EXHIBIT 4

THE EMPIRE DISTRICT ELECTRIC COMPANY

10K ANNUAL REPORT FILED MARCH 15, 2005

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2004 or

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from ____________________ to ____________________.

Commission file number: 1-3368

THE EMPIRE DISTRICT ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Kansas	**44-0236370**
(State of Incorporation)	(I.R.S. Employer Identification No.)
602 Joplin Street, Joplin, Missouri	**64801**
(Address of principal executive offices)	(zip code)

Registrant's telephone number: (417) 625-5100
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock ($1 par value)	New York Stock Exchange
Preference Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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. ☐

Book value per common share outstanding at end of year	**$ 14.76**	$ 15.17	$ 14.59	$ 13.64	$ 13.62
Capitalization:					
Common equity	**$ 379,180**	$ 378,825	$ 329,315	$ 268,308	$ 240,153
Long-term debt	**$ 399,917**	$ 410,393	$ 410,998	$ 358,615	$ 325,644
Ratio of earnings to fixed charges	**2.12x**	2.44x	2.25x	1.31x	2.25x
Total assets*	**$ 1,027,539**	$ 1,025,091	$ 991,034	$ 904,087	$ 852,369
Plant in service at original cost	**$ 1,254,255**	$ 1,221,352	$ 1,125,460	$ 1,080,100	$ 928,561
Capital expenditures (inc. AFUDC)	**$ 41,892**	$ 65,906	$ 76,877	$ 77,316	$ 131,824

* 2000 through 2003 have been reclassified to present cost of asset removal accruals as a regulatory liability. See Note 1 to the Consolidated Financial Statements included in Item 8.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

The Empire District Electric Company is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. We also provide water service to three towns in Missouri and have investments in some non-regulated businesses including fiber optics, Internet access, close-tolerance custom manufacturing and customer information system software services through our wholly owned subsidiary, EDE Holdings, Inc. In 2004, 93.0% of our gross operating revenues were provided from the sale of electricity, 0.4% from the sale of water and 6.6% from our non-regulated businesses.

The primary drivers of our electric operating revenues in any period are: (1) weather, (2) rates we can charge our customers, (3) customer growth, (4) the ability (or inability due to the lack of a fuel adjustment provision in Missouri) to recover increases in fuel costs in rates and (5) general economic conditions. Weather affects the demand for electricity for our regulated business. Very hot summers and very cold winters increase demand, while mild weather reduces demand. Residential and commercial sales are impacted more by weather than industrial sales, which are mostly affected by business needs for electricity and general economic conditions. The utility commissions in the states in which we operate, as well as the FERC, set the rates at which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely rate relief. We continue to assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary. Customer growth, which is the growth in the number of customers, contributes to the demand for electricity. We expect our annual customer growth to be approximately 1.6% over the next several years. We define sales growth to be growth in kWh sales excluding the impact of weather. The primary drivers of sales growth are customer growth and general economic conditions.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expense, (2) maintenance and repairs expense, (3) employee pension and health care costs, (4) taxes and (5) non-cash items such as depreciation and amortization expense. Fuel and purchased power costs are our largest expense items. Several factors affect these costs, including fuel and purchased power prices, plant outages and weather, which drives customer demand. In order to control the price we pay for fuel and purchased power, we have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and currently engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expense and improve predictability. We have purchased, and will install at our Riverton facility, a Siemens V84.3A2 combustion turbine with a summer rated capacity of 155 megawatts to be operational in 2007 to meet additional capacity requirements due to anticipated customer growth.

On December 10, 2004, we entered into a 20-year contract with PPM Energy, to purchase the energy generated at the proposed Elk River Windfarm which will be located in Butler County, Kansas. We expect that the amount and percentage of electricity we generate by natural gas will decrease in 2006 and in the immediate future thereafter due to this contract. We anticipate purchasing approximately 550,000 megawatt-hours of energy, or 10% of our annual needs, from the project beginning in December 2005. We anticipate the cost of this contract to also be offset by purchasing less higher-priced power from other suppliers or by displacing on-system generation. We believe this project is a significant step in assuring that our shareholders and customers benefit from a balanced mix of generation options. With the improvements made in wind generation technology and the extension of the production tax credits, wind energy provides price stability, is environmentally friendly and is economical for our customers.

