AR/S

ENERGY WEST

INC

P.E. 6/30/03

2003 annual report

"We have emerged from a very difficult year and are re-establishing solid growth and profitability."

– *John C. Allen*

Dear Shareholder,

Our company had to deal with a number of challenges and disappointments during the last year. To say the least, we are not happy with the financial results for Fiscal 2003. In response, in order to strengthen our company and to reinstate dividends to our shareholders as soon as we can do so prudently, your Board of Directors has taken the following decisive actions:

- Implemented a number of strong cost control and cost reduction measures. A visible example of these measures is this annual report, which wraps around Energy West's Form 10-K report filed with the Securities and Exchange Commission.
- Positioned Energy West to refocus on its core long-term business—distribution of natural gas and propane to retail and commercial customers, while retaining involvement in profitable pipelines and natural gas production.
- Exited the electricity marketing business (with only a few residual agreements remaining, all of which are hedged to avoid loss).
- Established a new banking relationship, which enables us to fund our operating cash needs at reasonable borrowing costs.
- Resolved the burdensome, expensive and distracting litigation over a supply agreement.

September 30, 2003 was a watershed for our company. We paid the final installment of our settlement of the supply agreement lawsuit, and began what we look forward to as a very mutually beneficial relationship with LaSalle Bank.

Although Fiscal 2003 was a difficult year, Energy West was able to achieve a number of very favorable accomplishments during the year.

- We secured rate adjustments in both Montana and Wyoming that we expect to permit complete recovery of the expenses and capital costs necessary to provide safe and reliable service to our utility customers while allowing a fair rate of return for our shareholders.
- We obtained permission from the Federal Energy Regulatory Commission to place the Shoshone Pipeline in service as an interstate open access pipeline system. The capacity on this pipeline already has been subscribed at sufficient levels to provide an attractive return on investment.
- Our subsidiary operations have acquired natural gas reserves at attractive prices.

The foundation for solid growth and profitability has been laid. We are determined to achieve these goals and to reinstate a dividend to our shareholders as quickly as possible.

We are confident that our dedicated employees are ready, willing and able to achieve these goals. Your Board of Directors and company management remain firmly committed to customer satisfaction and maximizing value for all of our shareholders.

Thank you for your continued support.

Very truly yours,

John C Allen

John C. Allen
Interim President & CEO

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended June 30, 2003

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 0-14183
ENERGY WEST, INCORPORATED
(Exact name of registrant as specified in its charter)

Montana	81-0141785
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1 First Avenue South, Great Falls, Montana	59401
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (406)-791-7500
Securities to be registered pursuant to Section 12(b) of the Act:
None
Securities registered pursuant to Section 12(g) of the Act:
Title of each class
Common Stock - Par Value $.15

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 [X] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.45 of this chapter) 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 [X].

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes [ ] No [X].

The aggregate market value of the voting stock held by non-affiliates of the registrant as of December 31, 2002: Common Stock, $.15 Par Value - $19,044,030

The number of shares outstanding of the registrant's classes of common stock as of September 30, 2003: Common Stock, $.15 Par Value - 2,595,250 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2003 Annual Meeting of Shareholders are incorporated by reference into Part III.

PART I

Item 1. – Business

General

Energy West, Incorporated (the "Company") is a regulated public utility, with certain non-utility operations conducted through its subsidiaries. The Company was originally incorporated in Montana in 1909. The Company's regulated utility operations involve the distribution and sale of natural gas to the public in and around Great Falls and West Yellowstone, Montana and Cody, Wyoming, and the distribution and sale of propane to the public through underground propane vapor systems in and around Payson, Arizona and Cascade, Montana. The Company's West Yellowstone, Montana operation is supplied by liquefied natural gas (LNG).

Certain non-regulated, non-utility operations are conducted by three wholly-owned subsidiaries of the Company: Energy West Propane, Inc. (EWP); Energy West Resources, Inc. (EWR); and Energy West Development, Inc. (EWD). EWP is engaged in wholesale distribution of bulk propane in Wyoming, Arizona and Montana, and is engaged in retail distribution of bulk propane in Arizona. EWR markets gas and electricity in Montana and Wyoming, and owns certain natural gas production properties in Montana. EWD owns two pipeline systems in Montana and Wyoming, natural gas production properties in north central Montana and certain other real property in Montana.

The Company's reporting segments are: Natural Gas Operations, Propane Operations, EWR and Pipeline Operations. To reflect management and business changes, the Company realigned its reporting segments effective July 1, 2002. The Company's wholly owned subsidiary, Energy West Development, Inc. (EWD), owns a renovated pipeline located in Wyoming and Montana. An application has been granted by the Federal Energy Regulatory Commission (FERC) and EWD began operations of this pipeline as a transmission pipeline on July 3, 2003. The revenue and expenses associated with this transmission pipeline are included in the "Pipeline Operations" segment. EWD also owns a gathering system pipeline in Wyoming and recently purchased natural gas production reserves in north central Montana. The revenue and expenses associated with EWD's gathering system pipeline were reported as part of the "EWR" segment for periods prior to fiscal year 2003. Beginning with fiscal year 2003, such revenue and expenses are reported as part of the "Pipeline Operations" segment as are the revenues and expenses associated with the recently purchased production properties. Also beginning with fiscal year 2003, the operations of a regulated propane distribution system located in Cascade, Montana are reported as part of the "Natural Gas Operations" segment. The Cascade, Montana system was reported as part of the Company's "Propane Operations" segment prior to fiscal year 2003. Segment information for prior periods has been restated to reflect the realignment of the Company's reporting segments.

Natural Gas Operations

The Company's primary business is the distribution and sale of natural gas to residential, commercial and industrial customers. The Company's natural gas operations consist of two divisions. The Energy West – Montana Division serves customers with operations in Great

Falls, West Yellowstone and Cascade, Montana. The Energy West – Wyoming Division serves customers in and around Cody, Meeteetse and Ralston, Wyoming. Generally, residential customers use natural gas for space heating and water heating, commercial customers use natural gas for space heating and cooking, and industrial customers use natural gas as a fuel in industrial processing and space heating. The Company's revenues from natural gas operations are generated under tariffs regulated by the state utility commissions of Montana and Wyoming, respectively. During fiscal year 2003 the Company filed applications for rate increases for its Great Falls, Montana and Cody, Wyoming operations with the Montana Public Service Commission (MPSC) and Wyoming Public Service Commission (WPSC), respectively. Effective on December 15, 2002, the Company received approval from the MPSC for an interim rate increase for the Great Falls, Montana operation of approximately $600,000 which became final on June 15, 2003, with a final rate increase approved for $687,000. Effective on June 1, 2003, the Company received approval from the WPSC for a rate increase for the Cody, Wyoming operation of approximately $721,000.

Energy West – Montana (EWM) Division

The EWM division provides natural gas service to customers in and around Great Falls and West Yellowstone, Montana and provides propane through an underground vapor system in Cascade, Montana. The division's service area has a population of approximately 79,000 in the Great Falls area, 1,200 in the West Yellowstone area and approximately 900 in the Cascade area.

The division has a franchise to distribute natural gas within the city of Great Falls that expires in 2021. The division also provides natural gas transportation service to certain customers who purchase natural gas from other suppliers.

The following table shows the EWM division's revenues by customer class for the fiscal year ended June 30, 2003 and the two preceding fiscal years:

	Gas Revenues (in thousands) Years Ended June 30,		
	2003	2002	2001
Residential	$ 13,643	$ 17,563	$ 17,180
Commercial	8,383	10,443	9,935
Transportation	1,789	1,958	2,045
Total	$ 23,815	$ 29,964	$ 29,160

Note: Revenues reduced in fiscal year 2003 compared to fiscal year 2002 due to the discontinuance of the surcharge to collect unrecovered gas costs and lower volume sales due to warmer than normal temperatures.

The following table shows the volumes of natural gas, expressed in millions of cubic feet (MMcf) (measured at standard operating pressure) sold or transported by the division for the fiscal year ended June 30, 2003 and the two preceding fiscal years:

Gas Volumes
(MMcf)

	Years Ended June 30,		
	2003	2002	2001
Residential	2,267	2,417	2,513
Commercial	1,359	1,442	1,430
Total Gas Sales	3,626	3,859	3,943
Transportation	1,462	1,522	1,615

Note: The reduction in sales volumes in fiscal year 2003 compared to fiscal year 2002 was due to warmer than normal temperatures experienced in the Great Falls area.

The EWM division has approximately 173 transportation customers. No customer of the EWM division accounted for more than 2% of the consolidated revenues of the Company in fiscal 2003.

The operations of the EWM division are subject to regulation by the MPSC. The MPSC regulates rates, adequacy of service, issuance of securities, compliance with U.S. Department of Transportation Safety Regulations and other matters.

In December 1998, the MPSC approved a proposed plan filed by the Company (the "Plan") to allow customers to choose a natural gas supplier other than the EWM division. The Plan allows customers to purchase natural gas from other suppliers. Under the Plan, the EWM division continues to provide delivery service to customers who purchase from other suppliers. Customers who do not wish to choose another supplier may continue purchasing natural gas from the EWM division.

The EWM division uses the NorthWestern Energy (NWE) pipeline transmission system to transport supplies of natural gas for its core load. The division also uses this pipeline capacity to provide transportation, distribution and balancing services to customers who have chosen to obtain natural gas from other suppliers. In 2000, the Company entered into a 10-year transportation agreement with NWE that fixes the cost of pipeline and storage capacity for the EWM division.

In October 2000, the Company filed its annual gas cost recovery application for the EWM division with the MPSC. The MPSC granted interim rate relief in December 2000. During late 2000, however, the EWM division's costs of gas rose due to an increase in index prices, and as a result the Company amended its application in February 2001. In response, the MPSC issued a second interim order in March 2001 (which the MPSC made final in August 2001). This order established a monthly cost tracking process under which the Company was required to file for an increase or decrease in rates if natural gas costs change more than $.10 per thousand cubic feet (Mcf) in any month, subject to an annual audit of the unrecovered balance by the MPSC and Montana Consumer Counsel.

In May 2002, after fully recovering the previous increase in gas costs experienced by the EWM division, the Company filed for a reduction in the rates as required by the MPSC's order. In June 2002, the Company received approval from the MPSC to reduce the rates charged by the EWM division effective July 1, 2002.

In September 2002, the Company filed an application with the MPSC seeking an increase in annual utility rates for the Great Falls, Montana operation. On December 15, 2002, the Company received from the MPSC an interim increase in annual revenues in the amount of $600,000. The Company subsequently entered into a stipulation with the Montana Consumer Counsel, the only other party to the rate application investigation, for a permanent increase in the amount of approximately $687,000. The permanent increase was approved by the MPSC in the amount of $687,000 on June 15, 2003.

Energy West – Wyoming (EWW) Division

The EWW division provides natural gas service to customers in and around Cody, Meeteetse and Ralston, Wyoming. This service area has a population of approximately 12,000. The EWW division has a certificate of public convenience and necessity granted by the WPSC for transportation and distribution covering the west side of the Big Horn Basin, which stretches approximately 70 miles north and south and 40 miles east and west from Cody. As of June 30, 2003, the EWW division provided service to approximately 5,750 customers, including one industrial customer. The division also offers transportation service for natural gas producers and other parties.

The following table shows the EWW division's revenues by customer class for the fiscal year ended June 30, 2003 and the two preceding fiscal years:

Gas Revenues
(in thousands)

	Years Ended June 30,		
	2003	2002	2001
Residential	$ 3,119	$ 3,434	$ 4,409
Commercial	2,591	3,035	3,512
Industrial	2,101	3,044	3,481
Transportation	301	346	447
Total	$ 8,112	$ 9,859	$ 11,849

Note: Lower revenues were experienced in fiscal year 2003 compared to fiscal year 2002 due to warmer than normal temperatures and reduced sales to a large industrial customer, Celotex. The lower revenues in fiscal year 2002 compared to fiscal year 2001 were the result of the discontinuance of a surcharge to collect unrecovered gas costs.

