Form 10-K

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

(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, 2005**

☐ 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 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 or a non-accelerated filer (as defined in Rule 12b-2 of the Act).
Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐

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, 2005, was $1,489,669,987.

As of February 1, 2006, there were 30,153,542 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2006 Annual Meeting of Shareholders are incorporated by reference in Part III.

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Definitions

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

Abbreviation or Acronym	Term
ADESA	ADESA, Inc.
AICPA	American Institute of Certified Public Accountants
ALLETE	ALLETE, Inc.
ALLETE Properties	ALLETE Properties, LLC
APB	Accounting Principles Board
Aqua Utilities	Aqua Utilities Florida, Inc.
AREA	Arrowhead Regional Emission Abatement
ATC	American Transmission Company LLC
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
Company	ALLETE, Inc. and its subsidiaries
Constellation Energy Commodities	Constellation Energy Commodities Group, Inc.
DOC	Minnesota Department of Commerce
DRI	Development of Regional Impact
EITF	Emerging Issues Task Force
Enventis Telecom	Enventis Telecom, Inc.
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Florida Landmark	Florida Landmark Communities, Inc.
Florida Water	Florida Water Services Corporation
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
FPSC	Florida Public Service Commission
FSP	Financial Accounting Standards Board Staff Position
GAAP	Accounting Principles Generally Accepted in the United States
Hibbard	Hibbard Energy Center
HickoryTech	Hickory Tech Corporation
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
IPO	Initial Public Offering
kV	Kilovolt(s)
Laskin	Laskin Energy Center
MAPP	Mid-Continent Area Power Pool
MBtu	Million British thermal units
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
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatthour(s)
NO_X	Nitrogen Oxide
Northwest Airlines	Northwest Airlines, Inc.
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
PSCW	Public Service Commission of Wisconsin
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
Rainy River Energy	Rainy River Energy Corporation
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards No.
SO_2	Sulfur Dioxide
Split Rock Energy	Split Rock Energy LLC
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
Town Center	Town Center at Palm Coast development project in Florida
WDNR	Wisconsin Department of Natural Resources

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

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 in forward-looking statements (as such term is defined in the Private Securities Litigation Reform Act of 1995) made by or on behalf of ALLETE in this Annual Report on Form 10-K, in presentations, in response to questions or otherwise. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (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 similar expressions) are not statements of historical facts and may be forward-looking.

Forward-looking statements involve estimates, assumptions, risks and uncertainties, and 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, which are difficult to predict, contain uncertainties, are beyond our control and may cause actual results or outcomes to differ materially from those contained in forward-looking statements:

- our ability to successfully implement our strategic objectives;
- our ability to manage expansion and integrate acquisitions;
- prevailing governmental policies and regulatory actions, including those of the United States Congress, state legislatures, the FERC, the MPUC, the FPSC, the PSCW, and various local and county regulators, and city administrators, about allowed rates of return, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power and capital investments, present or prospective wholesale and retail competition (including but not limited to transmission costs), and zoning and permitting of land held for resale;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with environmental and safety laws and policies;
- weather conditions;
- natural disasters;
- war and acts of terrorism;
- wholesale power market conditions;
- our ability to obtain viable real estate for development purposes;
- population growth rates and demographic patterns;
- the effects of competition, including competition for retail and wholesale customers;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- unanticipated project delays or changes in project costs;
- unanticipated changes in operating expenses and capital expenditures;
- global and domestic economic conditions;
- our ability to access capital markets;
- changes in interest rates and the performance of the financial markets;
- competition for economic expansion or development opportunities;
- 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 23 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-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

ALLETE has been incorporated under the laws of Minnesota since 1906. ALLETE's corporate headquarters are in Duluth, Minnesota. As of December 31, 2005, we had approximately 1,500 employees, 100 of which were part-time. Statistical information is presented as of December 31, 2005, 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.

ALLETE files annual, quarterly, and other reports and information with the SEC. You can read and copy any information filed by ALLETE with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You can obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including ALLETE. ALLETE also maintains an Internet site (www.allete.com) that contains documents as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC free of charge.

ALLETE's operations focus on two core businesses—**Energy** and **Real Estate**. In addition, we have other operations that provide earnings to the Company.

Energy is comprised of Regulated Utility, Nonregulated Energy Operations and, beginning in 2006, Investment in American Transmission Company LLC.

- **Regulated Utility** includes retail and wholesale rate regulated electric, water and gas services in northeastern Minnesota and northwestern Wisconsin under the jurisdiction of state and federal regulatory authorities.
- **Nonregulated Energy Operations** includes our coal mining activities in North Dakota and nonregulated generation (non-rate base generation sold at market-based rates to the wholesale market), which consisted primarily of generation from Taconite Harbor in northern Minnesota. Pending MPUC approval, Taconite Harbor will be integrated into our Regulated Utility business effective retroactive to January 1, 2006, to help meet forecasted base load energy requirements. Nonregulated Energy Operations also included generation secured through the Kendall County power purchase agreement, which was assigned to Constellation Energy Commodities in April 2005.
- **Investment in ATC** will include our estimated 9% ownership interest in ATC. In December 2005, we entered into an agreement that provides for us to invest $60 million in ATC by the end of 2006. The investment is subject to review by the PSCW.

Real Estate includes our Florida real estate operations.

Other includes our investments in emerging technologies, and earnings on cash, cash equivalents and short-term investments.

Year Ended December 31	**2005**	**2004**	**2003**
Consolidated Operating Revenue – Millions	$737.4	$704.1	$659.6
Percentage of Consolidated Operating Revenue			
Regulated Utility			
Industrial			
Taconite Producers	23%	25%	23%
Paper and Wood Products	9	9	9
Pipelines and Other Industries	6	7	6
Total Industrial	38	41	38
Residential	10	11	11
Commercial	11	11	11
Other Power Suppliers	7	5	7
Other Revenue	12	11	10
Total Regulated Utility	78	79	77
Nonregulated Energy Operations	16	15	16
Real Estate	6	6	7
	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 Notes 1 and 2.

Discontinued Operations. We successfully completed the spin-off of our Automotive Services business, and the sales of our Water Services and our telecommunications businesses.

Spin-Off of Automotive Services. Through a June 2004 IPO, our Automotive Services business, doing business as ADESA, Inc. (NYSE: KAR), issued 6.3 million shares of common stock, representing 6.6% of ADESA's common stock outstanding. In September 2004, we spun off the business by distributing to ALLETE shareholders all of ALLETE's remaining 93.4% of ADESA common stock.

Sale of Water Services Businesses. In early 2005, we completed the exit from our Water Services businesses with the sale of our wastewater assets in Georgia. In mid-2004, we sold our North Carolina water and wastewater assets, and our remaining 72 water and wastewater systems in Florida. Substantially all of our water assets in Florida were sold in 2003, under condemnation or imminent threat of condemnation. The net cash proceeds from the sale of all water and wastewater assets in 2003 and 2004, after transaction costs, retirement of most Florida Water debt and payment of income taxes, were approximately $300 million. In 2005, the FPSC ordered a $1.7 million reduction to plant investment, which the Company reserved for in 2005, and approved the transfer of 63 water and wastewater systems from Florida Water to Aqua Utilities. Aqua Utilities filed a protest and requested that the FPSC schedule evidentiary hearings. The FPSC's decision on these issues may change the reduction to plant investment ordered in 2005 and could result in an adjustment to the final purchase price paid by Aqua Utilities.

Sale of Enventis Telecom. On December 30, 2005, we sold all the stock of our telecommunications subsidiary, Enventis Telecom, to HickoryTech of Mankato, Minnesota, for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was included in our 2005 loss from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes.

Energy – Regulated Utility

Minnesota Power, an operating division of ALLETE, provides regulated utility electric service in a 26,000 square-mile service territory in northeastern Minnesota to 137,000 retail customers and wholesale electric service to 16 municipalities. **SWL&P** provides regulated utility electric, natural gas and water service in northwestern Wisconsin to 14,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Minnesota Power had an annual net peak load of 1,543 MW on December 20, 2005. Our regulated power supply sources are listed below.

Regulated Utility Power Supply	Unit No.	Year Installed	Net Winter Capability	For the Year Ended December 31, 2005 Electric Requirements	
			MW	MWh	%
Steam					
Coal-Fired					
Boswell Energy Center	1	1958	69		
near Grand Rapids, MN	2	1960	69		
	3	1973	351		
	4	1980	429		
			918	6,450,016	53.4%
Laskin Energy Center	1	1953	55		
in Hoyt Lakes, MN	2	1953	55		
			110	695,659	5.8
Purchased Steam					
Hibbard Energy Center in Duluth, MN	3 & 4	1949, 1951	47	76,128	0.6
Total Steam			1,075	7,221,803	59.8
Hydro					
Group consisting of ten stations in MN	Various		115	487,063	4.0
Purchased Power					
Square Butte burns lignite coal near Center, ND			322	2,268,397	18.8
Minnesota Power Nonregulated Energy Generation			–	202,710	1.7
All Other – Net			–	1,890,813	15.7
Total Purchased Power			322	4,361,920	36.2
Total			1,512	12,070,786	100.0%

Energy – Regulated Utility (Continued)

We have electric transmission and distribution lines of 500 kV (8 miles), 230 kV (605 miles), 161 kV (43 miles), 138 kV (126 miles), 115 kV (1,209 miles) and less than 115 kV (6,773 miles). We own and operate 185 substations with a total capacity of 8,872 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

We own offices and service buildings, an energy control center and repair shops, and lease offices and storerooms in various localities. Substantially all of our electric plant is subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and of 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. Wisconsin Public Power, Inc. (WPPI) owns 20% of Boswell Unit 4. WPPI has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 9.)

Split Rock Energy was a joint venture between Minnesota Power and Great River Energy. In March 2004, we terminated our ownership interest upon receipt of FERC approval.

Electric Sales

Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Regulatory Issues.)

Regulated Utility Electric Sales Year Ended December 31	**2005**	**2004**	**2003**
Millions of Kilowatthours			
Retail and Municipals			
Residential	1,102	1,053	1,065
Commercial	1,327	1,282	1,286
Industrial	7,130	7,071	6,558
Municipals and Other	956	902	921
	10,515	10,308	9,830
Other Power Suppliers	1,142	918	1,314
	11,657	11,226	11,144

Minnesota Power has wholesale contracts with 16 municipal customers, SWL&P and Dahlberg Light & Power Company in rural Wisconsin. (See Regulatory Issues – Federal Energy Regulatory Commission.)

Approximately 60% of the ore consumed by integrated steel facilities in the United States originates from six taconite customers of Minnesota Power. Taconite, an iron-bearing rock of relatively low iron content that is abundantly available in Minnesota, is an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the ore-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets. Strong worldwide steel demand, driven largely by extensive infrastructure development in China, has resulted in very robust world iron ore and steel pricing and has consequently resulted in very high demand for iron ore and steel. This globalization of demand has positively impacted Minnesota taconite producers, which all produced near their rated capacities in both 2005 and 2004. Annual taconite production in Minnesota was 41 million tons in 2005 (41 million tons in 2004; 35 million tons in 2003). Recent consolidation activities, combined with the strong steel market, have placed the Minnesota taconite producers in a strong position. During 2005, Cleveland-Cliffs Inc and United States Steel Corporation invested significant capital to bring production capacity back online and/or improve operating efficiencies. They also invested in required pollution control equipment to help insure the longevity of their operations.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper and pulp, and wood products industry. 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 the mill. Minnesota Power also serves four wood products manufacturers.

Minnesota Power's paper and pulp customers ran at or very near full capacity in 2005 despite the fact that after an economic rebound in 2004, the North American paper industry had a somewhat more difficult year in 2005. As the industry faced slightly lower demand, as well as increased fiber, chemical and energy costs, Minnesota Power's customers benefited from the temporary or permanent idling of capacity in North America at mills other than those served by Minnesota Power, the strength of the Euro and a Finnish paper industry labor strike which temporarily idled capacity.

Energy – Regulated Utility (Continued)

The pipeline and refining industry is the third key industrial segment served by Minnesota Power with services provided to two crude oil pipelines and one refinery. After years of near capacity operation in 2004 and 2005, both pipeline operators are evaluating expansion alternatives to transport newly developed 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 large power customer contracts with 12 customers (Large Power Customers), 11 of which require 10 MW or more of generating capacity and one that requires 8 MW or more of generating capacity. In 2005, contracts were successfully renegotiated with five of our Large Power Customers representing approximately 23% of 2005 regulated utility revenue. The durations of these contracts were extended several years with the termination dates ranging from February 28, 2010, to October 13, 2013. Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. (See Minimum Revenue and Demand Under Contract table.) 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 biannual (power pool season) or 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 kilowatthour used that recovers the variable costs incurred in generating electricity. Six of the Large Power Customers have interruptible service for a portion of their needs, which provides a discounted demand rate and energy priced at Minnesota Power's incremental cost after serving all firm power obligations. Minnesota Power also provides incremental production service for customer demand levels above the contract 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 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 kilowatthour 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 Regulatory Issues – 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. A normal 30-day billing cycle with a 15-day payment period left Minnesota Power greatly exposed to a significant revenue loss if a customer did not or could not make payment due to discontinued operations, or delayed making an electric service payment pending a bankruptcy filing. The 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. Taconite-producing Large Power Customers subject to weekly billings receive interest on the money paid to Minnesota Power within the billing cycle.

Minimum Revenue and Demand Under Contract **As of February 1, 2006**	**Minimum** **Annual Revenue** *(a,b)*	**Monthly** **Megawatts**
2006	$61.3 million	375
2007	$33.3 million	178
2008	$28.7 million	161
2009	$26.9 million	154
2010	$22.3 million	124

(a) Based on past experience, we believe revenue from our Large Power Customers will be substantially in excess of the minimum contract amounts. For example, in our 2004 Form 10-K we stated 2005 minimum annual revenue from these Large Power Customers would be $69.1 million. Actual 2005 demand revenue from these Large Power Customers was $115.5 million.

(b) Although several contracts have a feature that allows demand to go to zero after a two-year advance notice of a permanent closure, this minimum revenue summary does not reflect this occurrence happening in the forecasted period because we believe it is unlikely.

Energy – Regulated Utility (Continued)

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2006

Customer	Industry	Location	Ownership	Earliest Termination Date
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% Mittal Steel USA Inc. 23% Cleveland-Cliffs Inc 14.7% Stelco Inc.	February 28, 2010
Mittal Steel USA – Minorca Mine	Taconite	Virginia, MN	Mittal Steel USA Inc.	December 31, 2012
United States Steel Corporation (USS) Minntac	Taconite	Mt. Iron, MN	USS	October 31, 2013
USS Keewatin Taconite	Taconite	Keewatin, MN	USS	October 31, 2013
United Taconite LLC *(a)*	Taconite	Eveleth, MN	70% Cleveland-Cliffs Inc 30% Laiwu Steel Group	February 28, 2010
UPM, Blandin Paper Mill *(a,b)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	February 28, 2010
Boise White Paper, LLC	Paper	International Falls, MN	Madison Dearborn Partnership	December 31, 2008
Sappi Cloquet LLC *(a)*	Paper	Cloquet, MN	Sappi Limited	February 28, 2010
Stora Enso North America, Duluth Paper Mill and Duluth Recycled Pulp Mill *(b)*	Paper and Pulp	Duluth, MN	Stora Enso Oyj	August 31, 2013
USG Interiors, Inc. *(c)*	Manufacturer	Cloquet, MN	USG Corporation	February 28, 2007
Enbridge Energy Company, Limited Partnership *(c)*	Pipeline	Deer River, MN Floodwood, MN	Enbridge Energy Company, Limited Partnership	February 28, 2007
Minnesota Pipeline Company *(c)*	Pipeline	Staples, MN Little Falls, MN Park Rapids, MN	60% Koch Pipeline Co. L.P. 40% Marathon Ashland Petroleum LLC	February 28, 2007

(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 February 28, 2010.
(b) Minnesota Power filed with the MPUC a petition for approval of these newly executed contracts and anticipates approval during the first half of 2006.
(c) The contract will terminate one year 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 February 28, 2007.

Purchased Power

Minnesota Power has contracts to purchase capacity and energy from various entities, the largest is with Square Butte. Under an agreement with Square Butte expiring at the end of 2026, Minnesota Power is currently entitled to approximately 66% (60% beginning in 2007; 55% in 2008) of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 10.)

In May 2005, Minnesota Power entered into a 25-year agreement with an affiliate of FPL Energy, LLC to purchase all of the renewable energy from an approximately 50-MW (nameplate) wind facility to be built in North Dakota. FPL Energy, LLC expects the facility to be operational in the fall of 2006. The wind facility will be comprised of 22 new 2.3 MW wind turbines interconnected to the Square Butte substation in Center, North Dakota, near the BNI Coal mine. On December 20, 2005, the MPUC approved the power purchase agreement. In addition, Minnesota Power is continuing to pursue the purchase of renewable energy from a new wind facility that would be located in northern Minnesota. The project, expected to be operational in 2007, would be similar in size to the North Dakota project and would be subject to a power purchase agreement, as well as regulatory approvals. The Minnesota project also needs to be operational by the end of 2007 to be eligible for federal production tax credits which are essential to provide acceptable pricing.

Fuel

Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin coal field located in Montana. Coal consumption in 2005 for electric generation at Minnesota Power’s coal-fired generating stations was about 5.1 million tons. As of December 31, 2005, Minnesota Power had a coal inventory of about 464,000 tons. Minnesota Power has two coal supply agreements with expiration dates extending through 2009 and one contract expiring December 31, 2006. Under these agreements, Minnesota Power has the tonnage flexibility to procure 70% to 100% of its total coal requirements. In 2006, Minnesota Power will obtain coal under these coal supply agreements and in the spot market. This diversity in coal supply options allows Minnesota Power to manage market price and supply risk and to take advantage of favorable spot market prices. Minnesota Power is exploring future coal supply options. We believe that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Energy – Regulated Utility (Continued)

In 2001, Minnesota Power and Burlington Northern and Santa Fe Railway Company (Burlington Northern) entered into a long-term agreement under which Burlington Northern transports all of Minnesota Power's coal by unit train from the Powder River Basin directly to Minnesota Power's generating facilities or to a designated interconnection point. Minnesota Power also has an agreement with the Canadian National Railway and is negotiating a new agreement with Midwest Energy Resources Company to transport coal from the Burlington Northern interconnection point to certain Minnesota Power facilities.

Coal Delivered to Minnesota Power Year Ended December 31	2005	2004	2003
Average Price per Ton	$19.76	$19.01	$20.02
Average Price per MBtu	$1.08	$1.04	$1.12

The Square Butte generating unit operated by Minnkota Power burns North Dakota lignite coal supplied by BNI Coal, in accordance with the terms of a contract expiring in 2027. Square Butte's cost of lignite burned in 2005 was approximately 75 cents per MBtu. The lignite acreage that has been dedicated to Square Butte by BNI Coal is located on lands essentially all of which are under private control and presently leased by BNI Coal. This lignite supply is sufficient to provide the fuel for the anticipated useful life of the generating unit.

Regulatory Issues

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 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, and certain accounting and record-keeping practices. The PSCW has regulatory authority over the retail sales of electricity, water and gas by SWL&P. The MPUC, FERC and PSCW had regulatory authority over 56%, 8% and 8%, respectively, of our 2005 consolidated operating revenue.

Electric Rates. Minnesota Power has historically designed its electric service rates based on cost of service studies under which allocations are made to the various classes of customers. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, and recovery of current and deferred conservation improvement program expenditures.

In addition to Large Power Customer contracts, Minnesota Power also has contracts with large industrial and commercial customers with monthly demands of more than 2 MW but less than 10 MW of capacity. The terms of these contracts vary depending upon the customer's demand for power and the cost of extending Minnesota Power's facilities to provide electric service.

Minnesota Power requires that all large industrial and commercial customers under contract specify the date when power is first required. Thereafter, the customer is generally billed monthly for at least the minimum power for which they contracted. These conditions are part of all contracts covering power to be supplied to new large industrial and commercial customers and to current customers as their contracts expire or are amended. All rates and other contract terms are subject to approval by appropriate regulatory authorities.

Federal Energy Regulatory Commission. The FERC has jurisdiction over our wholesale electric service and operations. Minnesota Power's hydroelectric facilities, which are located in Minnesota, are licensed by the FERC. (See Environmental Matters – Water.)

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (EPAct 2005), which repealed PUHCA 1935 and 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, and a promotion of energy efficiency and wise energy use. The FERC is currently in the process of rulemakings effectuating EPAct 2005. These include (among others):

- the implementation of long-term transmission rights;
- the development of electric reliability organizations and delegated authority to regional entities for proposing and enforcing reliability standards;
- rules specifying the form for applications for federal construction permits to be issued in the exercise of federal backstop siting authority for transmission projects;
- establishment of rules requiring unregulated transmitting utilities to provide open access to their transmission systems;
- the development of procedures for expeditious consideration of merger applications under the revised Federal Power Act Section 203;

- the establishment of regional joint boards to consider economic dispatch;
- the issuance of rules necessary for FERC to facilitate transmission market transparency; and
- the manipulation of the energy market.

We continue to monitor FERC activity in these and other proceedings.

Municipal Customers. Minnesota Power has contracts with 16 Minnesota municipalities receiving wholesale electric service. One contract, currently being renegotiated, expires March 1, 2006 (168,000 MWh purchased in 2005), while the other 15 are for service through at least 2007, with the majority extending through at least 2010. In 2005, these municipal customers purchased 756,000 MWh from Minnesota Power. Minnesota Power also has a contract for wholesale service to Dahlberg Light & Power Company in Wisconsin. Dahlberg purchased 110,000 MWh in 2005.

Midwest Independent Transmission System Operator, Inc. (MISO). Minnesota Power and SWL&P are members of MISO. MISO was the first regional transmission organization (RTO) approved by FERC as meeting its Order No. 2000 criteria. Minnesota Power and SWL&P retain ownership of their respective transmission assets and control area functions, but their transmission network is under the regional operational control of the MISO, and they 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 the broad region encompassing all or parts of 15 states and one Canadian province, and over 100,000 MW of generating capacity.

Effective April 1, 2005, the method by which Minnesota Power engages in wholesale energy transactions changed, with both Minnesota Power load and generation participating in MISO's day-ahead and real-time markets (MISO Day 2). Generation also became subject to MISO economic dispatch authority. As a result of MISO Day 2 implementation, energy transactions to serve retail customers are sourced by wholesale transactions with MISO as the counterparty. The MPUC initially denied cost recovery of certain MISO Day 2 costs through the fuel clause in an order dated December 21, 2005 (see Minnesota Public Utilities Commission – Fuel Clause Recovery of MISO Day 2 Costs below). As a result of this order, the Company filed a Notice of Intent to Withdraw from MISO in December 2005 and is exploring alternatives to MISO. Withdrawal from MISO would also require MPUC and FERC approval.

Mid-Continent Area Power Pool (MAPP). Minnesota Power also participates in MAPP, a power pool operating in parts of eight states in the Upper Midwest and in two provinces in Canada. MAPP functions include a regional transmission committee and a generation reserve-sharing pool. Minnesota Power is also a member of the Midwest Reliability Organization that was established as a regional reliability council within the North American Electric Reliability Council on January 1, 2005.

Minnesota Public Utilities Commission. Minnesota Power's retail rates are based on a 1994 MPUC retail rate order that allows for an 11.6% return on common equity dedicated to utility plant. Minnesota Power does not expect to file a request to increase rates for its retail utility operations during 2006. We will, however, continue to monitor the costs of serving our retail customers and evaluate the need for a rate filing in the future.

Investigation of the Usefulness of the Fuel Clause. In June 2003, the MPUC initiated an investigation into the continuing usefulness of the fuel clause as a regulatory tool for electric utilities. Minnesota Power's initial comments on the proposed scope and procedure of the investigation were filed in July 2003. The investigation will focus on whether the fuel clause continues to be an appropriate regulatory tool. The initial steps will be to review the clause's original purpose, structure and rationale (including its current operation and relevance in today's regulatory environment), and then address its ongoing appropriateness and other issues if the need for continued use of the fuel clause is shown. The MPUC has not taken action on any proposal and, as a result, we are unable to predict the outcome or impact of this proceeding at this time.

Fuel Clause Recovery of MISO Day 2 Costs. Minnesota Power filed a petition with the MPUC in February 2005 to amend its fuel clause to accommodate costs and revenue related to MISO Day 2. On April 7, 2005, the MPUC approved interim accounting treatment of MISO Day 2 costs to be accounted for on a net basis and recovered through the fuel clause, subject to refund with interest. This interim treatment has continued while the MPUC has addressed the cost recovery petitions from Xcel Energy Inc., Otter Tail Power Company, Alliant Energy Corporation and Minnesota Power.

On December 21, 2005, the MPUC issued an order which denied recovery through the fuel clause of uplift charges, congestion revenue and expenses, and administrative costs related to Minnesota Power's MISO Day 2 market activities. Minnesota Power requested rehearing of the order in a filing made with the MPUC on January 10, 2006. The other three utilities affected by the order also filed for rehearing, as did the DOC and MISO. In a hearing on February 9, 2006, the MPUC granted rehearing of the MISO Day 2 docket and suspended the refund obligation. The MPUC will review the MISO Day 2 costs to determine which costs should be recovered on a current basis through the fuel clause and which costs are more appropriately deferred for potential recovery through base rates. The Company is unable to predict the outcome of this matter.

Energy – Regulated Utility (Continued)

Large Power Contracts. On September 9, 2005, the MPUC approved Minnesota Power's new electric service agreement with United States Steel Corporation for combined service to the Minntac and Keewatin Taconite facilities through October 31, 2013. On September 21, 2005, Minnesota Power filed with the MPUC a petition for approval of its new electric service agreement with the Mittal Steel USA – Minorca Mine that was approved by the MPUC on November 15, 2005 for service through December 31, 2012. On December 23, 2005, Minnesota Power filed with the MPUC a petition for approval of its new electric service agreement through August 31, 2013, with Stora Enso's Duluth mills. On January 25, 2006, Minnesota Power filed with the MPUC a petition for approval of its new electric service agreement through February 28, 2010, with Blandin Paper's Grand Rapids facilities.

Resource Plan. In September 2004, Minnesota Power filed our Integrated Resource Plan (Resource Plan). An October 2005 update to that plan provided a revised forecast that energy demand by customers in our service territory will increase at an average annual rate of 1.5% to 2019. We project a load growth of approximately 150 MW by 2010 with another 200 MW of growth anticipated by 2015. The forecasted growth of 15 MW to 28 MW per year is primarily from residential and smaller commercial expansion and a positive outlook from Large Power Customers in northeastern Minnesota, such as taconite processing facilities and paper mills. Minnesota Power also expects to realize a reduction in generating resource supply over the next three years, under the terms of a long-term energy supply contract with Square Butte. The combination of increased demand and reduced supply means Minnesota Power will need to secure additional capacity and energy to serve our customers in future years. In the Resource Plan, we provided several options designed to meet the predicted growing demand in the region.

In October 2005, Minnesota Power proposed to the MPUC a comprehensive solution to meet generation needs through 2010 that includes the following key components:

- a transition of the Taconite Harbor generating facility from nonregulated energy operations to regulated utility to help meet the utility's forecasted base load energy requirements;
- a 50-MW long-term power purchase agreement to meet near-term energy needs; and
- various resource additions to help meet forecasted base load, support the expansion of renewable generating assets and help meet Minnesota's Renewable Energy Objective that seeks a 10% supply of qualified renewable energy resources by 2015 for each Minnesota utility.

The proposal to transition Taconite Harbor to a regulated utility asset is supported by the DOC and a group of our Large Power Customers. Minnesota Power has received approval of a power purchase agreement for 50 MW of wind energy purchased from a wind facility in North Dakota. Minnesota Power is also continuing to pursue an agreement for an additional 50 MW of wind energy from a new facility being planned for Minnesota, and is proposing to obtain 10 MW of additional hydro generation through an expansion of the Fond du Lac hydroelectric station.

On November 16, 2005, the MPUC issued a Notice of Comment Period in Minnesota Power's Resource Plan docket that requested information on how the Resource Plan and the Arrowhead Regional Emission Abatement proposal (discussed below) are affected by the agreement reached between Minnesota Power, the Large Power Customer group and the DOC, along with information on how the MPUC should procedurally schedule the three identified items. Minnesota Power filed initial comments in response to the Notice on December 16, 2005, and filed reply comments on January 11, 2006. Final regulatory approval of our Resource Plan and the transition of Taconite Harbor is expected in mid 2006.

We are exploring various construction and purchase options for our anticipated resource needs in 2015. These options include:

- *North Dakota Generation Study.* On December 7, 2005, Minnesota Power, Basin Electric Power Cooperative, Minnkota Power and Montana-Dakota Utilities Company announced a project development agreement to evaluate the feasibility of a joint lignite-fueled generating resource in the vicinity of the existing Milton R. Young generating station near Center, North Dakota. The feasibility study, which is underway, is expected to take about one year to complete. Any final resource decision by Minnesota Power is subject to MPUC and other approvals.
- *Mesaba Energy Project.* Excelsior Energy Inc. (Excelsior) is a Minnesota-based independent energy development company. Excelsior has proposed to construct a 600 MW (net) coal-gasification generation facility in northern Minnesota. By utilizing new technology, Excelsior says it will be able to provide base load electric power supply with fewer emissions than traditional coal-fired generation facilities. This project is in the early development stages. Excelsior has yet to obtain necessary permits and financing, but says the facility could be operational in 2011.

Energy – Regulated Utility (Continued)

In 2003, the Minnesota legislature enacted several provisions that provide Excelsior with special considerations. This was done as part of Xcel Energy Inc.'s (Xcel) Prairie Island nuclear waste storage reauthorization. Excelsior is "entitled" to enter into a 450-MW power sales agreement with Xcel, subject to MPUC approval. On December 23, 2005, Excelsior filed with the MPUC a petition for approval of terms and conditions for the sale of power to Xcel under these statutory provisions. Other utilities in the state, including Minnesota Power, "must consider" Excelsior before pursuing new resource additions within the state.

On January 30, 2006, Minnesota Power filed comments with the MPUC in Excelsior's proposed power purchase agreement proceeding. Our comments focus on the importance to the state of maintaining a range of base load energy options including multiple fuel types and generating technologies.

- *Northeast Minnesota Facility.* A joint study with Minnesota Power, Xcel and another utility is underway to evaluate the environmental and economic merits of an advanced design super critical pulverized coal unit in northeastern Minnesota.
- *Natural Gas Combined Cycle Generation.* Minnesota Power is also continuing to study the feasibility of the construction of a natural gas-fired electric generating facility which could be located in northwestern Wisconsin or northeastern Minnesota.

Arrowhead Regional Emission Abatement (AREA) Plan. In October 2005, Minnesota Power announced a $60 million environmental initiative proposing current rate recovery for emission reductions pursuant to Minnesota statute. If approved by the MPUC, the AREA plan is expected to significantly reduce emissions from Taconite Harbor and Laskin. The AREA plan is designed to further reduce emissions while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. The Company believes that control and abatement technologies applicable to these plants have matured to the point where further significant air emission reductions can be attained in a relatively cost-effective manner.

If approved, Taconite Harbor will employ innovative multi-emission reduction technology, while Laskin will receive a retrofit focused on lowering NO_X emissions. The Company estimates an emission reduction of over 60% for NO_X at both facilities and a 65% reduction in SO_2 at Taconite Harbor. Laskin already has relatively low emission levels of SO_2 due to existing emission reduction technology. Additionally, with the emerging technology being applied at Taconite Harbor, there is the potential for a 90% reduction in mercury.

On December 13, 2005, a second filing detailing the rate rider cost recovery for the plan was submitted to the MPUC. The rate impact on residential and general service customers is expected to be about 2%, and about 3% for Large Power Customers when the plan is fully implemented at the end of 2008. We are seeking approval prior to June 30, 2006, when the statutory authorization for emission reduction riders sunsets. On January 17, 2006, the MPCA submitted its assessment of Minnesota Power's AREA plan from an environmental perspective to the MPUC. The MPCA supports the plan as a cost-effective means of reducing emissions at Taconite Harbor and Laskin.

Conservation Improvement Programs (CIP). Minnesota requires investor-owned electric utilities to spend a minimum of 1.5% of gross annual retail electric revenue on CIP 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 recovery, all CIP expenditures, as well as a carrying charge on the deferred account balance. Minnesota Power's CIP investment goal was $3.2 million for 2005 ($3.1 million for 2004; $2.9 million for 2003), with actual spending of $3.6 million in 2005 ($3.1 million in 2004; $5.0 million in 2003).

