160.0 million, the majority of which expire in January 2012. In addition, we have 0.5 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 3.5 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Auction Rate Securities. Included in Available-for-Sale Securities, as of September 30, 2009, are $14.3 million ($15.2 million at December 31, 2008) of three auction rate municipal bonds with stated maturity dates ranging between 14 and 27 years. One of these ARS bonds was called during the third quarter at par value of $7.0 million and payment was received on October 6, 2009. These ARS consist of guaranteed student loans insured or reinsured by the federal government. These ARS were historically auctioned every 35 days to set new rates and provided a liquidating event in which investors could either buy or sell securities. Beginning in 2008, the auctions have been unable to sustain themselves due to the overall lack of market liquidity and we have been unable to liquidate all of our ARS. As a result, we have classified the ARS as long-term investments and have the ability to hold these securities to maturity, until called by the issuer, or until liquidity returns to this market. In the meantime, these securities will pay a default rate which is above market interest rates.

Securities. In January 2009, we issued $42.0 million in principal amount of unregistered First Mortgage Bonds (Bonds) in the private placement market. The Bonds mature January 15, 2019, and carry a coupon rate of 8.17 percent. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for this type of transaction. We are using the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes. The Bonds were sold in reliance on exemption from registration under Section 4(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

In February 2008, we entered into a Distribution Agreement with KCCI, Inc., with respect to the issuance and sale of up to 2.5 million shares of our common stock. In February 2009, we amended and restated the Distribution Agreement with KCCI, Inc., such that it now provides for the issuance and sale of up to 5.0 million shares of our common stock, without par value. The shares may be offered for sale, from time to time, in accordance with the terms of the agreement pursuant to Registration Statement No. 333-147965. For the nine months ended September 30, 2009, 1.5 million shares of common stock were issued under this agreement resulting in net proceeds of $44.2 million.

In March 2009, we contributed 463,000 shares of ALLETE common stock, with an aggregate value of $12.0 million, to our pension plan. On May 19, 2009, we registered the 463,000 shares of ALLETE common stock with the SEC pursuant to Registration Statement No. 333-147965.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Year to date we have issued 0.3 million shares of common stock through Invest Direct, Employee Stock Purchase Plan and Retirement Savings and Stock Ownership Plan resulting in net proceeds of $9.5 million. These shares of common stock were registered under the following Registration Statement Nos. 333-150681, 333-105225, and 333-124455, respectively.

Pension and Other Postretirement Benefit Plans. The funded status of the defined pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations under the plans. The funded status may change over time due to several factors, including contribution levels, assumed discount rates and actual and assumed rates of return on plan assets. During 2008, the unfunded status of ALLETE's defined pension and postretirement benefit plans increased significantly, to $255 million at December 31, 2008, primarily due to a decline in the value of plan assets.

Management considers various factors when making funding decisions such as regulatory changes, actuarially determined minimum contribution requirements, and contributions required to avoid benefit restrictions for the pension plans. Estimated pension contributions for years 2010 through 2014 are approximately $25 million per year, and are based on estimates and assumptions that are subject to change. Funding for the other postretirement benefit plans is impacted by utility regulatory requirements. Estimated postretirement contributions for years 2010 through 2014 are approximately $11 million per year, and are based on estimates and assumptions that are subject to change. Based on the estimated contributions for the defined pension and other postretirement benefit plans and the sources of cash as described above, we do not anticipate these obligations to have a material impact on our financial condition or liquidity.

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. The most restrictive covenant requires ALLETE to maintain a ratio of its Funded Debt to Total Capital (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of September 30, 2009 our ratio was approximately 0.40 to 1.00. Failure to meet this covenant would give rise to an event of default, if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of September 30, 2009, ALLETE was in compliance with its financial covenants.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are summarized in our 2008 Form 10-K, with additional disclosure discussed in Note 14. Commitments, Guarantees and Contingencies of this Form 10-Q.

Capital Requirements

For the nine months ended September 30, 2009, capital expenditures totaled $186.7 million ($211.1 million at September 30, 2008). The expenditures were primarily made in the Regulated Operations segment. Internally generated funds and long-term debt and equity issuances were the primary sources of funding.

