United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2010**

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ______________ to ______________

Commission File No. **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

30 West Superior Street, Duluth, Minnesota 55802-2093
(Address of principal executive offices, including zip code)
(218) 279-5000
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Stock Exchange on Which Registered
Common Stock, without par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

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.
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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Act).
Large Accelerated Filer ☒ 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 Act).
Yes ☐ No ☒

The aggregate market value of voting stock held by nonaffiliates on June 30, 2010, was $1,214,198,439.

As of February 1, 2011, there were 35,820,559 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2011 Annual Meeting of Shareholders are incorporated by reference in Part III.

Index

Definitions

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

Abbreviation or Acronym	Term
ALLETE	ALLETE, Inc.
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison 1	Bison 1 Wind Project
Bison 2	Bison 2 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CO_2	Carbon Dioxide
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 8-K	ALLETE Current Report on Form 8-K
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	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
Hibbard	Hibbard Renewable Energy Center
IBEW Local 31	International Brotherhood of Electrical Workers Local 31
IBEW Local 1593	International Brotherhood of Electrical Workers Local 1593
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
kV	Kilovolt(s)
Laskin	Laskin Energy Center
Manitoba Hydro	Manitoba Hydro-Electric Board
MBtu	Million British thermal units
Medicare Part D	Medicare Part D provision of the Patient Protection and Affordable Care Act of 2010
Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency

Definitions (Continued)

MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NextEra Energy	NextEra Energy Resources, LLC
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
OES	Minnesota Office of Energy Security
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PolyMet	PolyMet Mining Corporation
PPA	Power Purchase Agreement
PSCW	Public Service Commission of Wisconsin
PUHCA 2005	Public Utility Holding Company Act of 2005
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
Standard & Poor’s	Standard & Poor’s Ratings Services, a division of The McGraw-Hill Companies, Inc.
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge 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," "outlook" or words of 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 Annual Report on Form 10-K, 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;
- prevailing governmental policies, regulatory actions, and legislation, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, 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;
- our ability to manage expansion and integrate acquisitions;
- 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 and capital 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 22 of this Annual Report on 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 Annual Report on Form 10-K 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

Item 1. Business

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 146,000 retail customers and wholesale electric service to 16 non-affiliated municipalities. Minnesota Power also provides regulated utility electric service to 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, 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. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land held-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2010, unless otherwise indicated. All subsidiaries of ALLETE are wholly owned unless otherwise specifically indicated. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	2010	2009	2008
Consolidated Operating Revenue – Millions	$907.0	$759.1	$801.0
Percentage of Consolidated Operating Revenue			
Regulated Operations	92%	90%	89%
Investments and Other	8%	10%	11%
	100%	100%	100%

For a detailed discussion of results of operations and trends, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Note 1. Operations and Significant Accounting Policies and Note 2. Business Segments.

REGULATED OPERATIONS

Electric Sales / Customers

Regulated Utility Electric Sales

Year Ended December 31	2010	%	2009	%	2008	%
Millions of Kilowatt-hours						
Retail and Municipals						
Residential	1,150	9	1,164	10	1,172	9
Commercial	1,433	11	1,420	12	1,454	12
Industrial	6,804	52	4,475	37	7,192	57
Municipals (FERC rate regulated)	1,006	7	992	8	1,002	8
Total Retail and Municipals	10,393	79	8,051	67	10,820	86
Other Power Suppliers	2,745	21	4,056	33	1,800	14
Total Regulated Utility Electric Sales	13,138	100	12,107	100	12,620	100

Seasonality

Due to the high concentration of industrial sales, Minnesota Power is not subject to significant seasonal fluctuations. The operations of our industrial customers, which make up a large portion of our sales portfolio as shown in the table above, are not typically subject to significant seasonal variations.

REGULATED OPERATIONS (Continued)

Industrial Customers. In 2010, our industrial customers represented 52 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite, paper, pulp and wood products, and pipeline industries.

Industrial Customer Electric Sales

Year Ended December 31	**2010**	**%**	**2009**	**%**	**2008**	**%**
Millions of Kilowatt-hours						
Taconite Producers	4,324	64	2,124	47	4,579	64
Paper, Pulp and Wood Products	1,573	23	1,454	33	1,567	22
Pipelines	494	7	504	11	582	8
Other Industrial	413	6	393	9	464	6
Total Industrial Customer Electric Sales	6,804	100	4,475	100	7,192	100

Approximately 60 percent of the ore consumed by integrated steel facilities in the United States originates from six taconite customers of Minnesota Power, which represented 4,324 million kilowatt-hours, or 64 percent, of our total industrial sales in 2010. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets.

During 2010, the domestic steel industry rebounded from the low levels of production seen in 2009. According to the American Iron and Steel Institute (AISI), United States raw steel production operated at approximately 70 percent of capacity in 2010, up significantly from 2009 levels of approximately 50 percent. Domestic steel demand rebounded for automobiles and durable goods, while still remaining soft for structural and construction steel products.

Annual 2010 taconite production in Minnesota increased from the 18 million tons produced in 2009 to approximately 36 million tons in 2010 (40 million tons in 2008), representing about 85 percent of capacity. As a result, kilowatt-hour sales to our taconite customers in 2010 were more than double our 2009 sales.

Projections from the AISI translate to United States steel production levels at about 75 percent of capacity in 2011. There has been a general historical correlation between U.S. steel production and Minnesota taconite production. Based on these projections Minnesota Power expects 2011 taconite production in Minnesota to be in the range of 2010 production levels. We will continue to market available power to Other Power Suppliers, when necessary, in an effort to mitigate the earnings impact of lower industrial sales. Other Power Supply 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.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry, which represented 1,573 million kilowatt-hours, or 23 percent, of our total industrial sales in 2010. In total, we serve four major paper and pulp mills directly and one paper mill indirectly by providing wholesale service to the retail provider of electricity to the mill. Minnesota Power's paper and pulp customers ran at, or very near, full capacity for the majority of 2010, as the paper industry stabilized and pricing and demand levels recovered following the global recession.

The pipeline industry is the third key industrial class served by Minnesota Power with services provided to two crude oil pipelines and one refinery indirectly through SWL&P, which represented 494 million kilowatt-hours, or 7 percent, of our total industrial sales in 2010. These customers have a common reliance on the importation of Canadian crude oil. After near-capacity operations for the past four years, both pipeline operators are executing expansion plans to transport Western Canadian crude oil reserves (Alberta Oil Sands) to United States markets. Access to traditional Midwest markets is being expanded to Southern markets as the Canadian supply is displacing domestic production and deliveries imported from the Gulf Coast.

Large Power Customer Contracts. Minnesota Power has 9 Large Power contracts with 10 Large Power Customers. All of these contracts serve requirements of 10 MW or more of customer load. The customers consist of five taconite producing facilities (two of which are owned by one company and are served under a single contract), one iron nugget plant, and four paper and pulp mills.

REGULATED OPERATIONS (Continued)
Large Power Customer Contracts (Continued)

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatt-hour used that recovers the variable costs incurred in generating electricity. Four of the Large Power Customers have interruptible service which provides a discounted demand rate for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatt-hour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Item 1. Business – Regulated Operations – Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's prediction of the customer's energy usage, forecasted energy prices, and fuel clause adjustment estimates. Minnesota Power's five taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, which makes the variance between the estimated usage and actual usage small.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2011

Customer	Industry	Location	Ownership	Earliest Termination Date
ArcelorMittal USA – Minorca Mine *(a)*	Taconite	Virginia, MN	ArcelorMittal USA Inc.	January 31, 2015
Hibbing Taconite Co. *(c)*	Taconite	Hibbing, MN	62.3% ArcelorMittal USA Inc. 23.0% Cliffs Natural Resources Inc. 14.7% United States Steel Corporation	December 31, 2015
United States Steel Corporation (USS) (USS – Minnesota Ore) *(a,b)*	Taconite	Mt. Iron, MN and Keewatin, MN	United States Steel Corporation	January 31, 2015
United Taconite LLC *(c)*	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	December 31, 2015
Mesabi Nugget Delaware, LLC *(c)*	Iron Nugget	Hoyt Lakes, MN	Steel Dynamics, Inc (80%) Kobe Steel USA (20%)	December 31, 2017
UPM, Blandin Paper Mill *(a)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	January 31, 2015
Boise White Paper, LLC *(c)*	Paper	International Falls, MN	Boise Paper Holdings, LLC	December 31, 2013
Sappi Cloquet LLC *(a)*	Paper and Pulp	Cloquet, MN	Sappi Limited	January 31, 2015
NewPage Corporation – Duluth Mills *(a)*	Paper and Pulp	Duluth, MN	NewPage Corporation	January 31, 2015

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is January 31, 2015.
(b) United States Steel Corporation owns both the Minntac Plant in Mountain Iron, MN and the Keewatin Taconite Plant in Keewatin, MN.
(c) As of February 1, 2011, the contract has not reached the period of advance notice of cancellation.

Residential and Commercial Customers. In 2010, our residential and commercial customers represented 20 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 146,000 residential and commercial customers. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

REGULATED OPERATIONS (Continued)

Municipal Customers. In 2010, our municipal customers represented 7 percent of total regulated utility kilowatt-hour sales, which included 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 customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers which will continue until the required three-year advance notice of cancellation has been given. To date, no termination notices have been received. Under the formula-based rates provision, wholesale rates are set at the beginning of the year based on expected costs and provide for a true-up calculation for actual costs.

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. 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.

Basin Power Sales Agreement. On October 29, 2009, Minnesota Power entered into an agreement to sell 100 MW of capacity and energy for a ten-year period to Basin which began in May 2010. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro-rata share of increased costs related to emissions that may occur during the last five years of the contract.

Power Supply

In order to meet our customers' electric requirements, we utilize a mix of Company generation and purchased power. The Company's generation is primarily coal-fired, but also includes approximately 101 MW of hydro generation from ten hydro stations in Minnesota, approximately 62 MW of wind generation, and 76 MW of biomass co-fired generation. Purchased power is made up of long-term coal, wind and hydro power purchase agreements and market purchases. The following table reflects the Company's generating capabilities as of December 31, 2010 and total electrical output for 2010. Minnesota Power had an annual net peak load of 1,604 MW on August 30, 2010.

REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability	Year Ended December 31, 2010 Generation and Purchases	
			MW	MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	68		
in Cohasset, MN	2	1960	66		
	3	1973	362		
	4	1980	468		
			964	5,680,246	42.2%
Laskin Energy Center	1	1953	56		
in Hoyt Lakes, MN	2	1953	51		
			107	516,369	3.8
Taconite Harbor Energy Center	1	1957	76		
in Schroeder, MN	2	1957	76		
	3	1967	79		
			231	1,244,316	9.2
Total Coal			1,302	7,440,931	55.2
Biomass/Coal/Natural Gas					
Hibbard Renewable Energy Center					
in Duluth, MN	3 & 4	1949, 1951	54	163,945	1.2
Cloquet Energy Center					
in Cloquet, MN	5	2001	22	104,636	0.8
Total Biomass/Coal/Natural Gas			76	268,581	2.0
Hydro					
Group consisting of ten stations in MN	Various		101	418,286	3.1
Wind *(a)*					
Taconite Ridge					
in Mt. Iron, MN	1-10	2008	4	63,958	0.5
Bison 1					
in Center, ND	1-16	2010	8	10,274	0.1
Total Wind			12	74,232	0.6
Total Company Generation			1,491	8,202,030	60.9
Long-Term Purchased Power					
Lignite Coal – Square Butte near Center, ND				1,294,082	9.6
Wind – Oliver County, ND				331,541	2.5
Hydro – Manitoba Hydro in Winnipeg, MB, Canada				523,825	3.9
Total Long-Term Purchased Power				2,149,448	16.0
Other Purchased Power *(b)*				3,112,782	23.1
Total Purchased Power				5,262,230	39.1
Total			1,491	13,464,260	100.0%

(a) The nameplate capacity of Taconite Ridge is 25 MW. The nameplate capacity of the first phase of Bison 1 is 36.8 MW and was commissioned December 8, 2010. The capacity reflected in the table is actual accredited capacity of the facility. Accredited capacity is the amount of net generating capability associated with the facility for which capacity credit was obtained using limited historical data. As more data is collected, actual accredited capacity may increase.

(b) Includes short-term market purchases in the MISO market and from Other Power Suppliers.

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin coal region located in Montana and Wyoming. Coal consumption in 2010 for electric generation at Minnesota Power's coal-fired generating stations was approximately 4.6 million tons. As of December 31, 2010, Minnesota Power had a coal inventory of about 824,000 tons. Minnesota Power's primary coal supply agreements have expiration dates through 2013. Under these agreements, Minnesota Power has the flexibility to procure 50 percent to 70 percent of its total coal requirements. In 2011, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. This diversity in coal supply options allows Minnesota Power to manage its coal market price and supply risk and to take advantage of favorable spot market prices. Minnesota Power continues to explore future coal supply options. We believe that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Minnesota Power also has transportation agreements in place for the delivery of a significant portion of its coal requirements. These transportation agreements expire in various years between 2013 and 2015.

REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Coal Delivered to Minnesota Power

Year Ended December 31	2010	2009	2008
Average Price per Ton	$25.49	$24.99	$22.73
Average Price per MBtu	$1.42	$1.37	$1.25

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under the agreement with Square Butte, which expires at the end of 2026, Minnesota Power is currently entitled to 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 10. Commitments, Guarantees, and Contingencies.) BNI Coal supplies lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte's cost of lignite burned in 2010 was approximately $1.28 per MBtu.

We have two wind PPAs with an affiliate of NextEra Energy to purchase the output from two wind facilities, Oliver Wind I and II located near Center, North Dakota. We began purchasing the output from Oliver Wind I, a 50-MW facility, in December 2006 and the output from Oliver Wind II, a 48-MW facility, in November 2007. Each agreement is for 25 years and provides for the purchase of all output from the facilities. We pay a contracted energy price and will receive any potential renewable energy or environmental air quality credits. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

We also have a PPA with Manitoba Hydro that began in May 2009 and expires in April 2015. Under the agreement with Manitoba Hydro, Minnesota Power is currently purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

On April 30, 2010, Minnesota Power signed a definitive agreement with Manitoba Hydro, subject to MPUC approval, to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power is committed to purchase at least one million MWh of energy over the contract term. On September 1, 2010, we filed a petition with the MPUC to approve our PPA with Manitoba Hydro. On October 28, 2010, the OES filed comments recommending approval.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 250 kV (465 miles), 230 kV (632 miles), 161 kV (43 miles), 138 kV (128 miles), 115 kV (1,100 miles) and less than 115 kV (6,234 miles). We own and operate 167 substations with a total capacity of 11,102 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

Investment in ATC

Rainy River Energy, our wholly owned subsidiary, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2010, our equity investment balance in ATC was $93.3 million ($88.4 million at December 31, 2009). (See Note 6. Investment in ATC.)

Properties

We own office and service buildings, an energy control center, repair shops, and storerooms in various localities. All of our electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Generally, we hold fee interest in our real properties subject only to the lien of the mortgages. Most of our electric lines are located on land not owned in fee, but are covered by appropriate easement rights or by necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4. Jointly-Owned Electric Facility.)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, issuance of ALLETE securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce, certain accounting and record-keeping practices and ATC. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by appropriate regulatory authorities. Minnesota Power designs its electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental and renewable expenditures.

Information published by the Edison Electric Institute (*Typical Bills and Average Rates Report – Summer 2010* and *Rankings – July 1, 2010*) ranked Minnesota Power as having the sixteenth lowest average retail rates out of 168 utilities in the United States. Minnesota Power had the lowest rates in Minnesota and fourth lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

Minnesota Public Utilities Commission. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, issuance of securities and other matters.

2010 Rate Case. On November 2, 2009, Minnesota Power filed an $81 million retail rate increase request 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. Interim rates were put into effect on January 1, 2010, and were originally estimated to increase revenues by $48.5 million in 2010. In April 2010, we adjusted our initial filing for events that had occurred since November 2009 – primarily increased sales to our industrial customers – resulting in a retail rate increase request of $72 million, a return on equity request of 11.25 percent, and a capital structure consisting of 54.29 percent equity and 45.71 percent debt. As a result of these increased sales, interim rates increased revenues to approximately $52 million for 2010.

On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail electric rate increase of approximately $54 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. In a hearing on January 19, 2011, the MPUC denied all reconsideration requests. Final rates will be implemented after MPUC acceptance of the compliance filing, estimated in the second quarter of 2011. Minnesota Power will continue to collect interim rates from its customers until the new rates go into effect. We expect no interim rate refunds will be issued.

North Dakota Wind Development. On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota, to Duluth, Minnesota. We use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is a two phase, 82 MW wind project in North Dakota. All permitting has been received and the first phase was completed in 2010. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of 16 2.3 MW wind turbines, all of which were in-service at the end of 2010. Phase two is expected to be completed late in 2011 and consists of the installation of 15 3.0 MW wind turbines. Bison 1 is expected to have a total capital investment of approximately $177 million, of which $121 million was spent through December 31, 2010. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery eligibility for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010.

Bison 2 is a 105 MW wind project in North Dakota which, if approved by the MPUC, is expected to be completed by the end of 2012. The total project investment is estimated to be approximately $160 million, and construction would begin upon the receipt of all regulatory and permitting approvals. We will file for MPUC approval for the project and NDPSC site permit approval in the first quarter of 2011. Once the Bison 2 project and related permitting are approved by the MPUC, we will seek current cost recovery eligibility for our investment.

Hibbard Biomass Upgrade Project. Hibbard is a 50 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The upgrade project, which was approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at an expected total cost of approximately $22 million. Upon receipt of any necessary permitting approvals, construction would begin in 2011, and could be completed by the end of 2012. We also plan to seek current cost recovery authorization for the project from the MPUC in 2011.

REGULATED OPERATIONS (Continued)
Regulatory Matters (Continued)

Integrated Resource Plan. On October 5, 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan, 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 through 2025, 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 CO_2); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan to reshape our generation portfolio by adding 300 to 500 MW of renewable energy to our generation mix, and exploring options to incorporate peaking or intermediate resources. The first phase of the Bison 1 wind project in North Dakota was put into service in 2010 and the second phase is expected to be in service in late 2011, increasing our renewable generation by a total of 82 MW. The Bison 2 105 MW wind project, if approved by the MPUC, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

We project average annual long-term growth, excluding prospective additional load from industrial and municipal customers, of approximately one percent in electric usage through 2025. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation. We expect MPUC action on our Integrated Resource Plan filing in 2011.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. In our 2010 rate case, the MPUC approved moving completed transmission projects from the current cost recovery rider to base rates. In July 2010, we filed for an updated billing factor that includes additional transmission projects and expenses which we expect to be approved in early 2011.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from retail customers through a billing adjustment and amounts included in retail base rates. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, as well as a carrying charge on the deferred account balance. Minnesota's Next Generation Energy Act of 2007 introduced, in addition to minimum spending requirements, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. In June 2008, a biennial filing was submitted for 2009 and 2010, and subsequently approved by the OES. Minnesota Power's CIP investment goal was $4.6 million for 2010 ($4.6 million for 2009; $3.7 million for 2008), with actual spending of $5.6 million in 2010 ($5.5 million in 2009; $4.8 million in 2008). For future program years, Minnesota Power will build upon current successful CIPs in an effort to meet or exceed the newly established 1.5 percent energy-saving goal. In June 2010, a triennial filing was submitted for 2011 through 2013, and subsequently approved by the OES.

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce, certain accounting and record-keeping practices and the operations of ATC.

Minnesota Power's non-affiliated municipal 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 customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers which will continue until the required three-year advance notice of cancellation has been given. To date, no termination notices have been received. The rates included in these contracts are calculated using a cost-based formula methodology that is set at the beginning of the year using estimated costs, and provides for a true-up calculation for actual costs. Under the formula-based rates provision, wholesale rates, including the estimate to true-up to actual costs, were comparable in 2010 to 2009, and are projected to be comparable in 2011.

The Energy Policy Act of 2005 (EPAct 2005) was signed into law, which enacted PUHCA 2005. PUHCA 2005 gives FERC certain authority over books and records of public utility holding companies and their affiliates. It also addresses FERC review and authorization of the allocation of costs for non-power goods, or administrative or management services when requested by a holding company system or state commission. In addition, EPAct 2005 directs the FERC to issue certain rules addressing electricity reliability, investment in energy infrastructure, fuel diversity for electric generation, promotion of energy efficiency and wise energy use.

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of our utility subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of our utility activities, including regulation of retail rates and environmental matters.

Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters.

During 2010, SWL&P's retail rates were based on a 2008 PSCW retail rate order, which was effective January 1, 2009. SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.80 percent increase in water rates, a 2.49 percent increase in natural gas rates and a 0.68 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2 million in additional revenue.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

On March 10, 2010, the NDPSC approved the construction of a 22-mile, 230 kV transmission line that connected Bison 1 to the DC transmission line at the Square Butte Substation in Center, North Dakota.

Regional Organizations

Midwest Independent Transmission System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets and control area functions, their transmission network is under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. MISO continues its efforts to standardize rates, terms, and conditions of transmission service over its broad region, encompassing all or parts of 15 states and one Canadian province, and over 100,000 MW of generating capacity.

Mid-Continent Area Power Pool (MAPP). Minnesota Power also participates in MAPP, a power pool operating in parts of nine states in the Upper Midwest and in two Canadian provinces. MAPP functions include a regional transmission committee that is charged with planning for the future transmission needs of the region as well as ensuring that all electric industry participants have equal access to the transmission system.

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota to 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. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resources Plan filed October 5, 2009 with the MPUC. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to meet the 12 percent renewable energy sales milestone by 2012.

Competition

Retail energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users outside of a municipality of 2 MW and above may be allowed to choose a supplier upon MPUC approval. Minnesota Power serves 10 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. No other large commercial or small industrial customers have attempted to seek a provider outside of Minnesota Power's service territory since 1994. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other fuels for their manufacturing processes.

For the year ended December 31, 2010, 7 percent of the Company's energy sales were sales to municipal customers in Minnesota and a private utility in Wisconsin by contract under a formula-based rate approved by FERC. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration.

The FERC has continued with its efforts to promote a more competitive wholesale market through open-access transmission and other means. As a result, our sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are in the competitive market.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 94 cities and towns located within its electric service territory. SWL&P holds 17 similar franchises for electric, natural gas and/or water systems in 1 city and 16 villages and towns within its service territory. The remaining cities, villages and towns served by us do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

INVESTMENTS AND OTHER

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal

BNI Coal is a low-cost supplier of lignite in North Dakota, producing about 4 million tons annually. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Coal's production of lignite under cost-plus, fixed fee coal supply agreements extending through 2026. (See Item 1. Business – Long-Term Purchased Power and Note 10. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. The average cost to reclaim one acre of land is approximately $35,000; however, depending on conditions, it could be significantly higher. Reclamation costs are included in the cost of coal passed through to customers. BNI Coal has lignite reserves of an estimated 600 million tons.