Public Service Commission of Wisconsin. SWL&P's current electric retail rates are based on a May 2005 PSCW retail rate order that allows for an 11.7% return on common equity and resulted in an average rate increase of 3.9%. In 2006, SWL&P plans to file for an increase in rates to be effective beginning in 2007 for its electric, water and gas utility services.

In December 2003, the PSCW unanimously approved the revised $420 million cost estimate for the Wausau-to-Duluth electric transmission line. Minnesota Power and transmission planners throughout the region believe the 220-mile, 345-kV transmission line is necessary. Minnesota Power has been actively involved in the permitting. Construction activities in Minnesota were completed in 2005. Construction commenced in Wisconsin in August 2005, and is scheduled to be completed in June 2008.

Energy – Regulated Utility (Continued)

Competition

We believe the overall impact of the EPAct 2005 on the electric utility industry will be positive and are evaluating the effects on our business as this legislation is being implemented. This federal legislation is designed to bring more certainty to energy markets that ALLETE participates in, as well as provides investment incentives for energy efficiency, energy infrastructure (such as electric transmission lines) and energy production. The FERC has the responsibility of implementing numerous new standards as a result of the promulgation of EPAct 2005. So far the FERC's regulatory efforts appear to be generally positive for the utility industry.

EPAct 2005's repeal of the PUHCA 1935 should result in more capital flowing into the industry while providing additional operational flexibility. The PUHCA 1935 repeal may also allow an acceleration of merger activity, although that is speculative and difficult to predict.

We cannot predict the timing or substance of any future legislation or regulation.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 90 cities and towns located within its electric service territory. SWL&P holds similar franchises for electric, natural gas and/or water systems in 15 cities and towns within its service territory. The remaining cities and towns served do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

Energy – Nonregulated Energy Operations

BNI Coal owns and operates a lignite mine in North Dakota. BNI Coal is the lowest-cost supplier of lignite in North Dakota, producing about 4.5 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 expiring in 2027. (See Fuel and Note 10.) The mining process disturbs and reclaims approximately 210 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. That means if the land we mine once grew crops, it must be able to do so again after reclamation. The cost to reclaim one acre of land averages about $15,000 and can run as high as $30,000. Reclamation costs are included in the cost of coal. In September 2004, BNI Coal entered into a master lease agreement with Farm Credit Leasing Services Corporation (Farm Credit). Under this new agreement, BNI Coal leases a dragline that went into operation in October 2004. BNI Coal is obligated to make lease payments totaling $2.8 million annually for the 23-year lease term, which expires in 2027. BNI Coal will have the option at the end of the lease term to renew the lease at a fair market rental, to purchase the dragline at fair market value, or to surrender the dragline to Farm Credit and pay a $3.0 million termination fee. With lignite reserves of an estimated 600 million tons combined with new dragline equipment, BNI Coal has ample capacity to expand production.

Nonregulated Generation. Nonregulated generation is primarily non-rate base generation sold at market-based rates to the wholesale market.

Taconite Harbor. In 2002, we commenced operation of the Taconite Harbor generating facilities, which we purchased in 2001. The generation output was primarily sold in the wholesale market and was sold in limited circumstances to Minnesota Power's retail utility customers.

In October 2005, Minnesota Power proposed to the MPUC a comprehensive solution to meet generation needs through 2010 that includes transitioning the Taconite Harbor generating facility from wholesale sales to retail sales to help meet the utility's forecasted base load energy requirements. With MPUC approval, our proposal would make the integration of Taconite Harbor into Minnesota Power's regulated utility business effective retroactive to January 1, 2006. (See Regulated Utility – Minnesota Public Utilities Commission.)

Rainy River Energy has been engaged in the acquisition and development of nonregulated generation and wholesale power marketing. On April 1, 2005, Rainy River Energy completed the assignment of its power purchase agreement with LSP-Kendall Energy, LLC, the owner of an energy generation facility located in Kendall County, Illinois, to Constellation Energy Commodities. Rainy River Energy paid Constellation Energy Commodities $73 million in cash to assume the power purchase agreement, which is in effect through mid-September 2017. The payment resulted in a charge to our operating income in the second quarter of 2005. The tax benefits of the payment will be realized through a capital loss carryback for federal income tax purposes and have been recorded as current deferred income tax assets. The tax benefits are expected to be realized in 2006. In addition, consent, advisory and closing costs of $4.9 million were incurred to complete the transaction. As a result of this transaction, ALLETE incurred a $77.9 million ($50.4 million after tax, or $1.84 per diluted share) charge in 2005.

Energy – Nonregulated Energy Operations (Continued)

Rainy River Energy Corporation - Wisconsin continues to study the feasibility of the construction of a natural gas-fired electric generating facility in northwestern Wisconsin. In accordance with the PSCW's final order approving the project, Rainy River Energy Corporation - Wisconsin undertook preliminary site preparation work in late 2003.

In 2005, we sold 1.5 million MWh of nonregulated generation (1.5 million in 2004; 1.5 million in 2003).

Nonregulated Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability
				MW
Steam				
Coal-Fired				
Taconite Harbor Energy Center in Taconite Harbor, MN *(a)*	1, 2 & 3	1957, 1957, 1967	2001	200
Cloquet Energy Center in Cloquet, MN	5	2001	2001	23
Rapids Energy Center *(b)* in Grand Rapids, MN	6 & 7	1969, 1980	2000	25
Hydro				
Conventional Run-of-River				
Rapids Energy Center *(b)* in Grand Rapids, MN	4 & 5	1917	2000	1

(a) Effective January 1, 2006, the operating assets were transferred to Regulated Utility operations, pending MPUC approval.
(b) The net generation is primarily dedicated to the needs of one customer.

Minnesota Land. We have about 18,000 acres of land in northern Minnesota, which is available for sale. We acquired this land in 2001 at the time we purchased Taconite Harbor from LTV Steel Mining Co. The cost basis of this land was $4.9 million at December 31, 2005.

Energy – Investment in ATC

In December 2005, ALLETE entered into an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC that provides for ALLETE, through its Wisconsin subsidiary Rainy River Energy Corporation - Wisconsin, to invest $60 million in ATC by the end of 2006. ATC is a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set to further the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. ALLETE's investment is expected to represent an estimated 9% ownership interest in ATC. The investment by ALLETE's subsidiary in ATC is subject to review by the PSCW. The FERC approved the transaction in December 2005.

Real Estate

ALLETE Properties is our real estate business that has operated in Florida since 1991. ALLETE Properties acquires real estate portfolios and large land tracts at bulk prices, adds value through entitlements and/or infrastructure improvements, and resells the property over time to developers, end-users and investors. ALLETE Properties is focused on acquiring vacant land in the coastal southeast United States. Management at ALLETE Properties uses their business relationships, understanding of real estate markets and expertise in the land development and sales processes to provide revenue and earnings growth opportunities to ALLETE.

ALLETE Properties is headquartered in Fort Myers, Florida, the location of its southwest Florida regional office. We also have a regional office in Palm Coast, Florida, which oversees northeast Florida operations.

Southwest Florida operations consist of land sales and a third-party brokerage business, with limited land development activities. Inventory includes commercial and residential land located in Lehigh Acres and Cape Coral. The inventory represents the remaining properties acquired in 1991 from the Resolution Trust Corporation and in 1999 from Avatar Properties, Inc. The operation also generates rental income from a 186,000 square foot retail shopping center located in Winter Haven, Florida. The center is anchored by Macy’s and Belk’s department stores, along with Staples.

Northeast Florida operations focus on land sales and development activities. Development activities involve mainly zoning, permitting, platting and master infrastructure construction. Development costs are financed through a combination of community development district bonds, bank loans and internally-generated funds. Our three major development projects include Town Center at Palm Coast, Palm Coast Park and Ormond Crossings.

Town Center. Town Center is a mixed-use, planned development with a neo-traditional downtown design. Surrounded by major arterial roads, including Interstate 95, the development was selected as the site for the City of Palm Coast’s new city hall and is adjacent to the local hospital, county airport and high school. At build-out, the development is expected to include 2,800 residential units and 3.6 million square feet of commercial space. Actual build-out will depend on future market conditions. All major land use approvals for the project have been received. Platting, infrastructure construction and marketing efforts continue. The major infrastructure improvements include 3.6 miles of roads, a storm water management system, with lakes and ponds located throughout the property, and underground utilities. Construction began in March 2005 and is expected to be completed in late 2006.

In March 2005, the Town Center at Palm Coast Community Development District (Town Center District) issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, due May 1, 2036. The bonds were issued to fund a portion of the Town Center at Palm Coast development project. Approximately $21 million of the bond proceeds will be used for construction of infrastructure improvements at Town Center, with the remaining funds to be used for capitalized interest, a debt service reserve fund and costs of issuance. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments will be included in the annual property tax bills of landowners beginning in November 2006. To the extent that we still own land at the time of the assessment, we will recognize an expense for our pro rata portion of assessments based upon our ownership of benefited property. At December 31, 2005, we owned approximately 92% of the assessable land in the Town Center District.

Additional Town Center development costs not funded through Town Center District bond financing, estimated at approximately $26 million (up to $11 million of which are reimbursable through traffic impact fee credits), will be financed with an $8.5 million revolving development loan of Florida Landmark, which is guaranteed by Lehigh Acquisition Corporation. Florida Landmark is a wholly-owned subsidiary of Lehigh Acquisition Corporation, which is an 80% owned subsidiary of ALLETE. The initial term of the revolving development loan is 36 months. Traffic impact fee credits are provided to the developer as mitigation payments are made to the city. We are reimbursed after the land is sold and a subsequent property owner constructs vertical improvements on the site. We recognize revenue resulting from these reimbursed fees when they are received.

The Town Center District is an independent unit of local government, created and established in accordance with Florida’s Uniform Community Development District Act of 1980 (Act). The Act provides legal authority for a community development district to finance the construction of major infrastructure for community development with general obligation, revenue and special assessment revenue debt obligations.

Florida Landmark has an agreement with Developers Realty Corporation (DRC) to develop the first phase of the urban core area of our Town Center. The agreement also includes the development of a 51-acre commercial retail site. DRC is a regional commercial developer with strong ties to national retailers and has experience developing “lifestyle center” projects.

During the initial phase of the Town Center project, our primary focus is to develop the major infrastructure, most of the development tracts, as well as plat lots for a variety of uses. The marketing program has targeted an appropriate blend and quantity of office, commercial, residential and mixed-use projects. Sites for all land uses that are planned in the initial phase are already sold or under contract, except adult housing. Negotiations are underway with several developers that specialize in adult housing units. After the next few years, once the market has substantially absorbed the land uses that are currently in the design phase, additional sites will be released for sale in order to maintain an orderly build-out of Town Center. Pacing the growth of Town Center consistent with absorption rates for each unit type will assure that our customers, the Town Center project developers, will be successful. This is expected to create and maximize value for the developers, end-users and investors.

Palm Coast Park. Palm Coast Park is a 4,700-acre mixed-use, planned development located in northwest Palm Coast along U.S. Highway 1, one mile south of its intersection with Interstate 95, with major rail line access. At build-out, the project is expected to include 3.2 million square feet of commercial space and 3,600 residential units ranging from affordable condominium units and apartments to estate golf homes. Actual build-out will depend on future market conditions. In December 2004, we received development order approval for the project.

In August 2005, Florida’s governor and cabinet voted unanimously to approve the creation of Palm Coast Park Community Development District. Bonds are expected to be issued by the district by mid-2006 to fund construction of infrastructure improvements for the project. The major infrastructure improvements, consisting primarily of utility extensions and a linear park along the U.S. Highway 1 frontage, are being permitted in anticipation of this bond financing, after which construction of the improvements will commence.

Platting is underway and is expected to be completed in early 2007. One residential development tract is under contract and negotiations are underway to sell two other residential development tracts. Commercial sites will be available for sale beginning in 2007.

Ormond Crossings. Ormond Crossings is a 6,000-acre mixed-use, planned development located along Interstate 95, at its interchange with U.S. Highway 1, in northwest Ormond Beach. This property has three miles of frontage on the east and west sides of Interstate 95, is adjacent to the local airport and has access to a major railroad line. In 2004, the property was annexed into the City of Ormond Beach and land-use approvals are in progress.

A Development of Regional Impact (DRI) Application for Development Approval was submitted in August 2005 to the East Central Florida Regional Planning Council for the project. Development uses and densities proposed in the DRI include 5 million square feet of commercial opportunities, along with up to 4,400 residential units. We anticipate that the DRI approval process will be concluded in late 2006, at which time we would receive a Development Order from the City of Ormond Beach. Engineering, design and permitting will continue through 2007. It is not anticipated that any sales will be made at Ormond Crossings until 2008.

Other Land. In addition to the major development projects, land inventories in Florida include 4,200 acres of other property. Several smaller development projects are under way to plat these properties, add infrastructure and modify and enhance existing entitlements.

Property sale prices may vary depending on location; physical characteristics; parcel size; whether parcels are sold as raw land, partially developed land or individually developed lots; degree and status of entitlement; and whether the land is ultimately purchased for residential, commercial or other form of development. In addition to minimum base price contracts, certain contracts allow us to receive participation revenue to the extent that an agreed upon percentage of gross revenue from land sales by our purchaser exceeds the minimum base price.

ALLETE Properties occasionally provides seller financing. At December 31, 2005, outstanding finance receivables were $7.4 million, with maturities ranging up to ten years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Real Estate (Continued)

Summary of Development Projects At December 31, 2005	Ownership	Total Acres *(a)*	Residential Units *(b)*	Commercial Sq. Ft. *(b,c)*
Town Center	80%			
At December 31, 2004		1,550	2,950	3,525,000
Property Sold		(70)	–	(643,000)
Change in Estimate *(a)*		–	(117)	45,700
		1,480	2,833	2,927,700
Palm Coast Park	100%	4,705	3,600	3,200,000
Ormond Crossings	100%			
At December 31, 2004		5,850	*(d)*	*(d)*
Change in Estimate *(a)*		110		
		5,960		
		12,145	6,433	6,127,700

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest. Acreage amounts may vary due to platting or surveying activity. Wetland amounts vary by property and are often not formally determined prior to sale.
(b) Estimated and includes minority interest. The actual property breakdown at full build-out may be different than these estimates.
(c) Includes industrial, office and retail square footage.
(d) The DRI submitted in August 2005 proposed 4,400 residential units and 5 million square feet of commercial space, and is subject to approval by regulating governmental entities.

Summary of Other Land Inventories At December 31, 2005	Ownership	Total	Mixed Use	Residential	Commercial	Agricultural
Acres *(a)*						
Palm Coast Holdings	80%					
At December 31, 2004		3,099	2,040	513	291	255
Property Sold		(533)	(348)	(167)	(10)	(8)
		2,566	1,692	346	281	247
Lehigh	80%					
At December 31, 2004		1,082	840	140	93	9
Property Sold		(469)	(450)	–	(19)	–
		613	390	140	74	9
Cape Coral	100%					
At December 31, 2004		104	–	1	103	–
Property Sold		(63)	–	–	(63)	–
		41	–	1	40	–
Other	100%					
At December 31, 2004		908	–	–	–	908
Property Sold		(37)	–	–	–	(37)
Contributed Land		(30)	–	–	–	(30)
Change in Estimate *(a)*		103	–	–	–	103
		944	–	–	–	944
		4,164	2,082	487	395	1,200

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest. Acreage amounts may vary due to platting or surveying activity. Wetland amounts vary by property and are often not formally determined prior to sale. The actual property breakdown at full build-out may be different than these estimates.

Real Estate (Continued)

Regulation

A substantial portion of our development properties in Florida is 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.

Development of real property in Florida entails an extensive approval process involving overlapping regulatory jurisdictions. Real estate projects must generally comply with the provisions of the Local Government Comprehensive Planning and Land Development Regulation Act (Growth Management Act), which requires counties and cities to adopt comprehensive plans guiding and controlling future real property development in their respective jurisdictions. In addition, development projects that exceed certain specified regulatory thresholds require approval of a comprehensive Development of Regional Impact (DRI) application. The DRI review process includes an evaluation of a project's impact on the environment, infrastructure and government services, and requires the involvement of numerous state and local environmental, zoning and community development agencies. Compliance with the Growth Management Act and the DRI process is usually lengthy and costly.

Competition

The real estate industry is very competitive. Our properties are located in Florida, which continues to attract competitive real estate operations at many different levels in the land development pipeline. Competitors include local and out-of-state institutional investors, real estate investment trusts and real estate operators, among others. These competitors, both public and private alike, compete with us in seeking real estate for acquisition, resources for development and sales to prospective buyers. Consequently, competitive market conditions may influence the timing and profitability of our real estate transactions.

Other

Our Other segment consists of investments in emerging technologies related to the electric utility industry, and earnings on cash, cash equivalents and short-term investments.

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. Since 1985, we have invested in start-up companies, which are developing technologies that may be utilized by the electric utility industry. We are committed to invest an additional $3.1 million at various times through 2007 and do not have plans to make any additional investments. The investments were first made through emerging technology funds (Funds) initiated by other electric utilities and us. We have also made investments directly in privately-held companies.

Companies in the Funds' portfolios may complete IPOs, and the Funds may, in some instances, distribute publicly tradable shares to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an IPO. As companies included in our emerging technology portfolio are sold, we will recognize a gain or a loss.

We account for our investment in venture capital funds under the equity method (see Note 15) and account for our direct investment in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $9.2 million at December 31, 2005 ($13.6 million at December 31, 2004). Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Our basis in direct investments in privately-held companies included in the emerging technology portfolio was zero at December 31, 2005 ($4.5 million at December 31, 2004). In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments that related to direct investments in certain privately-held, start-up companies whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. In 2004, we recorded $6.5 million ($4.1 million after tax) of impairments.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. We consider our businesses to be in substantial compliance with those environmental regulations currently applicable to their operations and believe all necessary permits to conduct such operations have been obtained. Due to future stricter 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 – Capital Requirements.) We are unable to predict if and when any such stricter environmental requirements will be imposed and the impact they will have on the Company. 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 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 expense unless recoverable in rates from customers.

Air. *Clean Air Act.* Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of these facilities are equipped with pollution control equipment such as scrubbers, bag houses or electrostatic precipitators. Permitted emission requirements are currently being met. The federal Clean Air Act Amendments of 1990 (Clean Air Act) created emission allowances for SO_2. Each allowance is an authorization to emit one ton of SO_2, and each utility must have sufficient allowances to cover its annual emissions. Most Minnesota Power facilities have surplus SO_2 emission allowances. Square Butte is meeting its SO_2 emission allowance requirements through increased use of its existing scrubber. During 2005, Taconite Harbor purchased SO_2 emission allowances to meet these requirements. Taconite Harbor does not expect to purchase SO_2 emission allowances in 2006 if the MPUC approves the transfer of its generating assets to regulated utility operations retroactive to January 1, 2006.

In accordance with the Clean Air Act, the EPA has established NO_X limitations for electric generating units. To meet NO_X limitations, Minnesota Power installed advanced low-emission burner technology and associated control equipment to operate the Boswell and Laskin facilities at or below the compliance emission limits. NO_X limitations at Taconite Harbor and Square Butte are being met by combustion tuning.

Clean Air Interstate Rule and Clean Air Mercury Rule. In March 2005, the EPA announced the final Clean Air Interstate Rule (CAIR) that reduces and permanently caps emissions of SO_2 and NO_X in many of the eastern United States. The CAIR includes Minnesota as one of the 28 states it considers an "eastern" state. The EPA also announced the final Clean Air Mercury Rule (CAMR) that reduces and permanently caps electric utility mercury emissions in the continental United States. The CAIR and the CAMR regulations have been challenged in the court system, which may delay implementation or modify provisions. Minnesota Power is participating in a legal challenge to the CAIR, but is not participating in the challenge of the CAMR. However, if the CAMR and the CAIR do go into effect, Minnesota Power expects to be required to (1) make emissions reductions, (2) purchase mercury, SO_2 and NO_X allowances through the EPA's cap-and-trade system, or (3) use a combination of both.

We believe that the CAIR contains flaws in its methodology and application, which will cause Minnesota Power to incur significantly higher compliance costs. Consequently, on July 11, 2005, Minnesota Power filed a Petition for Review with the U.S. Court of Appeals for the District of Columbia Circuit. The Company also filed a Petition for Reconsideration with the EPA. If the litigation and/or the Petition for Reconsideration are successful, we expect to incur lower compliance costs, consistent with the rules applicable to those states considered as "western" states under the CAIR. On November 22, 2005, the EPA agreed to reconsider certain aspects of its CAIR, including the Minnesota Power petition addressing modeling used to determine Minnesota's inclusion in the CAIR region and claims about inequities in the SO_2 allowance methodology. The EPA has stated it anticipates making a decision regarding the petitions in mid-March 2006.

Mercury Emissions. In December 2000, the EPA announced its decision to regulate mercury emissions from coal and oil-fired power plants under Section 112 of the Clean Air Act. Section 112 would require all such power plants in the United States to adhere to the EPA maximum achievable control technology (MACT) standards for mercury. However, on March 15, 2005, the EPA removed electric utilities from the Section 112(c) list of source categories subject to MACT requirements, instead referencing how the EPA is regulating utility emissions of mercury under Section 111 and how the EPA is providing for additional SO_2 and NO_X emission reductions that will deliver mercury reductions as a co-benefit of controls under the March 10, 2005 final CAIR. The EPA has assigned a mercury emission budget to each state that is based on achieving an approximate 70% overall reduction in baseline utility mercury emissions by the start of the second phase of the CAMR in 2018. The MPCA is now required to provide an implementation plan for EPA approval in 2006, by which time Minnesota will have determined if it will participate in the EPA's proposed mercury cap and trade program. The EPA's determination not to list electric utilities under Section 112(c) has already been subjected to court challenge. The Minnesota mercury emissions budget under the first phase of the CAMR is close to current emissions. The second phase allocation, effective 2018, will require that Minnesota sources provide for substantial mercury emission reductions or procure mercury emission credits from other sources that have a surplus of allowances. Continuous emission monitoring of mercury stack emissions will be required on larger units while smaller units with low mercury emissions may not require continuous monitoring. Minnesota Power is continuing to review the new mercury rule and considers the outcome of legal challenges as being critical before specific compliance measures can be established or assessed. Minnesota Power's

Environmental Matters (Continued)

preliminary estimates suggest that all of our affected facilities can be outfitted with continuous mercury emission monitors for under $2 million. Cost estimates about mercury cap and trade program impacts are premature at this time. In October 2005, Minnesota Power announced the AREA plan which, if approved by the MPUC, includes installing multi-emission reduction technology at Taconite Harbor that has the potential for a 90% reduction in mercury. (See Regulatory Issues – Minnesota Public Utilities Commission – Arrowhead Regional Emission Abatement.)

New Source Review Rules. In December 2002, the EPA issued changes to the existing New Source Review rules. These rules changed the procedures for MPCA review of projects at our electric generating facilities. These changes have been incorporated in Minnesota and have not had a material impact on our operations. In October 2003, the EPA announced additional changes clarifying the application of certain sections of the New Source Review rules. In December 2003, the U.S. Court of Appeals for the District of Columbia Circuit stayed the implementation of the October 2003 rule pending their further review, which is expected in 2006. These changes are not expected to have a material impact on Minnesota Power.

Square Butte Generating Facility. In June 2002, Minnkota Power, the operator of Square Butte, received a Notice of Violation from the EPA regarding alleged New Source Review violations at the M.R. Young Station, which includes the Square Butte generating unit. The EPA claims certain capital projects completed by Minnkota Power should have been reviewed pursuant to the New Source Review regulations, potentially resulting in new air permit operating conditions and possible significant capital expenditures to comply. Minnkota Power has held several meetings with the EPA to discuss the alleged violations. Discussions between Minnkota Power and the EPA are ongoing and we are unable to predict the outcome or cost impacts. If Square Butte is required to make significant capital expenditures to comply with the EPA requirements, we expect such capital expenditures to be debt financed. Our future cost of purchased power would include our pro rata share of this additional debt service.

Global Climate Change. Minnesota Power recognizes the international efforts to study the science and economic implications of global climate change are a work-in-progress. While the international forum continues its study and negotiations to address the complexities of climate change concerns, Minnesota Power believes it is appropriate to implement voluntary greenhouse gas emissions reduction or offset measures that are consistent with peer-reviewed climate science, provide a continued supply of competitive, low-cost power to our customers, and continue responsible environmental stewardship. As of 2004, Minnesota Power estimates that we offset the equivalent of over one million tons of carbon dioxide annually, or about 9% of the greenhouse gas emissions associated with the supply of electricity to its Minnesota retail customers.

Minnesota Power has been a participant along with other utilities in the voluntary U.S. Department of Energy's Climate Challenge program since its inception in 1991. The program is dedicated to the development of innovative programs to reduce, limit, avoid or offset emissions of greenhouse gases. Minnesota Power also supports Power Partners, a new voluntary program that is replacing the Climate Challenge program.

Minnesota Power is voluntarily submitting annual reports to the U.S. Department of Energy on activities outlined in Minnesota Power's Climate Challenge Participation Accord. Minnesota Power implemented measures that helped improve the energy efficiency of our generation and the energy used by our customers, increased our use of renewable hydroelectric generation, wind and wood waste fuel, established a waste paper recycling facility that reduces the demand on forest resources and landfills and helped establish a tree planting program in Minnesota that will mediate greenhouse gas emissions while providing Minnesota with another tool for good forestry management.

Water. The Federal Water Pollution Control Act requires National Pollutant Discharge Elimination System (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.

FERC Licenses. Minnesota Power holds FERC licenses authorizing the ownership and operation of seven hydroelectric generating projects with a total generating capacity of about 115 MW. In June 1996, Minnesota Power filed in the U.S. Court of Appeals for the District of Columbia Circuit a petition for review of the license as issued by the FERC for Minnesota Power's St. Louis River Hydro Project. Separate petitions for review were also filed by the U.S. Department of the Interior and the Fond du Lac Band of Lake Superior Chippewa (Fond du Lac Band), two intervenors in the licensing proceedings. The Fond du Lac Band, the U.S. Department of the Interior and Minnesota Power have reached a settlement agreement for the St. Louis River Hydro Project. This settlement must be approved by the FERC. In connection with such approval, the FERC would amend the project license to reflect the conditions of the settlement agreement. Minnesota Power submitted an application for amendment of the FERC license, based upon the terms and conditions of the settlement agreement in November 2004. In addition to a one-time retroactive payment of approximately $750,000, the Company estimates that it will spend $100,000 to $250,000 per year for the use of tribal lands, to fund fishery and natural resource enhancements by the Fond du Lac Band and the Minnesota Department of Natural Resources, and to conduct a mercury study under the terms of the settlement. Beginning in 1996, and most recently in February 2006, Minnesota Power filed requests with the FERC for extensions of time to comply with certain plans and studies required by the license that might conflict with the settlement agreement.

Environmental Matters (Continued)

Clean Water Act – Aquatic Organisms. In July 2004, the EPA issued Section 316(b) Phase II Rule of the Clean Water Act to ensure that the location, design, construction and capacity of cooling water intake structures at electric generating facilities reflect the best technology available to reduce fish mortality due to impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses). The new rule for fish impingement mortality requirements apply to the Boswell, Laskin, Hibbard and Square Butte generating facilities. The impingement and entrainment requirements apply to Taconite Harbor because it is located on Lake Superior. The rule requires biological studies and engineering analyses to be performed within the 2005 to 2008 timeframe. The biological studies were initiated in 2005. The estimated total cost of these studies for our facilities is expected to be in the range of $0.5 million to $1.0 million. At this time, we cannot estimate the capital and/or aquatic restoration expenditures that may be required to comply with the Section 316(b) Phase II Rule.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid wastes and hazardous wastes. As a result of this legislation, the EPA has promulgated various hazardous waste rules. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA. State environmental agencies are responsible for administering solid and hazardous waste rules on the local level with oversight by the EPA. We are in material compliance with these rules.

PCB Inventories. In response to the EPA Region V's request for utilities to participate in the Great Lakes Initiative by voluntarily removing remaining polychlorinated biphenyl (PCB) inventories, Minnesota Power replaced its remaining PCB capacitor banks in 2005. It is expected that PCB-contaminated oil in substation equipment will be largely replaced by the end of 2006. The total cost is expected to be about $2 million, of which $1.6 million was spent through December 31, 2005.

SWL&P Manufactured Gas Plant. In May 2001, SWL&P received notice from the WDNR that the City of Superior had found soil contamination on property adjoining a former Manufactured Gas Plant (MGP) site owned and operated by SWL&P from 1889 to 1904. The WDNR requested SWL&P to initiate an environmental investigation. The WDNR also issued SWL&P a Responsible Party letter in February 2002. In February 2003, SWL&P submitted a Phase II environmental site investigation report to the WDNR. This report identified some MGP-like chemicals that were found in the soil near the former plant site. During March and April 2003, sediment samples were taken from nearby Superior Bay. The report on the results of this sampling was completed and sent to the WDNR during the first quarter of 2004. The next phase of the investigation was to determine any impact to soil or ground water between the former MGP site and Superior Bay. Site work for this phase of the investigation was performed during October 2004, and the final report was sent to the WDNR in March 2005. Additional site investigation was performed during September and October 2005. It is anticipated that additional site work will be performed in 2006. Although it is not possible to quantify the potential clean-up cost until the investigation is completed, a $0.5 million liability was recorded in December 2003 to address the known areas of contamination. The Company has recorded a corresponding dollar amount as a regulatory asset to offset this liability. The PSCW has approved SWL&P's deferral of these MGP environmental investigation and potential clean-up costs for future recovery in rates, subject to a regulatory prudency review. In May 2005, the PSCW approved the collection through rates of $150,000 of site investigation costs that had been incurred at the time SWL&P filed their most recent rate request. ALLETE maintains pollution liability insurance coverage that includes coverage for SWL&P. A claim has been filed with respect to this matter. The insurance carrier has issued a reservation of rights letter and the Company continues to work with the insurer to determine the availability of insurance coverage.

Employees

At December 31, 2005, ALLETE had 1,500 employees, of which 1,400 were full-time.

Minnesota Power and SWL&P have 597 employees who are members of the International Brotherhood of Electrical Workers (IBEW), Local 31. The labor agreements with Local 31 expired on January 31, 2006, and a tentative agreement has been reached. The members of IBEW Local 31 are expected to vote on the tentative agreement by the end of February 2006.

BNI Coal has 94 employees who are members of the IBEW Local 1593. BNI Coal and Local 1593 have a labor agreement, which expires on March 31, 2008.

Executive Officers of the Registrant

Executive Officers	Initial Effective Date
Donald J. Shippar, Age 56	
Chairman, President and Chief Executive Officer	January 1, 2006
President and Chief Executive Officer	January 21, 2004
Executive Vice President – ALLETE and President – Minnesota Power	May 13, 2003
President and Chief Operating Officer – Minnesota Power	January 1, 2002
Deborah A. Amberg, Age 40	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Vice President, General Counsel and Secretary	March 8, 2004
Warren L. Candy, Age 56	
Senior Vice President – Utility Operations	February 1, 2004
Laura A. Holquist, Age 44	
President – ALLETE Properties	September 6, 2001
David J. McMillan, Age 44	
Senior Vice President – Marketing, Regulatory and Public Affairs – ALLETE and Executive Vice President – Minnesota Power	January 1, 2006
Senior Vice President – Marketing and Public Affairs	October 2, 2003
Mark A. Schober, Age 50	
Senior Vice President and Controller	February 1, 2004
Vice President and Controller	April 18, 2001
Controller	March 1, 1993
Donald W. Stellmaker, Age 48	
Treasurer	July 24, 2004
Timothy J. Thorp, Age 51	
Vice President – Investor Relations	July 1, 2004
Vice President – Investor Relations and Corporate Communications	November 16, 2001
James K. Vizanko, Age 52	
Senior Vice President and Chief Financial Officer	July 24, 2004
Senior Vice President, Chief Financial Officer and Treasurer	January 21, 2004
Vice President, Chief Financial Officer and Treasurer	August 28, 2001
Vice President and Treasurer	April 18, 2001
Treasurer	March 1, 1993
Claudia Scott Welty, Age 53	
Senior Vice President and Chief Administrative Officer	February 1, 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 executives held other positions with the Company during the past five years.