The following table shows the volumes of natural gas, expressed in millions of cubic feet (MMcf) (measured at standard operating pressure), sold by the EWW division for the fiscal year ended June 30, 2003 and the two preceding fiscal years:

Gas Volumes
(MMcf)

Years Ended June 30,

	2003	2002	2001
Residential	541	564	563
Commercial	531	550	521
Industrial	525	610	608
Total Gas Sales	1,597	1,724	1,692
Transportation	1,383	1,588	1,413

The EWW division's industrial customer, BPB America (dba Celotex), a manufacturer of gypsum wallboard, purchases gas pursuant to a special industrial tariff, which fluctuates with the volumes of gas sold and the cost of gas. In fiscal year 2003 Celotex accounted for approximately 27% of the revenues of the EWW division and approximately 3% of the consolidated revenues of the Company. Celotex's business is cyclical and dependent on the level of national housing starts. The division's sales to Celotex in fiscal year 2003 were approximately 14% less than fiscal year 2002.

EWR is the EWW division's primary supplier of natural gas, pursuant to an 18 month agreement entered into in May of 2003.

The EWW division transports gas for third parties pursuant to a tariff filed with and approved by the WPSC. The terms of the transportation tariff (currently between $.08 and $.31) per Mcf are established by the WPSC.

The EWW division's revenues are generated under regulated tariffs designed to recover a base cost of gas, administrative and operating expenses and provide sufficient return to cover interest and profit. The division's tariffs include a purchased gas adjustment clause which allows the division to adjust its rates periodically to recover changes in gas costs from base gas costs.

On December 24, 2002, the Company's Wyoming division filed an application with the WPSC seeking an increase in annual utility rates. The WPSC granted an annual rate increase of approximately $721,000 with an effective date of June 1, 2003.

Propane Operations

The Company reports as a separate business segment the regulated distribution of propane by the Company, and the unregulated distribution of propane by the Company's wholly-owned subsidiary, Energy West Propane, Inc. (EWP). The Company is engaged in the regulated distribution of propane through its Energy West Arizona (EWA) division and unregulated distribution of propane in Montana, Wyoming and Arizona through its Energy West Propane, Arizona, and Rocky Mountain Fuels divisions.

Regulated Propane Operations

The EWA division distributes propane in the Payson, Arizona area. The service area of the EWA division includes approximately 575 square miles and has a population of approximately 31,000. The operations of the EWA division are subject to regulation by the Arizona Corporation Commission (ACC), which regulates rates, adequacy of service, and other matters. The EWA division's properties include approximately 190 miles of underground distribution pipeline and an office building leased from a third party. The division purchases its propane supplies from EWP under terms reviewed periodically by the ACC. The EWA division has approximately 7,400 customers. The division's principal competition comes from bulk propane retailers who sell to customers who draw propane for use from storage tanks located at their homes or businesses, rather than using propane from the division's underground distribution system.

The following tables show the EWA division's revenues and propane volumes by customer class for the fiscal year ended June 30, 2003 and the two preceding fiscal years:

Regulated Propane Revenues
(in thousands)

	Years Ended June 30,		
	2003	2002	2001
Residential	$ 3,729	$ 3,384	$ 3,530
Commercial	1,639	1,520	1,459
Total	$ 5,368	$ 4,904	$ 4,989

Regulated Propane Volumes
(in thousands of gallons)

	Years Ended June 30,		
	2003	2002	2001
Residential	2,874	2,678	2,835
Commercial	1,070	1,012	1,063
Total Gas Sales	3,944	3,690	3,898

Unregulated Propane Operations

The Company's subsidiary Energy West Propane, Inc. (EWP) is engaged in the bulk sale of propane through its three divisions: Energy West Propane-Arizona, which serves the Payson, Arizona area; Energy West Propane-Montana, which sells bulk propane in the Cascade County area, surrounding Great Falls, Montana; and Rocky Mountain Fuels Wholesale which has wholesale operations primarily in Montana and Arizona. EWP had 9,430 customers as of June 30, 2003.

Energy West Propane - Arizona sells propane to residential and commercial customers in the Payson, Arizona area.

EWP's wholesale division, Rocky Mountain Fuels Wholesale (RMF), supplies propane for the Company's underground propane-vapor systems serving the cities of Payson, Arizona and Cascade, Montana and surrounding areas. The majority of RMF's Wyoming and Montana assets, including the Superior, Montana terminal were sold on August 21, 2003 to Jack's Wholesale Propane, Inc. (an affiliate of Northern Petro NGL Marketing Inc.) for approximately $1,370,000.

EWP faces competition from other propane distributors and suppliers of alternative fuels that compete with propane. Competition is based primarily on price and there is a high degree of competition with other propane distributors in each of the Company's service areas.

The following tables show the revenues and volumes for unregulated propane operations by customer class for the fiscal year ended June 30, 2003 and the two preceding fiscal years:

Unregulated Propane Revenues
(in thousands)

Years Ended June 30,

	2003	2002	2001
Residential	$ 1,348	$ 1,275	$ 1,421
Commercial	5,985	3,365	5,734
Total	$ 7,333	$ 4,640	$ 7,155

Unregulated Propane Volumess
(in thousands of gallons)

Years Ended June 30,

	2003	2002	2001
Residential	912	901	921
Commercial	10,870	6,934	7,821
Total Gas Sales	11,782	7,835	8,742

EWR

The Company's wholly owned subsidiary, EWR, conducts certain marketing and trading activities and wholesale distribution activities involving the sale of natural gas and electricity in Montana and Wyoming.

Montana legislation enacted in 1997, and subsequent MPSC orders, permitting open access on the NorthWestern Energy gas transportation and electricity transmission system, and other systems in Montana have presented opportunities for EWR to do business as a broker of natural gas and electricity. Although EWR has concentrated its efforts on industrial and large commercial customers, EWR began to market gas and electricity to small commercial and residential customers in fiscal year 2000. EWR has from time to time entered into certain financial agreements that hedge against the risks of fluctuation in prices of natural gas and electricity. If the price obtained through such instruments is favorable or unfavorable compared to subsequent market conditions, net earnings or losses can result from such arrangements. See Item 7, "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF CONSOLIDATED OPERATIONS—Derivatives and Risk Management." During fiscal year 2003, EWR effectively exited the electricity marketing business, with services currently provided only to one customer, delivering approximately one MW pursuant to a contract that continues through fiscal year 2005.

In order to provide a stable source of natural gas for a portion of its requirements, in May 2002, EWR purchased a 56% interest in a group of producing natural gas reserves located in northern Montana. EWR's portion of the estimated daily gas production from the reserves is approximately 600,000 cubic feet (600 Mcf), or approximately 3% of EWR's present volume requirements. This production gives EWR a natural hedge, due to fixed production expenses when market prices of natural gas are above the costs of production. One of the other owners of a partial interest in these reserves serves as the operator of the wells. As part of the transaction, EWR received a $300,000 settlement in connection with certain claims. The $300,000 was recorded as nonoperating income during the fourth quarter of fiscal year 2002.

Pipeline Operations

Pipeline Operations was added as a new segment as of July 1, 2002. The results of this segment reflect operation of natural gas gathering systems placed into service in fiscal year 2001, and transferred from EWR to EWD. The revenues and expenses associated with the pipeline gathering systems had previously been reported as part of the EWR segment.

The Company's wholly owned subsidiary, Energy West Development, Inc. (EWD), owns a renovated pipeline located in Wyoming and Montana. EWD began operations of this pipeline as a transmission pipeline on July 3, 2003. The revenue and expenses associated with this transmission pipeline will be included in the "Pipeline Operations" segment.

In March 2003, EWD acquired a 75% ownership interest in natural gas production properties located in northcentral Montana, which will provide a portion of the gas requirements of EWR. EWD's portion of the estimated daily gas production from these properties is approximately 350,000 cubic feet (350 Mcf), or approximately 2% of EWR's current volume requirements.

Capital Expenditures

The Company conducts ongoing construction activities, in all of its utility service areas, in order to support expansion, maintenance and enhancement of its gas and propane pipeline systems. The Company also continues to experience growth in its Pipeline Operations segment and purchased additional natural gas production properties during fiscal year 2003. In fiscal years 2003, 2002 and 2001, total capital expenditures for the Company were approximately

$4,970,000, $6,442,000 and $3,276,000, respectively, including purchases of natural gas production properties. Expenditures for fiscal year 2002 were higher than usual due to the renovation of the transmission pipeline between Wyoming and Montana and a by-pass loop around Cody, Wyoming.

Available Information

The internet address for the Company is: http://www.ewst.com. The Company makes available, free of charge, on its internet website annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and additional filings of the Company filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after these filings have been made with the SEC.

Competition

The principal competition faced by the Company in its distribution and sales of natural gas is from suppliers of alternative fuels, including electricity, oil, propane and coal. The principal considerations affecting a customer's selection of utility gas service over competing energy sources include service, price, equipment costs, reliability and ease of delivery. In addition, the type of equipment already installed in businesses and residences significantly affects the customer's choice of energy. However, where previously installed equipment is not an issue, households in recent years have generally preferred the installation of gas heat. The Company estimates that approximately 97% of the homes and businesses in the Great Falls service area use natural gas as their primary source for space heating fuel, approximately 93% use gas for water heating and approximately 99% of the new homes built on, or near, the Company's Great Falls service mains in recent years have selected natural gas as their energy source.

The EWW division estimates that approximately 95% of the homes and businesses in its service area use natural gas for space heating fuel, approximately 90% use gas for water heating, and approximately 99% of the new homes built on or near the division's service mains in recent years have selected gas as their energy source.

The EWA division estimates that approximately 67% of the homes and businesses adjacent to the division's distribution pipeline use the division's propane for space heating or water heating. Studies show that approximately 90% of new subdivisions within the division's distribution system are using propane as their primary fuel source.

The principal competition faced by the Company and its subsidiaries in the distribution and sale of propane is from electricity suppliers and other propane distributors. Competition is based primarily on price and customer service and there is a high degree of competition from other propane distributors in all of the service areas.

EWR's principal competition is from other gas marketing firms doing business in the State of Montana. As of July 1, 2003, EWR has successfully exited the electricity marketing business with the exception of maintaining one customer existing under a contract through fiscal year 2005.

Governmental Regulation

The Company's utility operations are subject to regulation by the MPC, the WPSC, and the ACC. Such regulation plays a significant role in determining the Company's return on equity. The commissions approve rates that are intended to permit a specified rate of return on investment. The Company's tariffs allow the cost of gas to be passed through to customers. The pass-through causes some delay, however, between the time that gas costs are incurred by the Company and the time that the Company recovers such costs from customers.

Seasonality

The business of the Company and its subsidiaries in all segments is temperature-sensitive. In any given period, sales volumes reflect the impact of weather, in addition to other factors, with colder temperatures generally resulting in increased sales by the Company. The Company anticipates that this sensitivity to seasonal and other weather conditions will continue to be reflected in the Company's sales volumes in future periods.

Environmental Matters

The Company owns property on which it operated a manufactured gas plant from 1909 to 1928. The site is currently used as an office facility for Company field personnel and storage location for certain equipment and materials. The coal gasification process utilized in the plant resulted in the production of certain by-products, which have been classified by the federal government and the State of Montana as hazardous to the environment.

Several years ago the Company initiated an assessment of the site to determine if remediation of the site was required. That assessment resulted in a submission of a proposed remediation plan to the Montana Department of Environmental Quality (MDEQ) in 1994. The Company has worked with the MDEQ since that time to obtain the data that would lead to a remediation action acceptable to the MDEQ. In the summer of 1999 the Company received final approval from the MDEQ for its plan for remediation of soil contaminants. The Company has completed its remediation of soil contaminants and in April of 2002 received a closure letter from MDEQ approving the completion of such remediation program.