For the twelve months ended December 31, 2004, basic and diluted earnings per weighted average share of common stock were $0.86 as compared to $1.29 for the twelve months ended December 31, 2003.

The following reconciliation of earnings per share between 2003 and 2004 is a non-GAAP presentation. We believe this information is useful in understanding the fluctuation in earnings per share between the prior and current year. The reconciliation presents the after tax impact of significant items and components of the statement of operations on a per share basis before the impact of additional stock issuances which is presented separately. Earnings per share for the years ended December 31, 2003 and 2004 shown in the reconciliation are presented on a GAAP basis and are the same as

the amounts included in the statements of income. This reconciliation may not be comparable to other companies or more useful than the GAAP presentation included in the statements of operations.

Earnings Per Share — 2003	**$ 1.29**
Revenues	
On-System — Electric	$ 0.11
Off-System — Electric	(0.12)
Non-Regulated	0.02
Water	0.00
Expenses	
Fuel	(0.34)
Purchased power	0.21
Regulated — other (excluding employee health care expense)	(0.06)
Regulated — other (employee health care expense only)	(0.03)
Non — Regulated expenses	(0.05)
Maintenance and repairs	(0.02)
Depreciation and amortization	(0.06)
Other taxes	(0.05)
Interest charges	0.06
Other income and deductions	0.00
Dilutive effect of additional shares	(0.10)
Earnings Per Share — 2004	**$ 0.86**

Fourth Quarter Results

Revenues for the fourth quarter of 2004 were $74.3 million compared to $73.0 million in the fourth quarter of 2003. The increase in revenues was primarily driven by customer growth. Earnings for the fourth quarter of 2004 were $2.0 million, or $0.08 per share, compared to fourth quarter 2003 earnings of $4.8 million, or $0.21 per share. While an increase in revenues for the fourth quarter of 2004 contributed an estimated $0.04 per share in the fourth quarter of 2004 as compared to the fourth quarter of 2003, due to customer growth, increases in total fuel and purchased power costs reduced earnings per share by an estimated $0.08 per share. Also negatively impacting earnings were increases in health care expense, depreciation, property taxes and losses from our non-regulated business units.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for 2004, compared to 2003, and for 2003, compared to

2002.

Electric Operating Revenues and Kilowatt-Hour Sales

Electric operating revenues comprised approximately 93% of our total operating revenues during 2004. Of these total electric operating revenues, approximately 41% were from residential customers, 31% from commercial customers, 17% from industrial customers, 4.5% from wholesale on-system customers, 2% from wholesale off-system transactions and 4.5% from miscellaneous sources, primarily transmission services. The breakdown of our customer classes has not significantly changed from 2003 or 2002.

The amounts and percentage changes from the prior periods in kilowatt-hour ("kWh") sales and operating revenues by major customer class for on-system electric sales were as follows:

	kWh Sales (in millions)					
	2004	2003	% Change*	2003	2002	% Change*
Residential	1,703.9	1,728.3	(1.4)%	1,728.3	1,726.5	0.1%
Commercial	1,417.3	1,386.8	2.2	1,386.8	1,378.2	0.6
Industrial	1,085.4	1,058.7	2.5	1,058.7	1,027.4	3.0
Wholesale On-System	305.7	308.6	(0.9)	308.6	323.1	(4.5)
Other***	108.0	103.9	4.2	103.9	102.8	1.1
Total On-System	4,620.3	4,586.3	0.7	4,586.3	4,558.0	0.6

	Operating Revenues (in millions)					
	2004	2003	% Change*	2003	2002**	% Change*
Residential	$124.4	$125.2	(0.6)%	$125.2	$119.5	4.7%
Commercial	92.4	90.6	2.0	90.6	85.5	5.9
Industrial	51.9	50.6	2.4	50.6	46.8	8.3
Wholesale On-System	13.6	12.4	9.4	12.4	11.9	4.8
Other***	7.5	7.3	3.2	7.3	6.8	7.3
Total On-System	$289.8	$286.1	1.3	$286.1	$270.5	5.8

* Percentage changes are based on actual kWhs and revenues and may not agree to the rounded amounts shown in this table.

** Revenues exclude amounts collected under the Interim Energy Charge during 2002 and refunded to customers during the first quarter of 2003. See discussion below.

*** Other kWh sales and Other Operating Revenues include street lighting, other public authorities and interdepartmental usage.