Mr. Shippar was chief operating officer of Minnesota Power.

Ms. Amberg was a senior attorney.

Mr. Candy was a vice president of Minnesota Power.

Ms. Holquist was senior vice president of ALLETE Properties.

Mr. McMillan was senior vice president strategic accounts and governmental affairs, and a vice president of Minnesota Power.

Mr. Stellmaker was director of financial planning, and manager of corporate finance, planning and budgets.

Mr. Thorp was director of investor relations.

Ms. Welty was vice president strategy and technology development.

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 9, 2006.

Item 1A. Risk Factors

Readers are cautioned that forward-looking statements, including those contained in this Form 10-K, should be read in conjunction with our disclosures under the heading: "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" located on page 3 of this Form 10-K and the factors described below. 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 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 12 Large Power Customers account for approximately 32% of our 2005 consolidated operating revenue (one of these customers alone accounts for more than 11%). These customers are involved in cyclical industries that by 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 and the communities that we serve.

Our energy business is subject to increased competition.

The independent power industry includes numerous strong and capable competitors, many of which have extensive experience in the operation, acquisition and development of power generation facilities. Our competition is based primarily on price and reputation for quality, safety and reliability. The electric utility and natural gas industries are also experiencing increased competitive pressures as a result of consumer demands, technological advances, deregulation and other factors.

We 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 FPSC, the PSCW, various local and county regulators, and city administrators. These governmental regulations relate to 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 and capital investments, and present or prospective wholesale and retail competition (including but not limited to transmission costs). 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 Regulated Utility and Nonregulated Energy 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 and other environmental considerations. 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. 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. (See Note 10.)

Risk Factors (Continued)

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 risks, breakdown or failure of facilities, the dependence on a specific fuel source, 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 was 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 improvement. (See Item I – Environmental Matters). 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.

We must have adequate and reliable transmission and distribution facilities to deliver electricity to our customers.

Minnesota Power depends on transmission and distribution facilities owned and operated by other utilities, as well as its own such facilities, to deliver the electricity it produces and sells to its 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 forgo sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. The cost to provide service to these customers may exceed the cost to serve other customers, resulting in lower gross margins. 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 one of our major products, electricity, and/or one of our major expenses, 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 commodities;
- 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, or 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 nonregulated operations at this time.

We are dependent on good labor relations.

We believe our relations to be good with our approximately 1,500 employees. Approximately 700 of these employees are members of either the International Brotherhood of Electrical Workers Local 31 or Local 1593. Failure to successfully renegotiate labor agreements could adversely affect the services we provide and our results of operations. The labor agreements with Local 31 expired on January 31, 2006, and a tentative agreement has been reached. The members of IBEW Local 31 are expected to vote on the tentative agreement by the end of February 2006. The labor agreement with Local 1593 at BNI Coal expires on March 31, 2008.

A downturn in economic conditions could adversely affect our real estate business.

The ability of our real estate business to generate revenue is directly related to the Florida real estate market, the national and local economy in general, and changes in interest rates. While real estate market conditions have remained healthy in our regions of development, continued demand for land is dependent on long-term prospects for strong, in-migration population expansion.

Risk Factors (Continued)

We are exposed to risks associated with real estate development.

Our real estate development activities entail risks that include construction delays or cost overruns, which may increase project development costs.

In addition, our real estate development activities require significant capital expenditures. We obtain funds for our capital expenditures through cash flow from operations and financings. We cannot be sure that the funds available from these sources will be sufficient to fund our required or desired capital expenditures for development. If we are unable to obtain sufficient funds, we may have to defer or otherwise limit our development activities. If we are unsuccessful in our selling efforts, we may not be able to recover these capital expenditures.

Our real estate business is subject to extensive regulation, which makes it difficult and expensive for us to conduct our operations.

Development of real property in Florida entails an extensive approval process involving overlapping regulatory jurisdictions. Real estate projects must generally comply with the provisions of the Local Government Comprehensive Planning and Land Development Regulation Act (Growth Management Act). In addition, development projects that exceed certain specified regulatory thresholds require approval of a comprehensive Development of Regional Impact (DRI) application.

The Growth Management Act requires counties and cities to adopt comprehensive plans guiding and controlling future real property development in their respective jurisdictions. After a local government adopts its comprehensive plan, all development orders and development permits must be consistent with the plan. Each plan must address such topics as future land use, capital improvements, traffic circulation, sanitation, sewage, potable water, drainage and solid waste disposal. The local governments' comprehensive plans must also establish "levels of service" with respect to certain specified public facilities and services to residents. Local governments are prohibited from issuing development orders or permits if facilities and services are not operating at established levels of service, or if the projects for which permits are requested will reduce the level of service for public facilities below the level of service established in the local government's comprehensive plan. If the proposed development would reduce the established level of services below the level set by the plan, the development order will require that, at the outset of the project, the developer either sufficiently improve the services to meet the required level or provide financial assurances that the additional services will be provided as the project progresses.

The Growth Management Act, in some instances, can significantly affect the ability of developers to obtain local government approval in Florida. In many areas, infrastructure funding has not kept pace with growth. As a result, substandard facilities and services can delay or prevent the issuance of permits. Consequently, the Growth Management Act could adversely affect our ability to develop our future real estate projects.

The DRI review process includes an evaluation of a project's impact on the environment, infrastructure and government services, and requires the involvement of numerous state and local environmental, zoning and community development agencies. Local government approval of any DRI is subject to appeal to the Governor and Cabinet by the Florida Department of Community Affairs, and adverse decisions by the Governor or Cabinet are subject to judicial appeal. The DRI approval process is usually lengthy and costly, and conditions, standards or requirements may be imposed on a developer with respect to a particular project, which may materially increase the cost of the project.

Environmental and other regulations may have an adverse effect on our real estate business.

A substantial portion of our development properties in Florida is subject to federal, state, and local regulations and restrictions that may impose significant costs or limitations on our ability to develop our 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.

The occurrence of natural disasters in Florida could adversely affect our business.

The occurrence of natural disasters in Florida, such as hurricanes, floods, fires, unusually heavy or prolonged rain or droughts, could have a material adverse effect on our ability to develop and sell properties or realize income from our projects. The occurrence of natural disasters could also cause increases in property insurance rates and deductibles, which could reduce demand or selling price for our properties.

Risk Factors (Continued)

Risks associated with acquisitions may hinder our ability to increase revenue and earnings.

In pursuing a strategy of acquiring other businesses, we face risks commonly encountered with growth through acquisitions. These risks include, but are not limited to:

- incurring significantly higher capital expenditures and operating expenses;
- failing to assimilate the operations and personnel of the acquired businesses;
- entering new, unfamiliar markets;
- potential undiscovered liabilities at acquired businesses;
- disrupting our ongoing business;
- diverting our limited management resources;
- failing to maintain uniform standards, controls and policies;
- impairing relationships with employees and customers as a result of changes in management; and
- increasing expenses for support services and computer systems, as well as integration difficulties.

We may not adequately anticipate all of the demands that our growth will impose on our systems, procedures and structures, including our financial and reporting control systems, data processing systems and management structure. If we cannot adequately anticipate and respond to these demands, our business could be materially harmed.

Although we conduct what we believe to be a prudent level of investigation regarding the operating condition of the businesses we purchase, in light of the circumstances of each transaction, an unavoidable level of risk remains regarding the actual operating condition of these businesses. Until we actually assume operating control of such business assets, we may not be able to ascertain the actual value of the acquired entity.

We can offer you no assurances that we will be able to execute an acquisition strategy without the costs of future acquisitions escalating.

Although there are potential acquisition candidates that fit our acquisition criteria, we are not certain that we will be able to consummate any such transactions in the future or identify those candidates that would result in the most successful combinations, or that future acquisitions will be able to be consummated at acceptable prices and terms. In addition, increased competition for acquisition candidates could result in fewer acquisition opportunities for us and higher acquisition prices. The magnitude, timing, pricing and nature of future acquisitions will depend upon various factors, including:

- the availability of suitable acquisition candidates;
- competition with other industry groups or new industry consolidators for suitable acquisitions;
- the negotiation of acceptable terms;
- our financial capabilities;
- the availability of skilled employees to manage the acquired companies; and
- general economic and business conditions.

Our credit ratings could be revised downward.

The current credit ratings for our long-term debt are investment grade. A rating reflects only the view of a rating agency, and it is not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward at any time by a rating agency if such rating agency decides that circumstances warrant such a change. If Standard & Poor’s or Moody’s were to downgrade our long-term ratings, particularly below investment grade, borrowing costs would increase and the potential pool of investors and funding sources would likely decrease.

We rely heavily on technology to automate and maximize the efficiencies of our businesses and to comply with regulations in a cost-effective manner. Technology is constantly evolving and, in order for us to remain competitive, we will embrace new technologies as they become proven and are economically viable.

Technology is an integral part of the operating and administrative functions of our businesses. The information systems and processes necessary to support business areas such as risk management, sales, customer service, and procurement and supply are complex and are constantly evolving. To successfully compete in our businesses, we must adapt to the evolving market by continually improving the responsiveness, functionality, and features of our services and systems to meet our customers’ and other stakeholders’ needs. With increasing regulatory requirements related to our operations, technology is also a key component to achieving and monitoring compliance. Increased automation through proven, economically viable technologies is among the primary tools that we use to enhance our competitive position; without these technologies, our businesses would not be able to safely operate or adequately respond to customer and other stakeholder needs.

Risk Factors (Continued)

Tax reserves and the recoverability of our deferred tax assets may have a significant impact on our results of operations.

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 use taxes. These judgments include reserves for potential adverse outcomes regarding tax positions that we have taken. We must also assess our ability to generate capital gains to realize tax benefits associated with capital losses expected to be generated in future periods. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the three prior or five succeeding years for federal purposes, and fifteen succeeding years for Minnesota. As of December 31, 2005, we have, where appropriate, recorded an allowance against our deferred tax assets associated with realized capital losses, and with impairment losses, which will become capital losses when realized for income tax purposes. The ultimate outcome of such matters could result in adjustments to our consolidated financial statements and such adjustments could be material.

Adequate insurance protection may not be cost effective or available to minimize risk.

Insurance, warranties or performance guarantees may not cover any or all of the lost revenue or increased expenses, including the cost of replacement power. Likewise, our ability to obtain insurance, and the cost of and coverage provided by such insurance, could be affected by events outside our control.

If we are not able to retain our executive officers and key employees, we may not be able to implement our business strategy and our business could suffer.

The success of our business heavily depends on the leadership of our executive officers, all of whom are employees-at-will and none of whom are subject to any agreements not to compete. If we lose the service of one or more of our executive officers or key employees, or if one or more of them decides to join a competitor or otherwise compete directly or indirectly with us, we may not be able to successfully manage our business or achieve our business objectives. We may have difficulty in retaining and attracting customers, developing new services, negotiating favorable agreements with customers and providing acceptable levels of customer service.

If we are not able to replace our mature workforce with qualified personnel, we may not be able to operate and maintain our business and the results of our operations would be negatively impacted.

The success of our business also depends on our talented workforce that operates and maintains our business and processes. If we are unable to attract and retain new personnel to replace our mature workforce, we may not be able to successfully operate and manage our business or achieve our business objectives. We may have difficulty effectively and efficiently running our business operations, maintaining existing services, meeting regulatory requirements, developing new services and providing acceptable levels of customer service.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

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, nor have a material adverse effect on our financial condition.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2005.

Part II

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

We have paid dividends without interruption on our common stock since 1948. A quarterly dividend of $0.3625 per share on our common stock will be paid on March 1, 2006, to the holders of record on February 15, 2006. Our common stock is listed on the New York Stock Exchange under the symbol ALE and our CUSIP number is 018522300. Dividends paid per share, and the high and low prices for our common stock for the periods indicated as reported by the New York Stock Exchange on its NYSEnet website, are in the accompanying chart.

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. In 2005, we paid out 259% of our per share earnings in dividends. The payout ratio in 2005 was impacted by a $1.84 per diluted share charge to assign the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. (See Note 11.)

Our Articles of Incorporation, and Mortgage and Deed of Trust contain provisions, which under certain circumstances would restrict the payment of common stock dividends. As of December 31, 2005, no retained earnings were restricted as a result of these provisions. At February 1, 2006, there were approximately 32,000 common stock shareholders of record.

	2005			2004		
	Price Range		Dividends	Price Range *(a)*		Dividends
Quarter	**High**	**Low**	**Paid**	**High**	**Low**	**Paid** *(b)*
First	$44.40	$35.65	$0.3000	$35.52	$30.00	$0.8475
Second	50.33	40.12	0.3150	36.71	31.62	0.8475
Third	51.70	42.80	0.3150			
July 1 – Sept. 20				33.70	26.02	0.8475
Sept. 21 – Sept. 30				32.54	30.76	–
Fourth	47.36	41.28	0.3150	37.46	32.20	0.3000
Annual Total			$1.2450			$2.8425

(a) Price ranges prior to September 21, 2004, are not comparable due to the spin-off of Automotive Services on September 20, 2004, (see Note 14) and do not reflect the one-for-three reverse stock split (see Note 8).
(b) Adjusted for the September 20, 2004, one-for-three reverse stock split.

We did not repurchase any ALLETE common stock during the fourth quarter of 2005.

Item 6. Selected Financial Data

Operating results of our Water Services businesses, our Automotive Services business, our telecommunications business and our retail stores are included in discontinued operations, and accordingly, amounts have been restated for all periods presented. (See Note 14.) Common share and per share amounts have also been adjusted for all periods to reflect our September 20, 2004, one-for-three common stock reverse split.

	2005	2004	2003	2002	2001
Millions					
Balance Sheet					
Assets					
Current Assets	$ 373.5	$ 355.0	$ 216.1	$ 184.8	$ 313.7
Discontinued Operations – Current	0.4	13.1	483.9	477.3	581.8
Property, Plant and Equipment	860.4	849.6	888.2	852.0	851.6
Investments	117.7	124.5	175.7	170.9	155.4
Other Assets	44.6	52.8	59.0	61.9	67.3
Discontinued Operations – Other	2.2	36.4	1,278.4	1,400.3	1,312.7
	$1,398.8	$1,431.4	$3,101.3	$3,147.2	$3,282.5
Liabilities and Shareholders' Equity					
Current Liabilities	$ 106.7	$ 91.7	$ 182.1	$ 436.2	$ 340.5
Discontinued Operations – Current	13.0	24.5	344.1	302.0	364.0
Long-Term Debt	387.8	389.4	513.9	566.9	835.2
Mandatorily Redeemable Preferred Securities	–	–	–	75.0	75.0
Other Liabilities	288.5	295.3	300.1	292.2	271.6
Discontinued Operations	–	–	300.9	242.5	252.4
Shareholders' Equity	602.8	630.5	1,460.2	1,232.4	1,143.8
	$1,398.8	$1,431.4	$3,101.3	$3,147.2	$3,282.5
Income Statement					
Operating Revenue					
Regulated Utility	$575.6	$555.0	$510.0	$497.9	$535.0
Nonregulated Energy Operations	113.9	106.8	106.6	84.7	50.4
Real Estate	47.5	41.9	42.6	33.6	61.1
Other	0.4	0.4	0.4	0.3	0.4
	737.4	704.1	659.6	616.5	646.9
Operating Expenses					
Fuel and Purchased Power	273.1	286.2	252.5	234.8	230.7
Operating and Maintenance	293.5	270.1	260.5	254.4	257.3
Kendall County Charge	77.9	–	–	–	–
Depreciation	47.8	46.9	48.9	47.0	45.2
Total Operating Expenses	692.3	603.2	561.9	536.2	533.2
Operating Income from Continuing Operations	45.1	100.9	97.7	80.3	113.7
Other Income (Expense)					
Interest Expense	(26.4)	(31.7)	(50.5)	(49.3)	(47.7)
Other	1.1	(12.2)	2.3	6.9	16.6
Total Other Expense	(25.3)	(43.9)	(48.2)	(42.4)	(31.1)
Income from Continuing Operations Before Minority Interest and Income Taxes	19.8	57.0	49.5	37.9	82.6
Minority Interest	2.7	2.1	2.6	1.0	1.2
Income from Continuing Operations Before Income Taxes	17.1	54.9	46.9	36.9	81.4
Income Tax Expense (Benefit)	(0.5)	16.4	17.7	12.3	28.7
Income from Continuing Operations Before Change in Accounting Principle	17.6	38.5	29.2	24.6	52.7
Income (Loss) from Discontinued Operations – Net of Tax	(4.3)	73.7	207.2	112.6	86.0
Change in Accounting Principle – Net of Tax	–	(7.8)	–	–	–
Net Income	13.3	104.4	236.4	137.2	138.7
Common Stock Dividends	34.4	79.7	93.2	89.2	81.8
Earnings Retained in (Distributed from) Business	$ (21.1)	$ 24.7	$143.2	$ 48.0	$ 56.9

	2005	2004	2003	2002	2001
Shares Outstanding – Millions					
Year-End	30.1	29.7	29.1	28.5	28.0
Average *(a)*					
Basic	27.3	28.3	27.6	27.0	25.3
Diluted	27.4	28.4	27.8	27.2	25.5
Diluted Earnings (Loss) Per Share					
Continuing Operations	$0.64 *(b,c)*	$1.35 *(d)*	$1.05	$0.91 *(f)*	$2.07 *(g)*
Discontinued Operations	(0.16)	2.59	7.47 *(e)*	4.13	3.37
Change in Accounting Principle	–	(0.27)	–	–	–
	$0.48	$3.67	$8.52	$5.04	$5.44
Return on Common Equity	2.2% *(b,c)*	8.3%	17.7%	11.4%	13.3%
Common Equity Ratio	60.7%	61.7%	64.4%	51.7%	49.9%
Dividends Paid Per Share	$1.2450	$2.8425	$3.3900	$3.3000	$3.2100
Dividend Payout	259% *(b,c)*	77%	40%	66%	59%
Book Value Per Share at Year-End	$20.03	$21.23	$50.18	$43.24	$40.85
Employees at Year-End	1,459	1,515	13,115	14,181	13,763
Income (Loss) *(h)*					
Regulated Utility	$ 45.7	$ 37.7	$ 32.4	$ 46.0	$ 45.3
Nonregulated Energy Operations	(48.5) *(b)*	(2.9)	1.1	(11.3) *(f)*	(0.6)
Real Estate	17.5	14.3	13.6	10.8	20.4 *(g)*
Other	2.9 *(c)*	(10.6) *(d)*	(17.9)	(20.9)	(12.4)
Continuing Operations	17.6	38.5	29.2	24.6	52.7
Discontinued Operations	(4.3)	73.7	207.2 *(e)*	112.6	86.0
Change in Accounting Principle	–	(7.8)	–	–	–
Net Income	$ 13.3	$104.4	$236.4	$137.2	$138.7
Average Electric Customers – Thousands	151.8	150.1	148.2	146.8	145.7
Electric Sales – Millions of MWh					
Regulated Utility	11.7	11.2	11.1	11.1	10.9
Nonregulated Energy Operations	1.5	1.5	1.5	1.2	0.2
Company Use and Losses	0.5	0.9	0.7	0.7	0.7
	13.7	13.6	13.3	13.0	11.8
Power Supply – Millions of MWh					
Regulated Utility					
Steam Generation	7.2	6.5	7.1	7.2	6.9
Hydro Generation	0.5	0.5	0.4	0.5	0.5
Long-Term Purchases – Square Butte	2.3	2.0	2.3	2.3	1.9
Purchased Power	2.1	3.0	1.9	1.8	2.3
	12.1	12.0	11.7	11.8	11.6
Nonregulated Energy Operations					
Steam	1.3	1.2	1.2	0.8	–
Hydro	0.1	0.1	0.1	0.1	0.2
Purchased Power	0.2	0.3	0.3	0.3	–
	1.6	1.6	1.6	1.2	0.2
	13.7	13.6	13.3	13.0	11.8
Coal Sold – Millions of Tons	4.5	4.2	4.3	4.6	4.1
Real Estate Sales					
Town Center – Commercial Square Feet	643,000	–	–	–	–
Equivalent Acres	*70*	–	–	–	–
Other Land – Acres	1,102	1,479	1,394	641	N/A
Lots	7	211	265	1,425	N/A
Capital Expenditures – Millions					
Continuing Operations	$58.6	$57.8	$ 68.7	$ 81.7	$ 51.0
Discontinued Operations	4.5	21.4	67.6	119.5	98.2
	$63.1	$79.2	$136.3	$201.2	$149.2

(a) Excludes unallocated ESOP shares.

(b) Impacted by a $50.4 million, or $1.84 per share, charge related to the assignment of the Kendall County power purchase agreement.

(c) Impacted by a $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive tax planning initiatives and a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.

(d) Included a $10.9 million, or $0.38 per share, after-tax debt prepayment cost incurred as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services and an $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to the Company's ESOP.

(e) Included a $71.6 million, or $2.59 per share, gain on the sale of the Water Services businesses.

(f) Included a $5.5 million, or $0.20 per share, charge related to the indefinite delay of a generation project in Superior, Wisconsin.

(g) Included an $11.1 million, or $0.45 per share, gain on the sale of the Company's largest single real estate transaction ever.

(h) In 2005, we began allocating corporate charges and interest expense to our business segments. For comparative purposes, segment information for prior periods has been restated to reflect the new allocation method.

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 3 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 below are realized.

Executive Summary

In 2005, **ALLETE's** operations were comprised of four business segments. **Regulated Utility** includes retail and wholesale rate-regulated electric, water and gas services in northeastern Minnesota and northwestern Wisconsin under the jurisdiction of state and federal regulatory authorities. **Nonregulated Energy Operations** includes our coal mining activities in North Dakota and nonregulated generation (non-rate base generation sold at market-based rates to the wholesale market) primarily from Taconite Harbor in northern Minnesota. Nonregulated Energy Operations also included generation secured through the Kendall County power purchase agreement, which was assigned to Constellation Energy Commodities in April 2005. **Real Estate** includes our Florida real estate operations. **Other** includes our investments in emerging technologies, and earnings on cash, cash equivalents and short-term investments. **Discontinued Operations** includes our Automotive Services business, costs incurred by ALLETE associated with the spin-off of ADESA, our Water Services businesses and our telecommunications business.

In 2005, ALLETE was successful both financially and operationally with our utility power sales higher across all customer classes and robust Florida real estate sales. We also achieved a number of milestones and accomplished important strategic objectives, which included:

- Assigning the Kendall County power purchase agreement to Constellation Energy Commodities, which eliminated projected after-tax operating losses of approximately $8 million per year;
- Entering into an agreement to invest $60 million in ATC by the end of 2006, which is expected to be a significant and consistent earnings contributor in our energy business;
- Extending electric contracts with five of our Minnesota Power customers in the taconite processing, and paper and pulp industries for an additional four to eight years;
- Announcing a $60 million plan to reduce air emissions at two generating stations while requesting current cost recovery;
- Entering an agreement to purchase renewable energy from a new wind facility to be built in North Dakota and continuing to pursue the purchase of renewable energy from a new wind facility being planned for northern Minnesota;
- Recording our first real estate sales at the Town Center development project, signing our first sales contract for the Palm Coast Park development, and beginning the Development of Regional Impact process for Ormond Crossings, our third major real estate development;
- Completing the exit from our Water Services businesses by selling our wastewater assets in Georgia; and
- Selling our telecommunications business, Enventis Telecom, a transaction that provided approximately $29 million in cash.

Executive Summary (Continued)

Millions Except Per Share Amounts	2005	2004	2003
Operating Revenue			
Regulated Utility	$575.6	$555.0	$510.0
Nonregulated Energy Operations	113.9	106.8	106.6
Real Estate	47.5	41.9	42.6
Other	0.4	0.4	0.4
	$737.4	$704.1	$659.6
Operating Expenses			
Regulated Utility	$486.0	$476.3	$439.1
Nonregulated Energy Operations	186.6 *(a)*	108.6	102.2
Real Estate	15.6	15.1	16.4
Other	4.1	3.2	4.2
	$692.3	$603.2	$561.9
Interest Expense			
Regulated Utility	$17.4	$18.5	$20.4
Nonregulated Energy Operations	6.6	4.9	4.8
Real Estate	0.1	0.3	0.2
Other	2.3	8.0	25.1
	$26.4	$31.7	$50.5
Other Income (Expense)			
Regulated Utility	$0.7	$ 0.1	$ 2.9
Nonregulated Energy Operations	1.7	0.6	1.9
Other	(1.3)	(12.9) *(c)*	(2.5)
	$1.1	$(12.2)	$ 2.3
Income (Loss)			
Regulated Utility	$45.7	$ 37.7	$ 32.4
Nonregulated Energy Operations	(48.5) *(a)*	(2.9)	1.1
Real Estate	17.5	14.3	13.6
Other	2.9 *(b)*	(10.6) *(c)*	(17.9)
Continuing Operations	17.6	38.5	29.2
Discontinued Operations	(4.3)	73.7	207.2
Change in Accounting Principle	–	(7.8)	–
Net Income	$ 13.3	$104.4	$236.4
Diluted Average Shares of Common Stock	27.4	28.4	27.8
Diluted Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$0.64 *(a,b)*	$1.35 *(c)*	$1.05
Discontinued Operations	(0.16)	2.59	7.47
Change in Accounting Principle	–	(0.27)	–
	$0.48	$3.67	$8.52
Return on Common Equity	2.2% *(a,b)*	8.3%	17.7%

(a) Impacted by a $77.9 million ($50.4 million after tax, or $1.84 per share) charge related to the assignment of the Kendall County power purchase agreement in April 2005. (See Note 11.)

(b) Impacted by a $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive tax planning initiatives and a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.

(c) Included an $18.5 million ($10.9 million after tax, or $0.38 per share) debt prepayment cost incurred as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services and an $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to our ESOP.

In 2005, we began allocating corporate charges and interest expense to our business segments. For comparative purposes, segment information for 2004 and 2003 has been restated to reflect the new allocation method used in 2005 for corporate charges and interest expense. This restatement had no impact on consolidated net income or earnings per share.

Executive Summary (Continued)

Reported net income in total for 2005 was $13.3 million, or $0.48 per diluted share ($104.4 million, or $3.67 per diluted share for 2004; $236.4 million, or $8.52 per diluted share for 2003). In 2005, a $50.4 million, or $1.84 per diluted share, charge to assign our Kendall County power purchase agreement to Constellation Energy Commodities (see Note 11) reduced net income, as did the absence of operations from our Automotive Services business spun off in September 2004 and the exit from our Water Services businesses, the majority of which were sold in 2003. Automotive Services contributed $74.4 million to income in 2004 ($113.6 million in 2003). Net income in 2003 included a $71.6 million net gain on the sale of substantially all of our Water Services assets. A $7.8 million non-cash after-tax charge for a change in accounting principle related to investments in our emerging technology portfolio also impacted 2004 net income. (See Note 15.)

Net income in 2005 reflected continued strong electric sales, higher Florida real estate sales, increased earnings on excess cash, the benefits of lower interest expense due to reduced debt balances, expense reductions following the spin-off of Automotive Services and exit from the Water Services businesses in 2004, tax savings due to comprehensive tax planning initiatives implemented in 2005, and positive resolution of income tax audit issues.

Earnings per share for 2005 were favorably impacted by ALLETE common stock purchased pursuant to the Company's Retirement Savings and Stock Ownership Plan. (See Note 18.)

Financial results for continuing operations for the periods discussed in this Form 10-K were significantly impacted by the following five transactions not representative of ongoing operations:

- **Kendall County Charge.** In 2005, we incurred a $77.9 million ($50.4 million after tax, or $1.84 per share) charge due to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities (Kendall County Charge).
- **Positive Resolution of Tax Audit Issues.** In 2005, we recognized a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.
- **Tax Planning Initiatives.** In 2005, we implemented comprehensive tax planning initiatives, which resulted in current and ongoing tax savings, and a deferred tax benefit of $2.5 million, or $0.09 per share.
- **Debt Prepayment Cost.** In 2004, we incurred an $18.5 million ($10.9 million after tax, or $0.38 per share) debt prepayment cost as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services.
- **Gain on Sale of ADESA Shares.** In 2004, we recognized an $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to our ESOP. (See Note 18.)

Reported income from continuing operations before the change in accounting principle was $17.6 million, or $0.64 per diluted share, for 2005, a decrease of $20.9 million, or $0.71 per diluted share from 2004. The decrease was attributed to the $50.4 million, or $1.84 per diluted share, Kendall County Charge. A 4% increase in total electric sales, higher Florida real estate land sales, a $1.9 million increase in earnings on excess cash, a $3.1 million decrease in interest expense and expense reductions following the spin-off of Automotive Services and exit from our Water Services businesses in 2004 partially offset the negative impact of the Kendall County Charge. In addition, comprehensive tax planning initiatives implemented in 2005 resulted in current and ongoing tax savings, and a deferred tax benefit equaling $2.5 million, or $0.09 per share. We also recognized $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.

	2005	2004	2003
Millions			
Kilowatthours Sold			
Regulated Utility			
Retail and Municipals			
Residential	1,102	1,053	1,065
Commercial	1,327	1,282	1,286
Industrial	7,130	7,071	6,558
Municipals	877	823	842
Other	79	79	79
	10,515	10,308	9,830
Other Power Suppliers	1,142	918	1,314
	11,657	11,226	11,144
Nonregulated Energy Operations	1,521	1,496	1,462
	13,178	12,722	12,606

Executive Summary (Continued)

Real Estate Revenue and Sales Activity	2005 Qty	2005 Amount	2004 Qty	2004 Amount	2003 Qty	2003 Amount
Dollars in Millions						
Revenue from Land Sales						
Town Center Sales						
Commercial Sq. Ft.	643,000 *(a)*	$15.2	–	–	–	–
Other Land Sales						
Acres	1,102	38.1	1,479	$32.8	1,394	$32.0
Lots	7	0.4	211	4.5	265	4.0
Contract Sales Price *(b)*		53.7		37.3		36.0
Deferred Revenue		(10.0)		(1.5)		–
Adjustments *(c)*		(1.7)		–		–
Revenue from Land Sales		42.0		35.8		36.0
Other Revenue		5.5		6.1		6.6
		$47.5		$41.9		$42.6

(a) For the year ended December 31, 2005, 70 acres were sold.
(b) Reflected total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method. (See Critical Accounting Policies and Note 2.)
(c) Contributed development dollars, which are credited to cost of real estate sold.

Net Income

Regulated Utility contributed income of $45.7 million in 2005 ($37.7 million in 2004; $32.4 million in 2003). Income was higher in 2005 due to a 4% increase in overall regulated utility kilowatthour electric sales. Healthier economic conditions in Minnesota Power's service territory combined with warmer weather in the summer of 2005 contributed to the increase in kilowatthour sales. Higher pension expense ($1.0 million) and an increase in maintenance expense ($2.0 million) were partially offset by the absence of Split Rock Energy expenses ($1.2 million), and lower interest expense ($0.6 million).

Overall, regulated utility kilowatthour electric sales in 2004 were similar to 2003. Sales to retail and municipal customers were up 5% from 2003, which reduced the energy available for sale to other power suppliers in 2004. The increase in retail and municipal sales was due to an 8% increase in sales to industrial customers as a result of our industrial customers operating at high production levels, with taconite and paper production at or near capacity.

In 2003, Regulated Utility income also included $1.7 million of equity income from Split Rock Energy, a joint venture which we terminated in March 2004. Equity income from Split Rock Energy in 2003 included a $2.3 million charge to exit the joint venture.

Nonregulated Energy Operations reported a $48.5 million loss in 2005 (loss of $2.9 million in 2004; income of $1.1 million in 2003), reflecting the $50.4 million charge to assign the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. The absence of operating losses from Kendall County favorably impacted 2005 financial results. Kendall County operating losses were $1.9 million in 2005 ($8.5 million in 2004; $8.2 million in 2003). In 2004, the Kendall County operating loss included a $0.7 million cost to terminate a transmission contract.

Income from Taconite Harbor was lower in 2005 than 2004, reflecting increased demand revenue offset by higher operating expenses. Demand revenue was higher primarily as a result of two new 5-year contracts. Contract services were up $0.6 million from 2004 as a result of a longer than anticipated scheduled outage as well as unscheduled outages in 2005. SO_2 emission allowances expense was up $1.3 million from 2004. Depreciation expense was up $0.7 million as a result of capitalized projects being completed and placed into operation. Income at Taconite Harbor was lower in 2004 than 2003, primarily due to a $0.8 million increase in costs associated with a scheduled maintenance outage in 2004 and a $0.5 million increase in costs for SO_2 emission allowances. In addition, wholesale power prices were lower in 2004 compared to 2003.