ENVIRONMENTAL MATTERS AND OTHER

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to restrictive environmental requirements through legislation and/or rulemaking in the future, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We are unable to predict the outcome of the matters discussed in Note 14. Commitments, Guarantees and Contingencies of this Form 10-Q.

NEW ACCOUNTING STANDARDS

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies of this Form 10-Q.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

SECURITIES INVESTMENTS

Available-For-Sale Securities. As of September 30, 2009, our available-for-sale securities portfolio consisted of securities in a grantor trust, established to fund certain employee benefits, and ARS. (See Note 3. Investments.)

Emerging Technology Investments. As part of our Emerging Technology Investments, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies.

COMMODITY PRICE RISK

Our regulated utility operations in Minnesota and Wisconsin incur costs for fuel (primarily coal), power and natural gas purchased for resale in our regulated service territories, and related transportation. Our regulated utilities' exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory environment, which generally allows a fuel clause surcharge if costs are in excess of those in the 2008 retail rate case filing. Conversely, costs below those in the 2008 retail rate case filing result in a credit to our ratepayers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of coal and power (in Minnesota), power and natural gas (in Wisconsin), and related transportation costs.

POWER MARKETING

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

Demand nominations for power from our taconite customers in 2009 are lower by approximately 40 percent from 2008 levels. We continue to remarket available power to Other Power Suppliers in an effort to mitigate the earnings impact of these lower industrial sales. These sales are dependent upon the availability of generation and are sold at market based prices into the MISO market on a daily basis or through bilateral agreements of various durations. For 2009, we have successfully mitigated approximately 85 percent of the earnings impact.

In 2009, we have entered into financial derivative instruments to manage price risk for certain power marketing contracts. Outstanding derivative contracts at September 30, 2009, consist of cash flow hedges for an energy sale that includes pricing based on daily natural gas prices, and FTRs purchased to manage congestion risk for forward power sales contracts. These derivative instruments are recorded on our consolidated balance sheet at fair value. As of September 30, 2009, we recorded approximately $1.1 million of derivatives in other assets on our consolidated balance sheet of which the entire balance relates to our FTRs. These derivative instruments settle monthly throughout 2009 and the first five months of 2010. (See Note 4. Derivatives.)

Approximately 200 MWs of capacity and energy from our Taconite Harbor facility in northern Minnesota has been sold through two sales contracts totaling 175 MWs (201 MWs including a 15 percent reserve), which were effective May 1, 2005, and expire on April 30, 2010. Both contracts contain fixed monthly capacity charges and fixed minimum energy charges. One contract provides for an annual escalator to the energy charge based on increases in our cost of coal, subject to a small minimum annual escalation. The other contract provides that the energy charge will be the greater of the fixed minimum charge or an annual amount based on the variable production cost of a combined-cycle, natural gas unit. Our exposure in the event of a full or partial outage at our Taconite Harbor facility is significantly limited under both contracts. When the buyer is notified at least two months prior to an outage, there is no liability. Outages with less than two months notice are subject to an annual duration limitation typical of this type of contract. These contracts qualify for the normal purchase normal sale exception under the guidance for derivative instruments and hedging activities and are not required to be recorded at fair value.

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

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

Power Sales Agreement. On October 29, 2009, Minnesota Power entered into an agreement to sell Basin Electric Power Cooperative 100 MW of capacity and energy for the next ten years. The transaction is scheduled to begin in May 2010, which coincides with the expiration of two power sales contracts on April 30, 2010. (See Item 3. Power Marketing.)

INTEREST RATE RISK

We are also exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. Interest rates on variable rate long-term debt are reset on a periodic basis reflecting current market conditions. Based on the variable rate debt outstanding at September 30, 2009, and assuming no other changes to our financial structure, an increase or decrease of 100 basis points in interest rates would impact the amount of pretax interest expense by $0.8 million. This amount was determined by considering the impact of a hypothetical 100 basis point change to the average variable interest rate on the variable rate debt outstanding as of September 30, 2009.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of September 30, 2009, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of ALLETE’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE’s reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

ITEM 1A. RISK FACTORS

None.