The Company and its consultants continue their work with the MDEQ relating to the remediation plan for water contaminants. The MDEQ has established regulations that allow water contaminants at a site to exceed standards if it is technically impracticable to achieve them. Although the MDEQ has not established guidance to attain a technical waiver, the U.S. Environmental Protection Agency (EPA) has developed such guidance. The EPA guidance lists factors which render mediations technically impracticable. The Company has filed a request for a waiver respecting compliance with certain standards with the MDEQ.

At June 30, 2003, the Company had incurred cumulative costs of approximately $2,034,000 in connection with its evaluation and remediation of the site. The Company also estimates that it will incur at least $60,000 in additional expenses in connection with its investigation and remediation for this site. On May 30, 1995, the Company received an order from the MPSC allowing for recovery of the costs associated with the evaluation and remediation of the site through a surcharge on customer bills. As of June 30, 2003, the Company had recovered approximately $1,443,000 through such surcharges.

On April 15, 2003, the MPSC issued an Order to Show Cause Regarding the Environmental Surcharge. The MPSC required the Company to show cause why it was not in violation of the 1995 order by failing to seek renewal of the surcharge at the conclusion of the initial two year recovery period. The Company responded to the MPSC and an interim order has been issued by the MPSC suspending the collection by the Company of the surcharge until further investigation can be conducted and requiring a new application from the Company respecting this surcharge. The Company has submitted its revised application and is awaiting further MPSC action. The Company currently has an unrecovered balance of $590,000 awaiting recovery through this mechanism. In the event that the MPSC does not approve the Company's revised application, in addition to potentially being unable to recover the unrecovered balance of $590,000, the Company could be required to refund to customers a portion of the $1,443,000 previously collected through surcharges.

Employees

The Company and its subsidiaries had an aggregate total of 131 employees as of June 30, 2003. Five of these employees were employed by EWR, 28 by the Company's Propane Operations, 85 were employed by the Company's Natural Gas Operations and 13 individuals were employed at the corporate office. The Company's Natural Gas Operations include 16 employees represented by two labor unions. Contracts with each of these unions expired on June 30, 2003, and the Company continues negotiations with the two labor unions. In July 2003, the Company initiated a cost reduction program and reduced the total number of Company employees to 125.

Executive Officers

The following table sets forth the names and ages of, and the positions and offices within the Company presently held by, the executive officers of the Company:

Name	Age	Position
John C. Allen	52	Interim President and Chief Executive Officer
Tim A. Good	58	Vice-President and Manager of Natural Gas Operations
Douglas R. Mann	56	Vice-President and Manager of Energy West Propane Operations
JoAnn S. Hogan	37	Vice-President, Treasurer and Secretary

Robert B. Mease	56	Vice-President and Controller
James E. Morin	49	President of Energy West Resources, Inc.

John C. Allen was appointed Interim President and Chief Executive Officer on September 22, 2003. He joined the Company in 1986 as Corporate Counsel and Secretary and was appointed General Counsel, Vice-President and Secretary of the Company in 1992. Prior to joining Energy West he was Staff Attorney for the Montana Consumer Counsel from 1979 to 1986.

Tim A. Good has been Vice-President of the Company and Manager of the Company's Natural Gas Operations since July 1, 2000. He served as Vice President and Division Manager of the EWW Division from 1988 to July 1, 2000.

Douglas R. Mann has been Vice-President and Manager of Energy West Propane Operations since July 1, 2000. From February, 1999 until July 1, 2000, he served as Vice-President and Manager of the EWA Division. From 1995 until July 1, 1999, he served as Assistant Vice-President and Manager of the Arizona Division.

JoAnn S. Hogan was appointed Vice-President, Treasurer and Secretary on September 25, 2003. From January 2002 until her most recent appointment she was Assistant Vice-President and Treasurer of the Company. She served as Controller from 2000 to 2002. From 1995 to 2000, she served in various financial capacities for the Company including Assistant Controller and Tax Manager.

Robert B. Mease was appointed Vice-President and Controller on September 25, 2003. From February 2002, when joining the Company, until September 25, 2003, he was Assistant Vice-President and Controller. From October 2000 to February 2002, he served as a business consultant with Junkermier, Clark, Campanella & Stevens, a public accounting firm. From 1998 to 2000 he was Vice-President and CFO of TMC Sales, a steel manufacturer and wholesale distributor located in Seattle, Washington. From 1994 to 1998, he was Vice-President of Finance for American Agri-Technology, located in Great Falls, Montana.

James E. Morin was appointed President of Energy West Resources, Inc., a wholly owned subsidiary of the Company in February of 2003. From July 2001 to February 2003, he served as Vice President of Electricity Marketing and from August 1997 to July 2001, he served as Manager of Industrial and Commercial Marketing for Energy West Resources, Inc.

Item 2. - Properties

The Company owns and leases properties located in the following states:

Montana: In Great Falls, Montana, the Company owns a 9,000 square foot office building, which serves as the Company's headquarters, and a 3,000 square foot service and operating center (with various outbuildings) which supports day-to-day maintenance and construction operations. The Company owns approximately 400 miles of underground distribution lines ("mains"), and related metering and regulating equipment in and around Great Falls, Montana.

In West Yellowstone, Montana, the Company owns an office building, and a liquefied natural gas plant that provides natural gas through approximately 13 miles of underground mains owned by the Company. The Company owns approximately 10 miles of underground mains in the town of Cascade.

As of June 30, 2003, EWP owned several large bulk propane tanks to serve the areas in and around the towns of Cascade and Superior, Montana. The wholesale propane assets located in Superior, Montana, including the bulk propane tanks, were sold on August 21, 2003.

During fiscal year 2002, EWR purchased a 56% ownership interest in natural gas production properties in north central, Montana, that provide approximately 600 Mcf of natural gas daily for resale.

At June 30, 2003, EWD owned approximately 30 acres of real property in Great Falls, Montana. The property was sold on September 8, 2003, and EWD realized a pre-tax gain of approximately $118,000. During fiscal year 2003, EWD purchased a 75% ownership interest in natural gas production properties in north central, Montana, that provide approximately 350 Mcf of natural gas daily for resale.

Wyoming: In Cody, Wyoming, the Company leases office and service buildings for the EWW division under long-term lease agreements. The Company owns approximately 483 miles of transportation and distribution mains, and related metering and regulating equipment, all of which are located in or around Cody, Meeteetse and Ralston.

EWP owns two large bulk propane tanks, located in Cody, to serve its customers in northern Wyoming. The wholesale propane assets located in Cody, Wyoming were sold on August 21, 2003.

EWD owns two pipelines in Wyoming. One is currently being operated as a gathering system. The other pipeline began operating as a natural gas interstate transmission pipeline on July 3, 2003. The pipelines are located north of Cody, Wyoming.

Arizona: The Company owns approximately 190 miles of distribution mains located in and around the community of Payson. The Company owns five acres of land in Payson, on which the Company maintains and operates a propane vapor system for its operations in Payson. The Company leases an office building in Payson under an agreement that expires in 2006. The Company has the right to extend the lease for two successive five year periods. EWP owns several large bulk propane tanks located in Pine, Strawberry, Payson and Starr Valley, which are used to serve customers in those communities and surrounding areas.

Item 3. - Legal Proceedings

From time to time the Company is involved in litigation relating to claims arising from its operations in the normal course of business. The Company utilizes various risk management strategies, including maintaining liability insurance against certain risks, employee education and safety programs and other processes intended to reduce liability risk.

In addition to other litigation referred to above, the Company or its subsidiaries are involved in the following described litigation.

EWR has been involved in a lawsuit with PPL Montana, LLC (PPLM) which was filed on July 2, 2001, and involved a wholesale electricity supply contract between EWR and PPLM dated March 17, 2000 and a confirmation letter thereunder dated June 13, 2000. On June 17, 2003, EWR and PPLM reached agreement on a settlement of the lawsuit. Under the terms of the settlement, EWR paid PPLM a total of $3,200,000, consisting of an initial payment of $1,000,000 on June 17, 2003, and a second payment of $2,200,000 on September 30, 2003, terminating all proceedings in the case. EWR had established reserves in fiscal year 2001 of approximately $3,032,000 to pay a potential settlement with PPLM and the remaining $168,000 was charged to operating expenses in fiscal year 2003.

By letter dated August 30, 2002, the Montana Department of Revenue (DOR) notified the Company that the DOR had completed a property tax audit of the Company for the period January 1, 1997 through and including December 31, 2001, and had determined that the Company had under-reported its personal property and that additional property taxes and penalties should be assessed.

On August 8, 2003, the Company reached agreement with the DOR to pay to DOR $2,430,000 in back taxes (without interest or penalty) for tax years 1992 through and including 2002. The settlement amount will be paid in ten equal annual installments of $243,000 on or before November 30 of each year beginning November 30, 2003.

Under Montana law, the Company believes it is entitled to recover the amounts paid in connection with the DOR settlement through future rate adjustments without seeking approval from the MPSC. The amended rates will go into effect on January 1 following the date of each tax payment. The amended rate schedules must be filed with the MPSC on or before the effective date of the changes in taxes paid and the commission has 45 days to act on the adjusted rates submitted. If the commission determines that the rates were adjusted in error, then refunds must be paid to the customers. The Company has established a regulatory asset and a liability in the amount of $2,430,000.

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

None

PART II

Item 5. - Market for Registrant's Common Equity and Related Stockholder Matters

Common Stock Prices and Dividend Comparison - Fiscal Years 2003 and 2002

Shares of the Company's Common Stock are traded on the Nasdaq National Market under the symbol: "EWST." The following table sets forth the high and low bid prices for the Company's common stock. These prices reflect inter-dealer prices, without retail mark-up, markdown or commission, and may not necessarily represent the actual transactions.

Price Range -- Fiscal Year 2003	High	Low
First Quarter	$ 9.79	$ 8.40
Second Quarter	$ 8.89	$ 7.25
Third Quarter	$ 9.00	$ 7.31
Fourth Quarter	$ 8.74	$ 4.74
Year	$ 9.79	$ 4.74

Price Range -- Fiscal Year 2002	High	Low
First Quarter	$ 14.10	$ 9.05
Second Quarter	$ 12.52	$ 10.40
Third Quarter	$ 11.50	$ 9.51
Fourth Quarter	$ 10.51	$ 9.00
Year	$ 14.10	$ 9.00

On September 30, 2003, there were approximately 450 holders of record of the Company's common stock. The Board of Directors historically considered approving common stock dividends for payments in March, June, September and January. On June 17, 2003, the Company's Board of Directors suspended the payment of quarterly dividends. The Company's current credit agreement with LaSalle Bank prohibits the payment of dividends by the Company until such time as the Company's long-term debt is restructured or refinanced as required by the LaSalle credit agreement. (See Item 7 "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Liquidity and Capital Resources"). Quarterly dividend payments per common share for fiscal years 2003 and 2002 were:

	Fiscal Year 2003	Fiscal Year 2002
September	$ 0.1350	$ 0.1300
January	$ 0.1350	$ 0.1300
March	$ 0.1350	$ 0.1300
June	-	$ 0.1350

Item 6. - Selected Financial Data

Selected Financial Data on a Consolidated Basis (2003-1999)

(dollar amounts in thousands, except per share data)

	2003	2002	2001	2000	1999
Operating results	$ 79,146	$ 90,172	$ 111,612	$ 64,398	$ 48,864
Operating revenue					
Operating expenses					
Gas and electric purchases	62,520	74,590	90,173	50,800	34,736
General and administrative	11,669	8,790	12,095	7,649	8,018
Maintenance	497	466	428	400	469
Depreciation and amortization	2,393	2,059	1,970	1,856	1,695
Taxes other than income	888	946	723	639	708
Total operating expenses	77,967	86,851	105,389	61,344	45,626
Operating income	1,179	3,321	6,223	3,054	3,238
Other income-net	302	658	282	449	909
Total interest charges	1,633	1,704	2,097	1,674	1,493
Income (loss) before taxes	(152)	2,275	4,408	1,829	2,654
Income tax expense (benefit)	(63)	874	1,643	708	1,067
Net Income (Loss)	$ (89)	$ 1,401	$ 2,765	$ 1,121	$ 1,587
Basic earnings (loss) per common share	$ (0.03)	$ 0.55	$ 1.11	$ 0.46	$ 0.66
Diluted earnings (loss) per common share	$ (0.03)	$ 0.55	$ 1.10	$ 0.46	$ 0.66
Dividends per common share	$ 0.41	$ 0.52	$ 0.51	$ 0.49	$ 0.47
Weighed average common shares Outstanding – diluted	2,586,487	2,558,782	2,509,738	2,456,555	2,418,910
At year end:					
Current assets	$ 18,172	$ 19,091	$ 26,621	$ 16,387	$ 11,429
Total assets	$ 61,874	$ 57,869	$ 62,278	$ 51,194	$ 43,710
Current liabilities	$ 21,569	$ 19,899	$ 24,416	$ 14,831	$ 7,230
Total long-term obligations	$ 14,834	$ 15,367	$ 15,881	$ 16,395	$ 16,840
Total stockholders' equity	$ 15,299	$ 16,272	$ 15,613	$ 13,786	$ 13,532
Total capitalization	$ 30,133	$ 31,639	$ 31,494	$ 30,181	$ 30,372

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

CRITICAL ACCOUNTING POLICIES

Note 1 to the Company's Consolidated Financial Statements contains a summary of the Company's significant accounting policies. The Company believes that its critical accounting policies are as follows:

Effects of Regulation—The Company follows Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation,* and its financial statements reflect the effects of the different rate making principles followed by the various jurisdictions regulating the Company. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). Costs recovered through rates include income taxes, property taxes, environmental remediation and costs of gas.