In 2005, income from our coal operations was up $1.3 million from 2004, primarily due to a 7% increase in tons of coal sold. In 2004, coal sales were lower than 2003 due to an outage at the Square Butte generating facility, BNI Coal's primary customer.

Net Income (Continued)

Real Estate contributed income of $17.5 million in 2005 ($14.3 million in 2004; $13.6 million in 2003), reflecting continued strong demand for real estate in Florida. In 2005, we also began selling property from our Town Center development project in northeast Florida. Since land is being sold before completion of the project infrastructure, revenue and cost of real estate sold are recorded using a percentage-of-completion method. (See Note 2.) As of December 31, 2005, we had $8.6 million of deferred profit on sales of real estate, before taxes and minority interest, on our balance sheet. We expect most of this deferred profit will be reflected in income during the next 12 months. The timing of the closing of real estate sales varies from period to period and impacts comparisons between years.

At December 31, 2005, total pending land sales under contract were $94.9 million and are anticipated to close at various times through 2012. Pricing on these contracts range from $20 to $50 per commercial square foot, $15,000 to $40,000 per residential unit and $1,000 to $524,000 per acre for all other properties. Prices per acre are stated on a gross acreage basis and are dependent on the type and location of the properties sold. The majority of the other properties under contract are zoned commercial or mixed use. In addition to minimum base price contracts, certain contracts allow us to receive participation revenue to the extent that an agreed upon percentage of gross revenue from land sales by our purchaser exceeds the minimum base price.

Real Estate Pending Contracts At December 31, 2005	Quantity	Contract Sales Price
Dollars in Millions		
Town Center		
Commercial Sq. Ft.	1,321,200	$38.2
Residential Units	1,212	25.5
Palm Coast Park		
Residential Units	500	7.5
Other Land		
Acres	1,116	23.7
		$94.9

Other reflected income of $2.9 million in 2005 ($10.6 million loss in 2004; $17.9 million loss in 2003). Improved financial results reflected a $3.7 million current tax benefit due to the positive resolution of income tax audit issues, a $2.5 million deferred tax benefit recorded in 2005 due to comprehensive tax planning initiatives, the decline in interest expense as a result of lower debt balances and increased earnings on excess cash. Interest expense was $1.3 million in 2005 ($4.7 million in 2004; $14.7 million in 2003). Earnings on excess cash were $3.2 million in 2005 ($1.3 million in 2004; $0.9 million in 2003). Cash was higher in 2005 and 2004 than in 2003 due to proceeds received from the sale of our Water Services businesses in 2004 and 2003, proceeds received from ADESA in 2004 and proceeds received from the sale of Enventis Telecom in 2005.

Financial results related to our emerging technology investments were better in 2005. Equity losses related to investments in venture capital funds declined in 2005 ($0 in 2005; $1.6 million in 2004). Impairments related to our emerging technology investment were also lower in 2005 ($3.3 million in 2005; $4.1 million in 2004). In 2003, we reported $2.3 million of net losses on the sale of shares we held directly in publicly-traded, emerging technology investments.

Financial results for 2004 also included an $11.5 million gain on the sale of ADESA stock related to our ESOP (see Note 18), which was partially offset by a $10.9 million debt prepayment cost associated with the retirement of long-term debt as a part of our financial restructuring in preparation for the spin-off of ADESA.

Discontinued Operations includes our Automotive Services business that was spun off on September 20, 2004, costs incurred by ALLETE associated with the spin-off of ADESA, our Water Services businesses, the majority of which were sold in 2003, and our telecommunications business, which we sold in December 2005.

Earnings from discontinued operations were lower in 2005, primarily due to the absence of operations from Automotive Services. Automotive Services contributed income of $74.4 million in 2004 ($113.6 million in 2003). Income in 2004 was down $39.2 million from 2003, reflecting a 6.6% reduction in our ownership of ADESA since the June 2004 IPO and the absence of ADESA operations following the spin-off. Income in 2004 was also down due to debt prepayment costs related to the early redemption of ADESA debt in August 2004, ALLETE's costs associated with the business separation, and additional corporate charges and separation expenses incurred by ADESA as it prepared to be a stand-alone, publicly-traded company. In addition, 2004 income included $4.1 million of charges in connection with a lawsuit related to ADESA's vehicle import business. Income in 2003 reflected strong vehicle sales, fee increases, the introduction and expansion of service offerings, lower interest expense due to lower debt balances at the time, gains on sale of property and strong receivable portfolio management at the floorplan financing business. Income in 2003 also included a $1.3 million recovery from the settlement of a lawsuit associated with ADESA's vehicle transport business.

Net Income (Continued)

Water Services financial results reflected a $2.5 million loss in 2005 (loss of $1.3 million in 2004; income of $93.0 million in 2003). In 2005, administrative and other expenses were incurred to support Florida Water transfer proceedings. A $1.0 million rate-base settlement charge related to the sale of 63 of Florida Water systems to Aqua Utilities was also recorded in 2005. A $71.6 million after-tax gain was recognized on the sale of these systems in 2003, net of all selling, transaction and employee termination benefit expenses, as well as impairments on certain remaining assets at the time. Gains in 2004 from the sale of our North Carolina assets and the remaining systems in Florida were offset by an adjustment to gains reported in 2003, resulting in an overall net loss of $0.5 million in 2004. The adjustment to gains reported in 2003 resulted primarily from an arbitration award in December 2004 relating to a gain-sharing provision on a system sold in 2003. Financial results for Water Services were also lower in 2004 and 2005 due to the absence of operations from water and wastewater systems sold. The majority of our Florida systems were sold in the fourth quarter of 2003. North Carolina assets were sold in June 2004. Our wastewater assets in Georgia were sold in February 2005.

Financial results for our telecommunications business reflected a loss of $1.8 million in 2005 (income of $0.6 million in each of the years 2004 and 2003). In 2005, we recorded a $3.6 million loss on the sale of this business to HickoryTech. In 2005, income from operations was $1.2 million higher than 2004 primarily due to increased margins on telecommunication services.

Change in Accounting Principle reflected the cumulative effect on prior years (to December 31, 2003) of changing to the equity method of accounting for investments in limited liability companies included in our emerging technology portfolio. (See Note 15.)

2005 Compared to 2004

Regulated Utility

Operating revenue was up $20.6 million, or 4%, from 2004. Revenue from other power suppliers was up $15.4 million from 2004 due to a 24% increase in kilowatthour sales and higher market prices. In 2005, changes in scheduled plant outages resulted in more energy available for sale than in 2004. Transmission revenue was up $4.2 million from 2004, reflecting increased MISO-related revenue. In 2005, the Company recovered $12.1 million of other MISO expenses, subject to refund with interest, through the fuel clause. (See Outlook.) Revenue from sales to retail and municipal customers was down $2.4 million, primarily due to lower fuel clause recoveries in 2005. (See operating expenses below.) Kilowatthour sales to retail and municipal customers remained strong—up 2% from 2004, reflecting increased usage. Residential and municipal customer usage was higher in 2005 due to higher than normal summer temperatures in 2005. Commercial usage was higher due to stronger economic conditions in our electric service territory in 2005. Sales to industrial customers were similar to last year because, as in 2004, the Company's industrial customers were operating at high production levels, with taconite and paper production at or near capacity. Overall, regulated utility kilowatthour sales were up 4% from 2004. Revenue from gas sales was up $2.5 million due to increased prices in the natural gas component of sales.

Operating expenses were up $9.7 million, or 2%, from 2004. Fuel and purchased power expense was down $1.4 million from 2004 due to fewer outages. In 2004, increased purchased power was necessitated by outages at Company generating facilities and the Square Butte generating facility. Maintenance expense was up $3.4 million from 2004, reflecting planned maintenance performed at Boswell Units 1, 2 and 3 during 2005, partially offset by lower maintenance expense related to Boswell Unit 4 and Laskin Unit 1. In 2004, maintenance expense increased due to maintenance scheduled for 2005 and 2006 that was performed while Boswell Unit 4 was down as a result of a generator failure. Other operating expenses were $7.7 million higher in 2005—MISO transmission costs increased $4.1 million, gas purchases increased $2.6 million due to higher prices and pension expense increased $1.7 million due to a change in the discount rate (5.50% in 2005; 5.75% in 2004). These increases were partially offset by the absence of $2.0 million of expenses related to Split Rock Energy, which we exited in March 2004.

Interest expense was down $1.1 million from 2004, primarily due to lower effective interest rates (6.07% in 2005; 6.67% in 2004).

2005 Compared to 2004 (Continued)

Nonregulated Energy Operations

Operating revenue was up $7.1 million, or 7%, from 2004. Revenue from Taconite Harbor increased $14.0 million from 2004, primarily due to higher demand as a result of two 5-year contracts (175 MW in total) that began in May 2005. Coal revenue, realized under a cost-plus contract, was up $5.0 million from 2004, reflecting a 7% increase in tons of coal sold and an 8% increase in the delivery price per ton due to higher coal production expenses. (See operating expenses below.) BNI Coal sold fewer tons of coal in 2004 due to a scheduled outage at the Square Butte generating facility. Revenue from Kendall County was down $13.4 million from 2004, reflecting the absence of operations since April 2005 when the Kendall County power purchase agreement was assigned to Constellation Energy Commodities. Overall, nonregulated kilowatthour sales were up 2% from 2004.

Operating expenses were up $78.0 million from 2004, primarily due to the $77.9 million charge related to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. Nonregulated generation fuel and purchased power expense was down $11.7 million from 2004, reflecting the absence of Kendall County operations. Operating and maintenance expenses at Taconite Harbor were higher in 2005, reflecting a $2.3 million increase in SO_2 emission allowance expense, a $1.0 million increase in contract services due to a longer than anticipated scheduled outage as well as unscheduled outages, and a $1.2 million increase in depreciation expense as a result of capitalized projects being completed and placed into operation. Expenses related to our coal operations were up $3.9 million, in part due to higher expenses associated with equipment repairs, increased fuel costs and a $2.1 million increase in lease expense related to the dragline.

Interest expense was up $1.7 million from 2004, reflecting higher allocations in 2005.

Other income (expense) reflected $1.1 million more income in 2005. Income from customer contract services was up $0.4 million from 2004. Income from Minnesota land sales was up $0.7 million from 2004, primarily due to an adjustment recorded as a result of an MPUC land reevaluation.

Real Estate

Operating revenue was up $5.6 million, or 13%, from 2004, reflecting strong land sales offset by the deferral of revenue associated with certain real estate sales. Revenue from land sales was $42.0 million in 2005 ($35.8 million in 2004). Town Center land sales accounted for $4.5 million of land sale revenue in 2005. In 2005, revenue of $10.0 million, primarily related to Town Center land sales, was deferred until development obligations are completed ($1.5 million in 2004). Revenue from lot sales was lower in 2005 because in January 2004 we sold the remaining 184 lots at Sugarmill Woods for $3.9 million, essentially exiting the lot sales business. In 2005, 1,172 acres and 7 lots were sold, of which 70 acres were located in Town Center. Town Center sales included assignments of rights to build up to 643,000 square feet of commercial space. In 2004, 1,479 acres and 211 lots were sold. Revenue from our brokerage business, Cape Properties, Inc., was down $0.7 million, reflecting unusually strong sales in 2004.

Operating expenses were up $0.5 million, or 3%, from 2004. Cost of real estate sold was $2.1 million higher in 2005 ($8.6 million in 2005; $6.5 million in 2004) due to the type and location of real estate sold. In 2005, cost of real estate sold totaling $2.2 million ($0.4 million in 2004) and selling expense of $0.3 million, primarily related to Town Center land sales, were deferred until development obligations are completed. Expenses for our brokerage business were down $0.2 million due to unusually strong sales in 2004. Selling expenses were down $1.1 million from 2004 due to lower transaction costs and fewer brokerage commissions on 2005 sales. Property taxes were down $0.3 million from 2004, reflecting a reduction in land owned.

Other

Operating expenses were up $0.9 million, or 28%, from 2004, primarily due to increased compensation.

Interest expense was down $5.7 million from 2004, primarily due to lower debt balances. The Company repaid a $53 million balance on a credit agreement in April 2004 and $125 million of 7.80% Senior Notes in July 2004. A combination of internally-generated funds, proceeds from the sale of our Water Services assets and proceeds received from ADESA were used to repay the debt.

Other income (expense) reflected $11.6 million less expense in 2005. Other income (expense) in 2005 reflected a $3.2 million increase in earnings on excess cash, a $1.2 million decrease in equity losses from our emerging technology investments and a $1.0 million charge to recognize the probable payment under our guarantee of Northwest Airlines debt. We also recorded $5.1 million of impairments related to our emerging technology investments in 2005 ($6.5 million in 2004). In 2004, other income (expense) included an $18.5 million debt prepayment cost related to the early redemption of $125 million in senior notes, an $11.5 million gain on the sale of ADESA shares held in our ESOP (see Note 18), and $0.9 million of income from a rabbi trust, established to secure certain deferred executive compensation.

2005 Compared to 2004 (Continued)

Income Taxes. The effective tax rate from continuing operations before minority interest was a 2.5% benefit in 2005 (28.8% expense in 2004). Income taxes in 2005 were affected by three major items, the adjustment of our deferred taxes from comprehensive tax planning initiatives, a current tax benefit from the positive resolution of audit issues and the inability to use state capital loss carryforwards. The adjustment of our deferred tax assets and liabilities resulted in a deferred tax benefit of $2.5 million. We received an audit report resolving open issues that resulted in a current tax benefit of $3.7 million. These items decreased our overall tax expense. The emerging technology investment impairments recorded in March 2005 and the Kendall County Charge recorded in April 2005 created capital losses. The current benefit for these items was limited to a federal benefit for income tax purposes. The state tax benefit from these items is not expected to be realized currently or in future periods. The benefit related to these state net capital loss carryforwards was fully offset by a valuation allowance. This resulted in an increase in our overall tax expense. Current taxes also increased in 2005 due to the expiration of the accelerated depreciation deduction allowed by the Jobs and Growth Tax Relief Act of 2003, which expired December 31, 2004. An increase in the Federal Medicare subsidy and the new Domestic Manufacturing Deduction contributed to lower taxes in 2005. Income taxes for 2004 were primarily affected as a result of the benefit of the nontaxable gain from the sale of ADESA common stock in our ESOP. (See Note 13.)

2004 Compared to 2003

Regulated Utility

Operating revenue was up $45.0 million, or 9%, in 2004, primarily due to higher fuel clause recoveries resulting from increased purchased power costs (see operating expenses below) and increased retail sales. Overall, regulated utility kilowatthour sales were similar to 2003 (up 1%) as a 5% increase in sales to retail and municipal customers reduced the energy available for sale to other power suppliers. Much of the increase in retail and municipal electric sales was attributable to large industrial customers due to their higher production levels in 2004. Outages at Company generating facilities and a scheduled maintenance outage at the Square Butte generating facility (see operating expenses below) also contributed to less energy being available for sale to other power suppliers.

Operating expenses in total were up $37.2 million, or 8%, in 2004, primarily due to a $32.6 million increase in fuel and purchased power expense. Increased purchased power was necessitated by outages at Company generating facilities and the Square Butte generating facility. In February 2004, we experienced a generator failure at our 534-MW Boswell Unit 4. Unit 4 came back into service in June 2004. As a result of the failure, we replaced significant components of the generator at a capital cost of approximately $6 million. The majority of the replacement cost was covered by insurance, subject to a deductible of $1 million. We entered into power purchase agreements to replace the power lost during the Unit 4 outage. The cost of this additional power was recovered through the regulated utility fuel clause in Minnesota. While Unit 4 was down, some work originally planned for 2005 and 2006 was done during the outage to minimize future outages. This outage did not have a material impact on our results of operations. Two multi-week scheduled maintenance outages also took place at our 55-MW Laskin Unit 1 and at the Square Butte generating facility. Maintenance expense was $3.2 million higher in 2004, primarily due to the outages at our generating facilities. Our pro rata share of the Square Butte maintenance outage costs was approximately $5 million. In addition, 2004 reflected a $4.4 million increase in pension expense, $1.7 million of MISO related expenses, a $2.6 million decrease in Split Rock Energy expenses as a result of our exiting the joint venture in March 2004 and a $1.7 million decrease in depreciation expense. In 2004, the MPUC approved longer depreciable lives for certain Company generating assets.

Interest expense was down $1.9 million from 2003 due to lower debt balances and lower effective interest rates (6.67% in 2004; 6.88% in 2003).

Other income (expense) reflected $2.8 million less income in 2004, primarily due to the absence of equity in net income from Split Rock Energy. Minnesota Power withdrew from Split Rock Energy trading activities, effective November 1, 2003, and terminated the joint venture in March 2004.

Nonregulated Energy Operations

Operating revenue in 2004 was similar to 2003 as a 2% increase in kilowatthour sales was mostly offset by lower wholesale prices. Kilowatthour sales were up 8% at Taconite Harbor despite a fourth quarter 2004 scheduled maintenance outage, while kilowatthour sales at Kendall County were down 26% from 2003.

Operating expenses were up $6.4 million, or 6%, in 2004 due to a $1.1 million increase in fuel and purchased power expense, $1.3 million of costs associated with a scheduled maintenance outage at Taconite Harbor, a $1.2 million transmission contract termination charge to exit a Kendall County agreement and a $0.9 million increase in costs for SO_2 emission allowances. Expenses in 2003 reflected a $0.9 million reduction in costs accrued in 2002 related to the indefinite delay of a generation project in Superior, Wisconsin.

Other income (expense) reflected $1.3 million of less income in 2004. The decrease was attributable to a reduction in gains on prior Minnesota land sales due to an MPUC required land reevaluation.

2004 Compared to 2003 (Continued)

Real Estate

Operating revenue was down $0.7 million, or 2%, in 2004. Revenue from land sales in 2004 was similar to 2003, reflecting a strong southwest Florida real estate market that began in the fall of 2003 and continued into 2004. In 2004, we sold 1,479 acres and 211 lots for $35.8 million (1,394 acres and 265 lots for $36.0 million in 2003). In 2004, land sales revenue of $1.5 million was deferred until development obligations are completed. At December 31, 2004, total land sales under contract were $71 million, of which $30 million were for properties in the Town Center development project at Palm Coast. Revenue in 2003 also included a $1.1 million recovery of a partially reserved receivable.

Operating expenses were down $1.3 million, or 8%, in 2004 because the cost of property sold in 2004 was lower than in 2003. Cost of real estate sold in 2004 was $6.5 million ($7.9 million in 2003). In 2004, cost of real estate sold totaling $0.4 million was deferred until development obligations are completed.

Other

Operating expenses were down $1.0 million, or 24%, in 2004, reflecting a reduction in expenses following the spin-off of Automotive Services and exit from the Water Services businesses in 2003.

Interest expense was down $17.1 million from 2003, primarily due to lower debt balances. We repaid $25 million of 6 1/4% First Mortgage Bonds in July 2003; $50 million of 7 3/4% First Mortgage Bonds in November 2003; $75 million of mandatorily redeemable preferred securities in December 2003; $3.5 million of Industrial Development Revenue Bonds in January 2004; and $125 million of 7.80% Senior Notes in July 2004. In addition, $111 million of Pollution Control Refunding Revenue Bonds were refinanced at a lower rate in August 2004 and a $250 million credit agreement entered into in July 2003 was paid off early ($197 million in 2003; $53 million in April 2004). A combination of internally-generated funds, proceeds from the sale of our Water Services assets and proceeds received from ADESA were used to repay the debt.

Other income (expense) reflected $10.4 million of additional expense in 2004, primarily due to an $18.5 million debt prepayment cost related to the early redemption of $125 million in senior notes in 2004 and $6.5 million of impairments recorded related to our emerging technology investments. In addition, $1.7 million of equity losses on emerging technology funds were recognized in 2004. These decreases were partially offset by an $11.5 million gain on the sale of ADESA shares held in our ESOP. (See Note 18.) In 2003, we recognized $3.5 million of losses related to the sale of shares we held directly in publicly-traded emerging technology investments.

Income Taxes. Income taxes for 2004 were primarily affected as a result of the benefit of the nontaxable gain from the sale of ADESA common stock in our ESOP. Income taxes for 2003 were slightly lower than the statutory rate due to the effects of investment tax credits.

Non-GAAP Financial Measures

We prepare financial statements in accordance with GAAP. Along with this information, we disclose and discuss certain non-GAAP financial information in our quarterly earnings releases, on investor conference calls and during investor conferences and related events. Management believes that non-GAAP financial data supplements our GAAP financial statements by providing investors with additional information which enhances the investors' overall understanding of our financial performance and the comparability of our operating results from period to period. The presentation of this additional information is not meant to be considered in isolation or as a substitute for our results of operations prepared and presented in accordance with GAAP.

As earlier mentioned, financial results for 2005 were significantly impacted by the following transactions:

- A $50.4 million after tax, or $1.84 per share, charge due to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities (see Note 11);
- A $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues; and
- A $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive tax planning initiatives.

In 2004, financial results were significantly impacted by the following transactions:

- A $10.9 million after tax, or $0.38 per share, debt prepayment cost as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services (see Note 12); and
- An $11.5 million after tax, or $0.41 per share, gain on the sale of ADESA shares related to our ESOP (see Note 18).

Non-GAAP Financial Measures (Continued)

Since these transactions significantly impacted the financial results from continuing operations in 2005 and 2004, we believe that for comparative purposes and a more accurate reflection of our ongoing operations, it is useful to present diluted earnings per share from continuing operations for each applicable period excluding the impact of these items. The table below reconciles actual reported diluted earnings per share from continuing operations before change in accounting principle to the adjusted results that exclude these transactions in the respective periods.

For the Year Ended December 31		2005	2004
Diluted Earnings Per Share of Common Stock			
Continuing Operations Before Change in Accounting Principle		$0.64	$1.35
Add:	Kendall County Charge	1.84	–
	Debt Prepayment Cost	–	0.38
Less:	Gain on Sale of ADESA Shares	–	0.41
	Positive Resolution of Tax Audit Issues	0.13	–
	Tax Planning Initiatives	0.09	–
		$2.26	$1.32

Critical Accounting Policies

Certain accounting measurements under applicable generally accepted accounting principles involve management's judgment about subjective factors and estimates, the effects of which are inherently uncertain. These policies are reviewed with the Audit Committee of our Board of Directors on a regular basis. The following summarizes those accounting measurements we believe are most critical to our reported results of operations and financial condition.

Real Estate Revenue and Expense Recognition. We account for sales of real estate in accordance with SFAS 66, "Accounting for Sales of Real Estate." Revenue from commercial, office, industrial and residential properties is recorded at the time of closing using the full profit recognition method, provided that cash collections are at least 20% of the contract price and the other requirements of SFAS 66 are met. However, if we are obligated to perform significant development activities subsequent to the date of the sale, we recognize revenue using the percentage-of-completion method. This method of accounting requires that we recognize gross profit based upon the relationship of development costs incurred to the total estimated costs to develop the parcels. During each reporting period, we must estimate the total costs to be incurred until project completion, including development overhead and interest capitalization costs. These total cost estimates will impact the recognition of profit on sales. The costs are allocated to each lot or parcel based on the relative sales value method. These estimates affect the amount of costs relieved as each lot is sold and incorrect estimates may result in a misstatement of the cost of real estate sold. Additionally, we must estimate the selling price of each individual lot or parcel that is included in inventory for inclusion in the inventory cost model. If the estimated selling prices of the lots are inaccurate, a material difference in the timing of recording cost of real estate sold for the lots sold could occur.

We record land held for sale at the lower of cost or fair value, which is determined by the evaluation of individual land parcels. 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. Based on the relative sales value of the parcels within each development project, we capitalize the real estate costs incurred to the cost of real estate parcels in accordance with SFAS 67, "Accounting for Costs and Initial Rental Operations of Real Estate Projects." When real estate is sold, we include the actual costs incurred and the estimate of future completion costs allocated to the parcel(s) sold, based upon the relative sales value method in the cost of real estate sold. We include land held for sale in Investments on our consolidated balance sheet. Traffic impact fee credits are provided to the developer as mitigation payments are made to the city. We are reimbursed after the land is sold and a subsequent property owner constructs vertical improvements on the site. We recognize revenue resulting from these reimbursed fees when they are received.

We annually review the real estate carrying value for impairment. If circumstances indicate that the carrying value may not be recoverable, we record the impairment and adjust the related assets to their estimated fair value less costs to sell.

Impairment of Long-Lived Assets. 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 using SFAS 144, "Accounting for the Impairment and 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 cash flows.

Critical Accounting Policies (Continued)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the provisions of SFAS 87, “Employers’ Accounting for Pensions,” and SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions.” These standards require the use of assumptions in determining the obligations and annual cost. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing this assumption, we consider the diversification and allocation of plan assets, the actual long-term historical performance for the type of securities invested in, the actual long-term historical performance of plan assets and the impact of current economic conditions, if any, on long-term historical returns. Our pension asset allocation is approximately 70% equity and 30% fixed-rate securities. Equity securities consist of a mix of market capitalization sizes and also include investments in real estate and venture capital. We currently use an expected long-term rate of return of 9% in our pension actuarial study. We annually review our expected long-term rate of return assumption and will adjust it to respond to any changing market conditions. A 1/2% decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1 million after tax; conversely, a 1/2% increase in the expected long-term rate of return would decrease the annual expense by approximately $1 million after tax. Currently for plan valuation purposes, we use a discount rate of 5.5%. The discount rate is determined considering high-quality long-term corporate bond rates at the valuation date. The discount rate is compared to various bond indices for reasonableness. We believe the bonds used in this comparison do not materially differ in duration and cash flows for our pension obligation. The Audit Committee of the Board of Directors annually reviews and approves the rate of return and discount rate used for pension valuation and accounting purposes. (See Note 17 for additional detail on our pension and postretirement health and life plans.)

Valuation of Investments. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investment in privately-held companies under the cost method because of our ownership percentage. These investments are included in Investments on our consolidated balance sheet. Our policy is to quarterly review these investments for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment and be recognized as a loss. In 2005, we recorded $5.1 million pretax of impairment losses on these investments ($6.5 million pretax in 2004; $0 in 2003).

Provision for Environmental Remediation. Our businesses are subject to regulation by various federal, state and local authorities concerning environmental matters. 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 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 expense. We do not currently anticipate that potential expenditures for environmental remediation and cleanup will be material; however, if we become subject to more stringent remediation at known sites, if we discover additional contamination or previously unknown sites, or if we become subject to related personal or property damage, we could incur material costs in connection with our environmental remediation.

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 use taxes. These judgments include reserves for potential adverse outcomes regarding tax positions that we have taken. We must also assess our ability to generate capital gains to realize tax benefits associated with capital losses expected to be generated in future periods. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the three prior or five succeeding years for federal purposes, and fifteen succeeding years for Minnesota. As of December 31, 2005, we have, where appropriate, recorded an allowance against our deferred tax assets associated with realized capital losses, and with impairment losses, which will become capital losses when realized for income tax purposes. While we believe the resulting tax reserve balances as of December 31, 2005, reflect the most likely outcome of these tax matters in accordance with SFAS 5, “Accounting for Contingencies” and SFAS 109, “Accounting for Income Taxes,” the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements and such adjustments could be material.

Outlook

Our vision is to forge a vibrant business that will sustain the confidence of investors, while maintaining the trust of communities we have energized for a century. We will pursue consistent growth in our energy and real estate businesses, and invest in other diverse business ventures that bring value to shareholders.

We believe our shareholders are best served by a company with sustainable earnings growth and cash flow that supports dividend and stock price growth. We believe our shareholders are best served by a business mix that mitigates economic cycles, and a company that maintains the respect and admiration of regulators and policy makers.

We value earning a return that rewards our shareholders, reinvests in our business and sustains our growth. In the last 10 years, our average annual total shareholder return was 16%. Approximately 5% of this average was attributed to dividends. A $100 investment in ALLETE stock at the end of 1995 would have been worth $443 at the end of 2005, assuming reinvestment of dividends and shares received in the ADESA distribution were sold and reinvested in ALLETE. By comparison, the Standard & Poor's 500 Index averaged 9% for the same period, of which approximately 2% of the average was attributed to dividends. A $100 investment in the Standard & Poor's 500 Index at the end of 1995 would have been worth $238 at the end of 2005, assuming reinvestment of dividends. We also value serving customers in a manner which meets their needs, promotes their satisfaction and supports our mutual long-term success.

Earnings Guidance. In 2006, we expect ALLETE's earnings per share from continuing operations to grow by 15% to 20%. The growth is expected to come from continued strong electric sales, increased real estate sales, the elimination of projected operating losses from Kendall County and our investment in ATC. In addition, we do not anticipate recording impairments related to our emerging technology portfolio. This earnings expectation is based on a 2005 diluted earnings per share from continuing operations of $2.26, which excludes the $1.84 per share Kendall County charge, a $0.13 per share current tax benefit due to the positive resolution of income tax audit issues and a $0.09 per share deferred tax benefit due to comprehensive tax planning initiatives. (See Non-GAAP Financial Measures.) Our 2006 earnings expectation does not include earnings from additional investments we may make in growth initiatives.

Energy. Over the next several years, we believe electric utilities will be facing the unfolding impacts of three major developments that occurred in 2005: changes in regional transmission operation; the start of rulemaking on the enactment of stricter environmental regulations; and federal legislation impacting the structure and organization of the electric utility industry. The FERC has consolidated many transmission regions, which impacts states' transmission regulation rights and is intended to result in more standardized wholesale power markets to oversee how transmission and energy market prices are determined. As part of this larger policy effort, MISO launched day-ahead and real-time energy market operations on April 1, 2005 (MISO Day 2). While the initial mechanics of the market launch were accomplished successfully, the market itself is still evolving. Consequently, as we work through these matters, we will be assessing the longer term impact of the MISO Day 2 market on Minnesota Power's operations. Rulemakings for stricter environmental requirements on several pollutants were issued by the EPA in 2005 and the final outcomes of these regulatory processes are expected to require significant capital investments in the 2008 to 2012 timeframe. The expenditures will relate to new emission controls on existing generating units. In August 2005, Congress passed the Energy Policy Act of 2005, which included the repeal of PUHCA 1935 and enacted PUHCA 2005. PUHCA 1935 imposed geographic restrictions on large electric and gas utility operations and limited diversification into non-utility businesses. While the exact impact of PUHCA 2005 is unknown, more electric industry consolidation could occur and new investors could enter the industry.

We believe our energy businesses are well positioned to successfully deal with the issues we have described and to compete successfully. Our access to and ownership of low-cost power are our greatest strengths. We anticipate that we will have ready access to sufficient capital for general business purposes. We believe electric industry deregulation is unlikely in Minnesota or Wisconsin in the next five years.

MISO and Fuel Clause. As a result of MISO Day 2 implementation in April 2005, energy transactions to serve retail customers are sourced through wholesale transactions with MISO as the counterparty. We filed a petition with the MPUC in February 2005 to amend our fuel clause to accommodate costs and revenue related to MISO Day 2 market implementation. In March 2005, the MPUC approved interim ratemaking treatment of MISO Day 2 costs, which allowed these costs to be recovered through the fuel clause, subject to refund with interest.

In December 2005, the MPUC issued an order that denied recovery of uplift charges, congestion revenue and expenses, and administrative costs related to our MISO Day 2 market activities through the fuel clause. As a result of that order, we filed a Notice of Intent to Withdraw from MISO on December 29, 2005, and began exploring alternatives to MISO. Withdrawal from MISO would also require MPUC and FERC approval.

Outlook (Continued)

We requested rehearing of the order in a filing made with the MPUC in January 2006. Three other utilities in the state affected by the order also filed for rehearing, as did the DOC and MISO. On February 9, 2006, the MPUC granted rehearing of the MISO Day 2 docket and suspended the refund obligation. The MPUC will review the MISO Day 2 costs to determine which costs should be recovered on a current basis through the fuel clause and which costs are more appropriately deferred for potential recovery through base rates.

In 2003, the MPUC initiated an investigation into the continuing usefulness of the fuel clause as a regulatory tool for electric utilities. The initial steps of the investigation were to review the clause's original purpose, structure and rationale (including its current operation and relevance in today's regulatory environment), and then address its ongoing appropriateness and other issues if the need for continued use of the fuel clause is shown. The MPUC has not taken action on any proposal and, as a result, we are unable to predict the outcome or impact of this proceeding at this time.