ALLETE Properties

ALLETE Properties is our Florida real estate investment. Our strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets at reasonable prices when opportunities arise, and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Ormond Crossings is a third major project that is currently in the planning stage. On February 16, 2010, the City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings. The agreement will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings. Market conditions will determine when our projects will be built out. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook for more information on ALLETE Properties' land holdings.

Town Center. Town Center, which is located in the City of Palm Coast, is a mixed-use development with a neo-traditional downtown core area. Construction of the major infrastructure improvements at Town Center was substantially complete at the end of 2008. At build-out, Town Center is expected to include approximately 3,000 residential units and 4.0 million square feet of various types of non-residential space. Sites have also been set aside for a new city hall, a community center, an art and entertainment center, and other public uses.

Palm Coast Park. Palm Coast Park, which is located in the City of Palm Coast, is a 4,700-acre mixed-use development. Construction of the major infrastructure improvements at Palm Coast Park was substantially complete at the end of 2007. At build-out, Palm Coast Park is expected to include approximately 4,000 residential units and 3.0 million square feet of various types of non-residential space and public facilities.

Ormond Crossings. Ormond Crossings, which is located in the City of Ormond Beach, is a 3,000-acre, mixed-use development. Planning, engineering design, and permitting of the master infrastructure are ongoing. At build out, Ormond Crossings is expected to include approximately 3,000 residential units and 5.0 million square feet of various types of non-residential space and public facilities. We do not expect any development activity at Ormond Crossings in 2011.

ALLETE Properties (Continued)

Lake Swamp. Lake Swamp wetland mitigation bank is a 1,900 acre regionally significant wetlands mitigation bank that was permitted by the St. Johns River Water Management District in 2008 and the U.S. Army Corps of Engineers in December 2009. Wetland mitigation credits will be used at Ormond Crossings and will also be available for sale to developers of other projects that are located in the bank's service area. When additional credits are needed, applications will be submitted to expand the bank by approximately 1,000 acres.

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. At December 31, 2010, outstanding finance receivables were $3.7 million, with maturities up to 3 years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Regulation. A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

Non-Rate Base Generation

As of December 31, 2010, non-rate base generation consists of 30 MW of generation at Rapids Energy Center. In 2010, we sold 0.1 million MWh of non-rate base generation (0.2 million in 2009 and 2008). In November 2009 Cloquet Energy Center was transferred from non-rate base generation to regulated operations.

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability (MW)
Rapids Energy Center *(a)*				
in Grand Rapids, MN				
Steam – Biomass *(b)*	6 & 7	1969, 1980	2000	29
Hydro – Conventional Run-of-River	4 & 5	1917	2000	1

(a) The net generation is primarily dedicated to the needs of one customer.
(b) Rapids Energy Center is supplemented by coal.

Other

Minnesota Land. We have approximately 7,000 acres of land available-for-sale in Minnesota. We acquired the land in 2001 when we purchased the Taconite Harbor generating facilities.

Environmental Matters

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

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to 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. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Requirements.)

We review environmental matters on a quarterly basis. Accruals for environmental liabilities 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 the consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is heavily regulated both at the Federal and State level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's generating facilities are equipped with pollution control equipment such as scrubbers, bag houses, and low NO_x technologies. These facilities are currently in compliance with applicable emission requirements.

Environmental Matters (Continued)

New Source Review. In August 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 asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements, and that the Boswell Unit 4 Title V permit was violated. Minnesota Power believes the projects were in full compliance with the Clean Air Act, NSR requirements and applicable permits.

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 emissions at Laskin and Boswell, and continues to reduce emissions at Boswell. 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.

EPA Transport Rule. On July 6, 2010, the EPA proposed a rule known as the Transport Rule (TR) requiring 31 states, including Minnesota and the District of Columbia, to reduce power plant SO_2 and NO_x emissions that can significantly contribute to ozone and fine particle pollution problems in other states. If adopted, the TR will replace the Clean Air Interstate Rule (CAIR) that was issued by the EPA in March 2005. Minnesota was included as one of the original 28 CAIR states but, following Minnesota Power's successful challenge to CAIR, the EPA granted an administrative stay of the CAIR requirements in Minnesota while it prepared the TR. The proposed TR responds to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR by replacing and reforming questionable provisions to address updated air quality standards, improved emissions data and reformed emissions transport modeling.

The EPA took public comments on the proposed rule through October 1, 2010, and plans to finalize the rule in June 2011. Emissions reductions are proposed to take effect in 2012, within one year of projected finalization of the rule.

The EPA has not yet determined whether trading of emission allowances between regulated generating units or states may be implemented. Since 2006, we have made substantial investments in pollution control equipment at our Laskin, Taconite Harbor and Boswell generating units which have significantly reduced emissions. These reductions may or may not satisfy Minnesota Power's obligations with respect to these requirements. We are unable to predict any additional compliance costs we might incur at this time.

Minnesota Regional Haze. The federal 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, put in place between 1962 and 1977, with emissions contributing to visibility impairment are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two 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 CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR. Subsequently, the MPCA requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirement for that unit. In December 2009, the MPCA approved the SIP for submittal to the EPA for its review and approval. Approval of the Minnesota SIP by the EPA is pending. If approved, Minnesota Power will have five years to bring Taconite Harbor Unit 3 into compliance. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Electric Utility Units. Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants for certain source categories. In December 2009, Minnesota Power and other utilities received an Information Collection Request from the EPA requiring that emissions data be provided and stack testing be performed in order to develop a database upon which to base future regulations. On March 30, 2010, Minnesota Power responded to the Information Collection Request. Stack testing was completed during the third quarter of 2010 and the results were submitted to the EPA. The EPA is subject to a consent decree which requires the EPA to propose a utility NESHAPs rule by March 2011, with the final rule by November 2011. As part of the NESHAPs rulemaking, the EPA will develop Maximum Achievable Control Technology standards for utilities. Costs for complying with potential future mercury and other hazardous air pollutant regulations under the Clean Air Act cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Costs for the Boswell Unit 4 emission reduction plan cannot be estimated at this time.

Environmental Matters (Continued)

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

Ozone NAAQS. The EPA is proposing to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to reduce the eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA expects to issue final standards by July 2011. As proposed, states have until early 2014 to submit plans outlining how they will meet the standards.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. The EPA established a more stringent 24-hour average fine particulate ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The District of Columbia Circuit Court of Appeals has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status. The EPA plans to finalize the new $PM_{2.5}$ standards in 2011, and state attainment status determination will likely not occur prior to 2013. As early as late 2014, affected sources would have to take additional control measures if modeling demonstrates non-compliance at the property boundary.

SO_2 and NO_2 NAAQS. The EPA recently finalized new one-hour NAAQS for SO_2 and NO_2. Monitor data indicates that Minnesota will likely be in compliance with these new standards; however, the SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. It is unclear what the outcome of this evaluation will be. These NAAQS could also result in more stringent emission limits on our steam generating facilities, possibly resulting in additional control measures on some of our units.

We are unable to predict the nature or timing of any additional NAAQS regulation or compliance costs we might incur at this time.

Climate Change. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customer's requirements:

- Expand our renewable energy supply.
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies.
- Provide energy conservation initiatives for our customers and engage in other demand side efforts.
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.
- Achieve overall carbon emission reductions.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations.

Midwestern Greenhouse Gas Reduction Accord. Minnesota is also participating in the Midwestern Greenhouse Gas Reduction Accord (the Accord), a regional effort to develop a multi-state approach to GHG emission reductions. The Accord includes an agreement to develop a multi-sector cap-and-trade system to help meet the targets established by the group.

EPA Regulation of GHG Emissions. On May 13, 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The PSD/Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications, and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V operating permits to include GHGs requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V operating permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as an increase of 75,000 tons per year or more of total GHG on a CO_2 equivalent basis.

Environmental Matters (Continued)

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

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed and are awaiting judicial determination. Comments to the Permitting Guidance were also submitted and may be addressed by EPA in the form of revised guidance documents.

We cannot predict the nature or timing of any additional GHG legislation or regulation. Although we are unable to predict the compliance costs we might incur, the costs could have a material impact on our financial results.

Research and Study Initiatives. We participate in several research and study initiatives aimed at mitigating the potential impact of carbon emissions regulation on our business. Initiatives include assessment of carbon emissions impacts through the use of renewable energy. In developing strategies for our comprehensive approach to reducing our carbon emissions, we participate in and fund organizations and studies.

We participate in the Electric Power Research Institute's CoalFleet for Tomorrow program, which reviews advanced clean coal generation and carbon capture research and assessment. Similarly we participate as a North Dakota Lignite Interest member of the Canadian Clean Power Coalition. The CoalFleet for Tomorrow program also reviews advanced clean coal technologies focusing on lower rank sub-bituminous and lignite fuel energy conversion technologies and carbon control options. Our participation provides Minnesota Power the ability to assess what technologies will best fit the economic fuels that are available in our region and when they may be available.

We also participate in research through the Plains CO_2 Reduction Partnership (PCOR). PCOR is looking at CO_2 capture technology through research conducted at the Energy and Environmental Research Center, University of North Dakota. Minnesota Power is a partner, along with a number of other utilities, technology providers, and consultants, to further research on CO_2 capture techniques, operational issues and costs. The partnership is funded by the members as well as the Department of Energy.

We cannot predict whether our participation in any of these activities will result in a benefit to ALLETE or impact the future financial position or results of operations of the Company.

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

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA. The Toxic Substances Control Act regulates the management and disposal of materials containing polychlorinated biphenyl (PCB). In response to the EPA Region V's request for utilities to participate in the Great Lakes Initiative by voluntarily removing remaining PCB inventories, Minnesota Power is in the process of voluntarily replacing its remaining PCB capacitor banks. Known PCB-contaminated oil in substation equipment was replaced by June 2007. We are in material compliance with these rules.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its steam electric stations. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use, or trucked to state permitted landfills. On June 18, 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory classifications for coal ash. Public comments were submitted to the EPA in November 2010. We are unable to predict the compliance costs we might incur; however, there is the possibility they could have a material impact.

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. At December 31, 2010, we have a $0.5 million liability for this site, and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Environmental Matters (Continued)

Employees

At December 31, 2010, ALLETE had 1,465 employees, of which 1,401 were full-time.

Minnesota Power and SWL&P had an aggregate 596 employees who are members of the IBEW Local 31. Throughout 2009, Minnesota Power, SWL&P and IBEW Local 31 worked towards settling new contracts to replace those which expired on January 31, 2009. Final resolution of the union contracts for Minnesota Power and SWL&P occurred in January and March 2010, respectively. Both agreements were retroactive to February 1, 2009, and were to expire on January 31, 2012. In December 2010, the current agreements were extended through January 31, 2014.

BNI Coal had 141 employees, of which 105 are members of the IBEW Local 1593. BNI Coal and IBEW Local 1593 have a labor agreement which expires on March 31, 2011. BNI Coal and the IBEW Local 1593 have a good working relationship and management anticipates negotiation with no disruption of service.

Availability of Information

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports, available free of charge on ALLETE's website www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

Executive Officers of the Registrant

As of February 16, 2011, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 51	
President and Chief Executive Officer – ALLETE	May 1, 2010
President – ALLETE	May 1, 2009
Chief Operating Officer – Minnesota Power	May 8, 2007
Senior Vice President – Minnesota Power Operations	September 22, 2006
Vice President – Minnesota Power Generation	May 1, 2005
Robert J. Adams, Age 48	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Vice President – Utility Business Development	February 1, 2004
Deborah A. Amberg, Age 45	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Vice President, General Counsel and Secretary	March 8, 2004
Steven Q. DeVinck, Age 51	
Controller and Vice President – Business Support	December 5, 2009
Controller	July 12, 2006
David J. McMillan, Age 49	
Senior Vice President - Marketing, Regulatory and Public Affairs – ALLETE	January 1, 2006
Executive Vice President - Minnesota Power	January 1, 2006
Senior Vice President - Marketing and Public Affairs – ALLETE	October 2, 2003
Mark A. Schober, Age 55	
Senior Vice President and Chief Financial Officer	July 1, 2006
Senior Vice President and Controller	February 1, 2004
Donald W. Stellmaker, Age 53	
Treasurer	July 24, 2004

All of the executive officers have been employed by us for more than five years in executive or management positions. Prior to election to the positions shown above, the following executive held other positions with the Company during the past five years:

Mr. DeVinck was Director of Nonutility Business Development, and Assistant Controller.

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 10, 2011.

Item 1A. Risk Factors

The factors discussed below, as well as other information set forth in this Form 10-K, which could materially affect our business, financial condition and results of operations should be carefully considered. The risks and uncertainties described below are not the only ones 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 below are realized.

Our results of operations could be negatively impacted if our Large Power Customers experience an economic down cycle or fail to compete effectively in the global economy.

Our ten Large Power Customers accounted for approximately 31 percent of our 2010 consolidated operating revenue (23 percent in 2009; 36 percent in 2008). One of these customers accounted for 12.5 percent of consolidated revenue in 2010 (8.0 percent in 2009; 12.5 percent in 2008). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the global marketplace. An economic downturn or failure to compete effectively in the global economy could have a material adverse effect on their operations and, consequently, could negatively impact our results of operations if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our operations are subject to extensive governmental regulations that may have a negative impact on our business and results of operations.

We are subject to prevailing governmental policies and regulatory actions, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC and the EPA. These governmental regulations relate to allowed rates of return, financings, industry rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities under established reliability standards), recovery of purchased power and capital investments, and present or prospective wholesale and retail competition. The Company must also comply with permits, licenses and any other authorizations as issued by local, state and federal agencies. These governmental regulations significantly influence our operating environment and may affect our ability to recover costs from our customers. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain current rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or current authorized rates of return on capital will be earned. Minnesota Power and SWL&P from time to time file rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in rate cases, if rates are reduced, if increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, or if cost recovery is not achieved at the requested level, we may experience an adverse impact on our financial condition, results of operations and cash flows. We are unable to predict the impact on our business and operations results from future regulatory activities of any of these agencies.

Our operations could be adversely impacted by emissions of GHG that are linked to global climate change.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations.

Our operations could be adversely impacted by initiatives designed to reduce the impact of GHG emissions such as CO_2 from our generating facilities.

Proposals for voluntary initiatives and mandatory controls to reduce GHGs such as CO_2, a by-product of burning fossil fuels, are being discussed within Minnesota, among a group of Midwestern states that includes Minnesota, in the United States Congress and worldwide. We currently use coal as the primary fuel in 95 percent of the energy produced by our generating facilities.

There is significant uncertainty regarding whether new laws or regulations will be adopted to reduce GHGs and what effect any such laws or regulations would have on us. If any new laws or regulations are implemented, they could have a material effect on our results of operations, particularly if implementation costs are not fully recoverable from customers.

The cost of environmental emission allowances could have a negative financial impact on our operations.

Minnesota Power is subject to numerous environmental laws and regulations which cap emissions and could require us to purchase environmental emissions allowances to be in compliance. The laws and regulations expose us to emission allowance price fluctuations which could increase our cost of operations. We are unable to predict the emission allowance pricing, regulatory recovery or ratepayer impact of these costs.

Our operations pose certain environmental risks which could adversely affect our results of operations and financial condition.

We are subject to extensive environmental laws and regulations affecting many aspects of our present and future operations, including air quality, water quality, waste management, reclamation, hazardous wastes and natural resources. These laws and regulations can result in increased capital, operating and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions.

The laws could, among other things, restrict the output of some existing facilities, limit the use of some fuels required for the production of electricity, require additional pollution control equipment and otherwise increase costs and lead to other environmental considerations.

These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the financial or operational outcome of any related litigation that may arise.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for non-compliance.

We rely on access to financing sources and capital markets. If we do not have access to sufficient capital in the amount and at the times needed, our ability to execute our business plans, make capital expenditures or pursue acquisitions that we may otherwise rely on for future growth could be impaired.

We rely on access to capital markets as sources of liquidity for capital requirements not satisfied by our cash flow from operations. If we are not able to access capital on satisfactory terms, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access financial markets. Such disruptions could include a severe prolonged economic downturn, the bankruptcy of non-affiliated industry leaders in the same line of business or financial services sector, deterioration in capital market conditions, or volatility in commodity prices.

The operation and maintenance of our generating facilities involve risks that could significantly increase the cost of doing business.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on a specific fuel source, failures in the supply availability or transportation of fuel, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency, the occurrence of any of which could result in lost revenue, increased expenses or both. A significant portion of Minnesota Power’s facilities were constructed many years ago. In particular, older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvements due to changing environmental standards and technological advances. Minnesota Power could be subject to costs associated with any unexpected failure to produce power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events. Further, our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement.

Our electrical generating operations must have adequate and reliable transmission and distribution facilities to deliver electricity to our customers.

Minnesota Power depends on transmission and distribution facilities owned by other utilities, and transmission facilities primarily operated by MISO, as well as its own such facilities, to deliver the electricity we produce and sell to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered. We may have to forego sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers with our service.

The price of electricity and fuel may be volatile.

Volatility in market prices for electricity and fuel may result from:

- severe or unexpected weather conditions;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at Minnesota Power's generating facilities or those of our competitors;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- natural disasters, wars, sabotage, terrorist acts or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Since fluctuations in fuel expense related to our regulated utility operations are passed on to customers through our fuel clause, risk of volatility in market prices for fuel and electricity mainly impacts our sales to Other Power Suppliers.

We are dependent on a qualified workforce and good labor relations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures or terms of collective bargaining agreements with union employees. We believe we have good relations with our members of the IBEW Local 31 and IBEW Local 1593, and have contracts in place through January 31, 2014, and March 31, 2011, respectively.

Market performance and other changes could decrease the value of pension and postretirement health benefit plan assets, which then could require significant additional funding and increase annual expense.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement benefit plans. We have significant obligations to these plans and the Company holds significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and postretirement benefit plan assets will increase the funding requirements under our benefit plans if the actual asset returns do not recover. Additionally, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and postretirement health care costs are generally recoverable in our electric rates as allowed by our regulators. However, there is no certainty that regulators will continue to allow recovery of these rising costs in the future.

Emerging technologies or cyber attacks may adversely affect our business operations.

While the pace of technology development has been increasing, the basic concept upon which our business model is based of how energy is produced, sold and delivered has remained essentially unchanged. The development of new commercially viable technology in areas such as distributed generation, energy storage and energy conservation could fundamentally change demand for our current products and services. A security breach of our information systems could subject us to financial harm associated with theft or inappropriate release of certain types of information, including, but not limited to, customer or system operating information. Cyber attacks could affect our operations and subject us to financial harm.

Risk Factors (Continued)

The current downturn in economic conditions may adversely affect our strategy to sell our Florida real estate.

ALLETE intends to sell its Florida land assets at reasonable prices over time or in bulk transactions when opportunities arise. However, if 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 operating losses similar to 2010. Additionally, because of the current real estate market conditions in Florida, we cannot predict when we will be able to sell these assets at prices we find to be reasonable.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Properties are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

Item 3. Legal Proceedings

Material legal and regulatory proceedings are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer’s, United Taconite, LLC, property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An expense related to any damages that may result from the lawsuit has not been recorded as of December 31, 2010, because a potential loss is not currently probable or reasonably estimable; however, the Company believes it has adequate insurance coverage for potential loss.

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. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Removed and Reserved

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.445 per share on our common stock will be paid on March 1, 2011, to the holders of record on February 15, 2011.

The following table shows dividends declared per share, and the high and low prices for our common stock for the periods indicated as reported by the NYSE:

	2010			2009		
	Price Range		Dividends	Price Range		Dividends
Quarter	**High**	**Low**	**Declared**	**High**	**Low**	**Declared**
First	$34.00	$29.99	$0.44	$33.27	$23.35	$0.44
Second	37.87	32.90	0.44	29.14	24.45	0.44
Third	37.75	33.16	0.44	34.57	27.75	0.44
Fourth	37.95	34.81	0.44	35.29	32.23	0.44
Annual Total			$1.76			$1.76

At February 1, 2011, there were approximately 28,000 common stock shareholders of record.

Common Stock Repurchases. During the fourth quarter of 2010, approximately 118,000 shares of ALLETE common stock were purchased on the open market and subsequently reissued under our Invest Direct program.

Item 6. Selected Financial Data

	2010	2009	2008	2007	2006
Millions					
Operating Revenue	$907.0	$759.1	$801.0	$841.7	$767.1
Operating Expenses	771.2	653.1	679.2	710.0	628.8
Income from Continuing Operations Before Non-Controlling Interest – Net of Tax	74.8	60.7	83.0	89.5	81.9
Income (Loss) from Discontinued Operations – Net of Tax	–	–	–	–	(0.9)
Net Income	74.8	60.7	83.0	89.5	81.0
Less: Non-Controlling Interest in Subsidiaries	(0.5)	(0.3)	0.5	1.9	4.6
Net Income Attributable to ALLETE	75.3	61.0	82.5	87.6	76.4
Common Stock Dividends	60.8	56.5	50.4	44.3	40.7
Earnings Retained in Business	$14.5	$4.5	$32.1	$43.3	$35.7
Shares Outstanding – Millions					
Year-End	35.8	35.2	32.6	30.8	30.4
Average *(a)*					
Basic	34.2	32.2	29.2	28.3	27.8
Diluted	34.3	32.2	29.3	28.4	27.9
Diluted Earnings (Loss) Per Share					
Continuing Operations	$2.19	$1.89	$2.82	$3.08	$2.77
Discontinued Operations *(b)*	–	–	–	–	(0.03)
Total Diluted Earnings (Loss) Per Share	$2.19	$1.89	$2.82	$3.08	$2.74
Total Assets	$2,574.9	$2,393.1	$2,134.8	$1,644.2	$1,533.4
Long-Term Debt	771.6	695.8	588.3	410.9	359.8
Return on Common Equity	7.8%	6.9%	10.7%	12.4%	12.1%
Common Equity Ratio	56%	57%	58%	64%	63%
Dividends Declared per Common Share	$1.76	$1.76	$1.72	$1.64	$1.45
Dividend Payout Ratio	81%	93%	61%	53%	53%
Book Value Per Share at Year-End	$27.25	$26.39	$25.37	$24.11	$21.90
Capital Expenditures by Segment					
Regulated Operations	$256.4	$299.2	$317.0	$220.6	$107.5
Investments and Other	3.6	4.5	5.9	3.3	1.9
Total Capital Expenditures	$260.0	$303.7	$322.9	$223.9	$109.4

(a) Excludes unallocated ESOP shares.
(b) Operating results of our Water Services businesses are included in discontinued operations, and accordingly, amounts have been restated for 2006.