Recoverable/ Refundable Costs of Gas and Propane Purchases—The Company accounts for purchased gas costs in accordance with procedures authorized by the MPSC, the WPSC and the ACC under which purchased-gas and propane costs that are different from those provided for in present rates are accumulated and recovered or credited through future rate changes.

Derivatives—The Company accounts for certain derivative contracts that are used to manage risk in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities,* which the Company adopted July 1, 2000.

RESULTS OF CONSOLIDATED OPERATIONS

Fiscal Year Ended June 30, 2003 Compared to Fiscal Year Ended June 30, 2002

Net Income

The Company's net loss for fiscal year 2003 was $89,000 compared to a net income of $1,401,000 in fiscal year 2002, a decrease of $1,490,000. The reduction in net income is primarily due to the natural gas operations reduction of $755,000 due to reduced volumes and additional operating expenses. The Propane Operations segment had reduced net income of approximately $465,000 due to lower margins resulting from higher costs of propane and additional operating expense. The Company's EWR segment experienced a reduction in net income of $130,000 due primarily to additional legal fees of $1,017,000 related to the PPLM litigation which were partially offset by additional margins from natural gas trading. The Pipeline Operations segment had reduced income of $140,000 primarily due to expenses incurred to obtain FERC regulatory approval.

Revenue

Operating revenues of the Company decreased by 12% from approximately $90,172,000 in fiscal year 2002 to $79,146,000 in fiscal year 2003. The Natural Gas Operations segment's revenues decreased $7,888,000 due to elimination of the surcharge approved by the MPSC in March 2001 for the recovery of increased gas costs that had been incurred prior to March 2001. The increased gas costs were fully recovered by June 2002, and the surcharge was eliminated. Also, warmer than normal weather experienced during fiscal year 2003 resulted in lower volumes. The Company's EWR segment experienced a decrease in revenues of $5,564,000 due to reduction in gas marketing revenues. The Propane Operations segment experienced an increase in revenues of $2,130,000 due to both higher prices and sales volumes and the Pipeline Operations segment experienced an increase in revenues of approximately $295,000.

Gross Margin

Gross margins (operating revenues less cost of gas and electricity) increased approximately $1,044,000, or 6.0% in fiscal year 2003. This increase was attributable mainly to increased gross margins in the Company's EWR segment of $1,436,000 offset by gross margin decreases in both the Propane Operations and Natural Gas Operations segments resulting from higher than normal propane and gas costs.

Operating Income

The Company's operating income decreased by approximately $2,142,000, from $3,321,000 in fiscal year 2002 to $1,179,000 in fiscal year 2003 due primarily to increased operating expenses. The Company's total operating expenses for fiscal year 2003 increased by approximately $3,186,000. This was primarily due to increases in general and administrative expenses of $2,879,000, as well as maintenance and depreciation increases of $31,000 and $334,000 respectively, with a corresponding decrease of $58,000 in taxes other than income.

General and administrative expenses increased from $8,790,000 in fiscal year 2002 to $11,669,000 in fiscal year 2003. This increase of $2,879,000 was due primarily to increased legal expenses related to the PPLM litigation and additional expenses incurred to obtain short term financing. The costs of the PPLM litigation were approximately $1,552,000 in fiscal year 2003 compared with approximately $565,000 in fiscal year 2002. The Company also incurred additional expenses of approximately $420,000 in fiscal year 2003 related to obtaining short term financing.

Other Income

Other income decreased by $356,000 from $658,000 in fiscal year 2002 to $302,000 in fiscal year 2003 primarily due to a non-recurring $300,000 settlement received by EWR in fiscal year 2002 as part of a transaction to purchase a group of producing natural gas reserves.

Interest Expense

Interest expense decreased by $71,000 from $1,704,000 in fiscal year 2002 to $1,633,000 in fiscal year 2003 due to lower overall corporate borrowings in fiscal year 2003. Interest expense is allocated among the segments based on capital employed.

Fiscal Year Ended June 30, 2002 Compared to Fiscal Year Ended June 30, 2001

Net Income

The Company's net income for fiscal year 2002 was $1,401,000 compared to $2,765,000 in fiscal year 2001, a decrease of $1,364,000. The EWR segment had an earnings decrease of $1,922,000 due to reductions in revenues primarily from the remarketing of power and reductions in its wholesale gas revenues. The unusually high margins in fiscal year 2001 resulted from a combination of factors, including historically high market prices and remarketing of uncommitted power. The reduction in net income from the EWR segment was partially offset by an increase in net income in the Natural Gas Operations segment of $324,000, an increase in income from the propane operations of $264,000 and a reduction in income from the Pipeline Operations segment of approximately $30,000. The increase in the Natural Gas Operations segment's net income is due primarily to record cold temperatures experienced during the months of April, May and June. In addition, the Natural Gas Operations segment implemented reductions in discretionary expenses due to the warmer-than-normal weather conditions experienced during the first nine months of fiscal year 2002. The increase in net income from the Propane Operations segment is due to divestiture of retail propane assets in Montana and Wyoming.

Revenue

Operating revenues of the Company decreased by 19% from approximately $111,612,000 to $90,172,000. This is due primarily to the EWR segment's reduction in revenues from remarketing power and natural gas of $17,125,000, a reduction of revenues from the Propane Operations segment of $3,211,000, and a reduction in revenue from the Natural Gas Operations segment of $1,090,000 related to lower prices of natural gas and a reduction from the Pipeline Operations segment of $14,000. The unusually high margins from the EWR segment in fiscal year 2001 resulted from a combination of unusual factors, including historically high market prices and remarketing of uncommitted power. The Company does not expect the combination of unusual factors that resulted in the unusually high income from the previous year to be repeated in the current year or in future years.

Gross Margin

Gross margins (operating revenues less cost of gas and electricity) decreased approximately $5,857,000. The Company's EWR segment decreased gross margins by $5,977,000 due mainly to reductions in remarketing of power. The gross margins from the Natural Gas Operations segment increased by $180,000 due to an increase in volumes of gas sold while the gross margin in the Propane Operations segment decreased by $45,000 due to higher propane costs. Gross margins decreased by $14,000 in the Pipeline Operations segment due to lower gathering revenues.

Operating Income

The Company's operating income decreased by approximately $2,902,000. Operating income from the EWR segment decreased by $3,550,000 due to lower gross margins from the remarketing of power. This lower margin was partially offset by a reduction in other operating expenses of $2,427,000.

Operating income from the Natural Gas Operations segment increased by approximately $462,000 due to increased gross margins of $180,000 and reductions in other operating expenses of $282,000. The Propane Operations segment experienced an increase of $263,000 in operating income primarily due to the gain on the sale of the retail propane assets, and a reduction in general and administrative expenses of $308,000 offset by an increase in other expenses of $45,000 and gross margin reductions of $45,000.

The Company's total operating expenses for fiscal year 2002 decreased by approximately $2,955,000. This reduction is due primarily to reduced incentive payments made during fiscal year 2002 compared to fiscal year 2001, reduced legal fees, a reduction in corporate overheads and the reduction attributable to the sale of the propane assets. Also, the Company implemented cutbacks in non-essential operating and maintenance expenses in fiscal year 2002. The cutback was due primarily to lower volumes being sold as a result of higher than normal temperatures in Montana, Wyoming and Arizona during the first nine months of fiscal year 2002.

Interest Expense

Interest expense decreased by $393,000 due to reduction in short term borrowings and a decrease in short term average interest rates from 8.4% to approximately 4.6%

Other Income

Other income increased by $376,000 due in part to a $300,000 settlement received by EWR as part of a transaction to purchase a group of producing natural gas reserves. EWR received the $300,000 discount on the portion of its purchase price from the seller as a settlement on any claims.

OPERATING RESULTS OF THE COMPANY'S NATURAL GAS OPERATIONS

	Years Ended June 30 (in thousands) 2003	2002	2001
Natural Gas Operations			
Operating revenues	$ 31,627	$ 39,515	$ 40,605
Gas purchased	21,754	29,465	30,735
Gross margin	9,873	10,050	9,870
Operating expenses	8,542	7,497	7,779
Operating income	1,331	2,553	2,091
Other (income) loss	(94)	(153)	(131)
Interest expense	999	1,170	1,254
Income tax expense	245	600	356
Net income natural gas operations	$ 181	$ 936	$ 612

Fiscal Year Ended June 30, 2003 Compared to Fiscal Year Ended June 30, 2002

Revenues and Gross Margins

The Natural Gas Operations segment's operating revenues decreased from approximately $39,515,000 in fiscal year 2002 to approximately $31,627,000 in fiscal year 2003. This decrease of $7,888,000 was due primarily to the elimination of the surcharge approved by the MPSC in March 2001 for the recovery of increased gas costs that had been incurred prior to March 2001.

The increased gas costs were fully recovered by June 2002, and the surcharge was eliminated. Also, warmer than normal weather experienced during fiscal year 2003 and reduced volumes being sold to a large industrial customer by EWW, resulted in lower total volumes of natural gas sold of approximately 369,000 Mcf, a 6% reduction from fiscal year 2002.

Gross margin, defined as operating revenues less cost of natural gas, declined from approximately $10,050,000 in fiscal year 2002 to approximately $9,873,000 in fiscal year 2003, primarily due to the reduction in sales volumes experienced during fiscal year 2003.

Natural gas purchases decreased from $29,465,000 in fiscal year 2002 to $21,754,000 in fiscal year 2003. The decrease in gas costs of $7,711,000 is due to lower volumes being sold and the lower cost of natural gas during fiscal year 2003.

Operating Expenses

The Natural Gas Operations segment's operating expenses were $8,542,000 for fiscal year 2003 compared to $7,497,000 for fiscal year 2002. The increase in operating expenses of $1,045,000 was due primarily to an increase in property taxes, an increase in general liability insurance premiums, increases in employee benefit costs and increases in general corporate overhead items allocated to the Natural Gas Operations segment.

Non Operating Income

Non operating income decreased by $59,000 from $153,000 in fiscal year 2002 to $94,000 in fiscal year 2003. The decrease was primarily due to a reduction in service sales related to home and industrial installations.

Interest Expense

Interest expense decreased from $1,170,000 in fiscal year 2002 to $999,000 in fiscal year 2003. The decrease of $171,000 was due primarily to reduced overall corporate borrowings.