*Rate Case***.** Minnesota Power does not expect to file a request to increase rates for its retail utility operations during 2006. We will, however, continue to monitor the costs of serving our retail customers and evaluate the need for a rate filing in the future. Minnesota Power's retail rates are based on a 1994 MPUC retail rate order. SWL&P's electric retail rates are based on a May 2005 PSCW retail rate order. In 2006, SWL&P plans to file for an increase in rates to be effective beginning in 2007 for its electric, water and gas utility services.

Industrial Customers. Approximately 50% of our regulated utility electric sales are made to our Large Power Customers in the taconite, paper and pulp, and pipeline industries. Based on our research of the taconite industry, Minnesota taconite production for 2006 is again anticipated to be about 41 million tons (41 million tons in each of the years 2005 and 2004; 35 million tons in 2003). Although the current taconite pellet market is strong, the taconite industry is cyclical and subject to several factors, which could change this forecast. Some paper industry analysts are cautiously optimistic about either price stabilization or a small increase in paper prices during 2006 due to temporary or permanent closures of capacity that occurred in 2005. For the North American paper industry, the potential for either of these positive developments to occur will, in large part, depend upon the level of imports and what happens to fiber, chemical and energy costs. If there is a significant change in the major industries served by Minnesota Power, we expect that any excess energy not used by our retail customers will be marketed primarily to the regional wholesale market.

Several natural resource-based companies have been making significant progress developing new projects in northeastern Minnesota. Minnesota Power has actively supported these projects which include paper, ferrous and non-ferrous developments projected to be constructed and on-line within the next several years. If these projects proceed, Minnesota Power could serve between 100 MW and 500 MW of new load.

In 2005, we reached new long-term, all requirements agreements with five of our Large Power Customers, extending contracts for an additional four to eight years. The extension of our electric supply contracts is an important achievement for both our Large Power Customers and Minnesota Power. Electric power is a key component in the production of taconite and paper, and these industries represent more than half of Minnesota Power's regulated utility electric sales. These agreements help to provide planning certainty for both our customers and us. Our strong relationships with industrial customers are unique in the electric industry and enable us to work closely with them to help ensure their success. We continue to maintain these relationships with this group of customers to help retain a solid industrial base in our region. We continue to make investments to maintain and improve the integrity of our generating, transmission and distribution assets, and maintain environmental compliance.

Resource Plan. In 2004, we filed an integrated resource plan (Resource Plan) with the MPUC, detailing our retail energy demand projections and our energy sourcing options to meet projected demand over the next 15 years. In an updated forecast to that plan, we predict that retail demand by customers in our service territory will increase at an average annual rate of 1.5% to 2019. We project a load growth of approximately 150 MW by 2010 with another 200 MW of growth anticipated by 2015. The forecasted growth of 15 MW to 28 MW per year, is primarily from residential and smaller commercial expansion, and a positive outlook from Large Power Customers in northeastern Minnesota, such as taconite processing facilities and paper mills. We expect a reduction in generating resource supply over the next few years under the terms of our long-term energy supply contract with Square Butte. The combination of increased demands and reduced supply means we will need to secure additional base load energy to serve our customers in future years.

We have been working with regulators and other stakeholders to determine the best way to meet our projected customer needs for more electricity reliably, cost-effectively and in an environmentally responsible way. In October 2005, we proposed to the MPUC a comprehensive solution to meet our generation needs through 2010 that includes the following key components:

- Transitioning our Taconite Harbor generating facility from nonregulated energy operations to regulated utility to help meet our forecasted base load energy requirements. With MPUC approval, our proposal would make the integration of Taconite Harbor into Minnesota Power's regulated utility business effective retroactive to January 1, 2006. Current wholesale contracts sourced from Taconite Harbor will be honored through their terms, which extend through mid-2010. Taconite Harbor would then meet the majority of our near-term increased demand for electricity without requiring the construction of new assets.

- Supplementing Taconite Harbor generation with a 50-MW long-term power purchase agreement to meet near-term energy needs.
- Supporting the expansion of our renewable generating assets and helping to meet Minnesota's Renewable Energy Objective that seeks a 10% supply of qualified renewable energy resources in the state by 2015 for each Minnesota utility. We have received regulatory approval of a power purchase agreement for 50 MW of energy purchased from a wind facility in North Dakota. We are also continuing to pursue an agreement for an additional 50 MW of wind energy from facilities located in northern Minnesota (see Wind Power) and are proposing to obtain 10 MW of additional hydro generation through an expansion of one of our hydroelectric stations.

Final regulatory approval of our Resource Plan and the transition of Taconite Harbor is expected in mid 2006.

We are also exploring construction and purchase options for our anticipated resource needs by 2015. In 2005, Minnesota Power, Basin Electric Power Cooperative, Minnkota Power and Montana-Dakota Utilities Company announced a project development agreement to evaluate the feasibility of a joint lignite-fueled generating resource in the vicinity of the existing Milton R. Young generating station near Center, North Dakota. The North Dakota feasibility study is expected to take about one year to complete. A formal study is underway for a facility in northeastern Minnesota. Any final resource decision by Minnesota Power is subject to MPUC and other approvals. We continue to study the feasibility of the construction of a natural gas-fired electric generating facility which could be located in northwestern Wisconsin or northeastern Minnesota.

Excelsior Energy Inc. (Excelsior) has proposed to construct a 600 MW (net) coal-gasification generation facility in northern Minnesota. The project is in the early development stages but may be an option for our long-term forecasted energy and capacity needs. Excelsior says the facility could be operational in 2011, but needs to obtain the necessary permits and financing. In 2003, the Minnesota legislature enacted several provisions that provide Excelsior with special considerations, including requiring utilities within the state to "consider" Excelsior before pursuing new resource additions within Minnesota. In December 2005, Excelsior filed a petition with the MPUC seeking approval of an unexecuted power purchase agreement with Xcel Energy Inc. In January 2006, Minnesota Power filed comments with the MPUC in Excelsior's proposed power purchase agreement proceeding, focusing on the importance to the state of maintaining a range of base load energy options including multiple fuel types and generating technologies.

Wind Power. In 2005, we added a significant resource to our Regulated Utility generation portfolio when we entered into a 25-year agreement to purchase approximately 50 MW of wind power from a new wind facility to be built in North Dakota by an affiliate of FPL Energy, LLC. FPL Energy expects the facility to be operational in the fall of 2006. The wind facility will include approximately 22 new wind turbines interconnected to the Square Butte substation in Center, North Dakota. The MPUC approved the power purchase agreement in December 2005. In addition, we are continuing to pursue the purchase of renewable energy from a new wind facility that would be located in northern Minnesota. This project, expected to be operational in 2007, would be similar in size to the North Dakota project and would be subject to a power purchase agreement, as well as regulatory approvals. The Minnesota project also needs to be operational by the end of 2007 to be eligible for federal production tax credits which are essential to provide acceptable pricing.

AREA Plan. In October 2005, we announced a $60 million environmental initiative which is expected to significantly reduce emissions from two of our electric generating facilities in northeastern Minnesota. Our Arrowhead Regional Emission Abatement (AREA) Plan is designed to reduce emissions while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. We believe that control and abatement technologies applicable to these plants have matured to the point where further significant air emission reductions can be attained in a relatively cost-effective manner.

At Taconite Harbor, we plan to employ innovative multi-emission reduction technology, while at Laskin we plan to install a retrofit to lower NO_X emissions. Upon project completion, we estimate an emission reduction of over 60% for NO_X at both facilities and a 65% reduction in SO_2 at Taconite Harbor. Laskin already has relatively low emission levels of SO_2 due to existing emission reduction technology. Additionally, with the emerging technology being proposed for Taconite Harbor, there is the potential for a 90% reduction in mercury emissions.

In October 2005, we filed the AREA plan with the MPUC followed by a second filing detailing current cost recovery outside of a rate case in December 2005. If approved by the MPUC, the rate impact on residential and general service customers is expected to be about 2% and about 3% for Large Power Customers when the plan is fully implemented at the end of 2008. We are seeking approval prior to June 30, 2006, when the statutory authorization for current cost recovery on utility emission reduction investments sunsets. In January 2006, the MPCA submitted its assessment of our AREA plan from an environmental perspective to the MPUC. The MPCA supports the plan as a cost-effective means of reducing emissions at Taconite Harbor and Laskin. Given the emission reduction that would be achieved and the reasonable costs of the proposal, the MPCA believes it is appropriate to allow current cost recovery for this project.

Outlook (Continued)

CAIR and CAMR. In March 2005, the EPA issued its Clean Air Interstate Rule (CAIR) which would reduce emissions of SO_2 and NO_X. In November 2005, EPA granted reconsideration of the CAIR. Minnesota Power filed comments for reconsideration arguing that the State of Minnesota did not belong in CAIR and that SO_2 allocations proposed under the CAIR were unfair. The CAIR comment period closed in January 2006 and a final rule is expected in 2006. In March 2005, EPA issued its Clean Air Mercury Rule (CAMR). EPA granted reconsideration of the CAMR in October 2005. Comments on reconsideration closed in December 2005. A final ruling on CAMR is anticipated in 2006. The final outcomes of these regulatory proceedings are expected to require significant capital investments in the 2008 to 2012 timeframe. (See Capital Requirements.)

Energy Policy Act. In August 2005, the Energy Policy Act of 2005 was signed into law. Key provisions in the law include: mandatory electric reliability standards; FERC backstop siting authority for transmission corridors of national interest, as well as giving the U.S. Department of Energy (DOE) "lead agency" authority to coordinate federal agencies involved in siting transmission lines; and the repeal of the PUHCA 1935 and the enactment of PUHCA 2005. The law also reforms the hydro licensing process and supports the DOE's clean coal/FutureGen program. We believe the overall impact on the electric utility industry will be positive and are evaluating the effects on our business as this legislation is being implemented.

Investment in ATC. In 2005, we announced plans to invest $60 million in ATC by the end of 2006. Our investment will represent an estimated 9% ownership interest in ATC and is expected to be a significant contributor to future earnings. Our investment in ATC is subject to review by the PSCW.

Strategy. As part of our strategy, we will leverage the strengths of our Regulated Utility business to improve our strategic and financial outlook and seek growth opportunities in close geographic proximity to existing operations in Minnesota, North Dakota and Wisconsin. In addition, we will evaluate growth opportunities through merger, acquisition or asset additions in our region.

Real Estate. With an inventory of land in desirable Florida locations (see Item 1 – Real Estate), ALLETE Properties is poised for a growing and consistent contribution to earnings and cash flow. A large portion of our real estate inventory is located in Florida's Flagler and Volusia Counties, an area with one of the fastest growing populations in the United States. We expect this population growth to continue, which will increase the demand for real estate in the area.

We have three major planned developments under way. They are Town Center, which will be a new downtown for Palm Coast, Palm Coast Park, located in northwest Palm Coast, and Ormond Crossings, located in Ormond Beach along Interstate 95. As property within these developments is made available for sale, we expect that these projects will contribute a significant amount of income for our real estate business. Other ongoing land sales and rental income at the retail shopping center in Winter Haven provide additional revenue.

ALLETE Properties plans to maximize the value of the property it currently owns through entitlement and infrastructure improvements. In addition to managing its current real estate inventory, ALLETE Properties is focused on identifying, acquiring and entitling vacant land in the coastal southeast United States.

As of December 31, 2005, we had $8.6 million of deferred profit on sales of real estate, before taxes and minority interest, on our balance sheet. We expect most of this deferred profit will be reflected in income during the next 12 months.

Town Center. Ground was broken on the Town Center development in early 2005. At December 31, 2005, pending land sales under contract for properties at Town Center totaled $63.7 million. Florida Landmark has an agreement with Developers Realty Corporation (DRC) to develop the first phase of the urban core area of Town Center. The agreement also includes the development of a 51-acre commercial retail site. Revenue associated with this agreement is anticipated to be $21.8 million over the life of the contract, which extends to September 2012.

During the initial phase of the Town Center project, our primary focus is to develop the major infrastructure, most of the development tracts, as well as plat lots for a variety of uses. The marketing program has targeted an appropriate blend and quantity of office, commercial, residential and mixed-use projects. Sites for all land uses that are planned in the initial phase are already sold or under contract, except adult housing. Negotiations are underway with several developers that specialize in adult housing units. After the next few years, once the market has substantially absorbed the land uses that are currently in the design phase, additional sites will be released for sale in order to maintain an orderly build-out of Town Center. Pacing the growth of Town Center consistent with absorption rates for each unit type will assure that our customers, the Town Center project developers, will be successful. This is expected to create and maximize value for the developers, end-users and investors.

Outlook (Continued)

Palm Coast Park. Designing has been completed and permitting is proceeding on the Palm Coast Park development, with infrastructure construction slated to begin in 2006. Development order approval from the City of Palm Coast was received in late 2005. Also in 2005, the State of Florida granted the Palm Coast Park Community Development District authority to issue special assessment revenue bonds to fund construction of infrastructure improvements for the project. The bonds are expected to be issued by the district by mid 2006. The major infrastructure improvements, consisting primarily of utility extensions and a linear park along the U.S. Highway 1 frontage, are being permitted in anticipation of this bond financing, after which construction of the improvements will commence. Platting is underway and expected to be completed in early 2007. Commercial sites will be available for sale beginning in 2007. At December 31, 2005, pending land sales under contract for properties at Palm Coast Park totaled $7.5 million. Negotiations are underway to sell two other residential development tracts.

Ormond Crossings. In 2005, a Development of Regional Impact (DRI) Application for Development Approval was submitted to the East Central Florida Regional Planning Council for the 6,000-acre Ormond Crossings project. Development uses and densities proposed in the DRI include 5 million square feet of commercial opportunities along with up to 4,400 residential units. We anticipate that the DRI review will be concluded and a development order will be issued by the City of Ormond Beach by the end of 2006. Engineering, design and permitting will continue through 2007. It is not anticipated that any sales will be made at Ormond Crossings until 2008. The Ormond Crossings DRI application represents the launch of our third major real estate development in Florida and the largest in terms of available commercial square feet and residential units.

Other. We have the potential to recognize gains or losses on the sale of investments in our emerging technology portfolio. We plan to sell investments in our emerging technology portfolio as shares are distributed to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an initial public offering. We have committed to make additional investments in certain emerging technology holdings. The total future commitment was $3.1 million at December 31, 2005, and is expected to be invested at various times through 2007. We do not have plans to make any additional investments beyond this commitment.

Diversification. We have a long history of both acquiring and selling companies in a variety of industries, and these activities have contributed significantly to overall financial results. We will seek to diversify our earnings stream to mitigate potential downside exposure to industrial customers in our Regulated Utility business and to provide additional earnings growth.

Liquidity and Capital Resources

Cash Flow Activities

A primary goal of our strategic plan is to improve cash flow from operations. Our strategy includes growing our businesses both internally by expanding facilities, services and operations (see Capital Requirements), and externally through acquisitions.

We believe our financial condition is strong, as evidenced by cash and cash equivalents of $89.6 million, $116.9 million of short-term investments and a debt to total capital ratio of 39% at December 31, 2005.

Operating Activities. Cash flow from operating activities was $53.5 million for 2005 ($175.0 million for 2004; $247.4 million for 2003). Cash from operating activities was lower in 2005, primarily due to the absence of cash from discontinued operations ($2.3 million in 2005; $108.8 million in 2004; $133.3 million in 2003). In 2004, we spun off our Automotive Services business and essentially completed the exit from our Water Services businesses. Cash from operating activities was also lower in 2005 due to a $50.4 million Kendall County Charge in 2005. In 2005, cash from operating activities was higher than in 2004 due to the collection in January 2005 of a $6.7 million outstanding receivable at December 31, 2004, from ATC for work on the Duluth-to-Wausau transmission line and other receivables, and an additional $7.5 million of deferred profit on real estate activities. Cash from operating activities in 2003 included the receipt of a $20.9 million outstanding receivable in 2002 related to a turbine generator sold following the indefinite delay of a generation project in Superior, Wisconsin.

Investing Activities. Cash flow from investing activities was $3.9 million for 2005 (cash flow for investing activities of $126.5 million for 2004; cash flow from investing activities of $210.3 million for 2003). Cash from investing activities was higher in 2005 than 2004, primarily due to a $179.9 million increase in net proceeds received from the sale of short-term investments. Gross proceeds from the sale of available-for-sale securities were $376.0 million in 2005 ($1.9 million in 2004; $7.4 million in 2003) and purchases were $343.7 million ($149.5 million in 2004; $0 in 2003). Cash from investing activities for 2005 was also higher by $35.5 million from the sale of Enventis Telecom. The increase was offset by $66.0 million proceeds received in 2004 from the sale of our remaining Water Services businesses. The increase was also offset by $12.0 million received from Split Rock Energy in 2004 upon termination of the joint venture. Additions to property, plant and equipment vary from year to year depending on special projects. Additions to property, plant and equipment in 2003 included expenses related to BNI Coal's dragline project. Cash flow from investing activities was lower in 2004 than 2003, primarily due to purchases of available-for-sales securities in 2004 ($149.5 million) and $445 million of proceeds received in 2003 from the sale of a major portion of our Water Services businesses.

Liquidity and Capital Resources (Continued)

Financing Activities. Cash flow for financing activities was $13.9 million for 2005 ($228.7 million for 2004; $470.7 million for 2003). The decrease in cash for financing activities was primarily attributed to significant debt repayment ($35.7 million in 2005; $241.1 million in 2004; $335.7 million in 2003). In 2005, we refinanced $35 million of first mortgage bonds at a lower rate. In 2004, we repaid $3.5 million of industrial development revenue bonds and $125 million of senior notes, and refinanced $111 million of pollution control refunding revenue bonds at a lower rate. In 2003, we repaid $75 million of first mortgage bonds and $75 million of mandatorily redeemable preferred securities. In addition, a $250 million credit agreement entered into in July 2003 was paid off early ($197 million in 2003; $53 million in April 2004). Proceeds from the sale of our Water Services assets in 2003 and 2004, and proceeds received from ADESA in 2004 were used to repay the debt in 2003 and 2004. Cash for financing activities also decreased in 2005 and 2004 due to lower dividends paid following the spin-off of Automotive Services.

Our Town Center development project in Florida is being financed with a revolving development loan and tax-exempt bonds issued by the Town Center at Palm Coast Community Development District (Town Center District). In March 2005, Florida Landmark entered into an $8.5 million revolving development loan with CypressCoquina Bank to fund approximately $26 million of Town Center development costs. The loan has an interest rate equal to the prime rate, with an initial term of 36 months. The term of the loan may be extended 24 months if certain conditions are met. Also in March 2005, the Town Center District issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, due May 1, 2036 (Bonds). Approximately $21 million of the Bond proceeds will be used for construction of infrastructure improvements at Town Center, with the remaining funds to be used for capitalized interest, a debt service reserve fund and costs of issuance. The Bonds are payable from and secured by the revenue derived from assessments to be imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments will be included in the annual property tax bills of landowners in the development project beginning in November 2006. To the extent that we still own land at the time of the assessment, we will recognize an expense for our pro rata portion of assessments, based upon our ownership of benefited property. At December 31, 2005, we owned approximately 92% of the assessable land in the Town Center District. The Town Center District is an independent unit of local government, created and established in accordance with Florida's Uniform Community Development District Act of 1980 (Act). The Act provides legal authority for a community development district to finance the construction of major infrastructure for community development with general obligation, revenue and special assessment revenue debt obligations.

Working Capital. Additional working capital, if and when needed, generally is provided by the sale of commercial paper. We have 0.8 million original issue shares of our common stock available for issuance through *Invest Direct*, our direct stock purchase and dividend reinvestment plan. We have bank lines of credit aggregating $170.0 million, the majority of which expire in January 2011. In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility with LaSalle Bank National Association, as Agent, for $150 million (Line). The Line matures on January 11, 2011. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. We may prepay amounts outstanding under the Line in whole or in part at our discretion. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity. The Line may be used for general corporate purposes, working capital and to provide liquidity in support of our commercial paper program. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs. We may sell securities to meet capital requirements, to provide for the retirement or early redemption of issues of long-term debt, to reduce short-term debt and for other corporate purposes.

Sale of Enventis Telecom. In 2005, we sold all the stock of Enventis Telecom to HickoryTech of Mankato, Minnesota, for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was included in our 2005 earnings from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes.

Securities

In March 2001, ALLETE, ALLETE Capital II and ALLETE Capital III, jointly filed a registration statement with the SEC, pursuant to Rule 415 under the Securities Act of 1933. The registration statement, which has been declared effective by the SEC, relates to the possible issuance of a remaining aggregate amount of $387 million of securities, which may include ALLETE common stock, first mortgage bonds and other debt securities, and ALLETE Capital II and ALLETE Capital III preferred trust securities. ALLETE also previously filed a registration statement, which has been declared effective by the SEC, relating to the possible issuance of $25 million of first mortgage bonds and other debt securities. We may sell all or a portion of the remaining registered securities if warranted by market conditions and our capital requirements. Any offer and sale of the above mentioned securities will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

In August 2005, we issued $35 million in principal amount of First Mortgage Bonds, 5.28% due 2020. Proceeds were used to redeem $35 million in principal amount of First Mortgage Bonds, 7 1/2% Series originally due 2007.

Liquidity and Capital Resources (Continued)

In October 2005, we accepted an offer from certain institutional buyers in the private placement market to purchase $50 million in principal amount of our first mortgage bonds. When issued, on or about March 1, 2006, the bonds will carry an interest rate of 5.69% and will have a term of 30 years. On January 30, 2006, we called for redemption on March 2, 2006, $50 million in principal amount of First Mortgage Bonds, 7% Series due 2008.

Financial Covenants

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 quarterly ratio of its funded debt to total capital of less than or equal to .65 to 1.00. Failure to meet this covenant could give rise to an event of default, if not corrected 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, 2005, ALLETE was in compliance with its financial covenants.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are discussed in Note 10.

Contractual Obligations and Commercial Commitments

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 below assumes the interest rate in effect at December 31, 2005, remains constant through the remaining term.

Unconditional purchase obligations represent our Square Butte power purchase agreement, and minimum purchase commitments under coal and rail contracts.

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. Our payment obligation is 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 following table reflects our share of future debt service based on our output entitlement of approximately 66% in 2006, 60% in 2007 and 55% thereafter. Upon compliance with a two-year advance notice requirement, Minnkota Power has the option to reduce our entitlement by approximately 5% annually, to a minimum of 50%. (See Note 10.)

Under an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC, we have a commitment to invest $60 million in ATC by the end of 2006. (See Note 10.) Our investment will represent an estimated 9% ownership interest in ATC. Our investment in ATC is subject to review by the PSCW.

Contractual Obligations As of December 31, 2006	Payments Due by Period Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Millions					
Long-Term Debt	$ 601.6	$ 24.9	$196.1	$30.2	$350.4
Operating Lease Obligations	73.2	6.4	15.8	7.9	43.1
Unconditional Purchase Obligations	374.7	57.8	71.0	29.0	216.9
Investment in ATC	60.0	60.0	–	–	–
	$1,109.5	$149.1	$282.9	$67.1	$610.4

In 2006, we expect to contribute approximately $8 million to our postretirement health and life plans and approximately $10 million to our defined benefit pension plans. We are unable to predict contribution levels after 2006.

Emerging Technology Portfolio. We have investments in emerging technologies through the minority investments in venture capital funds and privately-held, start-up companies. We have committed to make additional investments in certain emerging technology holdings. The total future commitment was $3.1 million at December 31, 2005 ($4.5 million at December 31, 2004; $4.8 million at December 31, 2003) and is expected to be invested at various times through 2007. We do not have plans to make any additional investments beyond this commitment.

Liquidity and Capital Resources (Continued)

Credit 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.

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa2
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds	A	Baa1
Pollution Control Bonds	A	Baa1
Unsecured Debt		
Collier County Industrial Development Revenue Bonds	BBB	–

Payout Ratio

In 2005, we paid out 259% (77% in 2004; 40% in 2003) of our per share earnings in dividends. The payout ratio in 2005 was impacted by a $1.84 per diluted share charge to assign the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. (See Note 11.)

On January 25, 2006, our Board of Directors increased the dividend on ALLETE common stock by 15%, declaring a dividend of 36.25 cents per share payable March 1, 2006, to shareholders of record at the close of business February 15, 2006.

Capital Requirements

Continuing Operations. Capital expenditures for 2005 totaled $58.6 million ($57.8 million in 2004; $68.7 million in 2003). Expenditures for 2005 included $46.5 million for Regulated Utility and $12.1 million for Nonregulated Energy Operations. Internally-generated funds were the source of funding for these expenditures.

Capital expenditures are expected to be $107 million in 2006 and total $630 million for 2007 through 2010. The 2006 amount includes $105 million for system component replacement and upgrades, and environmental upgrades within Regulated Utility, and $2 million for coal handling equipment and system component replacement, and upgrades within Nonregulated Energy Operations. Starting in 2006, Taconite Harbor's capital expenditures will be combined with Regulated Utility expenditures. Over the next five years, we expect to use internally-generated funds and new issue debt to fund our projected capital expenditures. Approximately $280 million of the estimated expenditures for 2007 through 2010 relate to environmental upgrades at our generation facilities, primarily due to the promulgation of two new EPA rules in 2005. Our environmental compliance plan incorporates a combination of solutions that include both technology and emission allowance purchases, and timing and scheduling of environmental retrofit during this period.

Real estate development expenditures are and will be funded with a revolving development loan and tax-exempt bonds issued by community development districts. The Town Center at Palm Coast Community Development District issued $26.4 million of tax-exempt bonds in 2005. Approximately $21 million of the bond proceeds will be used for construction of infrastructure improvements at Town Center, with the remaining funds to be used for capitalized interest, a debt service reserve fund and costs of issuance. We anticipate that the Palm Coast Park Community Development District will issue tax-exempt bonds to fund construction of infrastructure improvements for our Palm Coast Park project in mid-2006. Expenditures related to our real estate developments in Florida increase the value of our land assets, which are classified as Investments on our consolidated balance sheet.

Discontinued Operations. Capital expenditures for discontinued operations for 2005 totaled $4.5 million ($21.4 million in 2004; $67.6 million in 2003). Expenditures for 2005 related to our telecommunications business.

Environmental and Other Matters

As previously mentioned in our Critical Accounting Policies section, our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future stricter 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. (See Item 1 – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2005, our available-for-sale securities portfolio consisted of securities in a grantor trust established to fund certain employee benefits included in Investments, and various auction rate municipal bonds and variable rate municipal demand notes included as Short-Term Investments. Our available-for-sale securities portfolio had a fair value of $139.5 million at December 31, 2005 ($179.4 million at December 31, 2004) and a total unrealized after-tax gain of $2.1 million at December 31, 2005 ($1.5 million at December 31, 2004).

We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review on a quarterly basis available-for-sale securities for other than temporary impairment by assessing such factors as the share price trends and the impact of overall market conditions. As a result of our periodic assessments, we did not record any impairment of available-for-sale securities in 2005 or 2004.

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investment in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $9.2 million at December 31, 2005 ($13.6 million at December 31, 2004). Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Our basis in direct investments in privately-held companies included in the emerging technology portfolio was zero at December 31, 2005 ($4.5 million at December 31, 2004). In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments that related to direct investments in certain privately-held, start-up companies whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. In 2004, we recorded $6.5 million ($4.1 million after tax) of impairments. We did not record any impairments in 2003.

Interest Rate Sensitive Financial Instruments

	Principal Cash Flow by Expected Maturity Date							
	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$0.9	$80.9	$56.6	$1.6	$0.5	$189.4	$329.9	$331.9
Average Interest Rate – %	7.1	6.9	7.0	6.7	6.8	5.4	6.0	
Variable Rate	$1.8	$3.3	$0.8	$9.0	$4.4	$41.3	$60.6	$60.6
Average Interest Rate – % *(a)*	5.4	3.9	5.1	3.6	3.8	3.8	3.9	

(a) Assumes rate in effect at December 31, 2005, remains constant through remaining term.

Commodity Price Risk

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

Market Risk (Continued)

Power Marketing

Our power marketing activities consist of (1) purchasing energy in the wholesale market for resale in our regulated service territories when retail energy requirements exceed generation output, and (2) selling excess available generation and purchased power.

From time to time, our utility operations may have excess generation that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell this generation to the wholesale market to optimize the value of our generating facilities. This generation is generally sold in the MISO market at market prices.

We have approximately 200 MW of generation available for sale to the wholesale markets at our Taconite Harbor facility in northern Minnesota, which has been sold through various short-term and long-term capacity and energy contracts. Approximately 116 MW of existing capacity and energy sales contracts expired on April 30, 2005. Long-term, we have entered into two capacity and energy sales contracts totaling 175 MW (201 MW including a 15% reserve), which were effective May 1, 2005, and expire on April 30, 2010. Both contracts contain fixed monthly capacity charges and fixed minimum energy charges. One contract provides for an annual escalator to the energy charge based on increases in our cost of coal, subject to a small minimum annual escalation. The other contract provides that the energy charge will be the greater of a fixed minimum charge or an amount based on the variable production cost of a combined-cycle, natural gas unit. Our exposure in the event of a full or partial outage at our Taconite Harbor facility is significantly limited under both contracts. When the buyer is notified at least two months prior to an outage, there is no exposure. Outages with less than two months' notice are subject to an annual duration limitation typical of this type of contract. We also have a 50 MW capacity and energy sales contract that extends through April 2008 and a 15 MW energy sales contract that extends through May 2007. The 50 MW capacity and energy sales contract had fixed pricing through January 2006, with formula pricing based on variable production cost of a combustion-turbine, natural gas unit thereafter.

In addition to generation, Taconite Harbor will meet its sales contract obligations with two contracts that began in May 2005. We have a 50 MW capacity and energy purchase contract that extends through April 2006, with fixed capacity payments and the right to purchase energy at market price. We also had a 25 MW fixed-priced energy purchase contract that extended through January 2006.

New Accounting Standards

New accounting standards are discussed in Note 2.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition – 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, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, and supplementary data, also included, 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 our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report.

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, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2006 Annual Meeting of Shareholders (2006 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 "Report of the Audit Committee" section;
- **Audit Committee Members.** The identity of the Audit Committee members is included in the "Report of the Audit Committee" 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 "Section 16(a) Beneficial Ownership Reporting Compliance" section.

Our 2006 Proxy Statement will be filed with the SEC within 120 days after the end of our 2005 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 upon request without charge. 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 Executive Officers" and the "Director Compensation" sections in our 2006 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 "Security Ownership of Certain Beneficial Owners," the "Security Ownership of Management" and the "Equity Compensation Plan Information" sections in our 2006 Proxy Statement.

Item 13. Certain Relationships and Related Transactions

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2006 Proxy Statement.

Item 14. Principal Accountant Fees and Services

The information required by this Item is incorporated by reference herein from the "Report of the Audit Committee" section in our 2006 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, effective 12:00 p.m. Eastern Time on September 20, 2004 (filed as Exhibit 3 to the September 21, 2004, Form 8-K, File No. 1-3548).

*3(a)3 - 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 August 24, 2004 (filed as Exhibit 3 to the August 25, 2004, 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 (formerly Irving Trust Company) and Douglas J. MacInnes (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

*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).

Exhibit Number

*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 Trust N.A., 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

*4(d)1 - Rights Agreement, dated as of July 24, 1996, between Minnesota Power & Light Company (now ALLETE) and the Corporate Secretary of the Company, as Rights Agent (filed as Exhibit 4 to the August 2, 1996, Form 8-K, File No. 1-3548).

*4(d)2 - Certificate of Adjustment to the Rights Agreement as amended, dated as of July 24, 1996, between Minnesota Power & Light Company (now ALLETE) and the Corporate Secretary of the Company, as Rights Agent (filed as Exhibit 4(d) to the September 30, 2004, Form 10-Q, File No. 1-3548).

*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(b) - Amended and Restated Withdrawal Agreement (without Exhibits and Schedules), dated January 30, 2004, by and between Great River Energy and Minnesota Power (now ALLETE) (filed as Exhibit 10(p) to the 2003 Form 10-K, File No. 1-3548).

*10(c) - Master Agreement (without Appendices and Exhibits), dated December 28, 2004, by and between Rainy River Energy Corporation and Constellation Energy Commodities Group, Inc. (filed as Exhibit 10(c) to the 2004 Form 10-K, File No. 1-3548).