Item 7. 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 and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this report 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-K under the headings: "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" located on page 5 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only ones 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 in this Form 10-K 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 146,000 retail customers and wholesale electric service to 16 municipalities. Minnesota Power also provides regulated utility electric service to 1 private utility in Wisconsin. SWL&P provides regulated electric, 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. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2010, 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.

2010 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2010, to the year ended December 31, 2009.

Net income attributable to ALLETE for 2010 was $75.3 million, or $2.19 per diluted share, compared to $61.0 million, or $1.89 per diluted share, for 2009. Net income for 2010 was reduced by $4.0 million, or $0.12 per share, due to the elimination of the deduction for expenses reimbursed under Medicare Part D. Net income for 2009 was reduced by a $4.9 million, or $0.15 per share, after-tax charge for the accrual of retail rate refunds related to 2008. Earnings per diluted share decreased $0.14 compared to 2009 as a result of additional shares of common stock outstanding in 2010. (See Note 11. Common Stock and Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $79.8 million in 2010 compared to $65.9 million in 2009. In 2009, net income was reduced by a $4.9 million after-tax charge for the accrual of retail rate refunds related to 2008. The increase in 2010 is attributable to higher MPUC-approved retail rates (subject to final order), increased sales to our Large Power Customers, and increased transmission-related margins. In addition, 2010 reflected an increase of $0.3 million in after-tax earnings from our investment in ATC over 2009. These increases were significantly offset by higher operating and maintenance, depreciation, interest and income tax expenses. Also included in the fourth quarter of 2010 was a $3.4 million after-tax charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case. Income tax expense included a $3.6 million charge resulting from the elimination of the deduction for expenses reimbursed under Medicare Part D.

Investments and Other reflected a net loss attributable to ALLETE of $4.5 million in 2010 compared to a $4.9 million net loss in 2009. The decrease in net loss was primarily due to lower equity losses on investments of $2.6 million and an income tax benefit (including interest) resulting from the completion of a state income tax audit of $1.1 million. These items were partially offset by the transfer of a small generating facility to our Regulated Operations in November 2009. Income tax expense also included a $0.4 million charge resulting from the elimination of the deduction for expenses reimbursed under Medicare Part D. In 2010, ALLETE Properties recorded a net loss of $4.8 million compared to a net loss of $4.7 million in 2009.

2010 Compared to 2009

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

Regulated Operations

Operating revenue increased $153.7 million, or 23 percent, from 2009 due to higher MPUC-approved retail rates (subject to final order) and the absence of an accrual for prior year retail rate refunds related to our 2008 retail rate case. Also contributing to increased revenue were higher transmission revenues, higher fuel and purchased power recoveries, and increased sales to retail and municipal customers. These increases were partially offset by lower sales to Other Power Suppliers.

Interim retail rates authorized by the MPUC in December 2009 and effective January 1, 2010, resulted in an increase of approximately $52 million. (See Note 5. Regulatory Matters.)

Retail rate refunds related to 2008 resulting from the 2009 MPUC Order were recorded in 2009 and resulted in a reduction in 2009 revenues of $7.6 million.

Transmission revenues increased $24.3 million from 2009 primarily due to revenues related to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009. (See Note 10. Commitments, Guarantees and Contingencies.)

Higher fuel and purchased power recoveries, along with an increase in retail and municipal kilowatt-hour sales, combined for a total revenue increase of $115.5 million. Fuel and purchased power recoveries increased due to an increase in fuel and purchased power expense. (See Fuel and Purchased Power Expense.)

The increase in kilowatt-hour sales to retail and municipal customers has been partially offset by decreased revenue from marketing power to Other Power Suppliers, which decreased $50.3 million in 2010. 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.

Total kilowatt-hour sales to retail and municipal customers increased 29.1 percent from 2009 primarily due to an increase in sales to our taconite customers. Increased revenue from industrial sales was partially offset by a 32.3 percent decrease in kilowatt-hour sales to Other Power Suppliers.

Kilowatt-hours Sold	2010	2009	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,150	1,164	(14)	(1.2) %
Commercial	1,433	1,420	13	0.9 %
Industrial	6,804	4,475	2,329	52.0 %
Municipals	1,006	992	14	1.4 %
Total Retail and Municipals	10,393	8,051	2,342	29.1 %
Other Power Suppliers	2,745	4,056	(1,311)	(32.3) %
Total Regulated Utility Kilowatt-hours Sold	13,138	12,107	1,031	8.5 %

Revenue from electric sales to taconite customers accounted for 24 percent of consolidated operating revenue in 2010 (15 percent in 2009). The increase in revenue from our taconite customers was partially offset by a decrease in revenue from electric sales to Other Power Suppliers, which accounted for 12 percent of consolidated operating revenue in 2010 (20 percent in 2009). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2010 (9 percent in 2009). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2010 (7 percent in 2009).

Operating expenses increased $118.0 million, or 21 percent, from 2009.

Fuel and Purchased Power Expense increased $45.6 million, or 16 percent, from 2009. The increase is partially due to higher fuel costs of $18.6 million resulting from a 10 percent increase in coal generation at our facilities and higher coal prices and related transportation. Purchased power expense also increased $19.1 million reflecting increased kilowatt-hour purchases partially offset by lower market prices. Also included in the fourth quarter of 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case, which was determined to be no longer probable of recovery in future utility rates. In 2009, 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.

2010 Compared to 2009 (Continued)
Regulated Operations (Continued)

Operating and Maintenance Expense increased $56.5 million, or 24 percent, from 2009 reflecting additional MISO expenses of $17.3 million relating to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009, higher plant outage and maintenance of $10.2 million, higher environmental reagent expenses of $6.1 million, increased labor and employee benefit costs of $11.0 million and increased property taxes of $3.0 million due to more taxable plant.

Depreciation Expense increased $15.9 million, or 26 percent, from 2009 reflecting higher property, plant, and equipment placed in service.

Interest expense increased $4.0 million, or 14 percent, from 2009 primarily due to additional long-term debt issued to fund new capital investments and for general corporate purposes.

Income tax expense increased $16.2 million, or 46 percent, from 2009 primarily due to higher pretax income and a non-recurring income tax charge of $3.6 million from the deduction of expenses reimbursed under Medicare Part D.

Investments and Other

Operating revenue decreased $5.8 million, or 8 percent, from 2009 primarily due to a $4.8 million decrease in revenue from non-regulated generation. This decrease was primarily the result of the transfer of a small generating facility to Regulated Operations in November 2009. This decrease was partially offset by a $1.3 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue as a result of higher expenses in 2010. (See Operating Expense.)

Revenue at ALLETE Properties decreased $1.8 million from 2009 primarily due to lack of land sales during 2010. This was due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. During 2009, ALLETE Properties sold approximately 35 acres of property located outside of its three main development projects for $3.8 million.

ALLETE Properties	**2010**		**2009**	
Revenue and Sales Activity	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	–	–	35	$3.8
Revenue from Land Sales *(b)*		–		3.8
Other Revenue *(c)*		$2.2		0.2
Total ALLETE Properties Revenue		$2.2		$4.0

(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) Other Revenue includes a $0.7 million pretax gain in 2010 due to the return of seller-financed property from an entity which filed for voluntary Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $0.1 million from 2009 reflecting higher expenses at BNI Coal of $1.8 million primarily due to higher diesel fuel costs in 2010 which were recovered through the cost-plus contract (See Operating Revenue) and higher donation expenses of $1.5 million. These increases were mostly offset by lower non-regulated generation expenses of $2.2 million primarily due to the transfer of a small generating facility to Regulated Operations in November 2009, and decreased expenses at ALLETE Properties of $2.0 million due to reductions in the cost of land sold and general and administrative expenses.

Other income increased $4.8 million from 2009 primarily due to $4.4 million lower equity losses on investments in 2010.

Income Taxes – Consolidated

For the year ended December 31, 2010, the effective tax rate was 37.2 percent (33.7 percent for the year ended December 31, 2009). Excluding additional tax expense recorded as a result of the elimination of the deduction for expenses reimbursed under Medicare Part D, the 2010 effective tax rate was 33.8 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) by comparable amounts in each period due to deductions for depletion, investment tax credits, and wind production tax credits. The 2009 effective tax rate also included the effect of deductions for expenses reimbursed under Medicare Part D. (See Note 13. Income Tax Expense.)

2009 Compared to 2008

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

Regulated Operations

Operating revenue decreased $30.4 million, or 4 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 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 FERC-approved wholesale rates and increased revenue from MPUC-approved 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 $116.2 million. Fuel and purchased power recoveries decreased due to a reduction in fuel and purchased power expense. (See Fuel and Purchased Power Expense.) Total kilowatt-hour sales to retail and municipal customers decreased 26 percent from 2008 primarily due to idled production lines and temporary closures at some of our taconite customers' plants.

Natural gas revenue at SWL&P was lower by $7.8 million due to a 27 percent decrease in the price of natural gas and a 9 percent decline in sales. Natural gas revenue is primarily a flow-through of the natural gas costs. (See Operating and Maintenance Expense.)

Prior year retail rate refunds resulting from the 2009 MPUC Order and August 2009 Reconsideration Order were recorded in 2009 and resulted in a reduction in revenues of $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 $77.2 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.

Higher rates from the March 1, 2008, and February 1, 2009, FERC-approved wholesale rate increases for our municipal customers increased revenue by $13.2 million.

MPUC-approved current cost recovery rider revenue increased $10.4 million in 2009 from 2008 primarily due to increased capital expenditures related to our Boswell Unit 3 emission reduction plan.

Kilowatt-hours Sold	**2009**	**2008**	**Quantity Variance**	**% Variance**
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,164	1,172	(8)	(0.7)%
Commercial	1,420	1,454	(34)	(2.3)%
Industrial	4,475	7,192	(2,717)	(37.8)%
Municipals	992	1,002	(10)	(1.0)%
Total Retail and Municipals	8,051	10,820	(2,769)	(25.6)%
Other Power Suppliers	4,056	1,800	2,256	125.3%
Total Regulated Utility Kilowatt-hours Sold	12,107	12,620	(513)	(4.1)%

Revenue from electric sales to taconite customers accounted for 15 percent of consolidated operating revenue in 2009 (26 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 20 percent of consolidated operating revenue in 2009 (10 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 $20.1 million, or 3 percent, from 2008.

Fuel and Purchased Power Expense decreased $26.1 million, or 9 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 $3.5 million from 2008 primarily due to $7.4 million in lower natural gas costs at SWL&P from a decline in the price and quantity of natural gas purchased. This decrease was partially offset by increased salaries and benefits costs, rate case expenses and plant maintenance.

2009 Compared to 2008 (Continued)
Regulated Operations (Continued)

Depreciation Expense increased $9.5 million, or 19 percent, from 2008 reflecting higher property, plant and equipment balances placed in service.

Interest expense increased $4.3 million, or 18 percent, from 2008 primarily due to additional long-term debt issued to fund new capital investments and $0.5 million related to retail rate refunds.

Equity earnings increased $2.2 million, or 14 percent, from 2008 reflecting higher earnings from our increased investment in ATC. (See Note 6. Investment in ATC.)

Investments and Other

Operating revenue decreased $11.5 million, or 13 percent, from 2008 primarily due to a $14.3 million reduction in sales revenue at ALLETE Properties. In 2009, ALLETE Properties sold approximately 35 acres of properties located outside of our three main development projects for $3.8 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. In 2008, ALLETE Properties sold approximately 219 acres of property located outside of our three main development projects for $6.3 million and recognized $3.7 million of previously deferred revenue under percentage of completion accounting. Revenue at ALLETE Properties in 2008 also included a pretax gain of $4.5 million from the sale of a retail shopping center in Winter Haven, Florida.

ALLETE Properties	2009		2008	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	35	$3.8	219	$6.3
Contract Sales Price *(b)*		3.8		6.3
Revenue Recognized from Previously Deferred Sales		–		3.7
Revenue from Land Sales		3.8		10.0
Other Revenue *(c)*		0.2		8.3
Total ALLETE Properties Revenue		$4.0		$18.3

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflected total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method. (See Note 1. Operations and Significant Accounting Policies.)
(c) Included a $4.5 million pretax 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 $5.6 million as a result of higher expenses. (See Operating Expenses.)

Operating expenses decreased $6.0 million, or 7 percent, from 2008 reflecting lower fuel costs at our non-regulated generating facilities and decreased expense 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, a warranty credit in 2008, and dragline repairs in 2009. These costs were recovered through the cost-plus contract. (See Operating Revenue.)

Interest expense increased $3.2 million from 2008 primarily due to a decrease in the proportion of ALLETE interest expense assigned to Minnesota Power. We record interest expense for Minnesota Power regulated operations based on Minnesota Power's authorized capital structure and allocate the balance to Investments and Other. 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 (expense) decreased $16.0 million from 2008 primarily due to a $6.5 million pretax gain realized from the sale of certain available-for-sale securities in the first quarter of 2008, lower earnings on excess cash in 2009 of $1.9 million, and $1.4 million of interest income related to tax benefits recognized in the third quarter of 2008. Losses incurred on emerging technology investments totaled $4.6 million in 2009, and were $3.9 million higher than similar losses recorded in 2008.

2009 Compared to 2008 (Continued)

Income Taxes – Consolidated

For the year ended December 31, 2009, the effective tax rate was 33.7 percent (34.3 percent for the year ended December 31, 2008). The effective tax rate in each period deviated from the statutory rate (approximately 41 percent for 2009) due to deductions for expenses reimbursed under Medicare Part D, AFUDC-Equity, investment tax credits, wind production tax credits, and depletion. In addition, the effective rate for 2009 was impacted by lower pretax income. In 2008, non-recurring tax benefits due to the closing of a tax year and the completion of an IRS review totaled $4.6 million.

Critical Accounting Estimates

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the consolidated financial statements. These estimates and assumptions may be revised, which may have a material effect on the consolidated financial statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. The following represent the policies we believe are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are accounted for in accordance with the accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets or liabilities arise as a result of a difference between GAAP and the accounting treatment for certain items imposed by the regulatory agencies. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred.

The recoverability of regulatory assets is periodically assessed by considering factors such as, but not limited to, changes in regulatory rules and rate orders issued by applicable regulatory agencies. The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital, and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on our results of operations. (See Note 5. Regulatory Matters.)

Valuation of 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, and other investments. Our policy is to review these investments for impairment on a quarterly basis by assessing such factors as continued commercial viability of products, cash flow and earnings. Our consideration of possible impairment for our real estate assets requires us to make judgments with respect to the current fair values of this real estate. The poor market conditions for real estate in Florida at this time require us to make certain assumptions in the determination of fair values due to the lack of current comparable sales activity. Any impairment would reduce the carrying value of our investments and be recognized as a loss. In 2010 there were $0.8 million of impairment losses recognized ($1.1 million in 2009; none in 2008). (See Note 7. Investments.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of assumptions in determining our obligations and annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns. Our pension asset allocation at December 31, 2010, was approximately 52 percent equity securities, 29 percent debt, 14 percent private equity, and 5 percent real estate. Our postretirement health and life asset allocation at December 31, 2010, was approximately 58 percent equity securities, 33 percent debt, and 9 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. We currently use an expected long-term rate of return of 8.5 percent in our actuarial determination of our pension and other postretirement expense. We review our expected long-term rate of return assumption annually and will adjust it to respond to any changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.3 million, pretax.

Critical Accounting Estimates (Continued)

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension and other postretirement obligation. In 2010, we used a discount rate of 5.81 percent for our actuarial determination of our pension and other postretirement expense. We review our discount rate annually and will adjust it to respond to any changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $1.8 million, pretax. (See Note 15. Pension and Other Postretirement Benefit Plans.)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax asset will not be realized.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The company has as a key objective of achieving minimum average EPS growth of 5 percent per year and maintaining a competitive dividend payout. To accomplish this, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

We believe that over the long term, less carbon intensive and more sustainable renewable energy sources will play an increasingly important role in our nation's energy mix. We intend to develop additional renewable resources which will be used to meet the renewable supply requirements of our regulated businesses. In addition, we intend to establish a non-regulated renewable business to produce and sell renewable energy to others, subject to securing long-term power purchase agreements prior to construction of facilities. The establishment of a non-regulated renewable business is subject to appropriate MPUC approvals.

For wind development, we will capitalize on our existing presence in North Dakota through BNI Coal, our recently acquired DC transmission line and our Bison 1 and 2 wind projects. Through BNI Coal we have a long-term business presence and established landowner relationships in North Dakota. See Renewable Energy below for more discussion on the DC line acquisition and our Bison 1 and 2 projects.

We also plan to make investments in upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid, or take advantage of our geographical location between sources of renewable energy and end users. Minnesota Power is participating with other regional utilities in making regional transmission investments as a member of the CapX2020 initiative. In addition, we plan to make additional investments to fund our pro rata share of ATC's future capital expansion program. Both the CapX2020 initiative and our investment in ATC are discussed in more detail under Transmission below.

We are also exploring investing in other energy-centric businesses that will complement our non-regulated renewable energy business, or leverage demand trends related to transmission, environmental control or energy efficiency.

ALLETE intends to sell its Florida land assets at reasonable prices, over time or in bulk transactions, and reinvest the proceeds in its growth initiatives. ALLETE Properties does not intend to acquire additional real estate.

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and earn our allowed rate of return. Keeping the production of energy competitive enables Minnesota Power to effectively compete in the wholesale power markets, and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review environmental proposals and may challenge those that add considerable cost with limited environmental benefit. Current economic conditions require a very careful balancing of the benefit of further environmental controls with the impacts of the costs of those controls on our customers as well as on the Company and its competitive position. We will pursue current cost recovery riders to recover environmental and renewable investments, and will work with our legislators and regulators to earn a fair return.

Outlook (Continued)
Rates (Continued)

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

2010 Rate Case. On November 2, 2009, Minnesota Power filed an $81 million retail rate increase request 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. Interim rates were put into effect on January 1, 2010, and were originally estimated to increase revenues by $48.5 million in 2010. In April 2010, we adjusted our initial filing for events that had occurred since November 2009 – primarily increased sales to our industrial customers – resulting in a retail rate increase request of $72 million, a return on equity request of 11.25 percent, and a capital structure consisting of 54.29 percent equity and 45.71 percent debt. As a result of these increased sales, interim rates were approximately $52 million for 2010.

On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail electric rate increase of approximately $54 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. In a hearing on January 19, 2011, the MPUC denied all reconsideration requests. It is estimated final rates will be implemented in the second quarter of 2011, after review and acceptance of the required compliance filing. Minnesota Power will continue to collect interim rates from its customers until the new rates go into effect. We expect no interim rate refunds will be issued.

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal 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 customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. The rates included in these contracts are calculated using a cost-based formula methodology that is set at the beginning of the year using estimated costs, and provides for a true-up calculation for actual costs. The estimated true-up is recorded in the current year, then finalized and billed or paid to customers in the following year. The contracts include a termination clause requiring a 3 year notice to terminate. To date, no termination notices have been received. Under the formula-based rates provision, wholesale rates, including the estimate to true-up to actual costs, were comparable in 2010 to 2009, and are projected to be comparable in 2011.

Wisconsin Rates. SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, and allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.80 percent increase in water rates, a 2.49 percent increase in natural gas rates and a 0.68 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2 million in additional revenue.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. In 2010, approximately 52 percent (37 percent in 2009) of our Regulated Utility kilowatt-hour sales were made to our industrial customers, which includes the taconite, paper and pulp, and pipeline industries.

During 2010, the domestic steel industry rebounded from the low levels of production seen in 2009. According to the American Iron and Steel Institute (AISI), United States raw steel production operated at approximately 70 percent of capacity in 2010, up significantly from 2009, which was at approximately 50 percent capacity. Domestic steel demand rebounded for automobiles and durable goods, while structural and construction steel products were still down. Annual taconite production in Minnesota rebounded from the 18 million tons produced in 2009 to approximately 36 million tons in 2010 (40 million tons in 2008).

Projections from the AISI translate to U.S. steel production levels at about 75 percent of capacity in 2011. There has been a general historical correlation between U.S. steel production and Minnesota taconite production. Based on these projections, Minnesota Power expects 2011 taconite production in Minnesota to be in the range of 2010 production levels. We will continue to market available power to Other Power Suppliers, when necessary, in an effort to mitigate the earnings impact of lower industrial sales. Other Power Supply 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.

Minnesota Power's paper and pulp customers ran at, or very near, full capacity for the majority of 2010, as the paper industry stabilized and pricing and demand levels recovered following the global recession.

Our pipeline customers have a common reliance on the importation of Canadian crude oil. After near capacity operations in the past, our two pipeline customers have completed expansion projects to transport Western Canadian crude oil reserves (Alberta Oil Sands) to United States markets. Access to traditional Midwest markets is being expanded to Southern markets as the Canadian supply is displacing domestic production and deliveries imported from the Gulf Coast.

Outlook (Continued)
Industrial Customers (Continued)

Prospective Additional Load. Minnesota Power is, and will continue, to pursue new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in development of natural resource based projects that represent long-term growth potential and load diversity for Minnesota Power. These potential projects are in the ferrous and non-ferrous mining and steel industries and include PolyMet, Mesabi Nugget, and United States Steel Corporation's expansion at its Keewatin taconite facility. Additionally, Essar Steel Limited Minnesota (Essar) continues to work with local agencies on infrastructure development for its taconite mine, direct reduction iron-making facility, and steel mill within the Nashwauk, Minnesota municipal utility service boundary. Some, or potentially all, of these projects may not materialize. If some or all of these projects are completed, Minnesota Power could serve up to 600 MW of new load.

PolyMet. Minnesota Power has executed a long-term contract with PolyMet, a new industrial customer planning to start a copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. PolyMet began work on a Supplemental Draft Environmental Impact Statement (SDEIS) in 2010. The SDEIS further addresses environmental issues, most notably those dealing with the land exchange between PolyMet and the U.S. Forest Service (USFS). This land exchange is critical to the mine site development. The EPA and the USFS joined as lead agencies in the SDEIS process. Release of the SDEIS is expected in mid-2011, to be followed by a public review and comment period. Assuming successful completion of the Environmental Impact Statement process and subsequent issuance of permits, Minnesota Power could begin to supply between 45-70 MW of power in approximately 2013 through a 10-year long-term power supply contract that begins upon start-up.

Mesabi Nugget. The construction of the initial Mesabi Nugget facility is essentially complete and the first production occurred in January 2010. Steel Dynamics, Inc., the principal owner of Mesabi Nugget, has indicated that production ramp-up activities will continue in 2011, with full production levels expected to be reached during the year. Mesabi Nugget is currently pursuing permits for taconite mining activities on lands formerly mined by Erie Mining Company and LTV Steel Mining Company near Hoyt Lakes, Minnesota. Permits to mine are expected by the end of 2011. Mining activities could begin in 2012, which would allow Mesabi Nugget to self-supply its own taconite concentrates and would result in increased electrical loads above the current 15 MW long-term power supply contract with Mesabi Nugget lasting at least through 2017.