Income Tax Expense

Income tax expense was $600,000 for fiscal year 2002 compared to $245,000 for fiscal year 2003. The reduction of $355,000 is the result of reduced taxable income for the natural gas operations for fiscal year 2003. Income tax expense for each segment is computed as if the segment filed its own income tax returns.

Fiscal Year Ended June 30, 2002 Compared to Fiscal Year Ended June 30, 2001

Revenues and Gross Margins

The Natural Gas Operations segment's operating revenues in fiscal year 2002 decreased to $39,515,000 from $40,605,000 in fiscal year 2001. This was primarily due to warmer temperatures in the two states served by these operations, and lower cost of gas. In March 2001, the MPSC approved recovery of approximately $6,500,000 over one year for gas costs the Company had incurred prior to that period. As of June 2002, the EWM division had recovered all of the increased costs, and therefore, the surcharge previously approved by the MPSC was eliminated. Going forward, the MPSC requires a monthly filing to adjust customer rates if commodity prices increase or decrease by $.10 per Mcf or more.

Gross margin, which is defined as operating revenues less gas purchased, was approximately $10,050,000 for fiscal year 2002 compared to approximately $9,873,000 in fiscal year 2001 primarily due to lower cost of gas.

Gas purchases in the Natural Gas Operations segment decreased by $1,270,000 from $30,735,000 in fiscal year 2001 to $29,465,000 in fiscal year 2002. The decrease in gas costs are reflective of the lower volumes sold due to the warmer temperatures, the lower cost of gas and the new gas cost recovery mechanism in Montana, which allowed for a more responsive treatment of the regulated gas costs to reflect market prices.

Operating Expenses

The Natural Gas Operations segment's operating expenses were approximately $7,497,000 for fiscal year 2002, as compared to $7,779,000 for fiscal year 2001. The reduction of $282,000 is due to the reduction in operating expenses and reductions in the amount of overhead allocated to the Natural Gas Operations segment.

Non Operating Income

Non operating income increased by $22,000 from $131,000 in fiscal year 2001 to $153,000 in fiscal year 2002. The increase was due primarily to miscellaneous fixed assets sales during fiscal year 2002.

Interest Expense

Interest charges allocable to the Company's Natural Gas Operations segment decreased by $84,000 from $1,254,000 in fiscal year 2001 to $1,170,000 during fiscal year 2002. The reduction is the result of lower annual interest rates experienced in fiscal year 2002 and lower short term borrowings by the Company.

Income Tax Expense

State and federal income taxes of the Company's Natural Gas Operations segment increased by $244,000 from $356,000 in fiscal year 2001 to $600,000 during fiscal year 2002. The increase was the result of an increase in taxable income of the Natural Gas Operations segment.

OPERATING RESULTS OF THE COMPANY'S PROPANE OPERATIONS

	Years Ended June 30		
	2003	2002	2001
	(in thousands)		
Propane Operations			
Operating revenues	$ 12,786	$ 10,656	$ 13,867
Gas purchased	8,762	6,407	9,573
Gross margin	4,024	4,249	4,294
Operating expenses	3,600	3,065	3,373
Operating income	424	1,184	921
Other (income) loss	(187)	(199)	(128)
Interest expense	403	427	487
Income tax expense	68	351	221
Net income propane operations	$ 140	$ 605	$ 341

Fiscal Year Ended June 30, 2003 Compared to Fiscal Year Ended June 30, 2002

Revenues and Gross Margins

The Propane Operations segment's revenues rose from $10,656,000 in fiscal year 2002 to $12,786,000 in fiscal year 2003, an increase of $2,130,000 or 20%. This increase in revenues is due to increased sales prices in the second half of fiscal year 2003 in the Company's wholesale propane operations, coupled with an overall increase in volume in the Propane Operations segment. Total volume for the Propane Operations segment increased from 12,816,000 gallons in fiscal year 2002 to 16,033,000 gallons in fiscal year 2003, an increase of 25%. Cost of propane sold increased from $6,407,000 to $8,762,000 for the same period, a 37% increase, due to the increase in volumes sold and increases in the cost of propane for both the regulated utility and the wholesale propane operations. These increases in revenues and corresponding increase in cost of propane sold resulted in a decrease of $225,000 in gross margins, or 5.3%, from $4,249,000 in fiscal year 2002 to $4,024,000 in fiscal year 2003.

Operating Expenses

Operating expenses were $3,600,000 for fiscal year 2003 compared to $3,065,000 for fiscal year 2002. The increase of $535,000 was primarily related to increases in depreciation, corporate overhead allocations, and increased sales expenses in the wholesale propane operation.

Non Operating Income

Non operating income decreased by $12,000 from $199,000 in fiscal year 2002 to $187,000 in fiscal year 2003. This decrease is due primarily to the collection of a previously written off bad debt account in fiscal year 2002.

Interest Expense

Interest expense decreased from $427,000 in fiscal year 2002 to $403,000 in fiscal year 2003. The reduction of $24,000 is due to lower interest costs being allocated to the propane operations resulting from lower overall borrowings by the Company.

Income Tax Expense

Income taxes decreased from $351,000 in fiscal year 2002 to $68,000 in fiscal year 2003 due to lower taxable income.

Fiscal Year Ended June 30, 2002 Compared to Fiscal Year Ended June 30, 2001

Revenues and Gross Margins

The Propane Operations segment's revenues decreased from $13,867,000 in fiscal 2001 compared to $10,656,000 in fiscal year 2002, a reduction of $3,211,000 or 23%. This decrease in revenues is due mainly to lower spot market for propane sold during the year as well as a 10% reduction in volumes sold from fiscal year 2001 compared to fiscal year 2002. Also contributing to the reduction in revenues was the sale of the retail propane operations in Montana and Wyoming. The reduction in total revenues attributable to the sale of these two operations was approximately $260,000 related to the Wyoming operations and approximately $123,000 related to the Montana retail operations. The Propane Operations segment was able to take advantage of the lower market prices for propane. The cost of propane sold decreased from $9,573,000 during fiscal year 2001 to $6,407,000 for fiscal year 2002 or a reduction of approximately 33%. Gross margins decreased by $45,000, less than 1%.

Operating Expenses

Operating expenses were $3,065,000 for fiscal year 2002 compared to $3,373,000 for fiscal year 2001, a decrease of $308,000. Operating expenses decreased due to reduction in general and administrative expenses of $338,000 resulting from the sale of the retail propane assets in Montana and Wyoming offset by an increase to additional costs incurred for propane pipeline safety maintenance in the Arizona locations.

Non Operating Income

Non operating income increased by $71,000 from $128,000 in fiscal year 2001 to $199,000 in fiscal year 2002. This increase in due primarily to the collection of a previously written off bad debt account.

Interest Expense

Interest expense declined from $487,000 in fiscal year 2001 to $427,000 in fiscal year 2002. The reduction of $60,000 was due to lower interest costs being allocated to the propane operations resulting from lower overall borrowings by the Company and the lower average interest rate on short term borrowings.

Income Tax Expense

Income taxes increased from $221,000 in fiscal year 2001 to $351,000 in fiscal year 2002 due to higher taxable income for the year.

OPERATING RESULTS OF THE COMPANY'S EWR SEGMENT

	Years Ended June 30 (in thousands)		
	2003	2002	2001
EWR			
Operating revenues	$ 34,283	$ 39,847	$ 56,972
Gas purchased	31,717	38,717	49,865
Gross margin	2,566	1,130	7,107
Operating expenses	3,040	1,628	4,055
Operating income (loss)	(474)	(498)	3,052
Other (income) loss	(19)	(304)	(22)
Interest expense	223	104	338
Income tax expense (benefit)	(360)	(110)	1,002
Net income (loss) EWR operations	$ (318)	$ (188)	$ 1,734

Fiscal Year Ended June 30, 2003 Compared to Fiscal Year Ended June 30, 2002

Revenues and Gross Margins

The EWR segment's gross margins were approximately $2,566,000 for fiscal year 2003 compared to $1,130,000 for fiscal year 2002, an increase of $1,436,000. This increase was primarily due to a $1,509,000 increase in natural gas margins (primarily from the sale of storage inventories during the third quarter) and an increase in margins of $338,000 from production properties purchased in fiscal year 2002, offset by a decline of approximately $411,000 in gross margins from the sale of electricity.

Operating Expenses

Operating expenses for the EWR segment were approximately $3,040,000 for fiscal year 2003 compared to $1,628,000 for the previous fiscal year. The most significant factor causing the increase of $1,412,000 was increased legal expenses related to the PPLM litigation. The costs of the PPLM litigation were approximately $1,552,000 for fiscal year 2003 compared to approximately $535,000 for fiscal year 2002. The remainder of the increase in operating expenses of $395,000 was due primarily to increases in liability insurance, employee benefits, increased bad debt expenses and an increase in the amount of allocated corporate overhead.

Non Operating Income

Non operating income was approximately $19,000 in fiscal year 2003 compared to approximately $304,000 for fiscal year 2002. The reduction is primarily due to the EWR segment's receipt of a $300,000 discount on the purchase of production properties during fiscal year 2002 that was not repeated during the current fiscal year.

Interest Expense

Interest charges allocable to the EWR segment increased by $119,000 from $104,000 in fiscal year 2002 to $223,000 in fiscal year 2003. This increase was primarily due to the allocation of interest expense based on an increase in capital employed.

Income Tax Expense

The EWR segment experienced an income tax benefit of $360,000 during fiscal year 2003 compared to an income tax benefit of $110,000 in fiscal year 2002 due to the reduction in taxable income from its operations.

Fiscal Year Ended June 30, 2002 Compared to Fiscal Year Ended June 30, 2001

Revenues and Gross Margins

The EWR segment experienced a reduction in gross margin of $5,977,000 for the fiscal year 2002 compared to fiscal year 2001. The majority of the 84% decrease was due to the reduction in margins associated with the remarketing of electricity at unusually high market prices experienced during fiscal year 2001. The same market conditions were not present during fiscal year 2002.

Operating Expenses

Operating expenses for the EWR segment were $1,628,000 during fiscal year 2002 compared to $4,055,000 during fiscal year 2001. The $2,427,000 decrease was due mainly to the reduction in incentives and commissions related to the decrease in gross margins. Partially offsetting those reductions were approximately $535,000 in legal expenses related to the litigation with PPLM.

Non Operating Income

Non operating income was $282,000 higher in fiscal year 2002 compared to fiscal year 2001. This increase was due to a $300,000 settlement received by EWR as part of a transaction to purchase a group of producing natural gas reserves located in northern Montana. EWR received the $300,000 discount on the portion of its purchase price from the seller as a settlement on any claims against it by EWR. This transaction took place during the fourth quarter of fiscal year 2002.

Interest Expense

Interest expense decreased during fiscal year 2002 by $234,000 due mainly to a decrease in short-term borrowing rates, as well as an overall reduction in borrowing.

Income Tax Expense

The EWR segment experienced an income tax benefit of $110,000 during fiscal year 2002 compared to an expense of $1,002,000 in fiscal year 2001 due to the reduction in taxable income from its operations.

OPERATING RESULTS OF THE COMPANY PIPELINE OPERATIONS

	Years Ended June 30 (in thousands) 2003	2002	2001
Pipeline Operations			
Operating revenues	$ 449	$ 154	$ 168
Gas purchased	287	-	-
Gross margin	162	154	168
Operating expenses	265	71	9
Operating income (loss)	(103)	83	159
Other (income) loss	(1)	-	-
Interest expense	7	3	17
Income tax expense (benefit)	(17)	32	64
Net income (loss) pipeline operations	$ (92)	$ 48	$ 78

Pipeline Operations was added as a new segment as of July 1, 2002. The results of this segment reflect operation of natural gas gathering systems placed into service in fiscal year 2001, and transferred from EWR to EWD. For fiscal year 2003 the revenues reported in the Pipeline Operations segment consist of gathering revenues related to the pipeline operations in the Wyoming and Montana areas. Also included in the Pipeline Operations segment are the revenues and expenses associated with the recently purchased production reserves.