*10(d)1 - Third Amended and Restated Committed Facility Letter (without Exhibits), dated December 23, 2003, to ALLETE from LaSalle Bank National Association, as Agent (filed as Exhibit 10(s) to the 2003 Form 10-K, File No. 1-3548).

*10(d)2 - First Amendment to Third Amended and Restated Committed Facility Letter, dated December 14, 2004, by and among ALLETE and LaSalle Bank National Association, as Agent (filed as Exhibit 10(d)2 to the 2004 Form 10-K, File No. 1-3548).

*10(e) - Fourth Amended and Restated Committed Facility Letter (without Exhibits), dated January 11, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent (filed as Exhibit 10 to the January 17, 2006, Form 8-K, File No. 1-3548).

*10(f) - Master Separation Agreement, dated June 4, 2004, between ALLETE, Inc. and ADESA, Inc. (filed as Exhibit 10.1 to ADESA, Inc.'s June 30, 2004, Form 10-Q, File No. 1-32198).

*10(g) - Agreement (without Exhibit) dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10 to the December 21, 2005 Form 8-K, File No. 1-3548).

+*10(h)1 - Minnesota Power (now ALLETE) Executive Annual Incentive Plan, as amended, effective January 1, 1999 with amendments through January 2003 (filed as Exhibit 10 to the September 30, 2003, Form 10-Q, File No. 1-3548).

+*10(h)2 - November 2003 Amendment to the ALLETE Executive Annual Incentive Plan (filed as Exhibit 10(t)2 to the 2003 Form 10-K, File No. 1-3548).

+*10(h)3 - July 2004 Amendment to the ALLETE Executive Annual Incentive Plan (filed as Exhibit 10(a) to the June 30, 2004, Form 10-Q, File No. 1-3548).

+*10(h)4 - Form of ALLETE Executive Annual Incentive Plan 2005 Award (filed as Exhibit 10(a)1 to the March 31, 2005, Form 10-Q, File No. 1-3548).

+*10(h)5 - ALLETE Executive Annual Incentive Plan 2005 Goals (filed as Exhibit 10(a)2 to the March 31, 2005, Form 10-Q, File No. 1-3548).

+*10(h)6 - Form of ALLETE Executive Annual Incentive Plan 2006 Award – President of ALLETE Properties (filed as Exhibit 10(b) to the January 30, 2006, Form 8-K, File No. 1-3548).

Exhibit Number

+*10(i)1	-	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan, as amended and restated, effective January 1, 2004 (filed as Exhibit 10(u) to the 2003 Form 10-K, File No. 1-3548).
+*10(i)2	-	January 2005 Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (filed as Exhibit 10(b) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(j)1	-	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).
+*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(k)1	-	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(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	-	Minnesota Power (now ALLETE) Executive Long-Term Incentive Compensation Plan, effective January 1, 1996 (filed as Exhibit 10(a) to the June 30, 1996, Form 10-Q, File No. 1-3548).
+*10(m)2	-	Amendments through January 2003 to the Minnesota Power (now ALLETE) Executive Long-Term Incentive Compensation Plan (filed as Exhibit 10(z)2 to the 2002 Form 10-K, File No. 1-3548).
+*10(m)3	-	July 2004 Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan (filed as Exhibit 10(d) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(m)4	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2005 Nonqualified Stock Option Grant (filed as Exhibit 10(k)4 to the 2004 Form 10-K, File No. 1-3548).
+*10(m)5	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2005 Performance Share Grant (filed as Exhibit 10(k)5 to the 2004 Form 10-K, File No. 1-3548).
+*10(n)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(n)2	-	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(n)3	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Performance Share Grant (filed as Exhibit 10(a)2 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(n)4	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Long-Term Cash Incentive Award – President of ALLETE Properties (filed as Exhibit 10(a)3 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(n)5	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Stock Grant – President of ALLETE Properties (filed as Exhibit 10(a)4 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(o)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(o)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(o)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(o)4	-	ALLETE Director Compensation Summary (filed as Exhibit 10 to the June 30, 2005, Form 10-Q, File No. 1-3548).
+*10(p)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(p)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(p)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).

Exhibit Number

+*10(q)	-	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).
12	-	Computation of Ratios of Earnings to Fixed Charges.
21	-	Subsidiaries of the Registrant.
23(a)	-	Consent of Independent Registered Public Accounting Firm.
23(b)	-	Consent of General Counsel.
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.

We are a party to other long-term debt instruments 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 such omitted instrument does not exceed 10% of our total consolidated assets. These instruments include the following:

- $38,995,000 City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A, Series 1997B, Series 1997C and Series 1997D.
- $35,105,000 Collier County Industrial Development Authority, 6.50% Industrial Development Refunding Revenue Bonds (Florida Water Services Corporation, formerly Southern States Utilities, Inc., Project) Series 1996.

We will furnish copies of these instruments to the SEC upon its request.

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* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.*

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 17, 2006

By /s/ Donald J. Shippar
Donald J. Shippar
Chairman, 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
/s/ Donald J. Shippar Donald J. Shippar	Chairman, President, Chief Executive Officer and Director	February 17, 2006
/s/ James K. Vizanko James K. Vizanko	Senior Vice President and Chief Financial Officer	February 17, 2006
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Controller	February 17, 2006
/s/ Heidi J. Eddins Heidi J. Eddins	Director	February 17, 2006
/s/ Peter J. Johnson Peter J. Johnson	Director	February 17, 2006
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 17, 2006
/s/ George L. Mayer George L. Mayer	Director	February 17, 2006
/s/ Roger D. Peirce Roger D. Peirce	Director	February 17, 2006
/s/ Jack I. Rajala Jack I. Rajala	Director	February 17, 2006
/s/ Nick Smith Nick Smith	Director	February 17, 2006
/s/ Bruce W. Stender Bruce W. Stender	Director	February 17, 2006

Report of Independent Registered Public Accounting Firm

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

We have completed integrated audits of ALLETE, Inc.'s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the 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 at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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 accompanying index 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. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 15 to the consolidated financial statements, in 2004 the Company changed its method of accounting for investments in limited liability companies in accordance with EITF 03-16, "Accounting for Investments in Limited Liability Companies."

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 13, 2006

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

December 31	2005	2004
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$ 89.6	$ 43.7
Restricted Cash	–	30.3
Short-Term Investments	116.9	149.2
Accounts Receivable (Less Allowance of $1.0 for 2005 and 2004)	79.1	78.7
Inventories	33.1	31.8
Prepayments and Other	23.8	21.3
Deferred Income Taxes	31.0	–
Discontinued Operations	0.4	13.1
Total Current Assets	373.9	368.1
Property, Plant and Equipment – Net	860.4	849.6
Investments	117.7	124.5
Other Assets	44.6	52.8
Discontinued Operations	2.2	36.4
Total Assets	$ 1,398.8	$ 1,431.4
Liabilities and Shareholders' Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$ 44.7	$ 36.4
Accrued Taxes	19.1	22.4
Accrued Interest	7.4	6.9
Long-Term Debt Due Within One Year	2.7	1.8
Deferred Profit on Sales of Real Estate	8.6	1.1
Other	24.2	23.1
Discontinued Operations	13.0	24.5
Total Current Liabilities	119.7	116.2
Long-Term Debt	387.8	389.4
Deferred Income Taxes	138.4	139.2
Other Liabilities	144.1	150.5
Minority Interest	6.0	5.6
Total Liabilities	796.0	800.9
Commitments and Contingencies		
Shareholders' Equity		
Common Stock Without Par Value, 43.3 Shares Authorized 30.1 and 29.7 Shares Outstanding	421.1	400.1
Unearned ESOP Shares	(77.6)	(51.4)
Accumulated Other Comprehensive Loss	(12.8)	(11.4)
Retained Earnings	272.1	293.2
Total Shareholders' Equity	602.8	630.5
Total Liabilities and Shareholders' Equity	$ 1,398.8	$ 1,431.4

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

For the Year Ended December 31	2005	2004	2003
Millions Except Per Share Amounts			
Operating Revenue	$737.4	$704.1	$659.6
Operating Expenses			
Fuel and Purchased Power	273.1	286.2	252.5
Operating and Maintenance	293.5	270.1	260.5
Kendall County Charge	77.9	–	–
Depreciation	47.8	46.9	48.9
Total Operating Expenses	692.3	603.2	561.9
Operating Income from Continuing Operations	45.1	100.9	97.7
Other Income (Expense)			
Interest Expense	(26.4)	(31.7)	(50.5)
Other	1.1	(12.2)	2.3
Total Other Expense	(25.3)	(43.9)	(48.2)
Income from Continuing Operations Before Minority Interest and Income Taxes	19.8	57.0	49.5
Minority Interest	2.7	2.1	2.6
Income from Continuing Operations Before Income Taxes	17.1	54.9	46.9
Income Tax Expense (Benefit)	(0.5)	16.4	17.7
Income from Continuing Operations Before Change in Accounting Principle	17.6	38.5	29.2
Income (Loss) from Discontinued Operations – Net of Tax	(4.3)	73.7	207.2
Change in Accounting Principle – Net of Tax	–	(7.8)	–
Net Income	$ 13.3	$104.4	$236.4
Average Shares of Common Stock			
Basic	27.3	28.3	27.6
Diluted	27.4	28.4	27.8
Basic Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$0.65	$1.37	$1.06
Discontinued Operations	(0.16)	2.60	7.50
Change in Accounting Principle	–	(0.28)	–
	$0.49	$3.69	$8.56
Diluted Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$0.64	$1.35	$1.05
Discontinued Operations	(0.16)	2.59	7.47
Change in Accounting Principle	–	(0.27)	–
	$0.48	$3.67	$8.52
Dividends Per Share of Common Stock	$1.2450	$2.8425	$3.3900

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

For the Year Ended December 31	2005	2004	2003
Millions			
Operating Activities			
Net Income	$ 13.3	$104.4	$236.4
(Income) Loss from Discontinued Operations	4.3	(73.7)	(207.2)
Change in Accounting Principle	–	7.8	–
Loss on Impairment of Investments	5.1	6.5	–
Depreciation	47.8	46.9	48.9
Deferred Income Taxes	(34.2)	(1.1)	9.9
Minority Interest	2.7	2.1	2.6
Stock Compensation Expense	1.5	1.0	3.0
Bad Debt Expense	1.1	0.9	0.6
Changes in Operating Assets and Liabilities			
Accounts Receivable	(1.4)	(22.9)	16.5
Trading Securities	–	–	1.8
Inventories	(1.3)	(0.3)	0.2
Prepayments and Other	(2.5)	(3.6)	(1.7)
Accounts Payable	4.9	0.2	7.3
Other Current Liabilities	5.8	(4.8)	2.9
Other Assets	8.2	6.2	(0.6)
Other Liabilities	(4.1)	(3.4)	(6.5)
Net Operating Activities from Discontinued Operations	2.3	108.8	133.3
Cash from Operating Activities	53.5	175.0	247.4
Investing Activities			
Proceeds from Sale of Available-For-Sale Securities	376.0	1.9	7.4
Payments for Purchase of Available-For-Sale Securities	(343.7)	(149.5)	–
Changes to Investments	(1.1)	12.4	(16.6)
Additions to Property, Plant and Equipment	(58.6)	(57.8)	(68.7)
Other	0.6	2.0	3.7
Net Investing Activities from Discontinued Operations	30.7	64.5	284.5
Cash from (for) Investing Activities	3.9	(126.5)	210.3
Financing Activities			
Issuance of Common Stock	21.0	49.0	44.3
Issuance of Long-Term Debt	35.0	120.8	37.3
Reacquired Common Stock	–	(5.8)	–
Changes in Notes Payable – Net	–	(53.0)	(20.8)
Reductions of Long-Term Debt	(35.7)	(241.1)	(335.7)
Dividends on Common Stock and Distributions to Minority Shareholders	(36.7)	(79.7)	(93.2)
Redemption of Mandatorily Redeemable Preferred Securities	–	–	(75.0)
Net Increase in Book Overdrafts	3.4	–	–
Net Financing Activities for Discontinued Operations	(0.9)	(18.9)	(27.6)
Cash for Financing Activities	(13.9)	(228.7)	(470.7)
Effect of Exchange Rate Changes on Cash – Discontinued Operations	–	–	39.2
Change in Cash and Cash Equivalents	43.5	(180.2)	26.2
Cash and Cash Equivalents at Beginning of Period	46.1	226.3	200.1
Cash and Cash Equivalents at End of Period *(a)*	$ 89.6	$ 46.1	$226.3
Supplemental Cash Flow Information			
Cash Paid During the Period for			
Interest – Net of Amounts Capitalized	$34.9	$46.7	$69.2
Income Taxes	$27.1	$75.7	$87.4

(a) Included $0 of cash from Discontinued Operations at December 31, 2005 ($2.4 million at December 31, 2004; $116.1 million at December 31, 2003).

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 at December 31, 2002	$1,232.4	$488.7	$(22.2)	$(49.0)	$814.9
Comprehensive Income					
Net Income	236.4	236.4			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	3.6		3.6		
Interest Rate Swap	0.2		0.2		
Foreign Currency Translation Adjustments	39.2		39.2		
Additional Pension Liability	(6.3)		(6.3)		
Total Comprehensive Income	273.1				
Common Stock Issued – Net	44.3				44.3
Dividends Declared	(93.2)	(93.2)			
ESOP Shares Earned	3.6			3.6	
Balance at December 31, 2003	1,460.2	631.9	14.5	(45.4)	859.2
Comprehensive Income					
Net Income	104.4	104.4			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	0.7		0.7		
Foreign Currency Translation Adjustments	(23.5)		(23.5)		
Additional Pension Liability	(3.1)		(3.1)		
Total Comprehensive Income	78.5				
Common Stock Issued – Net	43.2				43.2
ADESA IPO	70.1				70.1
Spin-Off of ADESA	(963.6)	(363.4)			(600.2)
Receipt of ADESA Stock by ESOP	54.3			26.5	27.8
Purchase of ALLETE Shares by ESOP	(35.6)			(35.6)	
Dividends Declared	(79.7)	(79.7)			
ESOP Shares Earned	3.1			3.1	
Balance at December 31, 2004	630.5	293.2	(11.4)	(51.4)	400.1
Comprehensive Income					
Net Income	13.3	13.3			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	0.6		0.6		
Additional Pension Liability	(2.0)		(2.0)		
Total Comprehensive Income	11.9				
Common Stock Issued – Net	21.0				21.0
Dividends Declared	(34.4)	(34.4)			
Purchase of ALLETE Shares by ESOP	(30.3)			(30.3)	
ESOP Shares Earned	4.1			4.1	
Balance at December 31, 2005	$ 602.8	$272.1	$(12.8)	$(77.6)	$421.1

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. Business Segments

Presented below are the operating results and other financial information related to our reporting segments. For a description of our reporting segments, see Note 2.

In 2005, we began allocating corporate charges and interest expense to our business segments. For comparative purposes, segment information for 2004 and 2003 has been restated to reflect the new allocation method used in 2005 for corporate charges and interest expense. This restatement had no impact on consolidated net income or earnings per share.

For the Year Ended December 31	Consolidated	Regulated Utility	Nonregulated Energy Operations	Real Estate	Other
Millions					
2005					
Operating Revenue	$737.4	$575.6	$113.9	$47.5	$ 0.4
Fuel and Purchased Power	273.1	243.7	29.4	–	–
Operating and Maintenance	293.5	202.9	71.2	15.5	3.9
Kendall County Charge	77.9	–	77.9	–	–
Depreciation Expense	47.8	39.4	8.1	0.1	0.2
Operating Income (Loss) from Continuing Operations	45.1	89.6	(72.7)	31.9	(3.7)
Interest Expense	(26.4)	(17.4)	(6.6)	(0.1)	(2.3)
Other Income (Expense)	1.1	0.7	1.7	–	(1.3)
Income (Loss) from Continuing Operations Before Minority Interest and Income Taxes	19.8	72.9	(77.6)	31.8	(7.3)
Minority Interest	2.7	–	–	2.7	–
Income (Loss) from Continuing Operations Before Income Taxes	17.1	72.9	(77.6)	29.1	(7.3)
Income Tax Expense (Benefit)	(0.5)	27.2	(29.1)	11.6	(10.2)
Income (Loss) from Continuing Operations	17.6	$ 45.7	$ (48.5)	$17.5	$ 2.9
Loss from Discontinued Operations – Net of Tax	(4.3)				
Net Income	$ 13.3				
Total Assets	$1,398.8 *(a)*	$909.5	$185.2	$73.7	$227.8
Capital Expenditures	$63.1 *(a)*	$46.5	$12.1	–	–
2004					
Operating Revenue	$704.1	$555.0	$106.8	$41.9	$ 0.4
Fuel and Purchased Power	286.2	245.1	41.1	–	–
Operating and Maintenance	270.1	191.7	60.3	15.0	3.1
Depreciation Expense	46.9	39.5	7.2	0.1	0.1
Operating Income (Loss) from Continuing Operations	100.9	78.7	(1.8)	26.8	(2.8)
Interest Expense	(31.7)	(18.5)	(4.9)	(0.3)	(8.0)
Other Income (Expense)	(12.2)	0.1	0.6	–	(12.9)
Income (Loss) from Continuing Operations Before Minority Interest and Income Taxes	57.0	60.3	(6.1)	26.5	(23.7)
Minority Interest	2.1	–	–	2.1	–
Income (Loss) from Continuing Operations Before Income Taxes	54.9	60.3	(6.1)	24.4	(23.7)
Income Tax Expense (Benefit)	16.4	22.6	(3.2)	10.1	(13.1)
Income (Loss) from Continuing Operations	38.5	$ 37.7	$ (2.9)	$14.3	$ (10.6)
Income from Discontinued Operations – Net of Tax	73.7				
Change in Accounting Principle – Net of Tax	(7.8)				
Net Income	$104.4				
Total Assets	$1,431.4 *(a)*	$902.8	$161.4	$75.1	$242.6
Capital Expenditures	$79.2 *(a)*	$41.7	$15.7	–	$0.4

(a) Discontinued Operations represented $2.6 million of total assets in 2005 ($49.5 million in 2004) and $4.5 million of capital expenditures in 2005 ($21.4 million in 2004).

Note 1. Business Segments (Continued)

For the Year Ended December 31	Consolidated	Regulated Utility	Nonregulated Energy Operations	Real Estate	Other
Millions					
2003					
Operating Revenue	$659.6	$510.0	$106.6	$42.6	$ 0.4
Fuel and Purchased Power	252.5	212.5	40.0	–	–
Operating and Maintenance	260.5	185.4	54.8	16.3	4.0
Depreciation Expense	48.9	41.2	7.4	0.1	0.2
Operating Income (Loss) from Continuing Operations	97.7	70.9	4.4	26.2	(3.8)
Interest Expense	(50.5)	(20.4)	(4.8)	(0.2)	(25.1)
Other Income (Expense)	2.3	2.9	1.9	–	(2.5)
Income (Loss) from Continuing Operations Before Minority Interest and Income Taxes	49.5	53.4	1.5	26.0	(31.4)
Minority Interest	2.6	–	–	2.6	–
Income (Loss) from Continuing Operations Before Income Taxes	46.9	53.4	1.5	23.4	(31.4)
Income Tax Expense (Benefit)	17.7	21.0	0.4	9.8	(13.5)
Income (Loss) from Continuing Operations	29.2	$ 32.4	$ 1.1	$13.6	$ (17.9)
Income from Discontinued Operations – Net of Tax	207.2				
Net Income	$236.4				
Total Assets	$3,101.3 *(a)*	$917.3	$194.7	$78.6	$148.4
Capital Expenditures	$136.3 *(a)*	$42.2	$26.5	–	–

(a) Discontinued Operations represented $1,762.3 million of total assets and $67.6 million of capital expenditures.

Note 2. 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.

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.

Certain reclassifications have been made to prior years’ amounts to conform to current year classifications. We revised our Consolidated Statement of Cash Flows for the years ended December 31, 2004 and 2003, to reconcile Net Income to Cash from Operating Activities. Previously, we reconciled Income from Continuing Operations to Cash from Operating Activities. In addition, we have reclassified certain amounts in our balance sheet, income statement, cash flows and segment information to reflect discontinued operations treatment for the sale of our telecommunications business. These reclassifications had no effect on previously reported net income, shareholders’ equity, comprehensive income or cash flows.

Revision in the Classification of Certain Securities. In the quarterly period ended June 30, 2005, we concluded that it was appropriate to reclassify our auction rate municipal bonds and variable rate municipal demand notes as short-term investments. Previously, such investments had been classified as cash and cash equivalents. Accordingly, we now report these securities as short-term investments in a separate line item on our Consolidated Balance Sheet as of December 31, 2004. We have also made corresponding adjustments to our Consolidated Statement of Cash Flows for the period ended December 31, 2004, to reflect the gross purchases and sales of these securities as investing activities rather than as a component of cash and cash equivalents. This change in classification does not affect our previously reported Consolidated Statements of Income for any period.

For the year ended December 31, 2004, net cash used in investing activities related to these short-term investments of $149.2 million was included in cash and cash equivalents in our Consolidated Statement of Cash Flows.

Business Segments. Our Regulated Utility, Nonregulated Energy Operations and Real Estate segments were determined based on products and services provided and the manner in which we monitor and manage the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment. Discontinued Operations includes our telecommunications business, which we sold on December 30, 2005, our Automotive Services business that was spun off in September 2004, costs associated with the spin-off of ADESA incurred by ALLETE, and our Water Services businesses, the majority of which were sold in 2003.

Note 2. Operations and Significant Accounting Policies (Continued)

Regulated Utility includes retail and wholesale rate-regulated electric, water and gas services in northeastern Minnesota and northwestern Wisconsin. Minnesota Power, an operating division of ALLETE, and SWL&P, a wholly-owned subsidiary, provide regulated utility electric service to 151,000 retail customers in northeastern Minnesota and northwestern Wisconsin. Approximately 41% of regulated utility electric revenue is from Large Power Customers (32% of consolidated revenue). Large Power Customers consist of five taconite producers, four paper and pulp mills, two pipeline companies and one manufacturer under all-requirements contracts with expiration dates extending from February 2007 through December 2014. Revenue of $83.5 million (11.3% of consolidated revenue) was received from one taconite producer in 2005 (12.6% in 2004; 10.0% in 2003). Regulated utility rates are under the jurisdiction of various state and federal regulatory authorities. Billings are rendered on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules and that bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates.

Minnesota Power withdrew from Split Rock Energy, a joint venture with Great River Energy, in 2004. Upon withdrawal, we received a $12.0 million distribution in 2004. We accounted for our 50% ownership interest in Split Rock Energy under the equity method of accounting. For the year ended December 31, 2004, our pre-tax equity income from Split Rock Energy was less than $0.1 million ($2.9 million in 2003). In 2004, prior to our withdrawal, we made power purchases from Split Rock Energy of $6.2 million ($50.9 million in 2003) and power sales to Split Rock Energy of $1.9 million ($19.6 million in 2003).

Nonregulated Energy Operations includes our coal mining activities in North Dakota and nonregulated generation (non-rate base generation sold at market-based rates to the wholesale market) consisting primarily of Taconite Harbor in northern Minnesota. Pending MPUC approval, Taconite Harbor will be integrated into our Regulated Utility business effective retroactive to January 1, 2006, to help meet forecasted base load energy requirements. Nonregulated generation also included generation secured through the Kendall County power purchase agreement, which was assigned to Constellation Energy Commodities in April 2005. (See Note 11.)

Real Estate includes our Florida real estate operations. Our real estate operations include several wholly-owned subsidiaries and an 80% ownership in Lehigh Acquisition Corporation, which are consolidated in ALLETE's financial statements. All of our Florida real estate companies are principally engaged in real estate acquisitions, development and sales.

Full profit recognition is recorded on sales upon closing, provided cash collections are at least 20% of the contract price and the other requirements of SFAS 66, "Accounting 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 in accordance with SFAS 66. Pursuant to this method of accounting, gross profit is recognized based upon the relationship of development costs incurred as of that date to the total estimated costs to develop the parcels, including all related amenities or common costs of the entire project. Revenue and cost of real estate sold in excess of the amount recognized based on the percentage-of-completion method is deferred and recognized as revenue and cost of real estate sold during the period in which the related development costs are incurred. Revenue and cost of real estate sold are recorded net as Deferred Profit on Sales of Real Estate on our consolidated balance sheet.

Traffic impact fee credits are provided to the developer as mitigation payments are made to the city. We are reimbursed after the land is sold and a subsequent property owner constructs vertical improvements on the site. We recognize revenue resulting from these reimbursed fees when they are 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 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 SFAS 67, "Accounting for Costs and Initial Rental Operations of Real Estate Projects." When real estate is sold, the cost of real estate sold 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.

Other includes investments in emerging technologies, and earnings on cash, cash equivalents and short-term investments. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investment in privately-held companies under the cost method because of our ownership percentage. Short-term investments consist of auction rate municipal bonds and variable rate municipal demand notes, and are classified as available-for-sale securities. All income generated from these short-term investments is recorded as interest income.

Note 2. 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 and significant replacements and improvements are capitalized; maintenance and repair costs are expensed as incurred. Expenditures for major plant overhauls are also accounted for using this same policy. Gains or losses on nonregulated 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, pursuant to SFAS 71, "Accounting for the Effects of Certain Types of Regulations." Our Regulated Utility operations capitalize an allowance for funds used during construction, which includes both an interest and equity component. Our other operations capitalize interest during a construction project.

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 using SFAS 144, "Accounting for the Impairment and 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 cash flows.

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, the size of the portfolio, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable **December 31**	**2005**	**2004**
Millions		
Trade Accounts Receivable		
Billed	$69.2	$69.5
Unbilled	10.9	10.2
Less: Allowance for Doubtful Accounts	1.0	1.0
Total Accounts Receivable – Net	$79.1	$78.7

Inventories. Inventories are stated at the lower of cost or market. Cost is determined by the average cost method.

Inventories **December 31**	**2005**	**2004**
Millions		
Fuel	$11.0	$11.4
Materials and Supplies	22.1	20.4
Total Inventories	$33.1	$31.8

Unamortized Expense, Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using the effective interest method.

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

Restricted Cash. We sponsor a leveraged ESOP as part of our Retirement Savings and Stock Ownership Plan. At December 31, 2004, the ESOP had $30.3 million in cash, which was used to purchase ALLETE common stock on the open market during 2005. We reflected the cash held by the ESOP as Restricted Cash on our consolidated balance sheet. (See Note 18.) There was no restricted cash at December 31, 2005.

Accounting for Stock-Based Compensation. We have elected to account for stock-based compensation under the intrinsic value method in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees." Accordingly, we recognize expense for performance share awards granted and do not recognize expense for fixed employee stock options granted. The after-tax expense recognized for performance share awards was approximately $1.5 million in 2005 ($1.0 million in 2004; $3.0 million in 2003). The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS 123, "Accounting for Stock-Based Compensation."

Note 2. Operations and Significant Accounting Policies (Continued)

Effect of SFAS 123 Accounting for Stock-Based Compensation For the Year Ended December 31	2005	2004	2003
Millions Except Per Share Amounts			
Net Income			
As Reported	$13.3	$104.4	$236.4
Plus: Employee Stock Compensation Expense Included in Net Income – Net of Tax	1.5	1.0	3.0
Less: Employee Stock Compensation Expense Determined Under SFAS 123 – Net of Tax	1.5	1.3	3.5
Pro Forma	$13.3	$104.1	$235.9
Basic Earnings Per Share			
As Reported	$0.49	$3.69	$8.56
Pro Forma	$0.49	$3.68	$8.55
Diluted Earnings Per Share			
As Reported	$0.48	$3.67	$8.52
Pro Forma	$0.48	$3.66	$8.49

In the previous table, the pro forma expense for employee stock options granted determined under SFAS 123 was calculated using the Black-Scholes option pricing model and the following assumptions:

	2005	2004	2003
Risk-Free Interest Rate	3.7%	3.3%	3.1%
Expected Life – Years	5	5	5
Expected Volatility	20.0%	28.1%	25.2%
Dividend Growth Rate	5%	2%	2%

Foreign Currency Translation. Results of operations for our Canadian and Mexican automotive subsidiaries prior to the spin-off in 2004 were translated into United States dollars using the average exchange rates during the applicable periods. Assets and liabilities were translated into United States dollars using the exchange rate on the balance sheet date. Resulting translation adjustments were recorded in Accumulated Other Comprehensive Income (Loss) in Shareholders' Equity on our consolidated financial statements.

Other Liabilities December 31	2005	2004
Millions		
Deferred Regulatory Credits (See Note 4)	$ 31.8	$ 35.9
Deferred Compensation and Accrued Postretirement Benefits	59.5	66.3
Asset Retirement Obligations (See Note 3)	25.3	22.4
Other	27.5	25.9
Total Other Liabilities	$144.1	$150.5

Environmental Liabilities. 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 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.

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method as prescribed by SFAS 109, "Accounting 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, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. 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.

Note 2. Operations and Significant Accounting Policies (Continued)

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 the net basis and neither the amounts collected or paid are reflected on our consolidated statement of income.

New Accounting Standards. *SFAS 123(R).* In December 2004, the FASB issued SFAS 123(R), "Share-Based Payment," which will be effective for enterprises beginning with the first interim or annual reporting period of the registrants' first fiscal year beginning on or after June 15, 2005. SFAS 123(R) replaces SFAS 123, "Accounting for Stock-Based Compensation," and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees." The new standard requires that the compensation cost relating to share-based payment be recognized in financial statements at fair value. As such, reporting employee stock options under the intrinsic value-based method prescribed by APB Opinion No. 25 will no longer be allowed. Historically, we have elected to use the intrinsic value method and have not recognized expense for employee stock options granted. We implemented SFAS 123(R) January 1, 2006, using the modified prospective basis. We do not anticipate changing compensation plans for this accounting treatment. We do not believe it will have a material impact on our financial position, results of operations or cash flows.

The FASB has clarified the adoption of SFAS 123(R) with FSP SFAS 123(R)-1 "Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R)" and FSP SFAS 123(R)-2 "Practical Accommodation to the Application of Grant Date as Defined in FASB Statement No. 123(R)." These staff positions clarify the implementation of SFAS 123(R). We do not believe they will have a material impact on our financial position, results of operations or cash flows.

The FASB has proposed FSP SFAS 123(R)-c "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards." This proposed staff position provides for an alternate method for the implementation of SFAS 123(R). We do not believe it will have a material impact on the Company.

Interpretation No. 47. In March 2005, the FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations." Interpretation No. 47 clarifies that the term "conditional asset retirement obligation" as used in SFAS 143, "Accounting for Asset Retirement Obligations," refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. However, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Interpretation No. 47 requires that the uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation be factored into the measurement of the liability when sufficient information exists. Interpretation No. 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Interpretation No. 47 is effective for fiscal years ending after December 15, 2005. We have applied Interpretation No. 47 on a prospective basis.

SFAS 153. In December 2004, the FASB issued SFAS 153, "Exchanges of Nonmonetary Assets—An Amendment of APB Opinion No. 29, Accounting for Nonmonetary Transactions." SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets in paragraph 21(b) of APB Opinion No. 29, Accounting for Nonmonetary Transactions, and replaces it with an exception for exchanges that do not have commercial substance. SFAS 153 specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 is effective for fiscal periods beginning after June 15, 2005, and is required to be adopted beginning on January 1, 2006. We are currently evaluating the effect that the adoption of SFAS 153 will have on our consolidated results of operations and financial condition but do not expect it to have a material impact.

SFAS 154. In May 2005, the FASB issued SFAS 154, "Accounting Changes and Error Corrections" (SFAS 154) which replaces APB Opinion No. 20 "Accounting Changes" and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements—An Amendment of APB Opinion No. 28." SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We are currently evaluating the effect that the adoption of SFAS 154 will have on our consolidated results of operations and financial condition but do not expect that adoption will have a material impact.