Keewatin Taconite. In February 2008, United States Steel Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility (Keetac). This pellet line, which has been idled since 1980, could be restarted and updated as part of a $300 million investment, bringing about 3.6 million tons of additional pellet making capability to northeastern Minnesota. The Final Environmental Impact Statement has been judged to be adequate by the Minnesota Department of Natural Resources. Approval by the US Army Corps of Engineers is expected in the first quarter of 2011. Production could begin in 2014.

City of Nashwauk. On February 7, 2011, Minnesota Power signed a 10-year electric service agreement with the City of Nashwauk (the City). Pending FERC approval, the agreement is effective upon expiration of the current electric service agreement in place with the City in 2012. Under the new agreement, Minnesota Power will provide all of the City's electric service requirements, including any development within the municipality. This could include service beginning in 2012, for Essar's proposed taconite facility of approximately 100 MW which is currently under construction, as well as Essar's proposed approximate 300 MW expansion to include a direct reduced iron and steelmaking facility being considered for 2015.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota to 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. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resource Plan, filed October 5, 2009, with the MPUC. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to meet the 12 percent renewable energy sales milestone by 2012.

Our renewable energy strategy is currently being executed through two long-term power purchase agreements with NextEra Energy for wind energy in North Dakota (Oliver Wind I and II), Taconite Ridge Wind I, our wind facility located in northeastern Minnesota, our Bison 1 and Bison 2 wind development projects and our Hibbard biomass upgrade project.

North Dakota Wind Development. On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota, to Duluth, Minnesota. We use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Outlook (Continued)
Renewable Energy (Continued)

Bison 1 is a two phase, 82 MW wind project in North Dakota. All permitting has been received and the first phase was completed in 2010. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of 16 2.3 MW wind turbines, all of which were in-service at the end of 2010. Phase two is expected to be completed late in 2011 and consists of the installation of 15 3.0 MW wind turbines. Bison 1 is expected to have a total capital cost of approximately $177 million, of which $121 million was spent through December 31, 2010. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery eligibility for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010.

Bison 2 is a 105 MW wind project in North Dakota which, if approved by the MPUC, is expected to be completed by the end of 2012. Total project cost is estimated to be approximately $160 million, and construction would begin upon the receipt of all regulatory and permitting approvals. We will seek both MPUC approval for the project and NDPSC site permit approval in the first quarter of 2011. We will file for current cost recovery eligibility for Bison 2 from the MPUC once the project and related permitting have been approved.

Manitoba Hydro. Minnesota Power has a long-term power purchase agreement with Manitoba Hydro expiring in 2015. (See Item 1. Business – Power Supply.) In addition, on April 30, 2010, Minnesota Power signed a definitive agreement with Manitoba Hydro, subject to MPUC approval, to purchase surplus energy beginning in May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On September 1, 2010, we filed a petition with the MPUC to approve our PPA with Manitoba Hydro. On October 28, 2010, the OES filed comments recommending approval.

Hibbard Biomass Upgrade Project. Hibbard is a 50 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The upgrade project, which was approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at an expected total cost of approximately $22 million. Upon receipt of any necessary permitting approvals, construction would begin in 2011, and could be completed by the end of 2012. We also plan to seek current cost recovery authorization for the project from the MPUC in 2011.

Integrated Resource Plan. On October 5, 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan, 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 through 2025, 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 CO_2); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan to reshape our generation portfolio by adding 300 to 500 MW of renewable energy to our generation mix, and we are exploring options to incorporate peaking or intermediate resources. The first phase of the Bison 1 wind project in North Dakota was put into service in 2010 and the second phase is expected to be in service in late 2011, increasing our renewable generation by 82 MW. The Bison 2 105 MW wind project, if approved by the MPUC, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

We project average annual long-term growth, excluding prospective additional load from industrial and municipal customers, of approximately one percent in electric usage through 2025. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation. We expect MPUC action on our Integrated Resource Plan filing in 2011.

Transmission**.** We plan to make investments in upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. These investments include the CapX2020 initiative, investments in our transmission assets, and our investment in ATC.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. 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. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project–by-project basis.

Outlook (Continued)
Transmission (Continued)

Minnesota Power is currently participating in three CapX2020 projects: the Fargo to St. Cloud project, the Monticello to St. Cloud project, which together total a 238-mile, 345 kV line from Fargo to Monticello, and the 70-mile, 230 kV line between Bemidji and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $11.3 million was spent through December 31, 2010.

In July 2010, the MPUC granted a route permit for the 28-mile 345 kV transmission line between Monticello and St. Cloud. Construction of the project is expected to be complete in late 2011. The 210-mile 345 kV transmission line from St. Cloud to Fargo is expected to be complete by 2015. Construction for the Bemidji to Grand Rapids 230 kV line project commenced in January 2011.

We have an approved cost recovery rider in place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. In our 2010 rate case we moved completed transmission projects from the current cost recovery rider to base rates. In July 2010, we filed for an updated billing factor that includes additional transmission projects and expenses, including CapX2020 projects, which we expect to be approved in early 2011.

Investment in ATC. At December 31, 2010, our equity investment was $93.3 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. ATC has identified $3.4 billion in future projects needed over the next 10 years to improve the adequacy and reliability of the electric transmission system as well as to meet regional needs based on economic benefits and public policy initiatives for renewable energy. This investment is expected to be funded through a combination of internally generated 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. On January 31, 2011, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $2 million throughout 2011. (See Note 6. Investment in ATC.)

Investments and Other

BNI Coal. In 2010, BNI Coal sold approximately 3.8 million tons of coal (4.2 million tons in 2009) and anticipates 2011 sales to be similar to 2009.

ALLETE Properties. ALLETE Properties is our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets at reasonable prices when opportunities arise, and reinvest the proceeds in ALLETE's growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Ormond Crossings is a third major project that is currently in the planning stage. On February 16, 2010, the City of Ormond Beach, Florida, approved a new Development Agreement for Ormond Crossings. The agreement will facilitate development of the project as currently planned. Separately, Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Development Projects Land Available-for-Sale	**Ownership**	**Total Acres** *(a)*	**Residential Units** *(b)*	**Non-residential Sq. Ft.** *(b, c)*
Current Development Projects				
Town Center	80%	862	2,177	2,225,200
Palm Coast Park	100%	3,842	3,564	3,056,800
Total Current Development Projects		4,704	5,741	5,282,000
Proposed Development Project				
Ormond Crossings	100%	2,924	2,950	3,215,000
Other				
Lake Swamp Wetland Mitigation Project	100%	3,049	*(d)*	*(d)*
Total of Development Projects		10,677	8,691	8,497,000

(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) Lake Swamp wetland mitigation bank is a regionally significant wetlands mitigation bank that was permitted by the St. Johns River Water Management District in 2008 and by the U.S. Army Corps of Engineers in December 2009. Wetland mitigation credits will be used at Ormond Crossings and will also be available for sale to developers of other projects that are located in the bank's service area.

Outlook (Continued)
Investments and Other (Continued)

ALLETE Properties also has 1,979 acres of other land available-for-sale outside of the three development projects.

ALLETE intends to sell its Florida land assets at reasonable prices when opportunities arise. However, if 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.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2011. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, wind production tax credits, AFUDC-Equity, domestic manufacturer's deduction, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased production tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 30 percent for 2011.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's immediate cash flow needs. At December 31, 2010, we had a cash and cash equivalents balance of approximately $45 million, $153 million in available consolidated lines of credit which included a committed, syndicated, unsecured revolving line of credit of $150 million, and a debt-to-capital ratio of 44 percent. As of December 31, 2010, we project sufficient capital availability.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

Year Ended December 31	2010	%	2009	%	2008	%
Millions						
Common Equity	$976.0	55	$929.5	57	$827.1	57
Non-Controlling Interest	9.0	1	9.5	–	9.8	1
Long-Term Debt (Including Current Maturities)	785.0	44	701.0	43	598.7	42
Short-Term Debt	1.0	–	1.9	–	6.0	–
	$1,771.0	100	$1,641.9	100	$1,441.6	100

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

Year Ended December 31	2010	2009	2008
Millions			
Cash and Cash Equivalents at Beginning of Period	$25.7	$102.0	$23.3
Cash Flows from (used for)			
Operating Activities	228.7	137.4	153.6
Investing Activities	(250.9)	(320.0)	(276.1)
Financing Activities	41.4	106.3	201.2
Change in Cash and Cash Equivalents	19.2	(76.3)	78.7
Cash and Cash Equivalents at End of Period	$44.9	$25.7	$102.0

Operating Activities. Cash from operating activities was $228.7 million for 2010 ($137.4 million for 2009; $153.6 million for 2008). Cash from operating activities was higher in 2010 primarily due to higher net income, higher depreciation expense related to increased plant in service in 2010, and collections of income tax receivables due to bonus depreciation as a result of the American Recovery and Reinvestment Act of 2009 (the Act) and tax planning initiatives. This increase was partially offset by higher cash contributions to the defined benefit pension and other postretirement benefit plans in 2010 of $26.5 million and $12.8 million respectively ($20.9 million and $9.3 million in 2009).

Cash from operating activities was lower in 2009 than 2008 primarily due to lower net income, an increase in accounts receivable, and higher deferred regulatory assets, partially offset by higher deferred tax and depreciation expense. Accounts receivable increased due to a receivable for 2009 income tax refunds primarily resulting from substantial income tax deductions under bonus depreciation. Deferred regulatory assets increased due to the collection of certain current cost recovery rider revenue attributable to 2009 being deferred into a later year. Deferred tax expense increased also due to the bonus depreciation provisions of the Act, and depreciation expense increased in conjunction with the increase in property, plant and equipment.

Liquidity and Capital Resources (Continued)

Investing Activities. Cash used for investing activities was $250.9 million for 2010 ($320.0 million for 2009; $276.1 million for 2008). Cash used for investing activities was lower than 2009 reflecting decreased capital additions to property, plant and equipment, and lower investments in ATC.

Cash used for investing activities was higher in 2009 than 2008 reflecting increased capital additions to property, plant, and equipment. Capital additions to property, plant, and equipment increased due to the purchase of an existing 250 kV DC transmission line for $69.7 million offset by a decrease in other capital additions because of the completion of some major capital projects in 2008 and 2009. In addition, 2008 included higher net sales of short-term investments and proceeds from the sale of assets (retail shopping center) in Winter Haven, Florida.

Financing Activities. Cash from financing activities was $41.4 million for 2010 ($106.3 million for 2009; $201.2 million for 2008). Cash from financing activities was lower in 2010 due to higher internally generated cash and lower capital expenditures which resulted in lower common stock issuances and less incremental external financing required. Cash from financing activities in 2010 included new debt issuances of $155 million compared to $111.4 million in 2009, of which $65 million of the proceeds were used to pay off the syndicated revolving credit facility that was drawn in late 2009.

Cash from financing activities was lower in 2009 than 2008 due to less debt and common stock issuance. During 2009, $111.4 million of debt was issued, while in 2008 $198.7 million of debt was issued. During 2009, proceeds from common stock issuances totaled $65.2 million, while in 2008, proceeds from common stock issuances totaled $71.1 million. Lower debt and common stock issuance in 2009 was a result of issuing capital in 2008 ahead of the need for this capital.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of December 31, 2010, we had available consolidated bank lines of credit aggregating $153.0 million, the majority of which expire in January 2012. We expect to enter into new bank lines of credit during 2011 to replace the expiring facility. In addition, we had 1.9 million original issue shares of our common stock available for issuance through *Invest Direct*, our direct stock purchase and dividend reinvestment plan, and 3.1 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.

Securities. In February 2010, we issued $80.0 million in principal amount of unregistered First Mortgage Bonds (Bonds) in the private placement market in three series. We used the proceeds from the sale of Bonds to pay down $65 million on our syndicated revolving credit facility, to fund utility capital investments and for general corporate purposes.

In August 2010, we issued $75.0 million in principal amount of unregistered First Mortgage Bonds in the private placement market in two series. We used the proceeds to fund utility capital expenditures and for general corporate purposes.

For the February and August 2010 bond issuances 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 the terms and conditions of our utility mortgage. 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. (See Note 9. Short-Term and Long-Term Debt.)

We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the year ended December 31, 2010, 0.2 million shares of common stock were issued under this agreement resulting in net proceeds of $6.0 million. During 2009, 1.7 million shares of common stock were issued for net proceeds of $51.9 million. As of December 31, 2010, approximately 3.1 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2010 and 2009 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

In 2010, we issued 0.5 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan and the RSOP, resulting in net proceeds of $14.5 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225, and 333-124455, respectively.

Financial Covenants. See Note 9. Short-Term and Long-Term Debt for information regarding our financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 10. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments. Minnesota Power has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Following is a summarized table of contractual obligations and other commercial commitments at December 31, 2010.

Liquidity and Capital Resources (Continued)
Contractual Obligations and Commercial Commitments (Continued)

Contractual Obligations As of December 31, 2010	Payments Due by Period Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Millions					
Long-Term Debt	$1,322.5	$54.3	$210.3	$105.8	$952.1
Pension	102.0	7.8	74.2	20.0	–
Other Postretirement Benefit Plans	68.5	12.9	35.9	19.7	–
Operating Lease Obligations	86.8	8.1	25.6	15.0	38.1
Uncertain Tax Positions *(a)*	–	–	–	–	–
Unconditional Purchase Obligations	444.6	124.4	106.0	43.4	170.8
	$2,024.4	$207.5	$452.0	$203.9	$1,161.0

(a) Excludes $12.3 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions.

Long-Term Debt. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our consolidated balance sheet, plus interest. The table above assumes that the interest rate in effect at December 31, 2010, remains constant through the remaining term. (See Note 9. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Our pension and other postretirement benefit plan obligations represent our current estimate of employer contributions. The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Pension contributions will be dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, IRS and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. These amounts are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 15. Pension and Other Postretirement Benefit Plans.)

Unconditional Purchase Obligations. Unconditional purchase obligations represent our Square Butte power purchase agreements, minimum purchase commitments under coal and rail contracts, and purchase obligations for certain capital expenditure projects. (See Note 10. Commitments, Guarantees and Contingencies.)

Under our power purchase agreement with Square Butte that extends through 2026, we are obligated to pay our pro rata share of Square Butte's costs based on our entitlement to the output of Square Butte's 455-MW coal-fired generating unit near Center, North Dakota. 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. The table above reflects our share of future debt service based on our output entitlement of 50 percent. This debt service may be reduced if the contingent power sales agreement with Minnkota Power goes into effect in 2013. For further information on Square Butte see Note 10. Commitments, Guarantees and Contingencies.

We have two wind power purchase agreements with an affiliate of NextEra Energy to purchase the output from two wind facilities, Oliver Wind I and Oliver Wind II located near Center, North Dakota. We began purchasing the output from Oliver Wind I, a 50-MW facility, in December 2006 and the output from Oliver Wind II, a 48-MW facility in November 2007. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Credit Ratings. Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Liquidity and Capital Resources (Continued)
Credit Ratings (Continued)

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds *(a)*	A–	A2
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

(a) Includes collateralized pollution control bonds.

Common Stock Dividends. ALLETE is committed to providing an attractive, secure dividend to its shareholders while at the same time funding its growth. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. In 2010, we paid out 81 percent (93 percent in 2009; 61 percent in 2008) of our per share earnings in dividends. On January 20, 2011, our Board of Directors declared a dividend of $0.445 per share, which is payable on March 1, 2011, to shareholders of record at the close of business on February 15, 2011.

Capital Requirements

ALLETE's projected capital expenditures for the years 2011 through 2015 are presented in the table below. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies.

Capital Expenditures	2011	2012	2013	2014	2015	Total
Millions						
Regulated Utility Operations						
Base and Other	$88	$91	$92	$94	$99	$464
Current Cost Recovery *(a)*						
Renewable	126	117	2	8	1	254
Transmission *(b)*	15	33	49	25	3	125
Total Current Cost Recovery	141	150	51	33	4	379
Regulated Utility Capital Expenditures	229	241	143	127	103	843
Other	22	25	14	8	8	77
Total Capital Expenditures	$251	$266	$157	$135	$111	$920

(a) Estimated current capital expenditures recoverable outside of a rate case.
(b) Transmission capital expenditures related to CapX2020 are estimated at approximately $115 million.

We intend to finance expenditures from both internally generated funds and incremental debt and equity. Based on our above anticipated capital expenditures, we project our rate base to grow by approximately 20 percent through 2015. Pending environmental regulations could result in significant capital expenditures in the future that are not included in the table above. Currently, future CapX2020 projects are under discussions. Minnesota Power may elect to participate on a project by project basis.

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 10. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2010, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities. (See Note 7. Investments.)

Interest Rate Risk. We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. The table below presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2010.

Liquidity and Capital Resources (Continued)
Interest Rate Risk (Continued)

Interest Rate Sensitive Financial Instruments	Expected Maturity Date 2011	2012	2013	2014	2015	Thereafter	Total	Fair Value
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$1.6	$1.6	$71.1	$19.5	$0.6	$617.3	$711.7	$723.4
Average Interest Rate – %	5.9	5.9	5.2	6.9	5.3	6.0	5.8	
Variable Rate	$11.8	$1.7	$2.8	–	$15.7	$41.3	$73.3	$73.3
Average Interest Rate – % *(a)*	3.5	1.7	0.6	–	0.5	0.3	1.0	

(a) Assumes rate in effect at December 31, 2010, remains constant through remaining term.

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at December 31, 2010, and assuming no other changes to our financial structure, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by $0.7 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2010.

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

Power Marketing. Our power marketing activities consist of (1) purchasing energy in the wholesale market to serve our regulated service territory 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 to the wholesale market to optimize the value of this energy.

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.

Recently Adopted Accounting Standards.

Recently adopted accounting standards are discussed in Note 1.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our consolidated financial statements as of December 31, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, and supplementary data, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we conducted an evaluation 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 and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control—Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

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

Item 9B. Other Information

Mine Safety Disclosures – Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act

The Dodd-Frank Act requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act).

For the six months ended December 31, 2010, we received five citations under Section 104(a) for BNI Coal, however; fines or penalties were not assessed as of the filing of this Form 10-K. We do not expect these citations to result in material fine or penalties. For the six months ended December 31, 2010, there were no citations, orders or notices received under Sections 104, 104(b), 104(d), 107(a) or 104(e) of the Mine Safety Act, no violations of Section 110(b)(2) of the Mine Safety Act, and there were no fatalities.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2011 Annual Meeting of Shareholders (2011 Proxy Statement) under the following headings:

- **Directors.** The information regarding directors will be included in the "Election of Directors" section;
- **Audit Committee Financial Expert.** The information regarding the Audit Committee financial expert will be included in the "Audit Committee Report" section;
- **Audit Committee Members.** The identity of the Audit Committee members is included in the "Audit Committee Report" section;
- **Executive Officers.** The information regarding executive officers is included in Part I of this Form 10-K; and
- **Section 16(a) Compliance.** The information regarding Section 16(a) compliance will be included in the "Ownership of ALLETE Common Stock – Section 16(a) Beneficial Ownership Reporting Compliance" section.

Our 2011 Proxy Statement will be filed with the SEC within 120 days after the end of our 2010 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our chief executive officer, chief financial officer and controller. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the "Compensation of Directors and Executive Officers," the "Compensation Discussion and Analysis", the "Executive Compensation Committee Report" and the "Director Compensation 2010" sections in our 2011 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required for this Item is incorporated by reference herein from the "Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners," the "Ownership of ALLETE Common Stock – Securities Owned by Directors and Management" and the "Equity Compensation Plan Information" sections in our 2011 Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2011 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accounting Fees and Services

The information required for this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2011 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain Documents Filed as Part of this Form 10-K.

(1) Financial Statements

(2) Financial Statement Schedules

All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the consolidated financial statements or the notes.

(3) Exhibits including those incorporated by reference.

Exhibit Number

*3(a)1 - Articles of Incorporation amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).

*3(a)2 - Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).

*3(a)3 - Amendment to Articles of Incorporation, dated as of May 19, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).

*3(a)4 - Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).

*3(b) - Bylaws, as amended effective May 11, 2010 (filed as Exhibit 3(b) to the May 14, 2010, Form 8-K, File No. 1-3548).

*4(a)1 - Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Ming Ryan (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).

*4(a)2 - Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003 Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004 Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005 Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006 Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008 Form 10-Q)	4

Exhibit Number

Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
Thirty-first	February 1, 2010	1-3548 (March 31, 2010 Form 10-Q)	4
Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010 Form 10-Q)	4

*4(b)1 - Indenture of Trust, dated as of August 1, 2004, between the City of Cohasset, Minnesota and U.S. Bank National Association, as Trustee relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(b) to the September 30, 2004, Form 10-Q, File No. 1-3548).

*4(b)2 - Loan Agreement, dated as of August 1, 2004, between the City of Cohasset, Minnesota and ALLETE relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(c) to the September 30, 2004, Form 10-Q, File No. 1-3548).

*4(c)1 - Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).

*4(c)2 - Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3

*10(a) - Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).

*10(d)1 - Fourth Amended and Restated Committed Facility Letter, dated January 11, 2006, by and among ALLETE and Bank of America (formerly LaSalle Bank National Association), as Agent (filed as Exhibit 10(d)1 to the 2009 Form 10-K, File No. 1-3548).

*10(d)2 - First Amendment to Fourth Amended and Restated Committed Facility Letter dated June 19, 2006, by and among ALLETE and Bank of America (formerly LaSalle Bank National Association), as Agent (filed as Exhibit 10(a) to the June 30, 2006, Form 10-Q, File No. 1-3548).

*10(d)3 - Second Amendment to Fourth Amended and Restated Committed Facility Letter dated December 14, 2006, by and among ALLETE and Bank of America (formerly LaSalle Bank National Association), as Agent (filed as Exhibit 10(d)3 to the 2006 Form 10-K, File No. 1-3548).

*10(e)1 - Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).

*10(e)2 - Letter of Credit Agreement, dated as of July 5, 2006, among ALLETE, the Participating Banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b)2 to the June 30, 2006, Form 10-Q, File No. 1-3548).

*10(g) - Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).

+10(h)1 - ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011.

+*10(h)2 - ALLETE Executive Annual Incentive Plan Form of Awards Effective 2009 (filed as Exhibit 10(h)7 to the 2008 Form 10-K, File No. 1-3548).

+*10(h)3 - ALLETE Executive Annual Incentive Plan Form of Awards Effective 2010 (filed as Exhibit 10(h)3 to the 2009 Form 10-K, File No. 1-3548).

+10(h)4 - ALLETE Executive Annual Incentive Plan Form of Awards Effective 2011.

+*10(i)1 - ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).

+10(i)2 - Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011.

+10(i)3 - ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2011.

+*10(j)1 - Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).