On-System Electric Transactions

KWh sales for our on-system customers increased slightly during 2004 primarily due to continued sales growth. Revenues for our on-system customers increased approximately $3.7 million, with an estimated $1.8 million of this increase attributed to the Oklahoma and FERC rate increases discussed below. Continued sales growth contributed an estimated $8.5 million to revenues during 2004, offset by an estimated $6.4 million negative effect from weather. Our customer growth was 1.7% in 2004 and 1.6% in both 2003 and 2002. We expect our annual customer growth to be approximately 1.6% over the next several years.

Residential kWh sales and revenues, which are more weather sensitive than the other sales classes, decreased in 2004 due primarily to milder temperatures, which had a negative effect on sales, during the first, third and fourth quarters of 2004 as compared to the same periods in 2003. Commercial sales and revenues and industrial sales and revenues, which are not particularly weather sensitive, increased during 2004 primarily due to the continued sales growth discussed above. Industrial sales also benefited from the addition of two new oil pipeline pumping stations on our system that became fully operational in June 2003. In addition, industrial revenues, as well as residential and commercial revenues, were favorably impacted by the August 2003 Oklahoma rate increase.

On-system wholesale kWh sales decreased slightly while revenues associated with these FERC-regulated sales increased as a result of the FERC rate increase that became effective May 1, 2003 and as a result of the fuel adjustment clause applicable to such sales. This clause permits the distribution to customers of changes in fuel and purchased power costs. The decrease in kWh sales was mainly due to the change in customer status in June 2003 of an on-system wholesale customer/aggregator, comprising three of our on-system wholesale accounts, which elected to go off-system and purchase power from us at market-based rates. Revenues received from these accounts,

which comprised 5–6% of our on-system wholesale sales and revenues, but less than one-half percent of our total on-system sales and revenues in 2002, are now included in our off-system revenues.

KWh sales for our on-system customers increased slightly during 2003 as compared to 2002, primarily due to continued sales growth. Colder temperatures during the first quarter of 2003 as compared to milder temperatures during the same period in 2002 had a positive effect on sales with a new all-time winter peak of 987 megawatts being established on January 23, 2003, replacing the previous winter peak of 941 megawatts established in December 2000. However, the increase in first quarter sales was offset by unfavorable weather in the second, third and fourth quarters of 2003 notwithstanding setting a new summer peak demand of 1,041 megawatts on August 25, 2003. Despite only a slight increase in kWh sales, revenues from our on-system customers increased approximately $15.6 million, with an estimated $13 million of this increase attributed to the Missouri, Oklahoma and FERC rate increases discussed below with the remainder attributed to continued sales growth. This continued sales growth contributed an estimated $7 million to revenues during 2003 offset by an estimated $5 million negative effect from weather.

Notwithstanding the new summer peak demand, the slight increases in residential and commercial kWh sales in 2003 were due primarily to the continued sales growth discussed above. Industrial sales and revenues, which are not particularly weather sensitive, increased during 2003 mainly due to increased sales resulting from the addition of the two new oil pipeline pumping stations on our system in June 2003. Also contributing to the increase were increased sales during the first quarter of 2003 because of better economic conditions as compared to the first quarter of 2002 when our service territory experienced a general slowdown in economic activity. In addition, industrial revenues, as well as residential and commercial revenues, were favorably impacted by the December 2002 Missouri rate increase and, to a lesser extent, the August 2003 Oklahoma rate increase.

On-system wholesale kWh sales decreased due mainly to the change in customer status in June 2003 of the on-system wholesale customer/aggregator which elected to go off-system and purchase power from us at market-based rates. Overall revenues associated with these FERC-regulated sales increased as a result of the FERC rate increase that became effective May 1, 2003 and as a result of the fuel adjustment clause applicable to such sales.