Note 3. Property, Plant and Equipment

Property, Plant and Equipment December 31	2005	2004
Millions		
Regulated Utility	$1,457.4	$1,431.9
Construction Work in Progress	21.2	10.4
Accumulated Depreciation	(743.5)	(716.4)
Regulated Utility Plant – Net	735.1	725.9
Nonregulated Energy Operations	160.6	155.5
Construction Work in Progress	3.7	1.1
Accumulated Depreciation	(43.9)	(39.6)
Nonregulated Energy Operations Plant – Net	120.4	117.0
Other Plant – Net	4.9	6.7
Property, Plant and Equipment – Net	$ 860.4	$ 849.6

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of plant. 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	4 to 31 years	Nonregulated Energy Operations	5 to 35 years
	Transmission	40 to 60 years	Other Plant	5 to 30 years
	Distribution	30 to 70 years		

Asset Retirement Obligations. Pursuant to SFAS 143, "Accounting for Asset Retirement Obligations," we recognize, at fair value, obligations associated with the retirement of tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Asset retirement obligations relate primarily to the decommissioning of our utility steam generating facilities and reclamation at BNI Coal, and are included in Other Liabilities on our consolidated balance sheet. Removal costs associated with certain distribution and transmission assets have not been recognized as these facilities have been determined to have indeterminate useful lives. Prior to the adoption of SFAS 143, utility decommissioning obligations were accrued through depreciation expense at depreciation rates approved by the MPUC. 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 due to indeterminate settlement dates.

Asset Retirement Obligation	
Millions	
Obligation at December 31, 2003	$20.7
Accretion Expense	1.2
Additional Liabilities Incurred in 2004	0.5
Obligation at December 31, 2004	22.4
Accretion Expense	1.6
Additional Liabilities Incurred in 2005	1.3
Obligation at December 31, 2005	$25.3

Note 4. Regulatory Matters

Electric Rates. Entities within our regulated utility segment file for periodic rate revisions with the MPUC, the FERC or the PSCW. Minnesota Power's last retail rate filing with the MPUC was in 1994. SWL&P's current retail rates are based on a 2005 PSCW retail rate order. In 2005, 72% of our consolidated operating revenue was under regulatory authority (75% in 2004; 73% in 2003). The MPUC had regulatory authority over approximately 56% of our consolidated operating revenue in 2005 (60% in 2004; 57% in 2003).

Deferred Regulatory Charges and Credits. Our regulated utility operations are subject to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation." We capitalize as deferred regulatory charges incurred costs which are probable of recovery in future utility rates. Deferred regulatory credits represent amounts expected to be credited to customers in rates. Deferred regulatory charges and credits are included in Other Assets and Other Liabilities on our consolidated balance sheet.

Deferred Regulatory Charges and Credits **December 31**	**2005**	**2004**
Millions		
Deferred Charges		
Income Taxes	$ 12.0	$ 12.9
Premium on Reacquired Debt	3.5	4.1
Other	1.7	2.0
	17.2	19.0
Deferred Credits – Income Taxes	31.8	35.9
Net Deferred Regulatory Liabilities	$(14.6)	$(16.9)

Note 5. Financial Instruments

Securities Investments. At December 31, 2005, Investments included securities accounted for as available-for-sale under SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities," and securities in our emerging technology portfolio. Short-Term Investments included various auction rate municipal bonds and variable rate municipal demand notes. Income and realized gains and losses from these investments were included in Other Income (Expense) on our consolidated income statement.

Available-For-Sale Securities. At December 31, 2005, our available-for-sale securities portfolio consisted of securities in a grantor trust established to fund certain employee benefits included in Investments and various auction rate municipal bonds and variable rate municipal demand notes included as Short-Term Investments. 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. Our short-term investments classified as available-for-sale securities, however, are recorded at cost, which approximates fair market value due to their variable interest rates and typically reset every 7 to 35 days. Despite the long-term nature of their stated contractual maturities, we have the ability to quickly liquidate these securities. As a result, we had no cumulative gross unrealized holding gains (losses) or gross realized gains (losses) from our short-term investments. All income generated from these short-term investments was recorded as interest income. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review on a quarterly basis available-for-sale securities for other than temporary impairment by assessing such factors as the share price trends and the impact of overall market conditions. As a result of our periodic assessments, we did not record any impairment of available-for-sale securities in 2005 or 2004.

During the fourth quarter of 2004, we sold 3.3 million shares of ADESA stock received by our ESOP plan (see Note 18) as a result of the September 2004 spin-off of ADESA. In total, the ESOP received total proceeds of $65.9 million, resulting in a gain of $11.5 million, which we recognized during the fourth quarter of 2004. We accounted for the ADESA stock as available-for-sale.

During the second quarter of 2003, we sold the publicly-traded investments held in our emerging technology portfolio and recognized a $2.3 million after-tax loss. These publicly-traded emerging technology investments were accounted for as available-for-sale securities prior to sale.

Note 5. Financial Instruments (Continued)

Available-For-Sale Securities

Millions **At December 31**	**Cost**	**Gross Unrealized** **Gain**	 **(Loss)**	**Fair Value**
2005	$135.2	$4.4	$(0.1)	$139.5
2004	$176.4	$3.1	$(0.1)	$179.4
2003	$24.1	$1.4	–	$25.5

Year Ended December 31	**Sales Proceeds**	**Gross Realized** **Gain**	 **(Loss)**	**Net Unrealized Gain (Loss) in Other Comprehensive Income**
2005	$32.3	–	–	$1.3
2004	$65.9	$11.5	–	$1.6
2003	$6.4	$1.2	$(4.7)	$2.4

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method (see Note 15) and account for our direct investment in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $9.2 million at December 31, 2005 ($13.6 million at December 31, 2004). Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Our basis in direct investments in privately-held companies included in the emerging technology portfolio was zero at December 31, 2005 ($4.5 million at December 31, 2004). In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments that related to direct investments in certain privately-held, start-up companies whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. In 2004, we recorded $6.5 million ($4.1 million after tax) of impairments. We did not record any impairments in 2003.

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 **December 31**	**Carrying Amount**	**Fair Value**
Millions		
Long-Term Debt		
2005	$390.5	$392.5
2004	$391.2	$395.9

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 12 Large Power Customers. Receivables from these customers totaled approximately $10 million at December 31, 2005 ($9 million at December 31, 2004). 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.

Note 6. Investments

At December 31, 2005, Investments included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held for employee benefits and our emerging technology investments.

Investments **December 31**	**2005**	**2004**
Millions		
Real Estate Assets	$ 73.7	$ 75.1
Debt and Equity Securities	34.8	35.8
Emerging Technology Investments (See Note 5)	9.2	13.6
Total Investments	$117.7	$124.5

Real Estate Assets	**2005**	**2004**
Millions		
Land Held for Sale Beginning Balance	$47.2	$50.7
Additions during period: Capitalized Improvements	9.4	2.9
Deductions during period: Cost of Real Estate Sold	(8.6)	(6.4)
Land Held for Sale Ending Balance	48.0	47.2
Long-Term Finance Receivables	7.4	9.7
Other *(a)*	18.3	18.2
Total Real Estate Assets	$73.7	$75.1

(a) Consisted primarily of a shopping center.

Finance receivables have maturities ranging up to ten years, accrue interest at market-based rates and are net of an allowance for doubtful accounts of $0.6 million at December 31, 2005 ($0.7 million at December 31, 2004). Minority interest associated with real estate operations was $6.0 million at December 31, 2005 ($5.6 million at December 31, 2004).

Note 7. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding at December 31, 2005, was $2.7 million ($1.8 million at December 31, 2004) and consisted of Long-Term Debt Due Within One Year.

As of December 31, 2005, we had bank lines of credit aggregating $120.0 million ($111.5 million at December 31, 2004), the majority of which were to expire in December 2007. These bank lines of credit made financing available through short-term bank loans and provided credit support for commercial paper. At December 31, 2005, $1.1 million ($0 at December 31, 2004) was drawn on our lines of credit leaving a $118.9 million balance available for use ($111.5 million at December 31, 2004). The $1.1 million drawn amount relates to an $8.5 million revolving development loan with CypressCoquina Bank that we entered into in March 2005. The revolving development loan has an interest rate equal to the prime rate, with an initial term of 36 months. The term of the loan may be extended 24 months if certain conditions are met. The loan is guaranteed by Lehigh Acquisition Corporation. Certain lines of credit required a commitment fee of 0.15%. There was no commercial paper issued as of December 31, 2005, or December 31, 2004.

In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility (Line) with LaSalle Bank National Association for $150 million ($100 million at December 31, 2004). The Line matures on January 11, 2011, and requires a commitment fee of 0.125%. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. The Line may be used for general corporate purposes, working capital and to provide liquidity in support of our commercial paper program. We may prepay amounts outstanding under the Line in whole or in part at our discretion. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity.

Note 7. Short-Term and Long-Term Debt (Continued)

Long-Term Debt. The aggregate amount of long-term debt maturing during 2006 is $2.7 million ($84.1 million in 2007; $57.4 million in 2008; $10.6 million in 2009; $4.9 million in 2010; and $230.8 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgages securing various first mortgage bonds.

In August 2005, we issued $35 million in principal amount of First Mortgage Bonds, 5.28% due 2020. Proceeds were used to redeem $35 million in principal amount of First Mortgage Bonds, 7 1/2% Series originally due 2007.

In October 2005, we accepted an offer from certain institutional buyers in the private placement market to purchase $50 million in principal amount of our first mortgage bonds. When issued, on or about March 1, 2006, the bonds will carry an interest rate of 5.69% and will have a term of 30 years. On January 30, 2006, we called for redemption on March 2, 2006, $50 million in principal amount of First Mortgage Bonds, 7% Series due 2008.

Long-Term Debt December 31	**2005**	**2004**
Millions		
First Mortgage Bonds		
6.68% Series Due 2007	$ 20.0	$ 20.0
7% Series Due 2007	60.0	60.0
7 1/2% Series Due 2007	–	35.0
7% Series Due 2008	50.0	50.0
5.28% Series Due 2020	35.0	–
4.95% Pollution Control Series F Due 2022	111.0	111.0
Variable Demand Revenue Refunding Bonds		
Series 1997 A, B, C and D Due 2007 – 2020	39.0	39.0
Industrial Development Revenue Bonds 6.5% Due 2025	35.1	35.1
Other Long-Term Debt, 2.0% – 8.5% Due 2006 – 2025	40.4	41.1
Total Long-Term Debt	390.5	391.2
Less Due Within One Year	2.7	1.8
Net Long-Term Debt	$387.8	$389.4

The 6.68% Series Due 2007 and the 7% Series Due 2007 cannot be redeemed prior to maturity. The remaining debt may be redeemed in whole or in part at our option, according to the terms of the obligations.

Financial Covenants. 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 quarterly ratio of its funded debt to total capital of less than or equal to .65 to 1.00. Failure to meet this covenant could give rise to an event of default, if not corrected 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.

Note 8. Common Stock and Earnings Per Share

Our Articles of Incorporation and mortgages contain provisions that, under certain circumstances, would restrict the payment of common stock dividends. As of December 31, 2005, no retained earnings were restricted as a result of these provisions.

Reverse Common Stock Split. On September 20, 2004, our one-for-three reverse common stock split became effective. All common share and per share amounts have been adjusted for all periods to reflect the one-for-three reverse stock split.

Summary of Common Stock		Shares	Equity
Millions			
Balance at December 31, 2002		28.5	$814.9
2003	Employee Stock Purchase Plan	0.0	1.4
	Invest Direct *(a)*	0.3	19.9
	Options and Stock Awards	0.3	23.0
Balance at December 31, 2003		29.1	859.2
2004	Employee Stock Purchase Plan	0.0	1.0
	Invest Direct *(a)*	0.3	18.1
	ADESA IPO (See Note 14)	–	70.1
	Spin-Off of ADESA (See Note 14)	–	(600.2)
	Receipt of ADESA Stock by ESOP	–	27.8
	Reacquired	(0.1)	(5.8)
	Options and Stock Awards	0.4	29.9
Balance at December 31, 2004		29.7	400.1
2005	Employee Stock Purchase Plan	0.0	0.5
	Invest Direct *(a)*	0.2	10.5
	Options and Stock Awards	0.2	10.0
Balance at December 31, 2005		30.1	$421.1

(a) Invest Direct is ALLETE's direct stock purchase and dividend reinvestment plan.

Shareholder Rights Plan. In 1996, we adopted a rights plan that provides for a dividend distribution of one preferred share purchase right (Right) to be attached to each share of common stock.

The Rights, which are currently not exercisable or transferable apart from our common stock, entitle the holder to purchase one-and-a-half of one-hundredth (three two-hundredths) of a share of ALLETE's Junior Serial Preferred Stock A, without par value. The purchase price as defined in the Rights Plan, remains at $90. These Rights would become exercisable if a person or group acquires beneficial ownership of 15% or more of our common stock or announces a tender offer which would increase the person's or group's beneficial ownership interest to 15% or more of our common stock, subject to certain exceptions. If the 15% threshold is met, each Right entitles the holder (other than the acquiring person or group) to purchase common stock (or, in certain circumstances, cash, property or other securities of ours) having a market price equal to twice the exercise price of the Right. If we are acquired in a merger or business combination, or 50% or more of our assets or earning power are sold, each exercisable Right entitles the holder to purchase common stock of the acquiring or surviving company having a value equal to twice the exercise price of the Right. Certain stock acquisitions will also trigger a provision permitting the Board of Directors to exchange each Right for one share of our common stock.

The Rights, which expire on July 23, 2006, are nonvoting and may be redeemed by us at a price of $0.005 per Right at any time they are not exercisable. One million shares of Junior Serial Preferred Stock A have been authorized and are reserved for issuance under the plan.

Earnings Per Share. The difference between basic and diluted earnings per share arises from outstanding stock options and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. For 2005, no options to purchase shares of common stock were excluded from the computation of diluted earnings per share because they were anti-dilutive due to the option exercise prices being greater than the average market price of the common shares during the period (0.1 million shares were excluded for 2004; 0 shares were excluded for 2003).

Note 8. Common Stock and Earnings Per Share (Continued)

Reconciliation of Basic and Diluted Earnings Per Share For the Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2005			
Income from Continuing Operations	$17.6	–	$17.6
Common Shares	27.3	0.1	27.4
Per Share from Continuing Operations	$0.65	–	$0.64
2004			
Income from Continuing Operations Before Change in Accounting Principle	$38.5	–	$38.5
Common Shares	28.3	0.1	28.4
Per Share from Continuing Operations	$1.37	–	$1.35
2003			
Income from Continuing Operations	$29.2	–	$29.2
Common Shares	27.6	0.2	27.8
Per Share from Continuing Operations	$1.06	–	$1.05

Note 9. Jointly-Owned Electric Facility

We own 80% of the 536-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 Wisconsin Public Power, Inc., the owner of the other 20% 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. Our 80% share of the original cost of Boswell Unit 4, which is included in property, plant and equipment at December 31, 2005, was $310 million ($309 million at December 31, 2004). The corresponding accumulated depreciation balance was $162 million at December 31, 2005 ($157 million at December 31, 2004).

Note 10. Commitments, Guarantees and Contingencies

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

Minnesota Power was entitled to approximately 71% of the Unit's output under the Agreement. After 2005, and upon compliance with a two-year advance notice requirement, Minnkota Power has the option to reduce Minnesota Power's entitlement by approximately 5% annually, to a minimum of 50%. In December 2005, 2004 and 2003, we received notices from Minnkota Power that they will reduce our output entitlement by approximately 5% on January 1, 2006, 2007, and 2008, to 66%, 60% and 55% respectively.

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. At December 31, 2005, Square Butte had total debt outstanding of $310.7 million. Total annual debt service for Square Butte is expected to be approximately $26 million in each of the years 2006 through 2010. Variable operating costs include the price of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2005 was $56.4 million ($56.1 million in 2004 and $52.3 million in 2003). This reflects Minnesota Power's pro rata share of total Square Butte costs, based on the 71% output entitlement in 2005, 2004 and 2003. Included in this amount was Minnesota Power's pro rata share of interest expense of $13.6 million in 2005 ($12.6 million in 2004; $12.8 million in 2003). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Note 10. Commitments, Guarantees and Contingencies (Continued)

Leasing Agreements. In September 2004, BNI Coal entered into an operating lease agreement for a new dragline that was placed in service at BNI Coal's mine on September 30, 2004. BNI Coal is obligated to make lease payments totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at a fair market rental, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2013. The aggregate amount of minimum lease payments for all operating leases is $6.4 million in 2006, $5.9 million in 2007, $5.2 million in 2008, $4.7 million in 2009, $4.2 million in 2010 and $46.9 million thereafter. Total rent expense was $6.2 million in 2005 ($3.8 million in 2004; $3.2 million in 2003).

Coal, Rail and Shipping Contracts. We have three coal supply agreements with various expiration dates ranging from December 2006 to December 2009. We also have rail and shipping agreements for transportation of all of our coal, with various expiration dates ranging from December 2006 to December 2011. Our minimum annual payment obligations under these coal, rail and shipping agreements are currently $40.5 million in 2006, $9.7 million in 2007, $10.1 million in 2008, $6.1 million in 2009 and no specific commitments beyond 2009. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years.

Fuel Clause Recovery of MISO Day 2 Costs. Minnesota Power filed a petition with the MPUC in February 2005 to amend its fuel clause to accommodate costs and revenue related to MISO Day 2. On April 7, 2005, the MPUC approved interim accounting treatment of MISO Day 2 costs to be accounted for on a net basis and recovered through the fuel clause, subject to refund with interest. This interim treatment has continued while the MPUC has addressed the cost recovery petitions from Xcel Energy Inc., Otter Tail Power Company, Alliant Energy Corporation and Minnesota Power.

On December 21, 2005, the MPUC issued an order which denied recovery through the fuel clause of uplift charges, congestion revenue and expenses, and administrative costs related to Minnesota Power's MISO Day 2 market activities. Minnesota Power requested rehearing of the order in a filing made with the MPUC on January 10, 2006. The other three utilities affected by the order also filed for rehearing, as did the DOC and MISO. In a hearing on February 9, 2006, the MPUC granted rehearing of the MISO Day 2 docket and suspended the refund obligation. The MPUC will review the MISO Day 2 costs to determine which costs should be recovered on a current basis through the fuel clause and which costs are more appropriately deferred for potential recovery through base rates. The Company is unable to predict the outcome of this matter.

Emerging Technology Portfolio. We have investments in emerging technologies through minority investments in venture capital funds structured as limited liability companies, and direct investments in privately-held, start-up companies. The carrying value of our direct investments in privately-held, start-up companies was zero at December 31, 2005 ($4.5 million at December 31, 2004). We have committed to make additional investments in certain emerging technology venture capital funds. The total future commitment was $3.1 million at December 31, 2005 ($4.5 million at December 31, 2004), and is expected to be invested at various times through 2007. We do not have plans to make any additional investments beyond this commitment.

Investment in ATC. On December 16, 2005, ALLETE entered into an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC that provides for ALLETE, through its Wisconsin subsidiary, Rainy River Energy Corporation - Wisconsin, to invest $60 million in ATC by the end of 2006. ALLETE's investment will represent an estimated 9% ownership interest in ATC. The investment by ALLETE's subsidiary in ATC is subject to review by the PSCW.

Environmental Matters. Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future stricter 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 if and when any such stricter environmental requirements will be imposed and the impact they will have on the Company. 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 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 expense unless recoverable in rates from customers.

Note 10. Commitments, Guarantees and Contingencies (Continued)

SWL&P Manufactured Gas Plant. In May 2001, SWL&P received notice from the WDNR that the City of Superior had found soil contamination on property adjoining a former Manufactured Gas Plant (MGP) site owned and operated by SWL&P from 1889 to 1904. The WDNR requested SWL&P to initiate an environmental investigation. The WDNR also issued SWL&P a Responsible Party letter in February 2002. In February 2003, SWL&P submitted a Phase II environmental site investigation report to the WDNR. This report identified some MGP-like chemicals that were found in the soil near the former plant site. During March and April 2003, sediment samples were taken from nearby Superior Bay. The report on the results of this sampling was completed and sent to the WDNR during the first quarter of 2004. The next phase of the investigation was to determine any impact to soil or ground water between the former MGP site and Superior Bay. Site work for this phase of the investigation was performed during October 2004, and the final report was sent to the WDNR in March 2005. Additional site investigation was performed during September and October 2005. It is anticipated that additional site work will be performed in 2006. Although it is not possible to quantify the potential clean-up cost until the investigation is completed, a $0.5 million liability was recorded in December 2003 to address the known areas of contamination. The Company has recorded a corresponding dollar amount as a regulatory asset to offset this liability. The PSCW has approved SWL&P's deferral of these MGP environmental investigation and potential clean-up costs for future recovery in rates, subject to a regulatory prudency review. In May 2005, the PSCW approved the collection through rates of $150,000 of site investigation costs that had been incurred at the time SWL&P filed their most recent rate request. ALLETE maintains pollution liability insurance coverage that includes coverage for SWL&P. A claim has been filed with respect to this matter. The insurance carrier has issued a reservation of rights letter and the Company continues to work with the insurer to determine the availability of insurance coverage.

Square Butte Generating Facility. In June 2002, Minnkota Power, the operator of Square Butte, received a Notice of Violation from the EPA regarding alleged New Source Review violations at the M.R. Young Station, which includes the Square Butte generating unit. The EPA claims certain capital projects completed by Minnkota Power should have been reviewed pursuant to the New Source Review regulations, potentially resulting in new air permit operating conditions and possible significant capital expenditures to comply. Minnkota Power has held several meetings with the EPA to discuss the alleged violations. Discussions between Minnkota Power and the EPA are ongoing and we are unable to predict the outcome or cost impacts. If Square Butte is required to make significant capital expenditures to comply with the EPA requirements, we expect such capital expenditures to be debt financed. Our future cost of purchased power would include our pro rata share of this additional debt service.

Clean Water Act – Fish Impingement/Entrainment Reduction Standards. In July 2004, the EPA issued Section 316(b) Phase II Rule of the Clean Water Act to ensure that the location, design, construction and capacity of cooling water intake structures at electric generating facilities reflect the best technology available to reduce fish mortality due to impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses). The new rule for fish impingement mortality requirements apply to the Boswell, Laskin, Hibbard and Square Butte generating facilities. The impingement and entrainment requirements apply to Taconite Harbor because it is located on Lake Superior. The rule requires biological studies and engineering analyses to be performed within the 2005 to 2008 timeframe. The biological studies were initiated in 2005. The estimated total cost of these studies for our facilities is expected to be in the range of $0.5 million to $1.0 million. At this time, we cannot estimate the capital and/or aquatic restoration expenditures that may be required to comply with the Section 316 (b) Phase II Rule.

EPA Clean Air Interstate Rule and Clean Air Mercury Rule. In March 2005, the EPA announced the final Clean Air Interstate Rule (CAIR) that reduces and permanently caps emissions of SO_2 and NO_X in many of the eastern United States. The CAIR includes Minnesota as one of the 28 states it considers an "eastern" state. The EPA also announced the final Clean Air Mercury Rule (CAMR) that reduces and permanently caps electric utility mercury emissions in the continental United States. The CAIR and the CAMR regulations have been challenged in the court system, which may delay implementation or modify provisions. Minnesota Power is participating in a legal challenge to the CAIR, but is not participating in the challenge of the CAMR. However, if the CAMR and the CAIR do go into effect, Minnesota Power expects to be required to (1) make emissions reductions, (2) purchase mercury, SO_2 and NO_X allowances through the EPA's cap-and-trade system, or (3) use a combination of both.

We believe that the CAIR contains flaws in its methodology and application, which will cause Minnesota Power to incur significantly higher compliance costs. Consequently, on July 11, 2005, Minnesota Power filed a Petition for Review with the U.S. Court of Appeals for the District of Columbia Circuit. The Company also filed a Petition for Reconsideration with the EPA. If the litigation and/or the Petition for Reconsideration are successful, we expect to incur lower compliance costs, consistent with the rules applicable to those states considered as "western" states under the CAIR. On November 22, 2005, the EPA agreed to reconsider certain aspects of its CAIR, including the Minnesota Power petition addressing modeling used to determine Minnesota's inclusion in the CAIR region and claims about inequities in the SO_2 allowance methodology. The EPA anticipates making a decision regarding the petitions in mid-March 2006.

Note 10. Commitments, Guarantees and Contingencies (Continued)

Community Development District Obligations. In March 2005, the Town Center at Palm Coast Community Development District (Town Center District) issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, due May 1, 2036. The bonds were issued to fund a portion of the Town Center development project. Approximately $21 million of the bond proceeds will be used for construction of infrastructure improvements at Town Center, with the remaining funds to be used for capitalized interest, a debt service reserve fund and costs of issuance. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments will be included in the annual property tax bills of landowners beginning in November 2006. To the extent that we still own land at the time of the assessment, in accordance with EITF 91-10, we will recognize an expense for our pro rata portion of assessments, based upon our ownership of benefited property. At December 31, 2005, we owned approximately 92% of the assessable land in the Town Center District.

Guarantee. ALLETE guarantees $1.0 million of Northwest Airlines, Inc.'s (Northwest Airlines) payments of principal and interest on $24.7 million of "Duluth Airport Lease Revenue Bonds" (to be paid out of lease revenue from Northwest Airlines to the Duluth Economic Development Authority). In 2005, following Northwest Airlines' bankruptcy filing and its default on other obligations, we recorded a $1.0 million ($0.6 million after tax) charge to recognize the probable payments on this guarantee. In January 2006, Northwest Airlines was delinquent in their rent payments and the bond trustee drew $62,000 on ALLETE's letter of credit that collateralized ALLETE's guarantee to make the payment.

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, nor have a material adverse effect on our financial condition.

Note 11. Kendall County Charge

On April 1, 2005, Rainy River Energy, a wholly-owned subsidiary of ALLETE, completed the assignment of its power purchase agreement with LSP-Kendall Energy, LLC, the owner of an energy generation facility located in Kendall County, Illinois, to Constellation Energy Commodities. Rainy River Energy paid Constellation Energy Commodities $73 million in cash to assume the power purchase agreement that remains in effect through mid-September 2017. The payment resulted in a charge to our operating income in the second quarter of 2005. The tax benefits of the payment will be realized through a capital loss carryback for federal income tax purposes and have been recorded as current deferred income tax assets. The tax benefits are expected to be realized in 2006. In addition, consent, advisory and closing costs of $4.9 million were incurred to complete the transaction. As a result of this transaction, ALLETE incurred a charge to operating expenses totaling $77.9 million ($50.4 million after tax, or $1.84 per diluted share) in the second quarter of 2005.

Note 12. Other Income (Expense)

For the Year Ended December 31	2005	2004	2003
Millions			
Debt Prepayment Premium and Unamortized Debt Issuance Costs	–	$(18.5)	–
Gain on ESOP's Sale of ADESA Stock (See Note 18)	–	11.5	–
Loss on Emerging Technology Investments	$(6.1)	(8.6)	$(3.4)
Split Rock Energy Equity Income (See Note 2)	–	–	2.9
Investments and Other Income	7.2	3.4	2.8
Total Other Income (Expense)	$ 1.1	$(12.2)	$ 2.3

In July 2004, we repaid $125 million in principal amount of 7.80% Senior Notes due 2008. Proceeds from the sale of our water assets and proceeds received from ADESA were used to repay this debt. As a result of the redemption, we recognized an expense of $18.5 million in the third quarter of 2004 comprised of an early redemption premium and the write-off of unamortized debt issuance costs.

Note 13. Income Tax Expense

Income Tax Expense Year Ended December 31	2005	2004	2003
Millions			
Current Tax Expense			
Federal	$27.2 *(a)*	$11.2	$ 4.6
State	6.5 *(a)*	6.3	3.2
Total Current Tax Expense	33.7	17.5	7.8
Deferred Tax Expense (Benefit)			
Federal	(26.4) *(a)*	1.6	9.4
State	(9.5)	(2.3)	1.8
Total Deferred Tax Expense (Benefit)	(35.9)	(0.7)	11.2
Change in Valuation Allowance	3.0	0.9	0.1
Deferred Tax Credits	(1.3)	(1.3)	(1.4)
Income Tax Expense (Benefit) for Continuing Operations	(0.5)	16.4	17.7
Income Tax Expense for Discontinued Operations	3.4	57.6	125.8
Change in Accounting Principle	–	(5.5)	–
Total Income Tax Expense	$ 2.9	$68.5	$143.5

(a) Included a current federal tax benefit of $1.3 million, current state tax benefit of $0.4 million and a deferred federal tax benefit of $25.8 million related to the Kendall County Charge. (See Note 11.)

Note 13. Income Tax Expense (Continued)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense for Continuing Operations Year Ended December 31	**2005**	**2004**	**2003**
Millions			
Income from Continuing Operations Before Minority Interest and Income Taxes	$19.8	$57.0	$49.5
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35% Statutory Federal Rate	6.9	20.0	17.3
Increase (Decrease) in Tax Due to:			
Sale of ADESA Stock by ESOP	–	(4.1)	–
Amortization of Deferred Investment Tax Credits	(1.3)	(1.3)	(1.4)
State Income Taxes – Net of Federal Income Tax Benefit	1.1	3.6	2.8
Depletion	(1.0)	(0.6)	(0.7)
Employee Benefits	(0.5)	(0.4)	–
Domestic Manufacturing Deduction	(0.4)	–	–
Regulatory Differences for Utility Plant	(0.6)	(0.6)	0.1
Positive Resolution of Audit Issues	(3.7)	–	–
Other	(1.0)	(0.2)	(0.4)
Total Income Tax Expense (Benefit) for Continuing Operations	$ (0.5)	$16.4	$17.7

The effective tax rate on income from continuing operations before minority interest was a 2.5% benefit for 2005; (28.8% expense for 2004; 35.8% expense for 2003). The 2005 effective rate was impacted by three major items. Deferred taxes were adjusted by $2.5 million to reflect comprehensive tax planning initiatives. Current taxes were adjusted by $3.7 million to reflect the receipt of a positive audit report. The 2005 effective rate also reflected an increase in taxes due to the inability to recognize any state benefit for capital loss carryforwards.

Deferred Tax Assets and Liabilities December 31	**2005**	**2004**
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation	$ 47.6	$ 46.9
Property Related	31.0	29.4
Kendall County Capital Loss	30.5	–
Investment Tax Credits	12.9	13.8
Unrealized Loss Booked Through Equity	8.8	8.2
Excess of Tax Value Over Book Value *(a)*	5.6	4.9
Other	9.0	10.0
Gross Deferred Tax Assets	145.4	113.2
Deferred Tax Asset Valuation Allowance	(4.1)	(1.1)
Total Deferred Tax Assets	141.3	112.1
Deferred Tax Liabilities		
Property Related	210.8	210.5
Investment Tax Credits	18.3	19.7
Employee Benefits and Compensation	12.6	14.4
Fuel Clause Adjustment	5.4	2.8
Other	1.6	3.9
Total Deferred Tax Liabilities	248.7	251.3
Accumulated Deferred Income Taxes	$107.4	$139.2
Recorded as:		
Current Deferred Tax Assets	$ 31.0	–
Long-Term Deferred Tax Liabilities	138.4	$139.2
Net Deferred Tax Liabilities	$107.4	$139.2

(a) Included impairments related to the emerging technology portfolio.

Note 14. Discontinued Operations

Enventis Telecom. On December 30, 2005, we sold all the stock of our telecommunications subsidiary, Enventis Telecom, to HickoryTech of Mankato, Minnesota, for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was included in our 2005 loss from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes. In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we have reported our telecommunications business in discontinued operations for all periods presented. Our telecommunications business was previously included in our business segment identified as Other.

Automotive Services. On September 20, 2004, the spin-off of Automotive Services was completed by distributing to ALLETE shareholders all of ALLETE's shares of ADESA common stock. One share of ADESA common stock was distributed for each outstanding share of ALLETE common stock held at the close of business on September 13, 2004, the record date. The distribution was made from ALLETE's retained earnings to the extent of ADESA's undistributed earnings ($363.4 million), with the remainder made from common stock ($600.2 million).

In June 2004, ADESA issued 6.3 million shares of common stock through an IPO priced at $24.00 per share, which netted proceeds of $136.0 million after transaction costs, issued $125 million of senior notes and borrowed $275 million under a new $525 million credit facility. With these funds, ADESA repaid previously existing debt and all intercompany debt outstanding to ALLETE. The IPO represented 6.6% of ADESA's 94.9 million shares then outstanding. As a result of the IPO, ALLETE recorded a $70.1 million increase to Common Stock with no gain recognized pursuant to SEC Staff Accounting Bulletin Topic 5H, "Accounting for Sales of Stock by a Subsidiary." We accounted for the 6.6% public ownership of ADESA as a minority interest and continued to own and consolidate the remaining portion of ADESA until the spin-off was completed on September 20, 2004.

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we have reported our Automotive Services business in Discontinued Operations.