Exhibit Number

+*10(j)2	-	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(j)3	-	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(j)4	-	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(k)1	-	Minnesota Power and Affiliated Companies Executive Investment Plan II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to the 1988 Form 10-K, File No. 1-3548).
+*10(k)2	-	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(w)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(k)3	-	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(k)4	-	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(l)	-	Deferred Compensation Trust Agreement, as amended and restated, effective January 1, 1989 (filed as Exhibit 10(f) to the 1988 Form 10-K, File No. 1-3548).
+*10(m)1	-	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+10(m)2	-	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011.
+*10(m)3	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Nonqualified Stock Option Grant (filed as Exhibit 10(a)1 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(m)4	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Nonqualified Stock Option Grant Effective 2007 (filed as Exhibit 10(m)6 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)5	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2007 (filed as Exhibit 10(m)7 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)6	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2008 (filed as Exhibit 10(m)10 to the 2007 Form 10-K, File No. 1-3548).
+*10(m)7	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2009 (filed as Exhibit 10(m)11 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)8	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2009 (filed as Exhibit 10(m)12 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)9	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2010 (filed as Exhibit 10(m)8 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)10	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2010 (filed as Exhibit 10(m)9 to the 2009 Form 10-K, File No. 1-3548).
+10(m)11	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2011.
+10(m)12	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2011.
+*10(n)1	-	Minnesota Power (now ALLETE) Director Stock Plan, effective January 1, 1995 (filed as Exhibit 10 to the March 31, 1995, Form 10-Q, File No. 1-3548).
+*10(n)2	-	Amendments through December 2003 to the Minnesota Power (now ALLETE) Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(n)3	-	July 2004 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(n)4	-	January 2007 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(n)4 to the 2006 Form 10-K, File No. 1-3548).
+*10(n)5	-	May 2009 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(n)6	-	May 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(a) to the June 30, 2010, Form 10-Q, File No. 1-3548).
+*10(n)7	-	October 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10 to the September 30, 2010, Form 10-Q, File No. 1-3548).
+*10(n)8	-	ALLETE Non-Management Director Compensation Summary Effective May 1, 2010 (filed as Exhibit 10(b) to the March 31, 2010, Form 10-Q, File No. 1-3548).

Exhibit Number

+10(n)9	-	ALLETE Non-Management Director Compensation Summary effective January 19, 2011.
+*10(o)1	-	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(o)2	-	October 2003 Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(o)3	-	January 2005 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(o)4	-	August 2006 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(o)5	-	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(p)	-	ALLETE Director Compensation Trust Agreement, effective October 11, 2004 (filed as Exhibit 10(a) to the September 30, 2004, Form 10-Q, File No. 1-3548).
+10(q)	-	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective January 19, 2011.
12	-	Computation of Ratios of Earnings to Fixed Charges.
21	-	Subsidiaries of the Registrant.
23(a)	-	Consent of Independent Registered Public Accounting Firm.
31(a)	-	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	-	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	-	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	-	ALLETE News Release dated February 16, 2011, announcing earnings for the year ended December 31, 2010. **(This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**

SWL&P is a party to other long-term debt instruments, $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A and $6,130,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Bonds Series 2007B, that, pursuant to Regulation S-K, Item 601(b)(4)(iii), are not filed as exhibits since the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

We are a party to another long-term debt instrument, $38,995,000 original principal amount, of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A, Series 1997B and Series 1997C ($36,495,000 remaining principal balance) that, pursuant to Regulation S-K, Item 601(b)(4)(iii), is not filed as an exhibit since the total amount of debt authorized under this omitted instrument does not exceed 10 percent of our total consolidated assets. We will furnish copies of this instrument to the SEC upon its request.

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* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement pursuant to Item 15(b).*

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALLETE, Inc.

Dated: February 16, 2011 By Alan R. Hodnik

Alan R. Hodnik
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Alan R. Hodnik Alan R. Hodnik	President and Chief Executive Officer (Principal Executive Officer)	February 16, 2011
Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 16, 2011
Steven Q. DeVinck Steven Q. DeVinck	Controller and Vice President – Business Support (Principal Accounting Officer)	February 16, 2011

Signatures (Continued)

Signature	Title	Date
Kathleen A. Brekken Kathleen A. Brekken	Director	February 16, 2011
Kathryn W. Dindo Kathryn W. Dindo	Director	February 16, 2011
Heidi J. Eddins Heidi J. Eddins	Director	February 16, 2011
Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 16, 2011
James S. Haines, Jr James S. Haines, Jr	Director	February 16, 2011
James J. Hoolihan James J. Hoolihan	Director	February 16, 2011
Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 16, 2011
Douglas C. Neve Douglas C. Neve	Director	February 16, 2011
Leonard C. Rodman Leonard C. Rodman	Director	February 16, 2011
Donald J. Shippar Donald J. Shippar	Director	February 16, 2011
Bruce W. Stender Bruce W. Stender	Director	February 16, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc:

In our opinion, the accompanying consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries (the Company) at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 16, 2011

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

As of December 31	2010	2009
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$44.9	$25.7
Short-Term Investments	6.7	–
Accounts Receivable (Less Allowance of $0.9 and $0.9)	99.5	118.5
Inventories	60.0	57.0
Prepayments and Other	28.6	24.3
Total Current Assets	239.7	225.5
Property, Plant and Equipment – Net	1,805.6	1,622.7
Regulatory Assets	310.2	293.2
Investment in ATC	93.3	88.4
Other Investments	126.0	130.5
Other Non-Current Assets	34.3	32.8
Total Assets	$2,609.1	$2,393.1
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$75.4	$62.1
Accrued Taxes	22.0	20.6
Accrued Interest	13.4	11.1
Long-Term Debt Due Within One Year	13.4	5.2
Notes Payable	1.0	1.9
Other	33.7	32.2
Total Current Liabilities	158.9	133.1
Long-Term Debt	771.6	695.8
Deferred Income Taxes	325.2	253.1
Regulatory Liabilities	43.6	47.1
Other Non-Current Liabilities	324.8	325.0
Total Liabilities	1,624.1	1,454.1
Commitments and Contingencies (Note 10)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 35.8 and 35.2 Shares Outstanding	636.1	613.4
Unearned ESOP Shares	(36.8)	(45.3)
Accumulated Other Comprehensive Loss	(23.2)	(24.0)
Retained Earnings	399.9	385.4
Total ALLETE Equity	976.0	929.5
Non-Controlling Interest in Subsidiaries	9.0	9.5
Total Equity	985.0	939.0
Total Liabilities and Equity	$2,609.1	$2,393.1

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2010	2009	2008
Millions Except Per Share Amounts			
Operating Revenue			
Operating Revenue	$907.0	$766.7	$801.0
Prior Year Rate Refunds	–	(7.6)	–
Total Operating Revenue	907.0	759.1	801.0
Operating Expenses			
Fuel and Purchased Power	325.1	279.5	305.6
Operating and Maintenance	365.6	308.9	318.1
Depreciation	80.5	64.7	55.5
Total Operating Expenses	771.2	653.1	679.2
Operating Income	135.8	106.0	121.8
Other Income (Expense)			
Interest Expense	(39.2)	(33.8)	(26.3)
Equity Earnings in ATC	17.9	17.5	15.3
Other	4.6	1.8	15.6
Total Other Income (Expense)	(16.7)	(14.5)	4.6
Income Before Non-Controlling Interest and Income Taxes	119.1	91.5	126.4
Income Tax Expense	44.3	30.8	43.4
Net Income	74.8	60.7	83.0
Less: Non-Controlling Interest in Subsidiaries	(0.5)	(0.3)	0.5
Net Income Attributable to ALLETE	$75.3	$61.0	$82.5
Average Shares of Common Stock			
Basic	34.2	32.2	29.2
Diluted	34.3	32.2	29.3
Basic Earnings Per Share of Common Stock	$2.20	$1.89	$2.82
Diluted Earnings Per Share of Common Stock	$2.19	$1.89	$2.82
Dividends Per Share of Common Stock	$1.76	$1.76	$1.72

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2010	2009	2008
Millions			
Operating Activities			
Net Income	$74.8	$60.7	$83.0
Allowance for Funds Used During Construction	(4.2)	(5.8)	(3.3)
Loss (Income) from Equity Investments, Net of Dividends	(3.1)	0.1	(3.1)
Gain on Real Estate Foreclosure	(0.7)	–	–
Gain on Sale of Assets	–	(0.2)	(4.8)
Gain on Sale of Available-for-sale Securities	–	–	(6.4)
Loss on Impairment of Assets	–	3.1	–
Depreciation Expense	80.5	64.7	55.5
Amortization of Debt Issuance Costs	0.9	0.9	0.8
Deferred Income Tax Expense	66.0	75.2	38.8
Share-Based Compensation Expense	2.2	2.1	1.8
ESOP Compensation Expense	7.1	6.5	10.1
Bad Debt Expense	1.1	1.3	0.7
Changes in Operating Assets and Liabilities			
Accounts Receivable	17.9	(43.5)	2.4
Inventories	(3.0)	(7.3)	(0.2)
Prepayments and Other	(4.3)	–	11.2
Accounts Payable	5.8	10.5	(14.1)
Other Current Liabilities	5.2	5.3	5.9
Regulatory and Other Assets	16.3	(18.3)	(1.8)
Regulatory and Other Liabilities	(33.8)	(17.9)	(22.9)
Cash from Operating Activities	228.7	137.4	153.6
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	0.6	8.9	62.3
Payments for Purchase of Available-for-sale Securities	(2.3)	(2.2)	(44.8)
Investment in ATC	(1.6)	(7.8)	(7.4)
Changes to Other Investments	1.3	(0.7)	(9.2)
Additions to Property, Plant and Equipment	(248.9)	(318.5)	(301.1)
Proceeds from Sale of Assets	–	0.3	20.4
Other	–	–	3.7
Cash for Investing Activities	(250.9)	(320.0)	(276.1)
Financing Activities			
Proceeds from Issuance of Common Stock	20.5	65.2	71.1
Proceeds from Issuance of Long-Term Debt	155.0	111.4	198.7
Changes in Notes Payable	(0.9)	(4.1)	6.0
Reductions of Long-Term Debt	(71.0)	(9.1)	(22.7)
Debt Issuance Costs	(1.4)	(0.6)	(1.5)
Dividends on Common Stock	(60.8)	(56.5)	(50.4)
Cash from Financing Activities	41.4	106.3	201.2
Change in Cash and Cash Equivalents	19.2	(76.3)	78.7
Cash and Cash Equivalents at Beginning of Period	25.7	102.0	23.3
Cash and Cash Equivalents at End of Period	$44.9	$25.7	$102.0

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Balance as of December 31, 2007	$742.6	$350.4	$(4.5)	$(64.5)	$461.2
Comprehensive Income					
Net Income	83.0	83.0			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(6.0)		(6.0)		
Reclassification Adjustment for Gains Included in Income	(3.7)		(3.7)		
Defined Benefit Pension and Other Postretirement Plans	(18.8)		(18.8)		
Total Comprehensive Income	54.5				
Non-Controlling Interest in Subsidiaries	(0.5)	(0.5)			
Comprehensive Income Attributable to ALLETE	54.0				
Adjustment to apply change in Pension and Postretirement measurement date	(1.6)	(1.6)			
Common Stock Issued – Net	72.9				72.9
Dividends Declared	(50.4)	(50.4)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2008	827.1	380.9	(33.0)	(54.9)	534.1
Comprehensive Income					
Net Income	60.7	60.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	2.8		2.8		
Defined Benefit Pension and Other Postretirement Plans	6.2		6.2		
Total Comprehensive Income	69.7				
Non-Controlling Interest in Subsidiaries	0.3	0.3			
Comprehensive Income Attributable to ALLETE	70.0				
Common Stock Issued – Net	79.3				79.3
Dividends Declared	(56.5)	(56.5)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2009	929.5	385.4	(24.0)	(45.3)	613.4
Comprehensive Income					
Net Income	74.8	74.8			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	0.8		0.8		
Total Comprehensive Income	75.6				
Non-Controlling Interest in Subsidiaries	0.5	0.5			
Comprehensive Income Attributable to ALLETE	76.1				
Common Stock Issued – Net	22.7				22.7
Dividends Declared	(60.8)	(60.8)			
ESOP Shares Earned	8.5			8.5	
Balance as of December 31, 2010	$976.0	$399.9	$(23.2)	$(36.8)	$636.1

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. Operations and Significant Accounting Policies

Financial Statement Preparation. References in this report to "we," "us," and "our" are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue, and expenses. Actual results could differ from those estimates.

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

Principles of Consolidation. Our consolidated financial statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. Our Regulated Operations and Investments and Other segments were determined in accordance with the guidance on segment reporting. Segmentation is based on the manner in which we operate, assess, and allocate resources to the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes retail and wholesale rate-regulated electric, natural gas, and water services in northeastern Minnesota and northwestern Wisconsin along with our Investment in ATC. Minnesota Power provides regulated utility electric service to 146,000 retail customers in northeastern Minnesota. SWL&P, a wholly-owned subsidiary, provides regulated utility electric, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Regulated utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Our Investment in ATC includes our approximate 8 percent equity ownership interest in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. (See Note 6. Investment in ATC.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2010, Square Butte supplied approximately 50 percent (227.5 MW) of its output to Minnesota Power under a long-term contract. (See Note 10. Commitments, Guarantees and Contingencies.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

ALLETE Properties is our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions.

Full profit recognition is recorded on sales upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance for sales of real estate, are met. In certain cases, where there are obligations to perform significant development activities after the date of sale, we recognize profit on a percentage-of-completion basis. From time to time, certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

In certain cases, we pay fees or construct improvements to mitigate offsite traffic impacts. In return, we receive traffic impact fee credits as a result of some of these expenditures. We recognize revenue from the sale of traffic impact fee credits when payment is received.

Land held-for-sale is recorded at the lower of cost or fair value determined by the evaluation of individual land parcels and is included in Other Investments on our consolidated balance sheet. Real estate costs include the cost of land acquired, subsequent development costs and costs of improvements, capitalized development period interest, real estate taxes and payroll costs of certain employees devoted directly to the development effort. These real estate costs incurred are capitalized to the cost of real estate parcels based upon the relative sales value of parcels within each development project in accordance with the accounting standards for real estate. The cost of real estate includes the actual costs incurred and the estimate of future completion costs allocated to the real estate sold based upon the relative sales value method. Whenever events or circumstances indicate that the carrying value of the real estate may not be recoverable, impairments would be recorded and the related assets would be adjusted to their estimated fair value, less costs to sell. (See Note 7. Investments.)

Cash and Cash Equivalents. We consider all investments purchased with original maturities of three months or less to be cash equivalents.

Note 1. Operations and Significant Accounting Policies (Continued)

Supplemental Statement of Cash Flow Information

Consolidated Statement of Cash Flows Supplemental Disclosure Year Ended December 31	2010	2009	2008
Millions			
Cash Paid During the Period for			
Interest – Net of Amounts Capitalized	$35.7	$29.8	$25.2
Income Taxes (Net of refunds received of $57.1, $6.7 and $–) *(a)*	$(54.2)	$(5.6)	$6.5
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$7.5	$(24.1)	$17.1
AFUDC – Equity	$4.2	$5.8	$3.3
ALLETE Common Stock contributed to the Pension Plan	–	$(12.0)	–

(a) Due to bonus depreciation provisions in the Small Business Jobs Act of 2010 and the American Recovery and Reinvestment Act of 2009, lower estimated tax payments were made in 2010 and 2009. Refunds received in 2010 resulted from a 2009 NOL which was utilized by carrying it back against prior years' taxable income and the completion of a state income tax audit.

Accounts Receivable. Accounts receivable are reported on the balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable As of December 31	2010	2009
Millions		
Trade Accounts Receivable		
Billed	$67.6	$56.5
Unbilled	18.9	15.1
Less: Allowance for Doubtful Accounts	0.9	0.9
Total Trade Accounts Receivable	85.6	70.7
Income Taxes Receivable	13.9	47.8
Total Accounts Receivable – Net	$99.5	$118.5

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 10 Large Power Customers. Receivables from these customers totaled $17.3 million at December 31, 2010 ($9.6 million at December 2009). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, our taconite-producing Large Power Customers are on a weekly billing cycle, which allows us to closely manage collection of amounts due.

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivable to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals. (See Note 7. Investments.)

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as the share price trends and the impact of overall market conditions. (See Note 7. Investments.)

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

Inventories As of December 31	2010	2009
Millions		
Fuel	$22.9	$23.0
Materials and Supplies	37.1	34.0
Total Inventories	$60.0	$57.0

Note 1. Operations and Significant Accounting Policies (Continued)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the balance sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on non-rate base property, plant and equipment are recognized when they are retired or otherwise disposed. When regulated utility property, plant and equipment are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for Regulated Operations. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. However, the MPUC has approved current cost recovery for several large capital projects recently, resulting in lower recognition of AFUDC. (See Note 3. Property, Plant and Equipment.)

Long-Lived Asset Impairments. We account for our long-lived assets at depreciated historical cost. A long-lived asset is tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. We conduct this assessment in accordance with the accounting standards for impairment or disposal of long-lived assets. Judgments and uncertainties affecting the application of accounting for asset impairment include economic conditions affecting market valuations, changes in our business strategy, and changes in our forecast of future operating cash flows and earnings. We would recognize an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted future cash flows. Management judgment is involved in both deciding if testing for recoverability is necessary and in estimating undiscounted future cash flows.

Derivatives. We review all material power purchase and sales contracts for derivative treatment to determine if they qualify for the normal purchase normal sale exception under the guidance for derivatives and hedging.

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 16. Employee Stock and Incentive Plans.)

Prepayments and Other Current Assets **As of December 31**	**2010**	**2009**
Millions		
Deferred Fuel Adjustment Clause (See Note 5. Regulatory Matters)	$20.6	$15.5
Other	8.0	8.8
Total Prepayments and Other Current Assets	$28.6	$24.3

Other Non-Current Liabilities **As of December 31**	**2010**	**2009**
Millions		
Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Plans	$231.4	$231.2
Asset Retirement Obligation (See Note 3. Property, Plant and Equipment)	50.3	44.6
Other	43.1	49.2
Total Other Non-Current Liabilities	$324.8	$325.0

Environmental Liabilities. 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 the 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 operating expense unless recoverable in rates from customers. (See Note 10. Commitments, Guarantees and Contingencies.)

Revenue Recognition. Regulated utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Customers are billed on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain environmental and renewable energy expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause.

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using the straight-line method.

Note 1. Operations and Significant Accounting Policies (Continued)

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method in accordance with the accounting standards for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable. Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with the accounting standards for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 13. Income Tax Expense.)

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

Recently Adopted Accounting Standards.

Receivables. In July 2010, the FASB issued an accounting standards update requiring expanded disclosures on allowances for credit losses and the credit quality of the financing receivables of an entity. This guidance also requires a roll forward schedule of the allowance for credit losses for each reporting period. The guidance for greater transparency was adopted December 31, 2010, and did not have an impact on our consolidated financial position, results of operations or cash flows. The guidance for the roll forward requirement is effective January 1, 2011, and is not expected to have an impact on our consolidated financial position, results of operations or cash flows as the amended guidance provides only disclosure requirements.

Derivative Instruments and Hedging Activities. In March 2010, the FASB issued new guidance on the accounting for credit derivatives that are embedded in beneficial interests in securitized financial assets. This new guidance eliminated the scope exception for embedded credit derivatives and provided new guidance on the evaluation to be performed. This guidance was effective June 15, 2010. As of December 31, 2010, we did not have any embedded credit derivatives.

Subsequent Events. In February 2010, the FASB issued an accounting standards update that eliminates the requirement to disclose the date through which subsequent events have been evaluated. The amended guidance was adopted and effective during the first quarter of 2010, and did not have an impact on our consolidated financial position, results of operations or cash flows.

Fair Value. In January 2010, the FASB issued an amendment to the fair value measurement and disclosure standard improving disclosures about fair value measurements. This amended guidance requires separate disclosure of significant transfers in and out of Levels 1 and 2 and the reasons for the transfers. The amended guidance also requires that in the Level 3 reconciliation, the information about purchases, sales, issuances, and settlements be disclosed separately on a gross basis rather than as one net number. The guidance for the Level 1 and 2 disclosures was adopted January 1, 2010, and did not have an impact on our consolidated financial position, results of operations or cash flows. The guidance for the activity in Level 3 disclosures is effective January 1, 2011, and is not expected to have an impact on our consolidated financial position, results of operations or cash flows as the amended guidance provides only disclosure requirements.

Variable Interest Entities (VIEs). In June 2009, the FASB issued authoritative guidance changing the approach to determine a VIE's primary beneficiary and requiring ongoing assessments of whether an enterprise is the primary beneficiary of a VIE. This guidance also requires additional disclosures about a company's involvement with VIEs and any significant changes in risk exposure due to that involvement. This guidance was adopted January 1, 2010, and did not have an impact on our consolidated financial position, results of operations or cash flows.

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 investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments. For a description of our reportable business segments, see Item 1. Business.

	Consolidated	Regulated Operations	Investments and Other
Millions			
2010			
Operating Revenue	$907.0	$835.5	$71.5
Fuel and Purchased Power	325.1	325.1	–
Operating and Maintenance	365.6	292.3	73.3
Depreciation Expense	80.5	76.1	4.4
Operating Income (Loss)	135.8	142.0	(6.2)
Interest Expense	(39.2)	(32.3)	(6.9)
Equity Earnings in ATC	17.9	17.9	–
Other Income	4.6	3.8	0.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	119.1	131.4	(12.3)
Income Tax Expense (Benefit)	44.3	51.6	(7.3)
Net Income (Loss)	74.8	79.8	(5.0)
Less: Non-Controlling Interest in Subsidiaries	(0.5)	–	(0.5)
Net Income (Loss) Attributable to ALLETE	$75.3	$79.8	$(4.5)
Total Assets	$2,609.1	$2,375.4	$233.7
Capital Additions	$260.0	$256.4	$3.6

	Consolidated	Regulated Operations	Investments and Other
Millions			
2009			
Operating Revenue	$766.7	$689.4	$77.3
Prior Year Rate Refunds	(7.6)	(7.6)	–
Total Operating Revenue	759.1	681.8	77.3
Fuel and Purchased Power	279.5	279.5	–
Operating and Maintenance	308.9	235.8	73.1
Depreciation Expense	64.7	60.2	4.5
Operating Income (Loss)	106.0	106.3	(0.3)
Interest Expense	(33.8)	(28.3)	(5.5)
Equity Earnings in ATC	17.5	17.5	–
Other Income (Expense)	1.8	5.8	(4.0)
Income (Loss) Before Non-Controlling Interest and Income Taxes	91.5	101.3	(9.8)
Income Tax Expense (Benefit)	30.8	35.4	(4.6)
Net Income (Loss)	60.7	65.9	(5.2)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	–	(0.3)
Net Income (Loss) Attributable to ALLETE	$61.0	$65.9	$(4.9)
Total Assets	$2,393.1	$2,184.0	$209.1
Capital Additions	$303.7	$299.2	$4.5

Note 2. Business Segments (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
2008			
Operating Revenue	$801.0	$712.2	$88.8
Fuel and Purchased Power	305.6	305.6	–
Operating and Maintenance	318.1	239.3	78.8
Depreciation Expense	55.5	50.7	4.8
Operating Income	121.8	116.6	5.2
Interest Expense	(26.3)	(24.0)	(2.3)
Equity Earnings in ATC	15.3	15.3	–
Other Income	15.6	3.6	12.0
Income Before Non-Controlling Interest and Income Taxes	126.4	111.5	14.9
Income Tax Expense (Benefit)	43.4	43.6	(0.2)
Net Income	83.0	67.9	15.1
Less: Non-Controlling Interest in Subsidiaries	0.5	–	0.5
Net Income Attributable to ALLETE	$82.5	$67.9	$14.6
Total Assets	$2,134.8	$1,832.1	$302.7
Capital Additions	$322.9	$317.0	$5.9

Note 3. Property, Plant and Equipment

Property, Plant and Equipment As of December 31	2010	2009
Millions		
Regulated Utility	$2,649.2	$2,415.7
Construction Work in Progress	86.6	89.6
Accumulated Depreciation	(975.8)	(928.8)
Regulated Utility Plant – Net	1,760.0	1,576.5
Non-Rate Base Energy Operations	88.4	87.0
Construction Work in Progress	4.5	3.6
Accumulated Depreciation	(48.0)	(45.5)
Non-Rate Base Energy Operations Plant – Net	44.9	45.1
Other Plant – Net	0.7	1.1
Property, Plant and Equipment – Net	$1,805.6	$1,622.7

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets. The MPUC and the PSCW have approved depreciation rates for our Regulated Utility plant.