Rate Matters

The following table sets forth information regarding electric and water rate increases granted during the four year period ended December 31, 2004 affecting the revenue comparisons discussed above:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	November 3, 2000	$17,100,000	8.40%	October 2, 2001
Missouri — Electric	March 8, 2002	11,000,000	4.97%	December 1, 2002
Missouri — Electric	April 30, 2004	25,705,500	9.96%	March 27, 2005
Missouri — Water	May 15, 2002	358,000	33.70%	December 23, 2002
Kansas — Electric	December 28, 2001	2,539,000	17.87%	July 1, 2002

FERC — Electric	March 17, 2003	1,672,000	14.00%	May 1, 2003
Oklahoma — Electric	March 4, 2003	766,500	10.99%	August 1, 2003

The 2001 Missouri order approved an annual Interim Energy Charge, or IEC, of approximately $19.6 million effective October 1, 2001 and expiring two years later which was collected subject to refund (with interest). The 2002 Missouri electric order called for us to refund all funds collected under the IEC, with interest, by March 15, 2003. The refunds were made in the first quarter of 2003 and did not have a material impact on our earnings in any of the years from 2001 through 2003.

On March 4, 2003, we filed a request with the Oklahoma Corporation Commission for an annual increase in base rates for our Oklahoma electric customers in the amount of $954,540, or 12.97%. On August 1, 2003 a Unanimous Stipulation and Agreement was approved by the Oklahoma Corporation Commission providing an annual increase in rates for our Oklahoma customers of approximately $766,500, or 10.99%, effective for bills rendered on or after August 1, 2003. This reflects a rate of return on equity (ROE) of 11.27%.

On March 17, 2003, we filed a request with the FERC for an annual increase in base rates for our on-system wholesale electric customers in the amount of $1,672,000, or 14.0%. This increase was approved by the FERC on April 25, 2003 with the new rates becoming effective May 1, 2003.

On April 30, 2004, we filed a request with the Missouri Public Service Commission (MPSC) for an annual increase in base rates for our Missouri electric customers in the amount of $38,282,294, or 14.82%. As part of the filing, we asked the Commission to consider, in addition to a traditional ratemaking approach, two options that would allow us to recover our actual fuel and purchased power expenses: an IEC, subject to refund, similar to the one approved in our 2001 case, or a fuel adjustment clause, that would reflect actual fuel prices. We subsequently abandoned our request for a fuel adjustment clause due to Missouri statutes not providing for such clauses but retained our request for the IEC, subject to refund. We also asked for a ROE of 11.65% and an annual increase in Missouri depreciation expense of approximately $10 million.

On May 20, 2004, we filed a request with the MPSC to implement the proposed IEC no later than June 15, 2004. However, the MPSC denied this request on August 12, 2004. On September 20, 2004, the Staff of the MPSC filed direct testimony in response to our initial April 2004 filing recommending an IEC be adopted for a period of 24 months, due to the extreme volatility currently exhibited by natural gas prices. We completed two weeks of evidentiary hearings during December 2004. Items that were covered during the hearings were: ROE, depreciation, base fuel and purchased power costs and the term and amount of an IEC. On February 22, 2005, we, the Office of Public Counsel (OPC) and two intervenors filed a Nonunanimous Stipulation and Agreement Regarding Fuel and Purchased Power Expense establishing a three-year refundable IEC which became unanimous by operation of Commission rule on March 1, 2005.

Prior to the hearings, we were able to settle several miscellaneous issues with other parties to the case. On December 22, 2004, we, the MPSC Staff, the OPC and two intervenors filed a unanimous Stipulation and Agreement as to Certain Issues with the MPSC settling several of these issues. One of the issues we were able to agree on was a change in the recognition of pension costs. See Item 8 — "Financial Statements and Supplementary Data — Note 1 — Pensions" and "Note 8 — Retirement Benefits — Pensions."

The MPSC issued a final order on March 10, 2005 approving an annual increase in base rates of approximately $25.7 million, or 9.96%, effective March 27, 2005. The order granted us a return on equity of 11%, an increase in depreciation rates and an increase in base rates for fuel and purchased power at $24.68/MWH. In addition, the order approved an annual Interim Energy Charge (IEC) of approximately $8.2 million effective March 27, 2005 and expiring three years later. The IEC is $0.0021 per kilowatt hour of customer usage. The recent extraordinarily high natural gas prices and extreme volatility of natural gas led the MPSC to allow forecasted fuel costs to be used rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of two years, the excess money collected from customers, if any, above $10 million of the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time. At the end of the three year term of the IEC all excess money collected from customers, if any, of the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time.

On July 14, 2004, we filed a request with the Arkansas Public Service Commission for an annual increase in base rates for our Arkansas electric customers in the amount of $1,428,225, or 22.1%. Any new rates approved as a result of this request are not expected to be effective until the second quarter of 2005.