PART II. OTHER INFORMATION (Continued)
ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

In January 2009, we issued $42.0 million in principal amount of unregistered First Mortgage Bonds (Bonds) in the private placement market. The Bonds mature January 15, 2019, and carry a coupon rate of 8.17 percent. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for this type of transaction. We are using the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes. The Bonds were sold in reliance on exemption from registration under Section 4(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

Reference is made to our 2008 Form 10-K for background information on the following updates.

Ref. Page 12 – Regulated Operations, Minnesota Public Utilities Commission – First Paragraph

On May 2, 2008, Minnesota Power filed a retail rate increase request with the MPUC. On May 4, 2009, the MPUC issued its order (May Order) on the rate filing, and on June 25, 2009, the MPUC reconsidered the May Order. The reconsideration order was issued on August 10, 2009, resulting in an authorized rate increase of $20.4 million (slightly below the $21.1 million outcome in the May Order). The May Order allowing a 10.74 percent return on common equity and a capital structure consisting of 54.79 percent equity and 45.21 percent debt remains unchanged.

The reconsideration order reduced Minnesota Power's interim rates, which were in effect between August 2008 and October 31, 2009, by $6.3 million annually to approximately $15 million. This increased Minnesota Power's refunding obligation for 2008 and 2009.

As of September 30, 2009, we recorded a $20.0 million liability, including interest, for refunds anticipated to be paid to our customers as a result of the MPUC decision on our retail rate filing. Current year rate refunds totaling $11.9 million have been recorded on our consolidated statement of income and prior year rate refunds totaling $7.6 million are stated separately. Interest expense of $0.5 million was also recorded on our consolidated statement of income related to rate refunds.

On October 29, 2009, the MPUC approved the implementation of final rates to begin on November 1, 2009. Refunding of interim rates will commence in December 2009 and be completed during the first quarter of 2010.

With the May Order, the MPUC also approved the stipulation and settlement agreement that affirmed the Company's continued recovery of fuel and purchased power costs under the former base cost of fuel that was in effect prior to the retail rate filing. The transition to the former base cost of fuel will occur upon implementation of final rates. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

PART II. OTHER INFORMATION (Continued)
ITEM 5. OTHER INFORMATION (Continued)

Ref. Page 12 – Regulatory Matters – Sixth Paragraph

Integrated Resource Plan. On October 5, 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan (IRP), a comprehensive estimate of future capacity needs within Minnesota Power's service territory. Minnesota Power does not anticipate the need for new base load generation within the Minnesota Power service territory over the next 15 years, and plans to meet estimated future customer demand while achieving:

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily carbon dioxide); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan on reshaping our generation portfolio by adding 300 to 500 megawatts of renewable energy to our generation mix, and exploring options to incorporate peaking or intermediate resources. Our 76 MW Bison I wind project in North Dakota, expected to be in-service in 2010-2011, is part of this initiative, as is the 25 MW Taconite Ridge wind energy center in northern Minnesota that was placed in service in 2008.

We do not plan to add new coal generation or enter into long-term power purchase agreements from coal-based generation resources without a GHG solution. We project average annual long-term growth of approximately one percent in electric usage over the next 15 years. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation.

Ref. Page 18 – Employees – Second Paragraph

Minnesota Power, SWL&P and IBEW Local 31 continue to work under contract extensions of the agreements which expired on January 31, 2009. On April 10, 2009, IBEW Local 31 requested binding arbitration in accordance with the provisions of the contracts. The contracts also provide Minnesota Power and SWL&P with the protections of no strike clauses. The sole matter in dispute that would add cost to the agreement is wage adjustments; although the parties have not reached an agreement on this issue, the economic gap between the parties would not be considered material. The Company is also seeking changes to existing benefit plans. Arbitration hearings took place October 5, 2009, with final resolution expected in December 2009. We remain optimistic that we will achieve a fair and equitable result in both agreements.

ITEM 6. EXHIBITS

Exhibit
Number

31(a) Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(b) Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Section 1350 Certification of Periodic Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

ALLETE, INC.

November 3, 2009

/s/ Mark A. Schober
Mark A. Schober
Senior Vice President and Chief Financial Officer

November 3, 2009

/s/ Steven Q. DeVinck
Steven Q. DeVinck
Controller