Estimated Useful Lives of Property, Plant and Equipment

Regulated Utility –	Generation	1 to 35 years	Non-Rate Base Operations	3 to 61 years
	Transmission	42 to 61 years	Other Plant	5 to 25 years
	Distribution	14 to 65 years		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. Asset retirement obligations (ARO) relate primarily to the decommissioning of our utility steam generating facilities and land reclamation at BNI Coal, and are included in Other Non-Current Liabilities on our consolidated balance sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives. Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal costs have not been recognized because they are considered immaterial to our consolidated financial statements.

Long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries were included in accumulated depreciation. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-ARO obligations. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with the guidance for AROs. (See Note 5. Regulatory Matters.)

Note 3. Property, Plant and Equipment (Continued)

Asset Retirement Obligation	
Millions	
Obligation as of December 31, 2008	$39.5
Accretion Expense	2.3
Additional Liabilities Incurred in 2009	2.8
Obligation as of December 31, 2009	44.6
Accretion Expense	2.9
Additional Liabilities Incurred in 2010	2.8
Obligation as of December 31, 2010	$50.3

Note 4. Jointly-Owned Electric Facility

Following are our investments in jointly owned plants and the related ownership percentages as of December 31, 2010:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
Boswell Unit 4	$407.5	$175.5	$19.6	80
CapX2020	–	–	11.3	9.3 – 14.7
Total	$407.5	$175.5	$30.9	

We own 80 percent of the 585-MW Boswell Energy Center Unit 4 (Boswell Unit 4). While we operate the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which we and WPPI Energy, the owner of the remaining 20 percent of Boswell Unit 4, have equal representation and voting rights. Each of us must provide our own financing and is obligated to pay our ownership share of operating costs. Our share of direct operating expenses of Boswell Unit 4 is included in operating expense on our consolidated statement of income. We are a participant in the CapX2020 initiative to ensure reliable electric transmission and distribution in the surrounding region, along with other electric cooperatives, municipals, and investor-owned utilities. We are currently participating in three CapX2020 projects with varying ownership percentages.

Note 5. Regulatory Matters

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

2010 Rate Case. On November 2, 2009, Minnesota Power filed an $81 million retail rate increase request 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. Interim rates were put into effect on January 1, 2010, and were originally estimated to increase revenues by $48.5 million in 2010. In April 2010, we adjusted our initial filing for events that had occurred since November 2009 – primarily increased sales to our industrial customers – resulting in a retail rate increase request of $72 million, a return on equity request of 11.25 percent, and a capital structure consisting of 54.29 percent equity and 45.71 percent debt. As a result of these increased sales, interim rates were approximately $52 million for 2010.

On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of approximately $54 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. In a hearing on January 19, 2011, the MPUC denied all reconsideration requests. Final rates will be implemented after acceptance of the compliance filing, estimated in the second quarter of 2011. Minnesota Power will continue to collect interim rates from its customers until the new rates go into effect. We expect no interim rate refunds will be issued.

FERC-Approved Wholesale Rates. Minnesota Power’s non-affiliated municipal 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 customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. The rates included in these contracts are calculated using a cost-based formula methodology that is set at the beginning of the year using estimated costs, and provides for a true-up calculation for actual costs. The estimated true-up is recorded in the current year, then finalized and billed or paid to customers in the following year. The contracts include a termination clause requiring a 3 year notice to terminate. To date, no termination notices have been received.

Note 5. Regulatory Matters (Continued)

2010 Wisconsin Rate Increase. During 2010, SWL&P's retail rates were based on a 2008 PSCW retail rate order, which was effective January 1, 2009. SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, and allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.80 percent increase in water rates, a 2.49 percent increase in natural gas rates and a 0.68 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2 million in additional revenue.

Deferred Regulatory Assets and Liabilities. Our regulated utility operations are subject to the accounting guidance on Regulated Operations. We capitalize incurred costs, as regulatory assets, which are probable of recovery in future utility rates. Regulatory liabilities represent amounts expected to be refunded or credited to customers in rates. No regulatory assets or liabilities are currently earning a return.

Deferred Regulatory Assets and Liabilities As of December 31	2010	2009
Millions		
Deferred Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans *(a)*	$257.9	$235.8
Boswell Unit 3 Environmental Rider *(b)*	20.5	20.9
Deferred Fuel *(c)*	20.6	20.8
Income Taxes	17.3	15.7
Asset Retirement Obligation	7.8	6.3
Deferred MISO Costs	0.9	2.4
Premium on Reacquired Debt	1.8	2.0
Other	4.0	4.8
Total Deferred Regulatory Assets	$330.8	$308.7
Deferred Regulatory Liabilities		
Income Taxes	$23.4	$25.9
Plant Removal Obligations	16.9	16.9
Other	3.3	4.3
Total Deferred Regulatory Liabilities	$43.6	$47.1

(a) See Note 15. Pension and Other Postretirement Benefit Plans.
(b) MPUC-approved current cost recovery rider related to environmental improvements that were placed in service in November 2009. As part of our 2010 rate case, on November 2, 2010, the MPUC approved a proposal to move the rider balance to Property, Plant and Equipment to recover in rate base, which will be effective upon a final rate order.
(c) As of December 31, 2009, under our 2008 rate case, $5 million of this balance related to deferred fuel costs incurred under the former base cost of fuel calculation. During the fourth quarter of 2010, it was determined that the asset was no longer probable of recovery in future utility rates and was therefore written off.

Current and Non-Current Deferred Regulatory Assets and Liabilities As of December 31	2010	2009
Millions		
Total Current Deferred Regulatory Assets *(a)*	$20.6	$15.5
Total Non-Current Deferred Regulatory Assets	310.2	293.2
Total Deferred Regulatory Assets	$330.8	$308.7
Total Current Deferred Regulatory Liabilities	–	–
Total Non-Current Deferred Regulatory Liabilities	$43.6	$47.1
Total Deferred Regulatory Liabilities	$43.6	$47.1

(a) Current deferred regulatory assets consist of deferred fuel costs and are included in prepayments and other on the consolidated balance sheet.

Note 6. Investment in ATC

Investment in ATC. Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. ATC rates are FERC approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2010, our equity investment balance in ATC was $93.3 million ($88.4 million at December 31, 2009). On January 31, 2011, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $2 million throughout 2011.

Note 6. Investment in ATC (Continued)

ALLETE's Interest in ATC Year Ended December 31	2010	2009
Millions		
Equity Investment Beginning Balance	$88.4	$76.9
Cash Investments	1.6	7.8
Equity in ATC Earnings	17.9	17.5
Distributed ATC Earnings	(14.6)	(13.8)
Equity Investment Ending Balance	$93.3	$88.4

ATC Summarized Financial Data Balance Sheet Data As of December 31	2010	2009
Millions		
Current Assets	$59.9	$51.1
Non-Current Assets	2,888.4	2,767.3
Total Assets	$2,948.3	$2,818.4
Current Liabilities	$428.4	$285.5
Long-Term Debt	1,175.0	1,259.6
Other Non-Current Liabilities	84.9	76.9
Members' Equity	1,260.0	1,196.4
Total Liabilities and Members' Equity	$2,948.3	$2,818.4

Income Statement Data Year Ended December 31	2010	2009	2008
Millions			
Revenue	$556.7	$521.5	$466.6
Operating Expense	251.1	230.3	209.0
Other Expense	85.9	77.8	69.6
Net Income	$219.7	$213.4	$188.0
ALLETE's Equity in Net Income	$17.9	$17.5	$15.3

Note 7. Investments

Investments. At December 31, 2010, our long-term investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits and land held-for-sale in Minnesota.

Other Investments As of December 31	2010	2009
Millions		
ALLETE Properties	$94.0	$93.1
Available-for-sale Securities *(a)*	25.2	29.5
Other	6.8	7.9
Total Other Investments	$126.0	$130.5

(a) As of December 31, 2010, our remaining $6.7 million of Auction Rate Securities were classified as short-term as they were called prior to December 31, 2010, and redeemed at carrying value on January 5, 2011.

Note 7. Investments (Continued)

ALLETE Properties As of December 31	2010	2009
Millions		
Land Held-for-Sale Beginning Balance	$74.9	$71.2
Additions during period:		
Deeds to Collateralized Property *(a)*	9.9	–
Capitalized Improvements and Other	1.2	5.6
Deductions during period: Cost of Real Estate Sold	–	(1.9)
Land Held-for-Sale Ending Balance	86.0	74.9
Long-Term Finance Receivables (net of allowances of $0.8 and $0.4) *(a)*	3.7	12.9
Other	4.3	5.3
Total Real Estate Assets	$94.0	$93.1

(a) The deeds to collateralized property resulted primarily from an entity which filed for voluntary Chapter 11 bankruptcy and were recorded at fair value net of estimated selling costs. The change in the long-term finance receivables was primarily a result of the same transaction.

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 were recorded for the year ended December 31, 2010 (none in 2009).

Long-Term Finance Receivables. As of December 31, 2010, long-term finance receivables were $3.7 million net of allowance ($12.9 million net of allowance as of December 31, 2009). Long-term finance receivables are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. As of December 31, 2010, the reserve balance was due to an impairment of $0.8 million on a delinquent note receivable where the fair value of the collateralized property was less than the note balance ($0.3 million of impairments in 2009). This valuation technique constitutes a Level 3 non-recurring fair value measurement.

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.

In June 2010, ALLETE Properties received deeds in lieu of foreclosure to properties which had been sold in multiple transactions over various years to one purchaser. The properties were sold with seller financing, of which $7.0 million remained due and owing from the purchaser that filed for voluntary Chapter 11 bankruptcy protection in June 2009. The bankruptcy trustee approved the transfer of the properties back to ALLETE Properties in satisfaction of the amount owed. The fair value of the properties received net of selling expenses was $8.8 million. The receipt of properties resulted in a pretax gain of $0.7 million after reflecting other liabilities assumed and non-controlling interest.

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities.

Available-For-Sale Securities Million As of December 31	Cost	Gross Unrealized Gain	 (Loss)	Fair Value
2010	$27.4	$0.2	$(2.4)	$25.2
2009	$33.1	$0.1	$(3.7)	$29.5
2008	$40.5	–	$(7.9)	$32.6

Year Ended December 31	Net Proceeds	Gross Realized Gain	 (Loss)	Net Unrealized Gain (Loss) in Other Comprehensive Income
2010	$(1.7)	–	–	$1.4
2009	$6.7	–	–	$4.5
2008	$17.5	$6.5	$(0.1)	$(9.7)

Auction Rate Securities. As of December 31, 2010, our ARS were classified as a short-term investment as the remaining balance of $6.7 million was redeemed at carrying value on January 5, 2011. As of December 31, 2009, our ARS were classified as long-term investments.

Note 8. 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 December 31, 2010, and December 31, 2009. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	At Fair Value as of December 31, 2010			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities	$19.4	–	–	$19.4
Available-for-sale Securities				
Corporate Debt Securities	–	$7.5	–	7.5
Debt Securities Issued by States of the United States (ARS) *(a)*	–	–	$6.7	6.7
Total Available-for-sale Securities	–	7.5	6.7	14.2
Money Market Funds	0.8	–	–	0.8
Total Fair Value of Assets	$20.2	$7.5	$6.7	$34.4
Liabilities:				
Deferred Compensation	–	$13.3	–	$13.3
Total Fair Value of Liabilities	–	$13.3	–	$13.3
Total Net Fair Value of Assets (Liabilities)	$20.2	$(5.8)	$6.7	$21.1

(a) The remaining $6.7 million of ARS were redeemed at carrying value on January 5, 2011.

Recurring Fair Value Measures Activity in Level 3	**Derivatives**	**Debt Securities Issued by the States of the United States (ARS)**
Millions		
Balance as of December 31, 2009	$0.7	$6.7
Purchases, sales, issuances and settlements, net	(0.7)	–
Level 3 transfers in	–	–
Balance as of December 31, 2010 *(a)*	–	$6.7

(a) The remaining $6.7 million of ARS were redeemed at carrying value on January 5, 2011.

Note 8. Fair Value (Continued)

Recurring Fair Value Measures	At Fair Value as of December 31, 2009 Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	$17.8	–	–	$17.8
Available-for-sale Securities				
Corporate Debt Securities	–	$6.4	–	6.4
Debt Securities Issued by States of the United States	–	–	$6.7	6.7
Total Available-for-sale Securities	–	6.4	6.7	13.1
Derivatives	–	–	0.7	0.7
Money Market Funds	1.4	–	–	1.4
Total Fair Value of Assets	$19.2	$6.4	$7.4	$33.0
Liabilities:				
Deferred Compensation	–	$14.6	–	$14.6
Total Fair Value of Liabilities	–	$14.6	–	$14.6
Total Net Fair Value of Assets (Liabilities)	$19.2	$(8.2)	$7.4	$18.4

Recurring Fair Value Measures Activity in Level 3	Derivatives	Debt Securities Issued by the States of the United States (ARS)
Millions		
Balance as of December 31, 2008	–	$15.2
Purchases, sales, issuances and settlements, net *(a)*	$0.7	(8.5)
Level 3 transfers in	–	–
Balance as of December 31, 2009	$0.7	$6.7

(a) ARS were redeemed during 2009 at carrying value.

The Company's policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that caused the transfer. For the year ended December 31, 2010 and 2009, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the items listed below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the items below were 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, 2010	$785.0	$796.7
December 31, 2009	$701.0	$734.8

Note 9. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding as of December 31, 2010, was $14.4 million ($7.1 million at December 31, 2009) and consisted of long-term debt due within one year and notes payable. (See ALLETE consolidated balance sheet.)

As of December 31, 2010, we had bank lines of credit aggregating $154.0 million ($157.0 million at December 31, 2009), the majority of which expire in January 2012. We expect to enter into new bank lines of credit during 2011 to replace the expiring facility. These bank lines of credit are available to provide short-term bank loans and credit support for commercial paper. At December 31, 2010, $1.0 million ($69.2 million at December 31, 2009) was drawn on our lines of credit leaving a $153.0 million balance available for use ($87.8 million at December 31, 2009). In December 2009, we drew $65.0 million on our $150.0 million syndicated revolving credit facility to temporarily fund the purchase of the 250 kV DC transmission line. In February 2010, we issued $80.0 million of First Mortgage Bonds (Bonds) (see Long-Term Debt, below). We used the proceeds from the sale of the Bonds to pay off the outstanding amount drawn on the line, resulting in the $65.0 million borrowing under our line of credit being classified as long-term debt at December 31, 2009.

Note 9. Short-Term and Long-Term Debt (Continued)

On November 12, 2009, BNI Coal replaced a $6.0 million Promissory Note and Supplement (Line of Credit) with CoBANK, ACB with a $3.0 million Line of Credit and a $3.0 million term loan with CoBANK, ACB. The Line of Credit was renewed on December 22, 2010, and now expires on November 20, 2012. The Line of Credit is being used for general corporate purposes. As of December 31, 2010, $1.0 million was drawn on the Line of Credit. The $3.0 million term loan has a fixed interest rate of 5.19 percent and is payable in 28 equal quarterly installments commencing January 20, 2010, and ending on October 20, 2016.

Long-Term Debt. The aggregate amount of long-term debt maturing during 2011 is $13.4 million ($3.3 million in 2012; $73.9 million in 2013; $19.5 million in 2014; $16.3 million in 2015; and $658.6 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgages collateralizing various First Mortgage Bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

In February 2010, we issued $80.0 million in principal amount of unregistered First Mortgage Bonds in the private placement market in three series as follows:

Issue Date	Maturity	Principal Amount	Interest Rate
February 17, 2010	April 15, 2021	$15 Million	4.85%
February 17, 2010	April 15, 2025	$30 Million	5.10%
February 17, 2010	April 15, 2040	$35 Million	6.00%

We used the proceeds from the sale of the bonds to pay off an outstanding balance of $65 million on our syndicated revolving credit facility, to fund utility capital investments and for general corporate purposes.

In August 2010, we issued $75.0 million in principal amount of unregistered First Mortgage Bonds in the private placement market in two series as follows:

Issue Date	Maturity	Principal Amount	Interest Rate
August 17, 2010	October 15, 2025	$30 Million	4.90%
August 17, 2010	April 15, 2040	$45 Million	5.82%

We used the proceeds to fund utility capital investments and for general corporate purposes.

For the February and August 2010 bond issuances (the Bonds), 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 the terms and conditions of our utility mortgage. 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. Short-Term and Long-Term Debt (Continued)

Long-Term Debt As of December 31	2010	2009
Millions		
First Mortgage Bonds		
4.86% Series Due 2013	$60.0	$60.0
6.94% Series Due 2014	18.0	18.0
7.70% Series Due 2016	20.0	20.0
8.17% Series Due 2019	42.0	42.0
5.28% Series Due 2020	35.0	35.0
4.85% Series Due 2021	15.0	–
4.95% Pollution Control Series F Due 2022	111.0	111.0
6.02% Series Due 2023	75.0	75.0
4.90% Series Due 2025	30.0	–
5.10% Series Due 2025	30.0	–
5.99% Series Due 2027	60.0	60.0
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	–
5.82% Series Due 2040	45.0	–
SWL&P First Mortgage Bonds		
7.25% Series Due 2013	10.0	10.0
Senior Unsecured Notes 5.99% Due 2017	50.0	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A, B, and C Due 2012 – 2020	28.3	28.3
Industrial Development Revenue Bonds 6.5% Due 2025	6.0	6.0
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 Due 2025	27.8	27.8
Line of Credit Facility *(a)*	–	65.0
Other Long-Term Debt, 1.0% – 8.0% Due 2011 – 2037	36.9	42.9
Total Long-Term Debt	785.0	701.0
Less: Due Within One Year	13.4	5.2
Net Long-Term Debt	$771.6	$695.8

(a) A portion of the proceeds from the issuance on February 17, 2010, of $80 million principal amount of First Mortgage Bonds due in 2021, 2025 and 2040, was used to repay the outstanding borrowings on the Line of Credit Facility as of December 31, 2009.

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 December 31, 2010, our ratio was approximately 0.43 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2010, ALLETE was in compliance with its financial covenants.

Note 10. Commitments, Guarantees and Contingencies

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

Square Butte PPA. Minnesota Power has a power purchase agreement with Square Butte that extends through 2026 (Agreement). It provides a long-term supply of energy to customers in our electric service territory and enables Minnesota Power to meet 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, subject to the provisions of the Minnkota power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. We expect debt service, operating and maintenance and depreciation expenses for Square Butte to increase in 2011 due to environmental compliance obligations. As of December 31, 2010, Square Butte had total debt outstanding of $379.6 million. Annual debt service for Square Butte is expected to be approximately $39 million in each of the five years, 2011 through 2015. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2010 was $55.2 million ($53.9 million in 2009; $56.7 million in 2008). This reflects Minnesota Power's pro rata share of total Square Butte costs, based on the 50 percent output entitlement in 2010 (50 percent in 2009; 55 percent in 2008). Included in this amount was Minnesota Power's pro rata share of interest expense of $10.2 million in 2010 ($11.0 million in 2009; $11.6 million in 2008). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Minnkota Power Sales Agreement. In conjunction with the purchase of the existing 250 kV DC transmission line from Square Butte on December 31, 2009, Minnesota Power entered into a contingent power sales agreement with Minnkota Power. Under the power sales agreement, Minnesota Power will sell a portion of its output from Square Butte to Minnkota, resulting in Minnkota's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025.

No power will be sold under this agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in 2013. This new AC transmission line will allow Minnkota to transmit its entitlement from Square Butte directly to its customers, which, in turn, will provide Minnesota Power with additional capacity on the DC line to transmit new wind generation.

Wind PPA. In 2006 and 2007, we entered into two long-term wind PPA with an affiliate of NextEra Energy, Inc. to purchase the output from two wind facilities, Oliver Wind I (50 MW) and Oliver Wind II (48 MW), located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Hydro PPA. We have a PPA with Manitoba Hydro that began in May 2009 and expires in April 2015. Under the agreement with Manitoba Hydro, Minnesota Power is currently purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

On April 30, 2010, Minnesota Power signed a definitive agreement with Manitoba Hydro, subject to MPUC approval, to purchase surplus energy beginning in May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On September 1, 2010, we filed a petition with the MPUC to approve our PPA with Manitoba Hydro. On October 28, 2010, the OES filed comments recommending approval.

North Dakota Wind Development*.* On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota, to Duluth, Minnesota. We use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is a two phase, 82 MW wind project in North Dakota. All permitting has been received and the first phase was completed in 2010. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of 16 2.3 MW wind turbines, all of which were in-service at the end of 2010. Phase two is expected to be completed late in 2011 and consists of the installation of 15 3.0 MW wind turbines. Bison 1 is expected to have a total capital cost of approximately $177 million, of which $121 million was spent through December 31, 2010. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery eligibility for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We 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 $8.1 million in 2011, $8.4 million in 2012, $8.5 million in 2013, $8.7 million in 2014, $8.4 million in 2015 and $44.7 million thereafter. Total rent and lease expense was $9.4 million in 2010 ($9.3 million in 2009; $8.5 million in 2008).