On March 2, 2005, we notified the Kansas Corporation Commission of our intent to file an application requesting a change in base rates for our Kansas electric customers. We plan to file this application in the second quarter of 2005.

We will continue to assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Off-System Electric Transactions

In addition to sales to our own customers, we also sell power to other utilities as available and provide transmission service through our system for transactions between other energy suppliers. The following table sets forth information regarding these sales and related expenses for the applicable periods ended December 31,:

(in millions)	2004	2003	2002
Revenues	$10.8	$15.3	$21.9
Expenses	6.3	9.8	13.4
Net Revenue	$ 4.5	$ 5.5	$ 8.5

The decrease in revenues less expenses in 2004 as compared to 2003 and in 2003 as compared to 2002 resulted primarily from the non-renewal of short-term contracts for firm energy that ran from January 2002 through June 2003. We sold this energy in the wholesale market when it was not required to meet our own customers' needs during that period. See "— Competition" below. These expenses are included in our discussion of purchased power costs below.

Operating Revenue Deductions

During 2004, total operating expenses increased approximately $9.9 million (3.8%) compared to 2003. Total fuel costs increased approximately $12.1 million (23.1%) during 2004 offset by a decrease in purchased power costs of approximately $7.4 million (12.2%), resulting in a net increase of $4.7 million for fuel and purchased power. The increase in fuel costs was primarily due to increased generation by both our coal fired and gas fired units during 2004 (an estimated $7.9 million) and lower volumes of hedged natural gas in 2004 as compared to 2003 combined with higher prices for the unhedged portion of the natural gas that we burned in our gas-fired units (an estimated $5.1 million). The decrease in purchased power costs primarily reflected a shift from serving our energy needs with purchased power to generating our own power reflecting that it was more economical to run our own generating units during 2004 than to purchase power. The decrease in purchased power costs also reflects the non-renewal of the short-term contracts for firm energy that ran from January 2002 through June 2003. Despite the overall increase in fuel costs due to increased generation and higher costs, the positive effect of our gas hedging program reduced fuel cost by $11.5 million in 2004 and $9.4 million in 2003, in each case as compared to buying all natural gas requirements on the spot market. Given the current market conditions, we don't expect the results of our gas hedging program to reduce our 2005 fuel costs by amounts comparable to the 2004 and 2003 reductions. See "Hedging Activities" under "Critical Accounting Policies" for information on future hedging activity. We also expect fuel costs to increase in 2005 due to changes in delivered prices resulting from the expiration of our long-term coal and freight contracts. A long-term contract with a subsidiary of Peabody Holding Company, Inc. for the supply of low sulfur Western coal (Powder River Basin) at the Asbury and Riverton Plants expired in December 2004. We signed a new, three-year contract with Peabody on December 15, 2004 that covers approximately 100% of our anticipated 2005 Western coal requirements, approximately 67% of our anticipated 2006 Western coal requirements and approximately 33% of our anticipated Western coal requirements for 2007. We also currently have a contract with Union Pacific Railroad Company and The Kansas City Southern Railway Company which provides for transportation of the Powder River Basin coal which will expire at the end of June 2005. In 2004 we accepted a binding proposal and are in the process of finalizing contractual terms and conditions on a new transportation contract. We expect that, beginning in July 2005, this coal will be delivered under the new transportation contract. The delivered price of coal under the new contracts is expected to be higher than the 2004 price during the first and second quarters of 2005, but we expect the delivered price increase to be substantially mitigated beginning in the third quarter of 2005 due to a combination of our new coal supply and coal transportation contracts. We also expect changes in gas prices to contribute to variances in fuel costs, partially offset by the impact of our hedging program.

Regulated — other operating expenses increased approximately $3.2 million (6.5%) during 2004 as compared to 2003 primarily due to a $1.2 million increase in employee health care costs, an approximate $0.8 million increase in stock compensation costs, a $0.9 million increase in customer accounts expense, of which $0.4 million was a first quarter 2004 addition to bad debt expense, a $0.5 million increase in steam power operating expenses at the Asbury and Riverton plants and a $0.5 million increase in general administrative expense due primarily to $0.6

million associated with Sarbanes-Oxley compliance. These increases were partially offset by a $0.7 million decrease