Fiscal Year Ended June 30, 2003 Compared to Fiscal Year Ended June 30, 2002

Revenues and Gross Margins

The Pipeline Operations segment's revenues increased from $154,000 in fiscal year 2002 to approximately $449,000 in fiscal year 2003. The increase of $295,000 is due primarily to revenues generated from natural gas production properties purchased in fiscal year 2003. The cost of gas purchased increased $287,000 from fiscal year 2003 compared to fiscal year 2002 due to the increased costs associated with the cost of the production.

Operating Expenses

Operating expenses increased from $71,000 in fiscal year 2002 to $265,000 in fiscal year 2003. The increase of $194,000 is due to additional expenses associated with production properties and additional expenses incurred in obtaining FERC regulatory approval to operate the interstate natural gas transportation pipeline placed in service on July 3, 2003.

Income Tax Expense

Income tax expense decreased $49,000 from an income tax expense in fiscal year 2002 of $32,000 to an income tax benefit of $17,000 in fiscal year 2003. The decrease in income taxes is due to the reduction in taxable income from pipeline operations.

Fiscal Year Ended June 30, 2002 Compared to Fiscal Year Ended June 30, 2001

Revenues and Gross Margins

Revenues and gross margin decreased from $168,000 in fiscal year 2001 to $154,000 in fiscal year 2002. This decrease of $14,000 was due to reductions in gathering system revenues resulting from lower volumes being transported.

Operating Expenses

Operating expenses increased by $62,000 from $9,000 in fiscal year 2001 compared to $71,000 in fiscal year 2002. The increase was due to additional salaries and related benefits and depreciation of the natural gas gathering systems.

Income Tax Expense

Income tax expense decreased from $64,000 in fiscal year 2001 to $32,000 in fiscal year 2002. The decrease of $32,000 is due to lower taxable income from the pipeline operations.

CASH FLOW ANALYSIS

Fiscal Year Ended June 30, 2003 Compared to Fiscal Year Ended June 30, 2002

Cash provided by operating activities consists of net income and noncash items including depreciation, depletion, amortization and deferred income taxes. Additionally, changes in working capital are also included in cash provided by operating activities. The Company expects that internally generated cash, coupled with short-term borrowings, will be sufficient to satisfy its operating requirements and normal capital expenditures.

The primary cash flows during the last three years are summarized below:

	Years Ended June 30		
	2003	2002	2001
		(in thousands)	
Provided by Operating activities	$ 4,546,169	$ 7,114,030	$ 6,008,065
Used in investing activities	(4,073,912)	(5,149,890)	(3,287,843)
Provided by (used in) financing activities	1,098,854	(1,817,150)	(2,611,729)
Net increase in cash and cash equivalents	$ 1,571,111	$ 146,990	$ 108,493

Governmental Regulation

The Company's utility operations are subject to regulation by the MPC, the WPSC, and the ACC. Such regulation plays a significant role in determining the Company's return on equity. The commissions approve rates that are intended to permit a specified rate of return on investment. The Company's tariffs allow the cost of gas to be passed through to customers. The pass-through causes some delay, however, between the time that the gas costs are incurred by the Company and the time that the Company recovers such costs from customers.

Seasonality

The business of the Company and its subsidiaries in all segments is temperature-sensitive. In any given period, sales volumes reflect the impact of weather, in addition to other factors, with colder temperatures generally resulting in increased sales by the Company. The Company anticipates that this sensitivity to seasonal and other weather conditions will continue to be reflected in the Company's sales volumes in future periods.

LIQUIDITY AND CAPITAL RESOURCES

The Company's operating capital needs, as well as dividend payments and capital expenditures are generally funded through cash flow from operating activities and short term borrowing. Historically, to the extent cash flow has not been sufficient to fund capital expenditures, the Company has borrowed short-term funds. When the short-term debt balance significantly exceeds working capital requirements, the Company has issued long-term debt or equity securities to pay down short-term debt. The Company has greater need for short-term borrowing during periods when internally generated funds are not sufficient to cover all capital and operating requirements, including costs of gas purchased and capital expenditures. In general, the Company's short-term borrowing needs for purchases of gas inventory and capital expenditures are greatest during the summer and fall months and the Company's short-term borrowing needs for financing customer accounts receivable are greatest during the winter months.

At June 30, 2003, the Company had approximately $1,939,000 of cash on hand and a $10,595,000 unsecured bank credit facility, of which approximately $6,105,000 had been borrowed under the credit agreement. The Company's short-term borrowings under its lines of credit during fiscal 2003 had a daily weighted average interest rate of 4.54% per annum. At June 30, 2003, the Company had outstanding letters of credit totaling $4,400,000 related to electricity and gas purchase contracts. These letters of credit are netted against the Company's bank lines of credit, which resulted in net availability of approximately $90,000 under the Company's line of credit at June 30, 2003.

Following an adverse ruling in the PPLM lawsuit on March 7, 2003, the Company's bank lender, Wells Fargo Bank Montana, National Association ("Wells Fargo") and the Company began negotiations with respect to the Company's credit facility which was set to expire in May 2003. Wells Fargo granted a series of extensions of the credit facility through September 5, 2003.

On September 5, 2003, the Company reached an agreement with Wells Fargo for a new credit facility through October 15, 2003 (the "Wells Fargo Facility"). The terms of the new Wells Fargo Facility established a term loan of approximately $10,400,000, the proceeds of which were used to repay the prior Wells Fargo credit facility and to establish a reserve of approximately $2,600,000 for letters of credit that remained outstanding from the prior facility. In addition, the Wells Fargo Facility established a revolving line of credit under which the Company could borrow up to $3,000,000 for working capital and certain other expenses. Borrowings under the new Wells Fargo Facility were secured by liens on substantially all of the assets of the Company used in its regulated operations in Arizona, and by substantially all of the assets of the Company's subsidiaries. As required under the terms of the Company's outstanding long-term notes and bonds (the "Long Term Debt"), the Company's obligations under the Long Term Debt were secured on an equal and ratable basis with Wells Fargo in the collateral granted to secure the Wells Fargo Facility with the exception of the first $1,000,000 of debt under the Wells Fargo Facility.

On September 30, 2003, the Company established a $23,000,000 revolving credit facility (the "LaSalle Facility") with LaSalle Bank National Association, as Agent for certain banks (collectively, the "Lender"). The LaSalle Facility replaced the Wells Fargo Facility and the amount due under the Wells Fargo Facility was paid in full out of the proceeds of the LaSalle Facility. Borrowings under the LaSalle Facility are secured by liens on substantially all of the assets of the Company and its subsidiaries. As required under the terms of the Long Term Debt, the Company's obligations under the Long Term Debt are secured on an equal and ratable basis with the Lender in the collateral granted to secure the LaSalle Facility with the exception of the first $1,000,000 of debt under the LaSalle Facility.

Under applicable law, the Company was required to obtain approval from the MPSC and the WPSC to enter into the LaSalle Facility. Both commissions gave the necessary approval. The MPSC order granting approval imposed several requirements on the Company including restrictions on the use of the proceeds of the LaSalle Facility for anything other than utility purposes, and requirements that the Company provide ongoing reports to the MPSC with respect to the financial condition of the Company and its non-regulated subsidiaries, and certain other matters. The MPSC order provided that the Company could fund the remaining $2.2 million settlement payment owed by EWR to PPLM. The settlement payment was made on September 30, 2003, ending the litigation between the two parties.

The LaSalle Facility provides that the maximum availability under the facility will be reduced from $23,000,000 to $15,000,000 no later than March 31, 2004. From and after the date on which the amount of availability under the LaSalle Facility is reduced, the LaSalle Facility is to be secured by a senior priority lien in the accounts receivable and inventory of the Company and its subsidiaries. As a result of the provisions providing for the reduction in the maximum availability under the LaSalle Facility, the Company will be required to refinance or restructure the Long Term Debt by March 31, 2004. The Company anticipates that such refinancing or restructuring will involve providing a senior priority lien in the fixed assets of the Company and its subsidiaries to secure the Long Term Debt or any long-term debt that the Company issues to replace the current Long Term Debt. The Company also anticipates that it will increase the total amount of long-term debt outstanding in connection with such refinancing or restructuring. The Company presently anticipates that the amount of such increase in long-term debt will be approximately $8,000,000. The Company believes that it will be able to accomplish the Long Term Debt restructuring or refinancing by March 31, 2004. Failure to complete the restructuring or refinancing of the Long Term Debt, as discussed above, would be a default under the terms of the LaSalle Facility.

During the period prior to the refinancing or restructuring of the Company's Long Term Debt, the terms of the LaSalle Facility provide that the Company cannot pay dividends to its shareholders. In June 2003, the Company's Board of Directors suspended the Company's fourth quarter dividend to allow for strengthening of the Company's balance sheet. The Company expects that it will be able to accomplish the long-term debt restructuring by March 31, 2004.

Under the LaSalle Facility, the Company has the option to pay interest at either the London Interbank Offered Rate (LIBOR) plus 250 basis points (bps) or the higher of (a) the rate publicly announced from time to time by LaSalle as its "prime rate" or (b) the Federal Funds Rate plus 0.5% per annum. The LaSalle Facility also has a commitment fee of 35 bps due on the daily unutilized portion of the facility.

The LaSalle Facility requires that the Company maintain compliance with a number of financial covenants including limitations on annual capital expenditures to an amount equal to or less than $5,000,000. The Company must also maintain a total debt to total capital ratio of less than .65 to 1.00 and an interest coverage ratio (earnings before interest, taxes, depreciation and amortization (EBITDA), plus agreed upon add backs, divided by interest expense) of no less than 2.00 to 1.00. Finally, the Company must restrict its open positions and Value at Risk (VaR) in its wholesale operations to an amount not to exceed $1,000,000. The Company met all of these financial covenants at the time it entered into the LaSalle Facility.

At September 30, 2003, the Company had borrowed $16,601,548 under the LaSalle Facility and had $6,398,452 of borrowing capacity under the LaSalle Facility.

In addition to its bank lines of credit, the Company has outstanding certain notes and industrial development revenue obligations (collectively "Long Term Debt"). The Company's Long Term Debt is made up of three separate debt issues: $8,000,000 of Series 1997 unsecured notes bearing interest at the rate of 7.5%; $7,800,000 of Series 1993 unsecured notes bearing interest at rates ranging from 6.20% to 7.60%; and Cascade County, Montana Series 1992B Industrial Development Revenue Obligations in the amount of $1,800,000. As required by the terms of the Long Term Debt, the Company's obligations under the Long Term Debt are secured on an equal and ratable basis with the Lender in the collateral granted to secure the LaSalle Facility with the exception of the first $1,000,000 of debt under the LaSalle Facility.

The total amount of the Company's obligations under the Long Term Debt was $15,355,000 and $15,856,000, at June 30, 2003 and June 30, 2002, respectively. The portion of such obligations due within one year was $530,000 and $500,000 at June 30, 2003, and June 30, 2002, respectively. Under the terms of such Long Term Debt obligations, additional principal payments of $570,000 will be due during fiscal 2005, $610,000 during fiscal 2006, $655,000 during fiscal 2007, $700,000 during fiscal 2008, and $12,290,444 during periods after fiscal 2008.

A table of the Company's Long Term Debt, as well as other long-term commitments and contingencies, and the corresponding maturity dates are listed below. The table does not reflect commitments and liabilities incurred in the ordinary course of business (such as gas purchase agreements), which are payable within less than 12 months. The "Less than 1 year" amount listed below for "Unconditional Purchase Obligations" represents commitments for long term gas supply.