Note 10. Commitments, Guarantees and Contingencies (Continued)

Coal, Rail and Shipping Contracts. We have coal supply agreements and transportation agreements providing for the purchase and delivery of a significant portion of our coal requirements. These coal and transportation agreements, including option terms, expire in various years between 2011 and 2015. Our minimum annual payment obligation for 2011 is $41.0 million, 2012 is $1.6 million, and 2013 is $1.4 million. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

CapX2020 Transmission Projects. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. 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. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project–by-project basis.

Minnesota Power is currently participating in three CapX2020 projects: the Fargo to St. Cloud project, the Monticello to St. Cloud project, which together total a 238-mile, 345 kV line from Fargo to Monticello, and the 70-mile, 230 kV line between Bemidji and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $11.3 million was spent through December 31, 2010.

In July 2010, the MPUC granted a route permit for the 28-mile 345 kV transmission line between Monticello and St. Cloud. Construction of the project is expected to be complete in late 2011. The 210-mile 345 kV transmission line from St. Cloud to Fargo is expected to be complete by 2015. Construction for the Bemidji to Grand Rapids 230 kV line project commenced in January 2011.

We have an approved cost recovery rider in place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. In our 2010 rate case we moved completed transmission projects from the current cost recovery rider to base rates. In July 2010, we filed for an updated billing factor that includes additional transmission projects and expenses, including the CapX2020 projects, which we expect to be approved in early 2011.

Environmental Matters.

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

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to 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 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 become available. Accruals for environmental liabilities are included in the consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is heavily regulated both at the Federal and State level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's generating facilities are equipped with pollution control equipment such as scrubbers, bag houses, and low NO_x technologies. At this time, these facilities are substantially compliant with applicable emission requirements.

Note 10. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

New Source Review. In August 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 asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements, and that the Boswell Unit 4 Title V permit was violated. Minnesota Power believes the projects were in full compliance with the Clean Air Act, NSR requirements and applicable permits.

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 emissions at Laskin and Boswell, and continues to reduce emissions at Boswell. 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.

EPA Transport Rule. On July 6, 2010, the EPA proposed a rule known as the Transport Rule (TR) requiring 31 states, including Minnesota and the District of Columbia, to reduce power plant SO_2 and NO_x emissions that can significantly contribute to ozone and fine particle pollution problems in other states. If adopted, the TR will replace the Clean Air Interstate Rule (CAIR) that was issued by the EPA in March 2005. Minnesota was included as one of the original 28 CAIR states but, following Minnesota Power’s successful challenge to CAIR, the EPA granted an administrative stay of the CAIR requirements in Minnesota while it prepared the TR. The proposed TR responds to the United States Court of Appeals for the District of Columbia Circuit’s remand of CAIR by replacing and reforming provisions to address updated air quality standards, improved emissions data and reformed emissions transport modeling.

The EPA took public comments on the proposed rule through October 1, 2010, and plans to finalize the rule in June 2011. Emissions reductions are proposed to take effect in 2012, within one year of projected finalization of the rule.

The EPA has not yet determined whether trading of emission allowances between regulated generating units or states may be implemented. Since 2006, we have made substantial investments in pollution control equipment at our Laskin, Taconite Harbor and Boswell generating units which have significantly reduced emissions. These reductions may satisfy Minnesota Power’s obligations with respect to these requirements. We are unable to predict any additional compliance costs we might incur at this time.

Minnesota Regional Haze. The federal 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, put in place between 1962 and 1977, with emissions contributing to visibility impairment are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two 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 CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit’s remand of CAIR. Subsequently, the MPCA requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirements for that unit. In December 2009, the MPCA approved the SIP for submittal to the EPA for its review and approval. Approval by the EPA is pending on whether to approve the Minnesota SIP. If approved, Minnesota Power will have five years to bring Taconite Harbor Unit 3 into compliance. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Electric Utility Units. Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants for certain source categories. In December 2009, Minnesota Power and other utilities received an Information Collection Request from the EPA requiring that emissions data be provided and stack testing be performed in order to develop a database upon which to base future regulations. On March 30, 2010, Minnesota Power responded to the Information Collection Request. Stack testing was completed during the third quarter of 2010 and the results were submitted to the EPA. The EPA is subject to a consent decree which requires the EPA to propose a utility NESHAPs rule by March 2011, with the final rule by November 2011. As part of the NESHAPs rulemaking, EPA will develop Maximum Achievable Control Technology standards for utilities. Costs for complying with potential future mercury and other hazardous air pollutant regulations under the Clean Air Act cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility’s customers. Costs for the Boswell Unit 4 emission reduction plan cannot be estimated at this time.

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

Ozone NAAQS. The EPA is proposing to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to reduce the eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA expects to issue final standards by July 2011. As proposed, states have until early 2014 to submit plans outlining how they will meet the standards.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. The EPA established a more stringent 24-hour average fine particulate ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The District of Columbia Circuit Court of Appeals has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status. The EPA plans to finalize the new $PM_{2.5}$ standards in 2011, and state attainment status determination will likely not occur prior to 2013. As early as late 2014, affected sources would have to take additional control measures if modeling demonstrates non-compliance at the property boundary.

SO_2 and NO_2 NAAQS. The EPA recently finalized a new one-hour NAAQS for SO_2 and NO_2. Monitor data indicates that Minnesota will likely be in compliance with these new standards; however, the SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. It is unclear what the outcome of this evaluation will be. These NAAQS could also result in more stringent emission limits on our steam generating facilities, possibly resulting in additional control measures on some of our units.

We are unable to predict the nature or timing of any additional NAAQS regulation or compliance costs we might incur at this time.

Climate Change. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customer's requirements:

- Expand our renewable energy supply.
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies.
- Provide energy conservation initiatives for our customers and engage in other demand side efforts.
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.
- Achieve overall carbon emission reductions.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations.

Midwestern Greenhouse Gas Reduction Accord. Minnesota is also participating in the Midwestern Greenhouse Gas Reduction Accord (the Accord), a regional effort to develop a multi-state approach to GHG emission reductions. The Accord includes an agreement to develop a multi-sector cap-and-trade system to help meet the targets established by the group.

EPA Regulation of GHG Emissions. On May 13, 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The PSD/Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications, and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHGs requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons per year or more of total GHG on a CO_2 equivalent basis.

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

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed and are awaiting judicial determination. Comments to the Permitting Guidance were also submitted and may be addressed by EPA in the form of revised guidance documents.

We cannot predict the nature or timing of any additional GHG legislation or regulation. Although we are unable to predict the compliance costs we might incur, the costs could have a material impact on our financial results.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its steam electric stations. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use, or trucked to state permitted landfills. On June 18, 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Public comments were submitted to the EPA by November 19, 2010. We are unable to predict the compliance costs we might incur; however, there is the possibility they could have a material impact.

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. At December 31, 2010, we have a $0.5 million liability for this site, and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Other Matters

BNI Coal. As of December 31, 2010, 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, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional $10.0 million, of which $6.7 million is needed to meet the requirements for BNI Coal's total reclamation liability currently estimated at $25.1 million. BNI Coal does not believe it is likely that any of these outstanding bonds will be drawn upon.

ALLETE Properties. As of December 31, 2010, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $11.6 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in their various projects. The remaining work to be completed on these improvements is estimated to be approximately $9.0 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; and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable 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 December 31, 2010, we owned 69 percent of the assessable land in the Town Center District (69 percent at December 31, 2009) and 93 percent of the assessable land in the Palm Coast Park District (86 percent at December 31, 2009). At these ownership levels our annual assessments are $1.4 million for Town Center and $2.1 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Note 10. Commitments, Guarantees and Contingencies (Continued)

Legal Proceedings. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's, United Taconite, LLC, property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An expense related to any damages that may result from the lawsuit has not been recorded as of December 31, 2010, because a potential loss is not currently probable or reasonably estimable; however, the Company believes it has adequate insurance coverage for potential loss.

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.

Note 11. Common Stock and Earnings Per Share

Summary of Common Stock		Shares	Equity
		Thousands	Millions
Balance as of December 31, 2007		30,827	$461.2
2008	Employee Stock Purchase Plan	17	0.6
	Invest Direct	161	6.9
	Options and Stock Awards	24	4.6
	Equity Issuance Program	1,556	60.8
Balance as of December 31, 2008		32,585	$534.1
2009	Employee Stock Purchase Plan	24	0.7
	Invest Direct	456	13.6
	Options and Stock Awards	8	1.1
	Equity Issuance Program	1,685	51.9
	Contributions to Pension	463	12.0
Balance as of December 31, 2009		35,221	$613.4
2010	Employee Stock Purchase Plan	19	0.6
	Invest Direct	346	11.7
	Options and Stock Awards	51	4.4
	Equity Issuance Program	180	6.0
Balance as of December 31, 2010		35,817	$636.1

Equity Issuance Program. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the year ended December 31, 2010, 0.2 million shares of common stock were issued under this agreement resulting in net proceeds of $6.0 million. During 2009, 1.7 million shares of common stock were issued for net proceeds of $51.9 million. As of December 31, 2010, approximately 3.1 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2010 and 2009 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

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.

Earnings Per Share. The difference between basic and diluted earnings per share arises, if any, from outstanding stock options, non-vested restricted stock, and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. In accordance with accounting standards for earnings per share, for 2010, 0.5 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 be anti-dilutive (0.6 million shares were excluded for 2009 and 0.6 million in 2008).

Note 11. Common Stock and Earnings Per Share (Continued)

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2010			
Net Income Attributable to ALLETE	$75.3	–	$75.3
Common Shares	34.2	0.1	34.3
Per Share of Common Stock	$2.20	–	$2.19
2009			
Net Income Attributable to ALLETE	$61.0	–	$61.0
Common Shares	32.2	–	32.2
Per Share of Common Stock	$1.89	–	$1.89
2008			
Net Income Attributable to ALLETE	$82.5	–	$82.5
Common Shares	29.2	0.1	29.3
Per Share of Common Stock	$2.82	–	$2.82

Note 12. Other Income (Expense)

Year Ended December 31	2010	2009	2008
Millions			
AFUDC - Equity	$4.2	$5.8	$3.3
Investments and Other Income (a)	0.4	(4.0)	12.3
Total Other Income	$4.6	$1.8	$15.6

(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 13. Income Tax Expense

On March 23, 2010, the Patient Protection and Affordable Care Act, which was subsequently amended on March 30, 2010, was signed into law by the President. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of the provisions changes the tax treatment for retiree prescription drug expenses by eliminating the tax deduction for expenses that are reimbursed under Medicare Part D, beginning January 1, 2013. Based on this provision, we are subject to additional taxes in the future and were required to reverse previously recorded tax benefits in the period of enactment. Consequently, the elimination of the previously recorded tax benefit resulted in a non-recurring charge to net income of $4.0 million in 2010. On October 8, 2010, we submitted a filing with the MPUC to request deferral of the retail portion of Medicare Part D of this legislation. As we are unable to predict the outcome at this time, we have not deferred any portion of this amount as a regulatory asset.

Note 13. Income Tax Expense (Continued)

Income Tax Expense Year Ended December 31	2010	2009	2008
Millions			
Current Tax Expense (Benefit)			
Federal *(a)*	$(23.0)	$(42.6)	$6.2
State	1.3	(1.8)	(1.6)
Total Current Tax Expense (Benefit)	(21.7)	(44.4)	4.6
Deferred Tax Expense			
Federal *(b)*	61.4	66.0	29.3
State	5.3	10.3	13.4
Change in Valuation Allowance	0.2	(0.1)	(2.9)
Investment Tax Credit Amortization	(0.9)	(1.0)	(1.0)
Total Deferred Tax Expense	66.0	75.2	38.8
Total Income Tax Expense	$44.3	$30.8	$43.4

(a) The 2010 federal current tax benefit is primarily due to the implementation of tax planning initiatives and bonus depreciation provisions in the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 and the Small Business Jobs Act of 2010. The 2009 federal current tax benefit is primarily due to bonus depreciation provisions of the American Recovery and Reinvestment Act of 2009.

(b) The 2010 federal deferred tax expense is primarily due to tax planning initiatives and bonus depreciation provisions of the Small Business Jobs Act of 2010 and the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. Also included in 2010 is a one-time charge of $4.0 million as a result of the Patient Protection and Affordable Care Act. The 2009 federal deferred tax expense is primarily due to bonus depreciation provisions of the American Recovery and Reinvestment Act of 2009.

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense Year Ended December 31	2010	2009	2008
Millions			
Income Before Non-Controlling Interest and Income Taxes	$119.1	$91.5	$126.4
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$41.7	$32.0	$44.2
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	4.5	5.4	4.8
Impact of Patient Protection and Affordable Care Act	4.0	–	–
Regulatory Differences for Utility Plant	(2.0)	(2.5)	(1.6)
Production Tax Credit	(1.6)	(1.2)	(0.4)
Other	(2.3)	(2.9)	(3.6)
Total Income Tax Expense	$44.3	$30.8	$43.4

The effective tax rate on income was 37.2 percent for 2010 (33.7 percent for 2009; 34.3 percent for 2008).

Note 13. Income Tax Expense (Continued)

Deferred Tax Assets and Liabilities As of December 31	2010	2009
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation *(a)*	$121.8	$118.2
Property Related	51.1	46.5
NOL and Tax Credit Carryforward	28.2	–
Investment Tax Credits	9.7	10.0
Other	12.7	14.4
Gross Deferred Tax Assets	223.5	189.1
Deferred Tax Asset Valuation Allowance	(0.5)	(0.3)
Total Deferred Tax Assets	$223.0	$188.8
Deferred Tax Liabilities		
Property Related	$387.2	$294.1
Regulatory Asset for Benefit Obligations	105.8	96.5
Unamortized Investment Tax Credits	13.7	14.1
Partnership Basis Differences	19.4	14.6
Other	27.3	28.2
Total Deferred Tax Liabilities	$553.4	$447.5
Net Deferred Income Taxes	$330.4	$258.7
Recorded as:		
Net Current Deferred Tax Liabilities *(b)*	$5.2	$5.6
Net Long-Term Deferred Tax Liabilities	325.2	253.1
Net Deferred Income Taxes	$330.4	$258.7

(a) Includes unfunded employee benefits
(b) Included in Other Current Liabilities.

NOL and Tax Credit Carryforwards Year Ended December 31	2010	2009
Millions		
Federal NOL carryforward *(a)*	$62.0	$7.3
Federal tax credit carryforwards	3.7	1.9
State NOL carryforward *(a)*	71.7	59.6
State tax credit carryforwards, net of federal detriment	1.7	0.1

(a) Pretax amounts

In 2010 we had federal and state NOLs and tax credit carryforwards primarily due to bonus depreciation provisions in the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 and the Small Business Jobs Act of 2010. The 2010 federal NOL will be partially utilized by carrying it back against prior years' income with the remainder carried forward to offset future years' income. We expect to fully utilize the federal NOL and tax credit carryforwards; therefore a deferred tax asset has been recorded to recognize the resulting tax benefit. The state NOL and tax credits will be carried forward to future tax years. We have established a valuation allowance against certain state NOL and tax credits that we do not expect to utilize before their expiration. The 2009 federal and state NOL were primarily due to bonus depreciation provisions in the American Recovery and Reinvestment Act of 2009. The federal and state carryforward periods expire between 2014 and 2030.

Gross Unrecognized Income Tax Benefits	2010	2009	2008
Millions			
Balance at January 1	$9.5	$8.0	$5.3
Additions for Tax Positions Related to the Current Year	–	0.5	0.7
Reductions for Tax Positions Related to the Current Year	(0.2)	–	–
Additions for Tax Positions Related to Prior Years	4.4	1.0	4.5
Reduction for Tax Positions Related to Prior Years	–	–	(2.5)
Settlements	(0.3)	–	–
Lapse of Statute	(1.1)	–	–
Balance as of December 31	$12.3	$9.5	$8.0

Note 13. Income Tax Expense (Continued)

The gross unrecognized tax benefits as of December 31, 2010, includes $0.6 million of net unrecognized tax benefits that, if recognized, would affect the annual effective income tax rate.

As of December 31, 2010, we had $0.7 million ($0.9 million for 2009 and $0.6 million for 2008) of accrued interest related to unrecognized tax benefits included in the consolidated balance sheet. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses in the consolidated statement of income. In 2010, we recognized a $0.2 million reduction of interest expense (interest expense of $0.4 million for 2009 and $0.4 million for 2008). There were no penalties recognized for 2010, 2009 or 2008.

We file a consolidated federal income tax return in the United States and state income tax returns in various jurisdictions. ALLETE is currently under examination by the IRS for the tax years 2005 through 2009. ALLETE is no longer subject to federal or state examination for years before 2005.

During the next 12 months it is reasonably possible the amount of unrecognized tax benefits could be reduced by $4.0 million due to statute expirations and anticipated audit settlements. This amount is primarily due to timing issues.

Note 14. Other Comprehensive Income (Loss)

Other Comprehensive Income (Loss) Year Ended December 31	2010	2009	2008
Millions			
Net Income	$74.8	$60.7	$83.0
Other Comprehensive Income			
Unrealized Gain on Securities Net of income taxes of $0.6, $1.7, and $(3.7)	0.8	2.8	(6.0)
Reclassification Adjustment for Losses Included in Income Net of income taxes of $–, $–, and $(2.7)	–	–	(3.7)
Defined Benefit Pension and Other Postretirement Plans Net of income taxes of $–, $4.1, and $(13.3)	–	6.2	(18.8)
Total Other Comprehensive Income (Loss)	0.8	9.0	(28.5)
Total Comprehensive Income	$75.6	$69.7	$54.5
Less: Non-Controlling Interest in Subsidiaries	(0.5)	(0.3)	0.5
Comprehensive Income Attributable to ALLETE	$76.1	$70.0	$54.0

Accumulated Other Comprehensive Income (Loss) As of December 31	2010	2009
Millions		
Unrealized Loss on Securities	$(1.0)	$(1.8)
Defined Benefit Pension and Other Postretirement Plans	(22.2)	(22.2)
Total Accumulated Other Comprehensive Loss	$(23.2)	$(24.0)

Note 15. Pension and Other Postretirement Benefit Plans

We have noncontributory union and non-union defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. In 2010, we made total contributions of $26.5 million ($32.9 million in 2009 of which $12.0 million was contributed in shares of ALLETE common stock). We also have defined contribution pension plans covering substantially all employees. The 2010 plan year employer contributions, which are made through our employee stock ownership plan, totaled $7.2 million ($7.1 million for the 2009 plan year.) (See Note 11. Common Stock and Earnings Per Share and Note 16. Employee Stock and Incentive Plans)

In 2006, amendments were made to the non-union defined benefit pension plan and the RSOP. The non-union defined benefit pension plan was amended to suspend further crediting of service to the plan and closed the plan to new participants. In conjunction with the change, contributions were increased to the RSOP. In 2010, the Minnesota Power unions defined benefit pension plan was amended to close the plan to new participants.

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

We have postretirement health care and life insurance plans covering eligible employees. In 2010, our postretirement health plan was amended to close the plan to employees hired after January 31, 2011. The full eligibility requirement was also amended in 2010, to age 55 with 10 years of service. The postretirement health plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and irrevocable grantor trusts. In 2010 $12.8 million was contributed to the VEBAs. In 2009 we contributed $9.3 million to the VEBAs and $0.3 million to the grantor trust.

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements, and contributions required to avoid benefit restrictions for the pension plans. Estimated defined benefit pension and postretirement health and life contributions for 2011 are expected to be $7.8 million and $12.9 million, respectively. Contributions are based on estimates and assumptions that are subject to change.

Accounting for Defined Benefit Pension and Postretirement Benefit Plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but that are not recognized as components of net periodic benefit cost.

The defined benefit pension and postretirement health and life benefit costs recognized annually by our regulated companies are expected to be recovered through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset on our consolidated balance sheet, in accordance with the accounting standards for Regulated Operations. The defined benefit pension and postretirement health and life benefit costs associated with our other non-rate base operations are recognized in accumulated other comprehensive income.

Pension Obligation and Funded Status

Year Ended December 31	**2010**	**2009**
Millions		
Accumulated Benefit Obligation	$485.6	$435.9
Change in Benefit Obligation		
Obligation, Beginning of Year	$465.2	$440.4
Service Cost	6.2	5.7
Interest Cost	26.2	26.2
Actuarial Loss	47.1	14.6
Benefits Paid	(27.2)	(25.5)
Participant Contributions	8.1	3.9
Obligation, End of Year	$525.6	$465.3
Change in Plan Assets		
Fair Value, Beginning of Year	$327.6	$273.7
Actual Return on Plan Assets	45.6	41.6
Employer Contribution	36.0	37.8
Benefits Paid	(27.2)	(25.5)
Fair Value, End of Year	$382.0	$327.6
Funded Status, End of Year	$(143.6)	$(137.7)

Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(0.9)	$(0.9)
Noncurrent Liabilities	$(142.8)	$(136.8)

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

The pension costs that are reported as a component within our consolidated balance sheet, reflected in regulatory long-term assets and accumulated other comprehensive income, consist of the following:

Unrecognized Pension Costs

Year Ended December 31	2010	2009
Millions		
Net Loss	$225.1	$196.5
Prior Service Cost	1.4	1.8
Total Unrecognized Pension Costs	$226.5	$198.3

Components of Net Periodic Pension Expense

Year Ended December 31	2010	2009	2008
Millions			
Service Cost	$6.2	$5.7	$5.8
Interest Cost	26.2	26.2	25.4
Expected Return on Plan Assets	(33.7)	(33.8)	(32.5)
Amortization of Loss	6.6	3.4	1.6
Amortization of Prior Service Costs	0.5	0.6	0.6
Net Pension Expense	$5.8	$2.1	$0.9

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets

Year Ended December 31	2010	2009
Millions		
Net Loss	$35.2	$6.8
Amortization of Prior Service Costs	(0.5)	(0.6)
Amortization of Gain	(6.6)	(3.4)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$28.1	$2.8

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

Year Ended December 31	2010	2009
Millions		
Projected Benefit Obligation	$525.6	$465.3
Accumulated Benefit Obligation	$485.6	$435.9
Fair Value of Plan Assets	$382.0	$327.6

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Postretirement Health and Life Obligation and Funded Status		
Year Ended December 31	**2010**	**2009**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$192.1	$166.9
Service Cost	4.8	4.1
Interest Cost	10.9	10.0
Actuarial Loss	17.6	18.4
Participant Contributions	2.1	1.7
Plan Amendments	(14.2)	(1.3)
Benefits Paid	(9.2)	(7.7)
Obligation, End of Year	$204.1	$192.1
Change in Plan Assets		
Fair Value, Beginning of Year	$96.4	$78.6
Actual Return on Plan Assets	12.0	13.9
Employer Contribution	13.4	9.9
Participant Contributions	2.0	1.6
Benefits Paid	(9.1)	(7.6)
Fair Value, End of Year	$114.7	$96.4
Funded Status, End of Year	$(89.4)	$(95.7)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(0.8)	$(0.8)
Noncurrent Liabilities	$(88.6)	$(94.8)

According to the accounting standards for Retirement Benefits only assets in the VEBAs are treated as plan assets in the above table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $19.8 million in irrevocable grantor trusts included in Other Investments on our consolidated balance sheet at December 31, 2010 ($18.2 million at December 31, 2009).