in transmission and distribution expense, a $0.6 million decrease in professional service expenses and a $0.5 million decrease in employee pension expense. Based on the performance of our pension plan assets through January 1, 2003, we were required under the Employee Retirement Income Security Act of 1974 (ERISA) to fund approximately $0.3 million in 2004 in order to maintain minimum funding levels and contributed this $0.3 million to our pension plan in the first quarter of 2004. Based on the performance of our pension plan assets through December 31, 2004, we expect there will be no contribution required under ERISA in order to maintain minimum funding levels in 2005. This could change, however, based on actual investment performance, any future pension plan funding and finalization of actuarial assumptions. No minimum pension liability was required to be recorded as of December 31, 2003 or 2004. No significant changes are expected for our post-retirement benefits in 2005 as compared to 2004. See Note 8 of "Notes to Consolidated Financial Statements" under Item 8 for further discussion regarding our pension and post-retirement benefit plans.

Non-regulated operating expense for all periods presented is discussed below under "—Non-regulated Items".

Maintenance and repairs expense increased approximately $0.9 million (4.4%) during 2004 as compared to 2003 primarily due to the $1.0 million insurance deductible recorded to expense in the first quarter of 2004 related to the maintenance on the Energy Center's Unit No. 2 which experienced a rotating blade failure on January 7, 2004 (which caused damage throughout the machine) and to the second and third quarter maintenance costs related to repairs at the Energy Center not subject to insurance recovery. Also contributing to this increase was a $0.8 million increase in transmission and distribution maintenance and a $0.7 million increase in maintenance costs for the SLCC as compared to the prior year due mainly to a $1.8 million true-up credit (our share of the credit as 60% owners of the SLCC) received from Siemens Westinghouse in June 2003 related to our maintenance contract for the period July 2002 through June 2003 for the SLCC. These increases were partially offset by a $1.4 million decrease in maintenance costs for our coal-fired units during 2004 as compared to the prior year, reflecting the maintenance outages during the second quarter of 2003 when the Iatan Plant underwent a planned boiler outage, the Riverton Plant's Unit No. 7 had a 12-day scheduled spring maintenance outage and Unit No. 8 had an extended maintenance outage that ran from February 14, 2003 until May 14, 2003.

Depreciation and amortization expense increased approximately $2.1 million (7.4%) during 2004 due to increased plant in service. Total provision for income taxes decreased approximately $4.7 million (29.8%) during 2004 due primarily to lower taxable income. Our effective federal and state income tax rate for 2004 was 34.1% as compared to 34.5% for 2003. See Note 9 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding income taxes. Other taxes increased $1.9 million (11.6%) during 2004 due mainly to increased property taxes reflecting our additions to plant in service and increased city taxes in the first quarter of 2004 as compared to the first quarter of 2003 when we had a decrease in city taxes resulting from the refund of the IEC in the first quarter of 2003.

During 2003, total operating expenses increased approximately $15.0 million (6.0%) compared to 2002. Total fuel costs increased approximately $2.6 million (5.2%) during 2003 offset by a decrease in purchased power costs of approximately $2.6 million (4.1%) making total combined fuel and purchased power costs in 2003 virtually the same as in 2002. The increase in total fuel costs reflects a $1 million payment in the fourth quarter of 2003, expensed as additional fuel costs in the third quarter of 2003, pursuant to a settlement with Enron of a fuel contract dispute, a $0.7 million unfavorable coal inventory adjustment in August 2003 and increased generation by our coal-fired units, reflecting the non-renewal of short-term contracts for firm energy discussed above. Despite the effectiveness of our natural gas procurement program, increased natural gas prices during 2003 led to a 16.6 % increase in our average cost of gas as compared to 2002. See Note 14 — "Risk Management and Derivative Financial Instruments" under Item 8, "Financial Statements and Supplementary Data" for information on the over hedged and qualified portions of our hedging activities. The decrease in purchased power costs primarily reflects a shift from serving our energy needs with purchased power to generating our own power, reflecting that it was more economical to run our own generating units during the third and fourth quarters of 2003 than to purchase power. This decrease in purchased power costs also reflects the decrease in off-system sales due to the non-renewal of the short-term contracts for firm energy discussed above.

Regulated — other operating expenses increased approximately $6.7 million (15.5%) during 2003 as compared to 2002. This increase was primarily due to an increase of $5.6 million in employee pension expense due primarily to a decline in the value of invested funds. Expenses relating to our employee health care plan contributed $0.6

million to the increase in regulated — other operating expenses while increases in insurance premiums added $0.4 million.