	Payments Due by Period				
Contractual Obligations	Total	Less than 1 year	1 –3 years	4 – 5 years	After 5 Years
Long-Term Debt	$15,355,444	$530,000	$1,180,000	$1,355,000	$12,290,444
Operating Lease Obligations	746,011	183,765	295,198	181,248	85,800
Capital Lease Obligations	11,379	2,372	5,794	3,213	-----
Unconditional Gas Purchase Obligations	7,984,082	3,426,573	3,078,905	1,478,604	-----
Transportation and Storage Obligation	28,392,640	4,258,896	8,517,792	8,517,792	7,098,160
Total Obligations	52,489,556	8,401,606	13,077,689	11,535,857	19,474,404

Under the terms of the Long Term Debt obligations, the Company is subject to certain restrictions, including restrictions on total dividends and distributions, liens and secured indebtedness, and asset sales, and the Company is restricted from incurring additional long-term indebtedness if it does not meet certain financial debt and interest ratios. Management believes that the Company is in compliance with all Long Term Debt covenants as of June 30, 2003. For the fiscal year ended June 30, 2003, the Company's ratio of earnings to fixed charges was less than 1.5. Under the terms of the Long-Term Debt, the Company must achieve 1.5 ratio of earnings to fixed charges by the end of fiscal year 2004, or the Company will be restricted from incurring additional debt with a maturity of one year or longer. As required under the terms of the Long Term Debt, the Company's obligations under the Long Term Debt are secured on an equal and ratable basis with the Lender in the collateral granted to secure the LaSalle Facility with the exception of the first $1,000,000 of debt under the LaSalle Facility.

RISK FACTORS

The major factors which will affect the Company's future results include general and regional economic conditions, weather, customer retention and growth, the ability to meet competitive pressures and to contain costs, the adequacy and timeliness of rate relief, cost recovery and necessary regulatory approvals, and continued access to capital markets. In addition, changes in the competitive environment particularly related to the Company's propane and energy marketing segments could have a significant impact on the performance of the Company.

The regulatory structure in which the Company operates is in transition. Legislative and regulatory initiatives, at both the federal and state levels, are designed to promote competition. The changes in the gas industry have allowed certain customers to negotiate their own gas purchases directly with producers or brokers. To date, the changes in the gas industry have not had a negative impact on earnings or cash flow of the Company's regulated segment. The Company's regulated natural gas and propane vapor operations follow Statement of Accounting Standards (SFAS) No. 71 "Accounting for the Effects of Certain Types of Regulation," and its financial statements reflect the effects of the different rate making principles followed by the various jurisdictions regulating the Company. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). If the Company's natural gas and propane vapor operations were to discontinue the application of SFAS No. 71, the accounting impact would be an extraordinary, non-cash charge to operations that could be material to the financial position and results of operation of the Company. However, the Company is unaware of any circumstances or events in the foreseeable future that would cause it to discontinue the application of SFAS No. 71.

In addition to the factors discussed above, the following are important factors that could cause actual results to differ materially from any results projected, forecasted, estimated or budgeted:

- Fluctuating energy commodity prices, including prices for fuel and purchased power;
- The possibility that regulators may not permit the Company to pass through all such increased costs to customers;
- Fluctuations in wholesale margins due to uncertainty in the wholesale propane and power markets;
- Changes in general economic conditions in the United States and changes in the industries in which the Company conducts business;
- Changes in federal or state laws and regulations to which the Company is subject, including tax, environmental and employment laws and regulations;

- The impact of FERC and state public service commission statutes and regulation, including allowed rates of return, and the resolution of other regulatory matters;
- The ability of the Company and its subsidiaries to obtain governmental and regulatory approval of various expansion or other projects;
- The costs and effects of legal and administrative claims and proceedings against the Company or its subsidiaries;
- Conditions of the capital markets the Company utilizes to access capital to finance operations;
- The ability to raise capital in a cost-effective way;
- The effect of changes in accounting policies, if any;
- The ability to manage growth of the Company;
- The ability to control costs;
- The ability of each business unit to successfully implement key systems, such as service delivery systems;
- The ability of the Company and its subsidiaries to develop expanded markets and product offerings as well as their ability to maintain existing markets;
- The ability of customers of the energy marketing and trading business to obtain financing for various projects;
- The ability of customers of the energy marketing and trading business to obtain governmental and regulatory approval of various projects;
- Future utilization of pipeline capacity, which can depend on energy prices, competition from alternative fuels, the general level of natural gas and propane demand, decisions by customers not to renew expiring natural gas or propane contracts, and weather conditions; and
- Global and domestic economic repercussions from terrorist activities and the government's response thereto.

INFLATION

Capital intensive businesses, such as the Company's natural gas and propane vapor operations, are significantly affected by long-term inflation. Neither depreciation charges against earnings nor the ratemaking process reflect the replacement cost of utility plant. However, based on past practices of regulators, these businesses will be allowed to recover and earn on the actual cost of their investment in the replacement or upgrade of plant. Although prices for natural gas and propane vapor may fluctuate, earnings are not impacted because gas and propane vapor cost tracking procedures annually, and more often with approval of the various Public Service Commissions, balance gas and propane vapor costs collected from customers with the costs of supplying natural gas and propane vapor. The Company believes that the effects of inflation, at currently anticipated levels, will not materially affect results of operations.

ENVIRONMENTAL ISSUES

The Company owns property on which it operated a manufactured gas plant from 1909 to 1928. The site is currently used as an office facility for Company field personnel and storage location for certain equipment and materials. The coal gasification process utilized in the plant resulted in the production of certain by-products, which have been classified by the federal government and the State of Montana as hazardous to the environment.

Several years ago the Company initiated an assessment of the site to determine if remediation of the site was required. That assessment resulted in a submission of a proposed remediation plan to the Montana Department of Environmental Quality (MDEQ) in 1994. The Company has worked with the MDEQ since that time to obtain the data that would lead to a remediation action acceptable to the MDEQ. In the summer of 1999 the Company received final approval from the MDEQ for its plan for remediation of soil contaminants. The Company has completed its remediation of soil contaminants and in April of 2002 received a closure letter from MDEQ approving the completion of such remediation program.

The Company and its consultants continue their work with the MDEQ relating to the remediation plan for water contaminants. The MDEQ has established regulations that allow water contaminants at a site to exceed standards if it is technically impracticable to achieve them. Although the MDEQ has not established guidance to attain a technical waiver, the U.S. Environmental Protection Agency (EPA) has developed such guidance. The EPA guidance lists factors which render mediations technically impracticable. The Company has filed a request for a waiver respecting compliance with certain standards with the MDEQ.

At June 30, 2003, the Company had incurred cumulative costs of approximately $2,034,000 in connection with its evaluation and remediation of the site. The Company also estimates that it will incur at least $60,000 in additional expenses in connection with its investigation and remediation for this site. On May 30, 1995, the Company received an order from the MPSC allowing for recovery of the costs associated with the evaluation and remediation of the site through a surcharge on customer bills. As of June 30, 2003, the Company had recovered approximately $1,443,000 through such surcharges.

On April 15, 2003, the MPSC issued an Order to Show Cause Regarding the Environmental Surcharge. The MPSC required the Company to show cause why it was not in violation of the 1995 order by failing to seek renewal of the surcharge at the conclusion of the initial two year recovery period. The Company responded to the MPSC and an interim order has been issued by the MPSC suspending the collection by the Company of the surcharge until further investigation can be conducted and requiring a new application from the Company respecting this surcharge. The Company has submitted its revised application and is awaiting further MPSC action. Company management believes the Company's application will be granted. The Company currently has an unrecovered balance of $590,000 awaiting recovery through this mechanism. In the event that the MPSC does not approve the Company's revised application, in addition to potentially being unable to recover the unrecovered balance of $590,000, the Company could be required to refund to customers a portion of the $1,443,000 previously collected through surcharges.

DERIVATIVES AND RISK MANAGEMENT

Management of Risks Related to Derivatives—The Company and its subsidiaries are subject to certain risks related to changes in certain commodity prices and risks of counter-party performance. The Company has established policies and procedures to manage such risks. The Company has a Risk Management Committee (RMC), comprised of Company officers and management to oversee the Company's risk management program as defined in its risk management policy. The purpose of the risk management program is to minimize adverse impacts on earnings resulting from volatility of energy prices, counter-party credit risks, and other risks related to the energy commodity business.

General—From time to time the Company or its subsidiaries may use financial derivative contracts to mitigate the risk of commodity price volatility related to firm commitments to purchase and sell natural gas or electricity. The Company may use such arrangements to protect its profit margin on future obligations to deliver quantities of a commodity at a fixed price. Conversely, such arrangements may be used to hedge against future market price declines where the Company or a subsidiary enters into an obligation to purchase a commodity at a fixed price in the future. The Company accounts for such financial instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities.

In accordance with SFAS No. 133, contracts that do not qualify as normal purchase and sale contracts must be reflected in the Company's financial statements at fair value, determined as of the date of the balance sheet. This accounting treatment is also referred to as "mark-to-market" accounting. Mark-to-market accounting treatment can result in a disparity between reported earnings and realized cash flow, because changes in the value of the financial instrument are reported as income or loss even though no cash payment may have been made between the parties to the contract. If such contracts are held to maturity, the cash flow from the contracts, and their hedges, is realized over the life of the contract.

Quoted market prices for natural gas derivative contracts of the Company or its subsidiaries generally are not available. Therefore, to determine the fair value of natural gas derivative contracts, the Company uses internally developed valuation models that incorporate independently available current and historical pricing information.

During the third quarter of fiscal year 2002, EWR terminated its existing derivative contracts with Enron Canada Corporation (ECC), a subsidiary of Enron Corp. Most of these contracts were commodity swaps that EWR had entered into to mitigate the effects of fluctuations in the market price of natural gas. The derivative contracts with ECC were entered into at various times in order to lock in margins on certain contracts under which EWR had commitments to other parties to sell natural gas at fixed prices (the "Future Supply Agreements"). EWR made the decision to terminate these ECC contracts because of concerns relating to the bankruptcy of Enron Corp. At the date of termination, the market price of natural gas was substantially lower than the price had been when EWR entered into the contracts, resulting in a net amount due from EWR to ECC of approximately $5,400,000. EWR paid this amount to ECC upon the termination of the contracts, and thereby discharged the liability related to the contracts. The costs related to such termination were reflected in the Company's consolidated statement of income as adjustments to gas purchased for the fiscal year ended June 30, 2002. At the time the Company terminated the ECC derivative contracts, the Company entered into new gas purchase contracts (the "Future Purchase Agreements") at prices much lower than those provided for under the ECC contracts. The Company recognized income as a result of the mark-to-market accounting treatment of the Future Purchase Agreements, and therefore the termination of the ECC derivative contracts did not have a material impact on the Company's consolidated statement of income.

The Future Purchase Agreements and the Future Sales Agreements continue to be valued on a mark-to market basis. As of June 30, 2003, these agreements were reflected on the Company's consolidated balance sheet as derivative assets and liabilities at an approximate fair value as follows:

	Assets	Liabilities
Contracts maturing during fiscal year 2004:	$ 880,240	$ 285,610
Contracts maturing during fiscal years 2005 and 2006:	1,431,154	236,795
Contracts maturing during fiscal years 2007 and 2008:	352,849	221,052
Contracts maturing from fiscal years 2009 and beyond:	55,397	37,246
Total	$ 2,719,640	$ 780,703

During fiscal year 2003, the Company did not enter into any new contracts that would be accounted for using mark-to-market accounting under SFAS No. 133.

Natural Gas and Propane Operations—In the case of the Company's regulated divisions, gains or losses resulting from the derivative contracts are subject to deferral under regulatory procedures approved by the public service regulatory commissions of the States of Montana, Wyoming and Arizona. Therefore, related derivative assets and liabilities are offset with corresponding regulatory liability and asset amounts included in "Recoverable Cost of Gas Purchases", pursuant to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation.

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

The foregoing Management's Discussion and Analysis and other portions of this annual report on Form 10-K contain various "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Sections 21E of the Securities Exchange Act of 1934, as amended, which represent the Company's expectations or beliefs concerning future events. Forward-looking statements include, but are not limited to, statements regarding competition, the effects of the PPLM settlement and the DOR settlement, the outcome of regulatory proceedings, capital expenditure needs, the Company's liquidity position and the effects of inflation. Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "planned," "scheduled" or similar expressions. Although the Company believes these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that could cause future results to be materially different from the results stated or implied in this document.