The postretirement health and life costs that are reported as a component within our consolidated balance sheet, reflected in regulatory long-term assets and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs		
Year Ended December 31	**2010**	**2009**
Millions		
Net Loss	$80.1	$69.6
Prior Service Cost	(11.2)	(1.3)
Transition Obligation	0.2	6.9
Total Unrecognized Postretirement Health and Life Costs	$69.1	$75.2

Components of Net Periodic Postretirement Health and Life Expense			
Year Ended December 31	**2010**	**2009**	**2008**
Millions			
Service Cost	$4.8	$4.1	$4.0
Interest Cost	10.9	10.0	9.4
Expected Return on Plan Assets	(9.5)	(8.3)	(7.2)
Amortization of Prior Service Cost	(0.1)	–	–
Amortization of Loss	4.8	2.5	1.4
Amortization of Transition Obligation	2.5	2.5	2.5
Net Postretirement Health and Life Expense	$13.4	$10.8	$10.1

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets

Year Ended December 31 Millions	2010	2009
Net Loss	$15.3	$12.9
Prior Service Cost (Credit) Arising During the Period	(14.2)	(1.3)
Amortization of Prior Service Cost	0.1	–
Amortization of Transition Obligation	(2.5)	(2.5)
Amortization of Loss	(4.8)	(2.5)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$(6.1)	$6.6

Estimated Future Benefit Payments

Millions	Pension	Postretirement Health and Life
2011	$27.5	$8.5
2012	$28.4	$9.5
2013	$29.4	$10.5
2014	$30.6	$11.6
2015	$31.8	$12.7
Years 2016 – 2020	$174.6	$73.3

The pension and postretirement health and life costs recorded in other long-term assets and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2011, are as follows:

Millions	Pension	Postretirement Health and Life
Net Loss	$0.3	$8.5
Prior Service Costs	$12.1	$(1.7)
Transition Obligations	–	$0.1
Total Pension and Postretirement Health and Life Costs	$12.4	$6.9

Weighted-Average Assumptions Used to Determine Benefit Obligation

Year Ended December 31	2010	2009
Discount Rate		
Pension	5.36%	5.81%
Postretirement Health and Life	5.40%	5.81%
Rate of Compensation Increase	4.3 – 4.6%	4.3 – 4.6%
Health Care Trend Rates		
Trend Rate	10%	8.5%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2018	2017

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs

Year Ended December 31	2010	2009	2008
Discount Rate	5.81%	6.12%	6.25%
Expected Long-Term Return on Plan Assets			
Pension	8.5%	8.5%	9.0%
Postretirement Health and Life	6.8 – 8.5%	6.8 – 8.5%	7.2 – 9.0%
Rate of Compensation Increase	4.3 – 4.6%	4.3 – 4.6%	4.3 – 4.6%

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns.

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension obligation.

Sensitivity of a One-Percentage-Point Change in Health Care Trend Rates

	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$2.5	$(2.0)
Effect on Postretirement Health and Life Obligation	$23.1	$(19.2)

Actual Plan Asset Allocations

	Pension		Postretirement Health and Life *(a)*	
	2010	**2009**	**2010**	**2009**
Equity Securities	52%	53%	58%	54%
Debt Securities	29%	28%	33%	38%
Real Estate	5%	5%	–	–
Private Equity	14%	14%	9%	8%
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

Pension plan equity securities did not include any ALLETE common stock at December 31, 2010. At December 31, 2009, $9.9 million, or 3.0 percent, of ALLETE common stock was included.

To achieve strong returns within managed risk, we diversify our asset portfolio to approximate the target allocations in the table below. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds.

Plan Asset Target Allocations

	Pension	Postretirement Health and Life *(a)*
Equity Securities	50%	48%
Debt Securities	30%	34%
Real Estate	10%	9%
Private Equity	10%	9%
	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

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 as of the reported date. Active markets are those in which transactions for the asset occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

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 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.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets 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.

Pension Fair Value

	At Fair Value as of December 31, 2010			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities				
U.S. Large-cap *(a)*	$30.4	$29.9	$3.5	$63.8
U.S. Mid-cap Growth *(a)*	14.0	13.7	1.6	29.3
U.S. Small-cap *(a)*	13.7	13.5	1.6	28.8
International	–	77.1	–	77.1
Debt Securities:				
Mutual Funds	46.5		–	46.5
Fixed Income	–	65.7	–	65.7
Other Types of Investments:				
Private Equity Funds	–	–	50.7	50.7
Real Estate	–	–	20.1	20.1
Total Fair Value of Assets	$104.6	$199.9	$77.5	$382.0

Activity in Level 3	**Equity Securities (Auction Rate Securities)**	**Private Equity Funds**	**Real Estate**
Millions			
Balance as of December 31, 2009	$9.1	$44.7	$17.3
Actual Return on Plan Assets	–	(4.1)	(6.1)
Purchases, sales, and settlements, net	(2.4)	10.1	8.9
Balance as of December 31, 2010	$6.7	$50.7	$20.1

	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities				
U.S. Large-cap *(a)*	$23.2	$27.5	$5.2	$55.9
U.S. Mid-cap Growth *(a)*	8.9	10.6	2.0	21.5
U.S. Small-cap *(a)*	8.6	10.1	1.9	20.6
International	–	66.4	–	66.4
ALLETE	9.9	–	–	9.9
Debt Securities:				
Mutual Funds	32.0	–	–	32.0
Fixed Income	–	59.3	–	59.3
Other Types of Investments:				
Private Equity Funds	–	–	44.7	44.7
Real Estate	–	–	17.3	17.3
Total Fair Value of Assets	$82.6	$173.9	$71.1	$327.6

(a) The underlying investments classified under U.S. Equity Securities consist of Money Market Funds and U.S. Government Bonds (Level 1), Hedge Funds (Level 2), and Auction Rate Securities (Level 3), which are combined with futures, which settle daily, in a portable alpha program to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Recurring Fair Value Measures Activity in Level 3	Equity Securities (Auction Rate Securities)	Private Equity Funds	Real Estate
Millions			
Balance as of December 31, 2008	$10.2	$43.2	$17.0
Actual Return on Plan Assets	0.1	(8.7)	(8.6)
Purchases, sales, and settlements, net	(1.1)	10.2	8.9
Balance as of December 31, 2009	$9.1	$44.7	$17.3

Postretirement Health and Life Fair Value

	At Fair Value as of December 31, 2010			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities				
U.S. Large-cap	$15.7	–	–	$15.7
U.S. Mid-cap Growth	11.4	–	–	11.4
U.S. Small-cap	11.5	–	–	11.5
International	26.8	–	–	26.8
Debt Securities:				
Mutual Funds	9.0	–	–	9.0
Fixed Income	–	$27.9	–	27.9
Other Types of Investments:				
Private Equity Funds	–	–	$12.4	12.4
Total Fair Value of Assets	$74.4	$27.9	$12.4	$114.7

Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2009	$9.4
Actual Return on Plan Assets	1.4
Purchases, sales, and settlements, net	1.6
Balance as of December 31, 2010	$12.4

	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities				
U.S. Large-cap	$13.4	–	–	$13.4
U.S. Mid-cap Growth	9.0	–	–	9.0
U.S. Small-cap	6.3	–	–	6.3
International	21.4	–	–	21.4
Debt Securities:				
Mutual Funds	5.5	–	–	5.5
Fixed Income	–	$31.4	–	31.4
Other Types of Investments:				
Private Equity Funds	–	–	$9.4	9.4
Total Fair Value of Assets	$55.6	$31.4	$9.4	$96.4

Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2008	$7.9
Actual Return on Plan Assets	(1.1)
Purchases, sales, and settlements, net	2.6
Balance as of December 31, 2009	$9.4

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provides guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide postretirement health benefits that include prescription drug benefits, which qualify us for the federal subsidy under the Act.

Note 16. Employee Stock and Incentive Plans

Employee Stock Ownership Plan. We sponsor a leveraged ESOP within the RSOP. As of their date of hire, eligible employees may to contribute to the RSOP plan. In 1990, the ESOP issued a $75 million note (term not to exceed 25 years at 10.25 percent) to us as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The note was refinanced in 2006 at 6 percent. We make annual contributions to the ESOP equal to the ESOP's debt service less available dividends received by the ESOP. The majority of dividends received by the ESOP are used to pay debt service, with the balance distributed to participants. The ESOP shares were initially pledged as collateral for its debt. As the debt is repaid, shares are released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares are released from collateral, we report compensation expense equal to the current market price of the shares less dividends on allocated shares. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings; available dividends on unallocated ESOP shares are recorded as a reduction of debt and accrued interest. ESOP compensation expense was $7.1 million in 2010 ($6.5 million in 2009; $10.1 million in 2008).

According to the accounting standards for stock compensation, unallocated ALLETE common stock currently held and purchased by the ESOP will be treated as unearned ESOP shares and not considered as outstanding for earnings per share computations. ESOP shares are included in earnings per share computations after they are allocated to participants.

Year Ended December 31	2010	2009	2008
Millions			
ESOP Shares			
Allocated	2.2	2.2	2.0
Unallocated	1.3	1.5	1.9
Total	3.5	3.7	3.9
Fair Value of Unallocated Shares	$48.4	$49.0	$61.3

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, stock appreciation rights and other awards. There are 1.4 million shares of common stock reserved for issuance under the Executive Plan, with 0.7 million of these shares available for issuance as of December 31, 2010.

We had a Director Long-Term Stock Incentive Plan (Director Plan) which expired on January 1, 2006. No grants have been made since 2003 under the Director Plan. Approximately 2,586 options were outstanding under the Director Plan at December 31, 2010.

We currently have the following types of share-based awards outstanding:

Non-Qualified Stock Options. The options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to three months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are cancelled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is retirement eligible.

No stock options were granted under our Executive Long-Term Incentive Compensation Plan in 2009 or 2010. The following assumptions were used in determining the fair value of stock options granted during 2008, under the Black-Scholes option-pricing model:

Note 16. Employee Stock and Incentive Plans (Continued)

	2008
Risk-Free Interest Rate	2.8%
Expected Life	5 Years
Expected Volatility	20%
Dividend Growth Rate	4.4%

The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the grant date. Expected volatility is estimated based on the historic volatility of our stock and the stock of our peer group companies. We utilize historical option exercise and employee pre-vesting termination data to estimate the option life. The dividend growth rate is based upon historical growth rates in our dividends.

Performance Shares. Under the performance share awards plan, the number of shares earned is contingent upon attaining specific market goals over a three-year performance period. Market goals are measured by total shareholder return relative to a group of peer companies. In the case of qualified retirement, death or disability during a performance period, a pro-rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro-rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is determined by the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Restricted Stock Units. Under the restricted stock units plan, shares vest monthly over a three year period. In the case of qualified retirement, death or disability, a pro-rata portion of the award will be earned. In the case of termination of employment for any other reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro-rata portion of the award will be paid. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price. Because the discount is not greater than 5 percent, we are not required to apply fair value accounting to these awards.

RSOP. The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our consolidated statement of income for the periods presented.

Share-Based Compensation Expense **Year Ended December 31**	**2010**	**2009**	**2008**
Millions			
Stock Options	$0.1	$0.3	$0.7
Performance Shares	1.5	1.5	1.1
Restricted Stock Units	0.6	0.3	–
Total Share-Based Compensation Expense	$2.2	$2.1	$1.8
Income Tax Benefit	$0.9	$0.8	$0.7

There were no capitalized stock-based compensation costs at December 31, 2010, 2009, or 2008.

As of December 31, 2010, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our consolidated statements of income was $1.5 million and $0.7 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.6 years for both performance share awards and restricted stock units.

Note 16. Employee Stock and Incentive Plans (Continued)

Non-Qualified Stock Options. The following table presents information regarding our outstanding stock options as of December 31, 2010.

	2010		2009		2008	
	Number of Options	Weighted-Exercise Price	Number of Options	Weighted-Exercise Price	Number of Options	Weighted-Exercise Price
Outstanding as of January 1,	646,235	$40.05	672,419	$39.99	510,992	$39.83
Granted *(a)*	–	–	–	–	180,815	$39.10
Exercised	40,769	$27.76	4,508	$18.85	16,627	$25.56
Forfeited	44,579	$43.16	21,676	$42.62	2,761	$39.39
Outstanding as of December 31,	560,887	$40.69	646,235	$40.05	672,419	$39.99
Exercisable as of December 31,	523,491	$39.76	512,743	$37.34	406,894	$34.48

(a) Stock options have not been granted since 2008.

Cash received from non-qualified stock options exercised was $1.1 million in 2010. The weighted-average grant-date intrinsic value of options granted in 2008 was $6.18 for 2008 (none in 2010 or 2009). The intrinsic value of a stock award is the amount by which the fair value of the underlying stock exceeds the exercise price of the award. The total intrinsic value of options exercised was $0.3 million during 2010 ($0.1 million in 2009; $0.2 million in 2008).

	Range of Exercise Price		
As of December 31, 2010	$18.85 to $29.79	$37.76 to $41.35	$44.15 to $48.65
Options Outstanding and Exercisable:			
Number Outstanding and Exercisable	44,738	296,770	181,983
Weighted Average Remaining Contractual Life (Years)	1.5	5.4	5.5
Weighted Average Exercise Price	$26.96	$39.44	$46.37

Performance Shares. The following table presents information regarding our non-vested performance shares as of December 31, 2010.

	2010		2009		2008	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1,	121,825	$41.96	79,238	$47.94	68,501	$45.63
Granted	49,302	$35.44	69,800	$35.06	36,684	$54.05
Unearned Grant Award	(22,909)	$54.50	(24,615)	$41.97	(23,624)	$42.80
Forfeited	(25,729)	$36.45	(2,598)	$38.78	(2,323)	$50.87
Non-vested as of December 31,	122,489	$38.15	121,825	$41.96	79,238	$47.94

Less than 0.1 million performance share were granted in February 2010 for the performance period ending in 2012. The ultimate issuance is contingent upon the attainment of certain future market goals of ALLETE during the performance periods. The grant date fair value of the performance share awards was $1.2 million.

No performance shares were awarded in February 2010 for the three year performance period ending in 2009, as performance targets were not met. However, in accordance with the accounting standards for stock compensation, no compensation expense previously recognized in connection with those grants will be reversed.

Less than 0.1 million performance shares were awarded in February 2011 for the three year performance period ending in 2010. The grant date fair value of the shares awarded was $1.6 million.

Note 16. Employee Stock and Incentive Plans (Continued)

Restricted Stock Units. The following table presents information regarding our available restricted stock units as of December 31, 2010.

	2010		2009	
	Number of Shares	Weighted- Average Grant Date Fair Value	Number of Shares	Weighted- Average Grant Date Fair Value
Available as of January 1,	28,983	$29.41	–	–
Granted	26,589	$31.83	30,465	$29.41
Awarded	(3,091)	$29.75	–	–
Forfeited	(8,678)	$30.62	(1,482)	$29.41
Available as of December 31,	43,803	$30.61	28,983	$29.41

Less than 0.1 million restricted stock units were granted in February 2010 for the vesting period ending in 2012. The grant date fair value of the restricted stock unit awards was $0.7 million.

Less than 0.05 million restricted stock units were awarded in 2010. The grant date fair value of the shares awarded was $0.1 million.

Note 17. Derivatives

Occasionally we enter into financial derivative instruments to manage price risk for certain power marketing contracts. Changes in a derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria is met. The mark-to-market fluctuations on any cash flow hedge are recorded in other comprehensive income on the consolidated balance sheet. During 2010, we did not enter into any new derivative instruments, and have no outstanding derivative contracts at December 31, 2010. There were no changes in fair value of derivatives recognized in 2010 in earnings, and no mark-to market changes in cash flow hedges recorded in 2010.

During 2009 we entered into two types of financial derivative instruments consisting of cash flow hedges for an energy sale that included pricing based on daily natural gas prices, and FTRs purchased to manage congestion risk for forward power sales contracts. As of December 31, 2009, approximately $0.7 million remained in other assets on our consolidated balance sheet for FTRs, which settled monthly throughout the first five months of 2010 at cost. During 2009, changes in the fair value of outstanding derivatives resulted in the recognition of $.04 million of revenue in the first two quarters, and a decrease in revenue of $0.4 million in the third quarter of 2009 when the energy swap contract ended. The mark-to-market fluctuations on the cash flow hedge in 2009 were recorded in other comprehensive income as a $0.1 million increase in fair value in the first quarter and a decrease of $0.1 million in the second quarter of 2009.

Note 18. Quarterly Financial Data (Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	**Mar. 31**	**Jun. 30**	**Sept. 30**	**Dec. 31**
Millions Except Earnings Per Share				
2010				
Operating Revenue	$233.6	$211.2	$224.1	$238.1
Operating Income	$46.1	$31.7	$35.3	$22.7
Net Income Attributable to ALLETE	$23.0	$19.4	$19.6	$13.3
Earnings Per Share of Common Stock				
Basic	$0.68	$0.57	$0.57	$0.38
Diluted	$0.68	$0.57	$0.56	$0.38
2009				
Operating Revenue	$199.6	$164.7	$178.8	$216.0
Operating Income	$31.1	$15.7	$25.4	$33.8
Net Income Attributable to ALLETE	$16.9	$9.4	$16.0	$18.7
Earnings Per Share of Common Stock				
Basic	$0.55	$0.29	$0.49	$0.56
Diluted	$0.55	$0.29	$0.49	$0.56

Schedule II

ALLETE
Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions Charged to Income	Additions Other Charges	Deductions from Reserves *(a)*	Balance at End of Period
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2008 Trade Accounts Receivable	$1.0	$1.0	–	$1.3	$0.7
Finance Receivables – Long-Term	$0.2	–	–	$0.1	$0.1
2009 Trade Accounts Receivable	$0.7	$1.3	–	$1.1	$0.9
Finance Receivables – Long-Term	$0.1	$0.3	–	–	$0.4
2010 Trade Accounts Receivable	$0.9	$1.1	–	$1.1	$0.9
Finance Receivables – Long-Term	$0.4	$0.8	–	$ 0.4	$0.8
Deferred Asset Valuation Allowance					
2008 Deferred Tax Assets	$3.3	$ (2.9)	–	–	$0.4
2009 Deferred Tax Assets	$0.4	$ (0.1)	–	–	$0.3
2010 Deferred Tax Assets	$0.3	$0.2	–	–	$0.5

(a) Includes uncollectible accounts written off.

Exhibit 12

ALLETE
Computation of Ratios of Earnings to Fixed Charges (Unaudited)

Year Ended December 31	2010	2009	2008	2007	2006
Millions					
Earnings, as defined:					
Pretax Income Before Non-Controlling Interest	$119.1	$91.5	$126.4	$137.2	$128.2
Add: Fixed Charges	43.4	38.3	30.3	26.6	27.7
Less: Non-Controlling Interest *(a)*	–	–	–	–	–
Undistributed Income from Less than 50 percent Owned Equity Investment	3.4	3.7	3.8	3.3	2.3
Total Earnings as defined	$159.1	$126.1	$152.9	$160.5	$153.6
Fixed Charges:					
Interest on Long-Term Debt	$39.7	$34.2	$27.4	$23.2	$22.8
Other Interest Charges	1.0	1.6	0.4	1.5	2.9
Interest Component of All Rentals (b)	2.7	2.5	2.5	1.9	2.0
Total Fixed Charges	$43.4	$38.3	$30.3	$26.6	$27.7
Ratio of Earnings to Fixed Charges	3.67	3.29	5.05	6.03	5.55

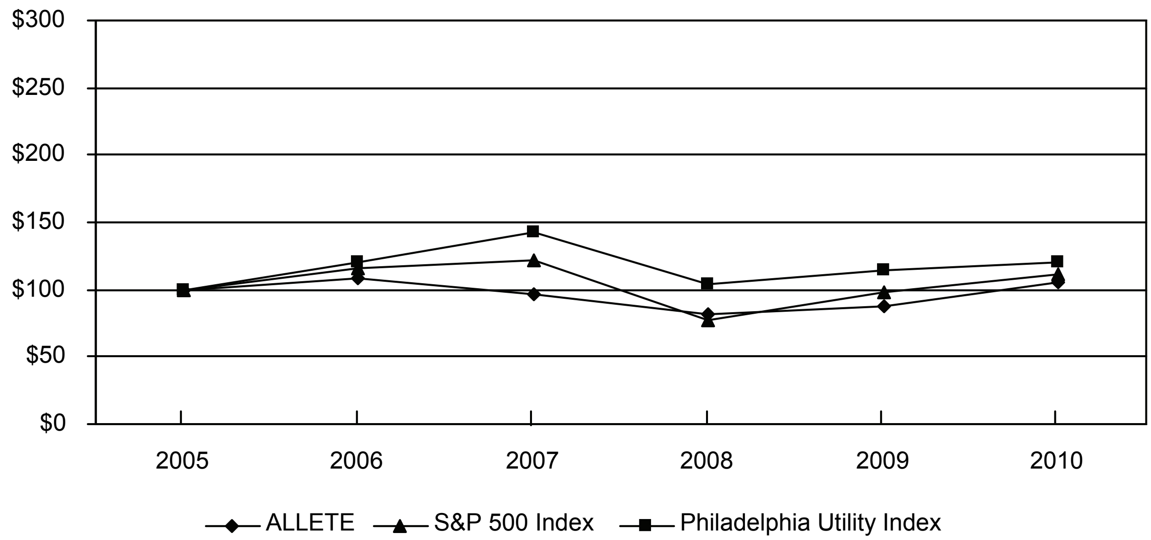
(a) Pretax income of subsidiaries that have not incurred fixed charges.
(b) Represents interest portion of rents estimated at 33 1/3 percent.

ALLETE Common Stock Performance

The following graph compares ALLETE's cumulative Total Shareholder Return on its common stock with the cumulative return of the S&P 500 Index and the Philadelphia Utility Index. The S&P 500 Index is a capitalization-weighted index of 500 stocks designed to measure performance of the broad domestic economy through changes in the aggregate market value of 500 stocks representing all major industries. Because this composite index has a broad industry base, its performance may not closely track that of a composite index comprised solely of electric utilities. The Philadelphia Utility Index is a capitalization-weighted index of 20 utility companies involved in the production of electric energy.

The calculations assume a $100 investment on December 31, 2005, and reinvestment of dividends.

Total Shareholder Return for the
Five Years Ending December 31, 2010



	2005	2006	2007	2008	2009	2010
ALLETE	$100	$109	$96	$82	$88	$106
S&P 500 Index	$100	$116	$122	$77	$97	$112
Philadelphia Utility Index	$100	$120	$143	$104	$114	$121