There were no expenses during 2003 relating to the terminated merger with Aquila, Inc. as compared with $1.5 million during 2002. Expenses related to the terminated merger in 2002 were primarily the result of expenses related to severance benefits incurred under our Change in Control Severance Pay Plan in the first quarter of 2002. These expenses are shown on the Other line in our Consolidated Statement of Income under the heading "Operating revenue deductions".

Maintenance and repairs expense decreased approximately $4.5 million (18.3%) during 2003 as compared to 2002. Maintenance and repairs expense for the State Line and Energy Center units decreased approximately $6.1 million partially offset by an approximate $1.3 million increase in maintenance and repairs at our Riverton Plant reflecting a scheduled five-year maintenance outage for Unit No. 8 in the first and second quarters of 2003 as well as to make necessary repairs to a high-pressure cylinder. The decrease in maintenance and repairs expense for the State Line Combined Cycle Unit reflects, in part, the $1.8 million true-up credit received from Siemens Westinghouse discussed above as well as estimated monthly credits we have been accruing since July 2003. Monthly payments on this contract had been based on an assumption of 250 equivalent starts per unit each year. Actual starts during the twelve month period ended June 30, 2003, however, were significantly less than originally estimated resulting in the June 2003 true-up credit. We expensed maintenance costs and accrued a credit based on a combination of starts and actual monthly usage hours for the contract year ended June 30, 2004. As of December 31, 2003, we had accrued $0.9 million in estimated credits. A $0.5 million payment during the third quarter of 2002, per contract terms, to Westar Generating, Inc. (WGI) for maintenance expense related to our usage of the existing Unit No. 2 turbine prior to WGI's 40% joint ownership of the State Line Combined Cycle Unit also contributed to the decreased maintenance expense in 2003. Lower payments during the first half of 2003 on our long-term operating plant maintenance contracts for outage services on Units No. 1 and No. 2 at the Energy Center and State Line Unit No. 1 as compared to the first half of 2002 when we were making additional payments of approximately $1.1 million also contributed to the decrease. Lastly, renegotiated terms for the Energy Center units and State Line Unit No. 1 contract for outage services reduced maintenance costs during 2003 by $0.5 million.

Depreciation and amortization expense increased approximately $2.6 million (10.0%) during 2003 due to increased plant in service. Total provision for income taxes increased approximately $2.4 million (17.6%) during 2003 due primarily to higher taxable income. Our effective federal and state income tax rate for 2003 was 34.5% as compared to 34.3% for 2002. See Note 9 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding income taxes.

Non-regulated Items

We began investing in non-regulated businesses in 1996. Our non-regulated businesses, which we operate through our wholly-owned subsidiary EDE Holdings, Inc., include leasing of fiber optics cable and equipment (which we are also using in our own operations), Internet access, close-tolerance custom manufacturing and customer information system software services. On January, 31, 2005, we sold our 100% interest in Southwest Energy Training, a company that offers technical training to the utility industry. This divestiture will not have a material impact on our balance sheets or statements of income in future periods. We evaluated our non-regulated businesses for impairment at December 31, 2004, and determined that no impairment exists based on our forecast of future net cash flows. Failure to achieve forecasted cash flows could result in an impairment in the future.

During 2004, total non-regulated operating revenue increased approximately $0.7 million (3.5%) while total non-regulated operating expense increased approximately $1.8 million (8.6%) as compared with 2003. The increase in revenues was mainly due to the activities of our fiber optics business and Fast Freedom, an Internet provider we own a 100% interest in. The increase in expenses was due mainly to MAPP, which we own a 50.01% interest in, and Conversant, Inc., a software company that we own a 100% interest in which began business in early 2002. Conversant markets Customer Watch, an Internet-based customer information system software, and began contributing revenues in the fourth quarter of 2003.

During 2003, total non-regulated operating revenue increased approximately $10.6 million while total non-regulated operating expense increased approximately $9.2 million as compared with 2002. The significant increases

during 2003 were primarily due to the inclusion of a full year of MAPP operating revenues and expenses as compared to the prior year results which reflected the acquisition of our 50.01% interest in MAPP in July 2002. The increase in expenses was also due to the activities of