Water Services. During 2003, we sold, under condemnation or imminent threat of condemnation, substantially all of our water assets in Florida for a total sales price of approximately $445 million. Income from discontinued operations for 2003 included a $71.6 million after-tax gain on the sale of substantially all our Water Services businesses. The gain was net of all selling, transaction and employee termination benefit expenses, as well as impairment losses on certain remaining assets.

In June 2004, we essentially concluded our strategy to exit our Water Services businesses when we completed the sale of our North Carolina water assets and the sale of the remaining 72 water and wastewater systems in Florida. Aqua Utilities purchased our North Carolina water assets for $48 million and assumed approximately $28 million in debt. Aqua Utilities also purchased 63 of our water and wastewater systems in Florida for $14 million. Seminole County purchased the remaining 9 Florida systems for a total of $4 million. The FPSC approved the Seminole County transaction in September 2004. On December 20, 2005, the FPSC ordered a $1.7 million reduction to plant investment, which the Company reserved for in 2005, and approved the transfer of the remaining 63 water and wastewater systems from Florida Water to Aqua Utilities. Aqua Utilities filed a protest and requested that the FPSC schedule evidentiary hearings. The FPSC's decision on these issues may change the reduction to plant investment ordered in 2005 and could result in an adjustment to the final purchase price paid by Aqua Utilities. Gains in 2004 from the sale of our North Carolina assets and the remaining systems in Florida were offset by an adjustment to gains reported in 2003, resulting in an overall net loss of $0.5 million in 2004. The adjustment to gains reported in 2003 resulted primarily from an arbitration award in December 2004 relating to a gain-sharing provision on a system sold in 2003; $5.1 million was recorded in 2004 ($1.2 million in 2003).

In February 2005, we completed the exit from our Water Services businesses with the sale of our wastewater assets in Georgia for an immaterial gain. In 2005, we also incurred administrative and other expenses to support Florida Water transfer proceedings and recorded the $1.7 million rate-base settlement charge related to the sale of 63 of Florida Water systems to Aqua Utilities mentioned above.

The net cash proceeds from the sale of all water assets in 2003 and 2004, after transaction costs, retirement of most Florida Water debt and payment of income taxes, were approximately $300 million. These net proceeds were used to retire debt at ALLETE.

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we suspended depreciating our Water Services assets when they were classified as held-for-sale in 2001. Had we not suspended depreciation, depreciation expense at our Water Services businesses would have been $2.6 million in 2004 and $12.9 million in 2003.

Note 14. Discontinued Operations (Continued)

Summary Discontinued Operations

Millions

Summary Income Statement For the Year Ended December 31	**2005**	**2004**	**2003**
Operating Revenue			
Automotive Services	–	$681.7	$ 924.1
Water Services	–	18.5	107.4
Enventis Telecom	$50.7	47.3	32.7
Total Operating Revenue	$50.7	$747.5	$1,064.2
Pre-Tax Income (Loss) from Operations			
Automotive Services	–	$132.5	$185.4
Water Services	–	(1.7)	34.4
Enventis Telecom	$ 3.0	1.0	1.1
	3.0	131.8	220.9
Income Tax Expense (Benefit)			
Automotive Services	–	54.0	73.1
Water Services	–	(0.9)	13.0
Enventis Telecom	1.2	0.4	0.5
	1.2	53.5	86.6
Total Net Income from Operations	1.8	78.3	134.3
Gain (Loss) on Disposal			
Automotive Services	–	(6.7)	2.0
Water Services	(4.5)	6.2	110.1
Enventis Telecom	0.6	–	–
	(3.9)	(0.5)	112.1
Income Tax Expense (Benefit)			
Automotive Services	–	(2.6)	0.7
Water Services	(2.0)	6.7	38.5
Enventis Telecom	4.2	–	–
	2.2	4.1	39.2
Net Gain (Loss) on Disposal	(6.1)	(4.6)	72.9
Income (Loss) from Discontinued Operations	$(4.3)	$ 73.7	$207.2

Summary Balance Sheet Information December 31	**2005**	**2004**
Assets of Discontinued Operations		
Cash and Cash Equivalents	–	$2.4
Other Current Assets	$0.4	$10.7
Property, Plant and Equipment	$2.2	$36.4
Liabilities of Discontinued Operations		
Current Liabilities	$13.0	$24.5

Note 15. Change in Accounting Principle

In the third quarter of 2004, we adopted EITF 03-16, "Accounting for Investments in Limited Liability Companies," which requires the use of the equity method of accounting for investments in all limited liability companies, including investments we have in venture capital funds within our emerging technology portfolio. EITF 03-16 was issued in the second quarter of 2004. We had previously accounted for these investments under the cost method of accounting. EITF 03-16 is effective for reporting periods beginning after June 15, 2004. Pursuant to EITF 03-16, the effect of adoption is reported as the cumulative effect of a change in accounting principle. The cumulative effect of this change on prior years was a loss of $13.3 million ($7.8 million after-tax), which was recorded as a change in accounting principle and reflected in income for the year ended December 31, 2004. During 2004, $1.6 million of current losses under the equity method were recognized ($0 in 2005).

Pro Forma Amounts Assuming the Equity Method Was Applied Retroactively **For the Year Ended December 31**	**2003**
Millions Except Per Share Amounts	
Net Income	
As Reported	$236.4
Pro Forma Adjustment	(2.3)
Pro Forma	$234.1
Basic Earnings Per Share	
As Reported	$8.56
Pro Forma Adjustment	(0.08)
Pro Forma	$8.48
Diluted Earnings Per Share	
As Reported	$8.52
Pro Forma Adjustment	(0.08)
Pro Forma	$8.44

Note 16. Other Comprehensive Income (Loss)

Other Comprehensive Income Year Ended December 31	**Pre-Tax Amount**	**Tax Expense (Benefit)**	**Net-of-Tax Amount**
Millions			
2005			
Unrealized Gain on Securities During the Year	$ 1.3	$ 0.7	$ 0.6
Additional Pension Liability	(3.4)	(1.4)	(2.0)
Other Comprehensive Loss	$(2.1)	$(0.7)	$(1.4)
2004			
Unrealized Gain on Securities			
Gain During the Year	$ 13.1	$ 0.9	$ 12.2
Less: Gain Included in Net Income	11.5	–	11.5
Net Unrealized Gain on Securities	1.6	0.9	0.7
Foreign Currency Translation Adjustments	(23.5)	–	(23.5)
Additional Pension Liability	(5.7)	(2.6)	(3.1)
Other Comprehensive Loss	$(27.6)	$(1.7)	$(25.9)
2003			
Unrealized Gain on Securities			
Gain During the Year	$ 2.4	$ 1.0	$ 1.4
Add: Loss Included in Net Income	3.5	1.3	2.2
Net Unrealized Gain on Securities	5.9	2.3	3.6
Interest Rate Swap	0.2	–	0.2
Foreign Currency Translation Adjustments	39.2	–	39.2
Additional Pension Liability	(10.8)	(4.5)	(6.3)
Other Comprehensive Income	$34.5	$(2.2)	$36.7

Accumulated Other Comprehensive Income (Loss) December 31	**2005**	**2004**
Millions		
Unrealized Gain on Securities	$ 2.1	$ 1.5
Additional Pension Liability	(14.9)	(12.9)
Total Accumulated Other Comprehensive Loss	$(12.8)	$(11.4)

Note 17. Pension and Other Postretirement Benefit Plans

We have noncontributory defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. We also have defined contribution pension plans covering substantially all employees; employer contributions are made through our employee stock ownership plan (see Note 18), except for BNI Coal, which made cash contributions of $0.7 million in 2005 ($0.6 million in each of the years 2004 and 2003).

We have postretirement health care and life insurance plans covering eligible employees. 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 an irrevocable grantor trust. Contributions deductible for income tax purposes are made directly to the VEBAs; nondeductible contributions are made to the irrevocable grantor trust. Amounts are transferred from the irrevocable grantor trust to the VEBAs when they become deductible for income tax purposes. In December 2005, after the measurement date, $11.4 million was transferred from the grantor trust to the VEBAs.

We use a September 30 measurement date for the pension and postretirement health and life plans.

Pension Obligation and Funded Status **At September 30**	**2005**	**2004**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$380.0	$353.4
Service Cost	8.7	8.4
Interest Cost	21.3	20.7
Actuarial Loss	16.6	10.0
Benefits Paid	(18.9)	(17.3)
Other	4.7	4.8
Obligation, End of Year	412.4	380.0
Change in Plan Assets		
Fair Value, Beginning of Year	310.1	285.3
Actual Return on Assets	40.6	28.9
Employer Contribution	0.6	8.4
Benefits Paid	(18.9)	(17.3)
Other	4.7	4.8
Fair Value, End of Year	337.1	310.1
Funded Status	(75.3)	(69.9)
Unrecognized Amounts		
Net Loss	90.6	89.3
Prior Service Cost	4.5	5.2
Transition Obligation	(0.1)	–
Net Assets Recognized	$ 19.7	$ 24.6
Amounts Recognized in Consolidated Balance Sheet Consist of:		
Prepaid Pension Cost	$33.8	$33.3
Accrued Benefit Liability	(42.3)	(33.8)
Intangible Assets	2.3	2.6
Accumulated Other Comprehensive Income	25.9	22.5
Net Assets Recognized	$19.7	$24.6

Components of Net Periodic Pension Expense (Income) **Year Ended December 31**	**2005**	**2004**	**2003**
Millions			
Service Cost	$ 8.7	$ 8.4	$ 6.7
Interest Cost	21.3	20.7	19.5
Expected Return on Assets	(28.2)	(27.4)	(28.8)
Amortized Amounts			
Unrecognized Loss	3.1	1.4	–
Prior Service Cost	0.2	0.8	0.9
Transition Obligation	0.6	0.3	0.2
Net Pension Expense (Income)	$ 5.7	$ 4.2	$(1.5)

Note 17. Pension and Other Postretirement Benefit Plans (Continued)

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets At September 30	2005	2004
Millions		
Projected Benefit Obligation	$177.5	$163.1
Accumulated Benefit Obligation	$157.7	$140.6
Fair Value of Plan Assets	$116.3	$108.8

Additional Pension Information Year Ended December 31	2005	2004	2003
Millions			
Increase in Minimum Liability Included in Other Comprehensive Income	$3.4	$5.7	$10.8

The accumulated benefit obligation for all defined benefit pension plans was $369.5 million and $332.9 million at September 30, 2005 and 2004, respectively.

Postretirement Health and Life Obligation and Funded Status At September 30	2005	2004
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$117.2	$117.2
Service Cost	4.0	3.9
Interest Cost	6.6	6.5
Actuarial Loss (Gain)	13.1	(6.6)
Participation Contributions	1.3	1.1
Benefits Paid	(5.3)	(4.9)
Obligation, End of Year	136.9	117.2
Change in Plan Assets		
Fair Value, Beginning of Year	54.1	46.9
Actual Return on Assets	7.1	6.1
Employer Contribution	3.6	4.9
Participation Contributions	1.4	1.1
Benefits Paid	(5.3)	(4.9)
Fair Value, End of Year	60.9	54.1
Funded Status	(76.0)	(63.1)
Unrecognized Amounts		
Net Loss	25.8	15.5
Transition Obligation	17.4	20.0
Accrued Cost	$ (32.8)	$ (27.6)

Under SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions,” only assets in the VEBAs are treated as plan assets in the table above for the purpose of determining funded status. In addition to the postretirement health and life assets reported above, we had $22.6 million in an irrevocable grantor trust at December 31, 2005 ($28.8 million at December 31, 2004). We consolidate the irrevocable grantor trust and it is included in Investments on our consolidated balance sheet.

Components of Net Periodic Postretirement Health and Life Expense Year Ended December 31	2005	2004	2003
Millions			
Service Cost	$4.0	$3.9	$3.7
Interest Cost	6.7	6.6	6.6
Expected Return on Assets	(4.8)	(4.6)	(4.0)
Amortized Amounts			
Unrecognized Loss	0.7	0.4	0.1
Transition Obligation	2.4	2.4	2.4
Net Expense	$9.0	$8.7	$8.8

Note 17. Pension and Other Postretirement Benefit Plans (Continued)

Estimated Future Benefit Payments	Pension	Postretirement Health and Life
Millions		
2006	$19	$5
2007	$19	$5
2008	$20	$6
2009	$21	$6
2010	$22	$7
Years 2011 – 2015	$129	$42

Weighted-Average Assumptions Used to Determine Benefit Obligation At September 30	2005	2004
Discount Rate	5.50%	5.75%
Rate of Compensation Increase	3.5 – 4.5%	3.5 – 4.5%
Health Care Trend Rates		
Trend Rate	10%	11%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2010	2011

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs Year Ended December 31	2005	2004	2003
Discount Rate	5.75%	6.0%	6.75%
Expected Long-Term Return on Plan Assets			
Pension	9.0%	9.0%	9.5%
Postretirement Health and Life	5.0 – 9.0%	7.2 – 9.0%	7.6 – 9.5%
Rate of Compensation Increase	3.5 – 4.5%	3.5 – 4.5%	3.5 – 4.5%

In establishing the expected long-term return on plan assets, we consider the diversification and allocation of plan assets, the actual long-term historical performance for the type of securities invested in, the actual long-term historical performance of plan assets and the impact of current economic conditions, if any, on long-term historical returns.

Currently for plan valuation purposes, the discount rate is determined considering high-quality long-term corporate bond rates at the valuation date. The discount rate is compared to various bond indices for reasonableness.

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	$1.6	$(1.3)
Effect on Postretirement Health and Life Obligation	$17.5	$(14.4)

	Pension		Postretirement Health and Life *(a)*	
Plan Asset Allocations	**2005**	**2004**	**2005**	**2004**
Equity Securities	64.9%	60.4%	68.6%	64.4%
Debt Securities	29.6	30.9	30.5	34.9
Real Estate	1.3	2.2	–	–
Venture Capital	2.9	5.2	–	–
Cash	1.3	1.3	0.9	0.7
	100.0%	100.0%	100.0%	100.0%

(a) Included VEBAs and irrevocable grantor trust.

Pension plan equity securities include ALLETE common stock in the amount of $22.6 million (7.3% of total plan assets) at September 30, 2004. Pension plan equity securities did not include ALLETE common stock at September 30, 2005.

Note 17. Pension and Other Postretirement Benefit Plans (Continued)

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. In addition, all debt securities must have a Standard & Poor's credit rating of A or higher.

Plan Asset Target Allocations	**Pension**	**Postretirement Health and Life** *(a)*
Equity Securities	62%	66%
Debt Securities	30	33
Real Estate	2	–
Venture Capital	5	–
Cash	1	1
	100%	100%

(a) Included VEBAs and irrevocable grantor trust.

We expect to contribute approximately $8 million to our postretirement health and life plans and approximately $10 million to our defined benefit pension plans in 2006.

In May 2004, the FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act)," which provides accounting and disclosure guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 requires that the accumulated postretirement benefit obligation and postretirement benefit cost reflect the impact of the Act upon adoption. We provide postretirement health benefits that include prescription drug benefits and have concluded that our prescription drug benefits will qualify us for the federal subsidy to be provided for under the Act. We adopted FSP 106-2 in the third quarter of 2004. The impact of adoption reduced our after-tax postretirement medical expense by $3.5 million for 2005 ($1.6 million for 2004).

In 2005, we determined that our postretirement health care plans meet the requirements of the Centers for Medicare and Medicaid Services' (CMS) regulations, and enrolled with the CMS to begin recovering the subsidy. We expect to receive the first subsidy check in early 2007 for 2006 credits.

Note 18. Employee Stock and Incentive Plans

Employee Stock Ownership Plan. We sponsor a leveraged employee stock ownership plan (ESOP) within the Retirement Savings and Stock Ownership Plan (RSOP) that covers certain eligible employees. In 1989, the ESOP used the proceeds from a $16.5 million third-party loan, guaranteed by us, to purchase 0.6 million shares (0.4 million shares adjusted for stock splits) of our common stock on the open market. This loan was fully repaid in 2004, and all shares originally purchased with loan proceeds have been allocated to participants. In 1990, the ESOP issued a $75 million note (term not to exceed 25 years at 10.25%) to us as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The Company makes 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, the Company reports 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 $5.5 million in 2005 ($5.0 million in 2004; $3.7 million in 2003).

As a result of the September 2004 spin-off of ADESA, the ESOP received 3.3 million shares of ADESA common stock related to unearned ESOP shares that had not been allocated to participants. The ESOP was required to sell the ADESA common stock and use the proceeds to purchase ALLETE common stock on the open market. At December 31, 2004, the ESOP had sold all of these ADESA shares. The 3.3 million ADESA shares sold by the ESOP in 2004 resulted in total proceeds of $65.9 million and an after-tax gain of $11.5 million, which we recognized in the fourth quarter of 2004. (See Note 12.)

Under the direction of an independent trustee, the ESOP began using the proceeds to purchase shares of ALLETE common stock in October 2004. As of February 15, 2005, the remaining proceeds ($30.3 million classified as Restricted Cash at December 31, 2004) had been used to purchase ALLETE common stock, which were recorded using the treasury method as Unearned ESOP Shares within Shareholders' Equity as presented on our consolidated balance sheet.

Note 18. Employee Stock and Incentive Plans (Continued)

Summary of ALLETE Common Stock Purchases		Shares	Amount
Millions Except Shares			
2004	October	80,600	$ 2.7
	November	669,578	23.5
	December	262,600	9.4
2005	January	544,797	21.4
	February	214,928	8.9
		1,772,503	$65.9

In September 2005, the ESOP's independent trustee directed the sale of approximately 1.4 million shares of ADESA common stock that remained invested in the RSOP participants' ADESA common stock funds at September 1, 2005. Proceeds from the sale of the ADESA common stock were $30.4 million, of which the majority was used to purchase ALLETE common stock as required by the terms of the RSOP. The process was completed on October 26, 2005. Proceeds totaling $28.5 million were used to purchase a total of 644,450 shares of ALLETE common stock (289,900 shares in September 2005; 354,550 shares in October 2005).

Pursuant to AICPA Statement of Position 93-6, "Employers' Accounting for Employee Stock Ownership Plans," 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	2005	2004	2003
Millions			
ESOP Shares			
Allocated	1.9	1.4	1.2
Unallocated	2.6	2.0	1.1
Total	4.5	3.4	2.3
Fair Value of Unallocated Shares	$115.0	$72.7	$105.0

Stock Option and Award Plans. We have an Executive Long-Term Incentive Compensation Plan (Executive Plan) that allows for the grant of up to 3.2 million shares of our common stock to key employees. To date, these grants have taken the form of stock options, performance share awards and restricted stock awards. Stock options are exercisable at the market price of common shares on the date the options are granted and vest in equal annual installments over three years, with expiration ten years from the date of the grant. Performance shares are earned over multi-year time periods and are contingent upon the attainment of certain performance goals of ALLETE. Restricted stock vests once certain periods of time have elapsed. At December 31, 2005, 1.1 million shares were held in reserve for future issuance under the Executive Plan.

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 9,900 options were outstanding at December 31, 2005.

	2004		2003	
Stock Option Activity *(a)*	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Options in Millions				
Outstanding, Beginning of Period	0.8	$64.47	0.8	$67.44
Granted	0.1	$97.65	0.2	$61.77
Exercised	(0.4)	$67.14	(0.2)	$61.32
Cancelled	–	–	–	$68.13
Outstanding, End of Period	0.5	$69.85	0.8	$64.47
Exercisable, End of Period	–	–	0.5	$67.26
Fair Value of Options Granted During the Period	$20.01		$8.16	

(a) All amounts above are prior to the ADESA spin-off and the historical option and weighted average exercise prices have been adjusted for the one-for-three reverse stock split on September 20, 2004. The 2004 amounts are up to the September 20, 2004, spin-off of ADESA.

Note 18. Employee Stock and Incentive Plans (Continued)

Stock Option Activity *(a)*	2004 Options	2004 Weighted Average Exercise Price
Options in Millions		
Outstanding as of September 20, 2004, after spin-off	0.5	$28.56
Granted	–	–
Exercised	(0.1)	$24.40
Cancelled	–	–
Outstanding, End of Year	0.4	$28.94
Exercisable, End of Year	0.3	$26.57

(a) Amounts subsequent to the ADESA spin-off.

Stock Option Activity	2005 Options	2005 Weighted Average Exercise Price
Options in Millions		
Outstanding, Beginning of Year	0.4	$28.94
Granted	0.1	$41.35
Exercised	(0.1)	$26.74
Cancelled	–	–
Outstanding, End of Year	0.4	$34.29
Exercisable, End of Year	0.2	$28.35
Fair Value of Options Granted During the Year	$6.51	

The employee stock options outstanding at the date of the spin-off were converted to reflect the spin-off and one-for-three reverse stock split. This conversion was done to preserve the noncompensatory nature of the options under FASB Interpretation No. 44, "Accounting for Certain Transactions Involving Stock Compensation."

At December 31, 2005, options outstanding consisted of less than 0.1 million with exercise prices ranging from $15.88 to $18.85, 0.1 million with exercise prices ranging from $23.79 to $29.79 and 0.2 million with exercise prices ranging from $37.76 to $41.35. The options with exercise prices ranging from $23.79 to $29.79 have an average remaining contractual life of 5.7 years, with 0.1 million exercisable on December 31, 2005, at a weighted average price of $26.85. The options with exercise prices ranging from $37.76 to $41.35 have an average remaining contractual life of 8.6 years, with less than 0.1 million exercisable on December 31, 2005 at a weighted average price of $37.87.

Less than 0.1 million performance share grants were awarded in February 2005 for performance periods ending in 2007. The ultimate issuance is contingent upon the attainment of certain future performance goals of ALLETE during the performance periods. The grant date fair value of the performance share awards was $1.0 million.

A total of 0.1 million performance share grants were awarded in February 2004 for the performance periods ended December 31, 2005 and 2006. The grant date fair value of the share awards was $1.6 million. Performance share grants related to the 2005 period will be issued in early 2006.

In February 2006, we granted stock options to purchase 0.1 million shares of common stock (exercise price of $44.15 per share).

Employee Stock Purchase Plan. We have an Employee Stock Purchase Plan that permits eligible employees to buy up to $23,750 per year of our common stock at 95% of the market price. At December 31, 2005, 0.5 million shares had been issued under the plan and 0.1 million shares were held in reserve for future issuance.

Note 19. Quarterly Financial Data (Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year. Financial results for the second quarter of 2005 included a $50.4 million, or $1.84 per share, charge related to the assignment of the Kendall County purchase power agreement. (See Note 11.) Financial results for the fourth quarter of 2005 included a $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive tax planning initiatives and a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.

Financial results for the first quarter of 2004 included a $7.8 million, or $0.27 per share, non-cash after-tax charge for a change in accounting principle related to investments in our emerging technology portfolio. Financial results for the third quarter of 2004 included a $10.9 million, or $0.38 per share, after-tax debt prepayment cost as part of ALLETE's financial restructuring in preparation for the spin-off of ADESA, which occurred on September 20, 2004. Financial results for the fourth quarter of 2004 included an $11.5 million, or $0.41 per share, after-tax gain on the sale of ADESA shares held by our ESOP. The ESOP received the ADESA shares as a result of the spin-off.

Quarter Ended		**Mar. 31**	**Jun. 30**	**Sept. 30**	**Dec. 31**
Millions Except Earnings Per Share					
2005					
Operating Revenue		$193.3	$174.4	$177.4	$192.3
Operating Income (Loss) from Continuing Operations		$41.1	$(56.0)	$32.7	$27.3
Income (Loss)	Continuing Operations	$17.4	$(39.8)	$15.8	$24.2
	Discontinued Operations	–	(0.5)	(0.6)	(3.2)
Net Income (Loss)		$17.4	$(40.3)	$15.2	$21.0
Earnings (Loss) Per Share of Common Stock					
Basic	Continuing Operations	$0.64	$(1.46)	$0.58	$0.89
	Discontinued Operations	–	(0.02)	(0.02)	(0.12)
		$0.64	$(1.48)	$0.56	$0.77
Diluted	Continuing Operations	$0.64	$(1.46)	$0.58	$0.88
	Discontinued Operations	–	(0.02)	(0.02)	(0.12)
		$0.64	$(1.48)	$0.56	$0.76
2004					
Operating Revenue		$198.0	$170.4	$166.9	$168.8
Operating Income from Continuing Operations		$44.2	$18.6	$22.5	$15.6
Income (Loss)	Continuing Operations	$21.4	$ 2.0	$ (1.0)	$16.1
	Discontinued Operations	31.3	34.7	14.1	(6.4)
	Change in Accounting Principle	(7.8)	–	–	–
Net Income		$44.9	$36.7	$13.1	$ 9.7
Earnings (Loss) Per Share of Common Stock					
Basic	Continuing Operations	$0.77	$0.06	$(0.03)	$0.57
	Discontinued Operations	1.11	1.23	0.48	(0.22)
	Change in Accounting Principle	(0.28)	–	–	–
		$1.60	$1.29	$ 0.45	$0.35
Diluted	Continuing Operations	$0.76	$0.06	$(0.03)	$0.56
	Discontinued Operations	1.10	1.23	0.48	(0.22)
	Change in Accounting Principle	(0.27)	–	–	–
		$1.59	$1.29	$ 0.45	$0.34

ALLETE
Valuation and Qualifying Accounts and Reserves

For the Year Ended December 31		Balance at Beginning of Year	Additions Charged to Income	Additions Other Changes	Deductions from Reserves *(a)*	Balance at End of Period
Millions						
Reserve Deducted from Related Assets						
Reserve For Uncollectible Accounts						
2005	Trade Accounts Receivable	$1.0	$1.1	–	$1.1	$1.0
	Finance Receivables – Long-Term	0.7	–	–	0.1	0.6
2004	Trade Accounts Receivable	1.1	0.9	–	1.0	1.0
	Finance Receivables – Long-Term	1.2	–	–	0.5	0.7
2003	Trade Accounts Receivable	2.1	0.6	–	1.6	1.1
	Finance Receivables – Long-Term	1.7	–	–	0.5	1.2
Deferred Asset Valuation Allowance						
2005	Deferred Tax Assets	1.1	3.8	–	0.8	4.1
2004	Deferred Tax Assets	0.2	0.9	–	–	1.1
2003	Deferred Tax Assets	0.1	0.1	–	–	0.2

(a) Included uncollectible accounts written off.

Exhibit Index

Exhibit Number

12	-	Computation of Ratios of Earnings to Fixed Charges.
21	-	Subsidiaries of the Registrant.
23(a)	-	Consent of Independent Registered Public Accounting Firm.
23(b)	-	Consent of General Counsel.
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.

Exhibit 12

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

For the Year Ended December 31	2005	2004	2003	2002	2001
Millions Except Ratios					
Income from Continuing Operations Before Income Taxes	$17.1	$ 54.9	$ 46.9	$ 36.9	$ 81.4
Add (Deduct)					
Undistributed Income from Less than 50% Owned Equity Investment	–	–	(2.9)	(4.7)	(1.5)
Minority Interest	–	–	–	–	0.1
	17.1	54.9	44.0	32.2	80.0
Fixed Charges					
Interest on Long-Term Debt	23.3	60.3	70.0	73.9	80.0
Capitalized Interest	0.3	0.7	1.2	0.8	1.0
Other Interest Charges	14.0	8.7	4.3	5.3	12.9
Interest Component of All Rentals	2.8	3.5	8.0	9.9	10.4
Total Fixed Charges	40.4	73.2	83.5	89.9	104.3
Earnings Before Income Taxes and Fixed Charges (Excluding Capitalized Interest)	$57.2	$127.4	$126.3	$121.3	$183.3
Ratio of Earnings to Fixed Charges	1.42	1.74	1.51	1.35	1.76

SUBSIDIARIES OF THE REGISTRANT
(As of December 31, 2005)
(Reported Under Item 601 of Regulation S-K)

Name	State or Country of Organization
ALLETE, Inc. *(d.b.a. ALLETE; Minnesota Power; Minnesota Power, Inc.; Minnesota Power & Light Company; MPEX; MPEX A Division of Minnesota Power)*	Minnesota
ALLETE Automotive Services, LLC	Minnesota
ALLETE Capital II	Delaware
ALLETE Capital III	Delaware
ALLETE Properties, LLC *(d.b.a. ALLETE Properties)*	Minnesota
ALLETE Commercial, LLC	Florida
Cape Coral Holdings, Inc.	Florida
Cape Properties, Inc.	Florida
Lehigh Acquisition Corporation	Delaware
Florida Landmark Communities, Inc.	Florida
Cliffside Properties, Inc.	California
Enterprise Lehigh, Inc.	Florida
Lehigh Corporation	Florida
Lehigh Land & Investment, Inc.	Florida
Mardem, LLC	Florida
Palm Coast Holdings, Inc.	Florida
Interlachen Lakes Estates, Inc.	Florida
SRC of Florida, Inc.	Florida
Sundowner Properties, Inc.	Pennsylvania
Palm Coast Forest, LLC	Florida
Palm Coast Land, LLC	Florida
Tomoka Holdings, LLC	Florida
Winter Haven Citi Centre, LLC	Florida
ALLETE Water Services, Inc.	Minnesota
Florida Water Services Corporation	Florida
Auto Replacement Property, LLC	Indiana
Energy Replacement Property, LLC	Minnesota
Georgia Water Services Corporation	Georgia
Energy Land, Incorporated	Wisconsin
Lakeview Financial Corporation I	Minnesota
Lakeview Financial Corporation II	Minnesota
Logistics Coal, LLC	Minnesota
Minnesota Power Enterprises, Inc.	Minnesota
BNI Coal, Ltd.	North Dakota
MP Affiliate Resources, Inc.	Minnesota
Rainy River Energy Corporation	Minnesota
Rainy River Energy Corporation - Wisconsin	Wisconsin
Synertec, Incorporated	Minnesota
Upper Minnesota Properties, Inc.	Minnesota
Upper Minnesota Properties - Development, Inc.	Minnesota
Upper Minnesota Properties - Irving, Inc.	Minnesota
Upper Minnesota Properties - Meadowlands, Inc.	Minnesota
Meadowlands Affordable Housing Limited Partnership	Minnesota
MP Investments, Inc.	Delaware
RendField Land Company, Inc.	Minnesota
Superior Water, Light and Power Company	Wisconsin

Exhibit 23(a)

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-02109, 333-41882, 333-57104) and Form S-8 (Nos. 333-16445, 333-16463, 333-82901, 333-91348, 333-105225, 333-124455) of ALLETE, Inc. of our report dated February 13, 2006, relating to the consolidated financial statements, financial statement schedule, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Minneapolis, Minnesota
February 16, 2006

Exhibit 23(b)

Consent of General Counsel

The statements of law and legal conclusions under “Item 1. Business” in ALLETE’s Annual Report on Form 10-K for the year ended December 31, 2005, have been reviewed by me and are set forth therein in reliance upon my opinion as an expert.

I hereby consent to the incorporation by reference of such statements of law and legal conclusions in Registration Statement Nos. 333-02109, 333-41882 and 333-57104 on Form S-3, and Registration Statement Nos. 333-16445, 333-16463, 333-82901, 333-91348, 333-105225 and 333-124455 on Form S-8.

/s/ Deborah A. Amberg

Deborah A. Amberg
Duluth, Minnesota
February 16, 2006

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

I, Donald J. Shippar, Chairman, President and Chief Executive Officer of ALLETE, Inc. (ALLETE), certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2005, of ALLETE;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2006

/s/ Donald J. Shippar

Donald J. Shippar
Chairman, President and Chief Executive Officer

Exhibit 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

I, James K. Vizanko, Senior Vice President and Chief Financial Officer of ALLETE, Inc. (ALLETE), certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2005, of ALLETE;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2006

/s/ James K. Vizanko

James K. Vizanko
Senior Vice President and Chief Financial Officer

Exhibit 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

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, each of the undersigned officers of ALLETE, Inc. (ALLETE), does hereby certify that:

1. The Annual Report on Form 10-K of ALLETE for the fiscal year ended December 31, 2005, (Report) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of ALLETE.

Date: February 16, 2006

/s/ Donald J. Shippar

Donald J. Shippar
Chairman, President and Chief Executive Officer

Date: February 16, 2006

/s/ James K. Vizanko

James K. Vizanko
Senior Vice President and Chief Financial Officer

This certification shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to liability pursuant to that section. Such certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that ALLETE specifically incorporates it by reference.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ALLETE and will be retained by ALLETE and furnished to the Securities and Exchange Commission or its staff upon request.