Such forward-looking statements, as well as other oral and written forward-looking statements made by or on behalf of the Company from time to time, including statements contained in the Company's filings with the Securities and Exchange Commission and its reports to shareholders, involve known and unknown risks and other factors which may cause the Company's actual results in future periods to differ materially from those expressed in any forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to the risk factors set forth under the heading "Risk Factors."

Any such forward-looking statement is qualified by reference to these risk factors. The Company cautions that these risks and factors are not exclusive. The Company does not undertake to update any forward-looking statement that may be made from time to time by or on behalf of the Company except as required by law.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company's is subject to certain market risks, including commodity price risk (i.e., natural gas and propane prices) and interest rate risk. The adverse effects of potential changes in these market risks are discussed below. The sensitivity analyses presented do not consider the effects that such adverse changes may have on overall economic activity nor do they consider additional actions management may take to mitigate the Company's exposure to such changes. Actual results may differ. See the notes to the financial statements for a description of the Company's accounting policies and other information related to these financial instruments.

Commodity Price Risk

The Company protects itself against price fluctuations on natural gas and electricity by limiting the aggregate level of net open positions, which are exposed to market price changes and through the use of natural gas derivative instruments. The net open position is actively managed with strict policies designed to limit the exposure to market risk, and which require at least weekly reporting to management of potential financial exposure. The risk management committee has limited the types of financial instruments the company may trade to those related to natural gas commodities. The Company's results of operations are significantly impacted by changes in the price of natural gas. During fiscal years 2003 and 2002, natural gas accounted for 55% and 62% respectively, of the Company's operating expenses. In order to provide short-term protection against a sharp increase in natural gas prices, the Company from time to time enters into natural gas call and put options, swap contracts and purchase commitments. The Company's gas hedging strategy could result in the Company not fully benefiting from certain gas price declines.

Interest Rate Risk

The Company's results of operations are affected by fluctuations in interest rates (e.g. interest expense on debt). The Company mitigates this risk by entering into long-term debt agreements with fixed interest rates. The Company's notes payable, however, are subject to variable interest rates. A hypothetical 10% change in market rates applied to the balance of the notes payable would not have a material effect on the Company's earnings.

Credit Risk

Credit risk relates to the risk of loss that the Company would incur as a result of non-performance by counterparties of their contractual obligations under the various instruments with the Company. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances which relate to other market participants which have a direct or indirect relationship with such counterparty. The Company seeks to mitigate credit risk by evaluating the financial strength of potential counterparties. However, despite mitigation efforts, defaults by counterparties may occur from time to time. To date, no such default has occurred.

Item 8. Financial Statements and Supplementary Data

The Consolidated Financial Statements of the Company are filed under this Item, beginning on page F-1 of this Annual Report on Form 10-K.

Selected quarterly financial data required under this Item is included in Note 16 to the Company's Consolidated Financial Statements.

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

The Company's current report on Form 8-K dated October 25, 2001, describes the dismissal of Ernst & Young as the Company's independent accountant and the engagement of Deloitte & Touche as the Company's new independent accountant. At the time of the dismissal of Ernst & Young, there were no reportable events with respect to the Company's relationship with its independent accountants.

Item 9A. – Controls and Procedures

(a) Evaluation of disclosure controls and procedures.

Our management evaluated, with the participation of our Interim Chief Executive Officer (principal executive officer) and our Vice President and Controller (principal financial officer), the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. Based on this evaluation, our Interim Chief Executive Officer (principal executive officer) and our Vice President and Controller (principal financial officer) have concluded that our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

(b) Changes in internal controls over financial reporting.

There was no change in our internal control over financial reporting that occurred during the period covered by this Annual Report on Form 10-K that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART III

Item 10. - Directors and Executive Officer of the Registrant

Information concerning the executive officers of the Company is included in Part I, Item I of this Form 10-K. The information contained under the heading "Proposal 1: Election of Directors" in the Proxy Statement is incorporated by reference in response to this Item.

Item 11. - Executive Compensation

The information contained under the heading "Executive Compensation" in the Proxy Statement is incorporated by reference in response to this Item.

Item 12. - Security Ownership of Certain Beneficial Owners and Management

The information contained under the heading "Certain Beneficial Ownership of the Company's Common Stock" in the Proxy Statement is incorporated by reference in response to this Item.

Item 13. - Certain Relationships and Related Transactions

There are no transactions with management or business relationships with others that require disclosure under Item 404 of Regulation S-K.

Item 14. – Principal Accountant Fees and Services

Pursuant to SEC Release No. 33-8183 (as corrected by Release No. 33-81834), the disclosure requirements of this Item 14 are not effective until the Company's first fiscal year ending after December 31, 2003.

PART IV

Item 15. - Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a)	1. Financial Statements included in Part II, Item 8:	Page
	Report of Independent Auditors	F-2
	Consolidated Balance Sheets	F-4
	Consolidated Statements of Operations	F-6
	Consolidated Statements of Stockholders' Equity	F-7
	Consolidated Statements of Cash Flows	F-8
	Notes to Consolidated Financial Statements	F-10
	2. Financial Statement Schedules included in Item 15(d):	
	Schedule II - Valuation and Qualifying Accounts	

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

3. The Exhibits required to be filed by Item 601 of Regulation S-K are listed under the heading "Exhibit Index," below.

(b) Reports on Form 8-K.

The Company filed a Form 8-K, in response to Items 5 and 7, on June 27, 2003 announcing that it had agreed with Wells Fargo Bank Montana, N.A. on an extension of its credit facility through July 31, 2003.

The Company filed a Form 8-K, in response to Items 5 and 7, on June 24, 2003 announcing that Wells Fargo Bank Montana, N.A. had extended the maturity date of its credit facility through June 26, 2003.

The Company filed a Form 8-K, in response to Items 5 and 7, on June 18, 2003 announcing that its subsidiary, Energy West Resources, Inc. ("EWR"), and PPL Montana, LLC ("PPLM"), agreed to settle their lawsuit pending in the United States District Court for the District of Montana, for payments by EWR to PPLM totaling $3.2 million and announcing the suspension of its quarterly dividend, other actions to strengthen its financial position and the impact of the settlement with PPLM.

The Company filed a Form 8-K, in response to Items 5 and 7, on June 3, 2003, announcing it agreed with Wells Fargo Bank Montana, N.A., on an extension of its credit facility through June 23, 2003. The Company also issued a press release on June 3, 2003 correcting an error in the headline of the June 2, 2003 press release.

The Company filed a Form 8-K, in response to Items 5 and 7, on May 1, 2003, announcing it had agreed with Wells Fargo Bank Montana, N.A., on an extension of its credit facility through June 2, 2003.

(c) EXHIBITS. The Exhibits required to be filed by Item 601 of Regulation S-K are listed under the heading "Exhibit Index," below.

(d) SCHEDULE II

VALUATION AND QUALIFYING ACCOUNTS

ENERGY WEST, INCORPORATED

JUNE 30, 2003

Description	Balance At Beginning of Period	Charged to Costs & Expenses	Write-Offs Net of Recoveries	Balance at End of Period
ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS				
Year Ended June 30, 2001	$ 87,999	$ 169,785	$ (53,214)	$ 204,570
Year Ended June 30, 2002	$ 204,570	$ 59,506	$ (109,825)	$ 154,251
Year Ended June 30, 2003	$ 154,251	$ 164,499	$ (105,737)	$ 213,013

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.

ENERGY WEST, INCORPORATED

Date: October 9, 2003

/s/ John C. Allen
By: John C. Allen
Interim President and Chief Executive Officer
(principal 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.

/s/ John C. Allen John C. Allen	Interim President, Chief Executive Officer and Director (principal executive officer)	October 9, 2003
/s/ Robert B. Mease Robert B. Mease	Vice President and Controller (principal financial officer and principal accounting officer)	October 9, 2003
/s/ Andrew I. Davidson Andrew I. Davidson	Director	October 9, 2003
/s/ W.E. Argo W.E. Argo	Director	October 9, 2003
/s/ G. Montgomery Mitchell G. Montgomery Mitchell	Director	October 9, 2003
/s/ George D. Ruff George D. Ruff	Director	October 9, 2003
/s/ David A. Flitner David A. Flitner	Director	October 9, 2003
/s/ Terry M. Palmer Terry M. Palmer	Director	October 9, 2003
/s/ Richard J. Schulte Richard J. Schulte	Director	October 9, 2003

EXHIBIT INDEX

3.1 Restated Articles of Incorporation of the Company, as amended to date (incorporated by reference to Exhibit 3.1 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).

3.2 Bylaws of the Company, as amended to date (incorporated by reference to Exhibit 3.2 on Form 10-K/A for the fiscal year ended June 30, 2002, filed with the Commission on November 25, 2002).

4.1 Form of Indenture (including form of Note) relating to the Company's Series 1993 Notes (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-2, File No. 33-62680).

4.2 Loan Agreement, dated as of September 1, 1992, relating to the Company's Series 1992A and Series 1992B Industrial Development Revenue Bonds (incorporated by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-2, File No. 33-62680).

10.1 Credit Agreement dated September 30, 2003 by and among Energy West, Incorporated, Various Financial Institutions and LaSalle Bank National Association (incorporated by reference to Exhibit 10.1 to the Company's Amendment No. 1 to the Current Report on Form 8-K/A filed with the Commission on October 9, 2003).

10.2 Delivered Gas Purchase Contract dated February 23, 1997, as amended by that Letter Amendment Amending Gas Purchase Contract dated March 9, 1982; that Amendment to Delivered Gas Purchase Contract applicable as of March 20, 1986; that Letter Agreement dated December 18, 1986; that Letter Agreement dated April 12, 1988; that Letter Agreement dated April 28, 1992; that Letter Agreement dated March 14, 1996; that Letter Agreement dated April 15, 1996; a second Letter Agreement dated April 15, 1996; that Letter dated February 18, 1997; and that Letter dated April 1, 1997, transmitting a Notice of Assignment effective February 26, 1993 (incorporated by reference to Exhibit 10.6 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).

10.3 Delivered Gas Purchase Contract dated December 1, 1985, as amended by that Letter Agreement dated July 1, 1986; that Letter Agreement dated November 19, 1987; that Letter Agreement dated December 1, 1988; that Letter Agreement dated July 30, 1992; that Assignment Conveyance and Bill of Sale effective as of January 1, 1993; that Letter Agreement dated March 8, 1993; that Letter Agreement dated October 21, 1993; that Letter Agreement dated October 18, 1994; that Letter Agreement dated January 30, 1995; that Letter Agreement dated August 30, 1995; that Letter Agreement dated October 3, 1995; that Letter Agreement dated October 31, 1995; that Letter Agreement dated December 21, 1995; that Letter Agreement dated April 25, 1996; that Letter Agreement dated January 29, 1997; and that Letter dated April 11, 1997 (incorporated by reference to Exhibit 10.7 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).

10.4 Natural Gas Sale and Purchase Agreement dated July 20, 1992 between Shell Canada Limited and the Company, as amended by that Letter Agreement dated August 23, 1993; that Amending Agreement effective as of November 1, 1994; and that Schedule A Incorporated Into and Forming a part of That Natural Gas Sale and Purchase Agreement, effective as of November 1, 1996 (incorporated by reference to Exhibit 10.8 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).

10.5 Employee Stock Ownership Plan Trust Agreement (incorporated by reference to Exhibit 10.2 to Registration Statement on Form S-1, File No. 33-1672).*

10.6 1992 Stock Option Plan (incorporated by reference to Exhibit 10.10 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).*

10.7 Form of Incentive Stock Option under the 1992 Stock Option Plan (incorporated by reference to Exhibit 10.11 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).*

10.8 Management Incentive Plan (incorporated by reference to Exhibit 10.12 on Form 10-K/A for the fiscal year ended June 30, 1996, filed with the Commission on July 9, 1997).*

10.9 Energy West Senior Management Incentive Plan (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K for the fiscal year ended June 30, 2002, filed with the Commission on September 30, 2002).*

10.10 Energy West Incorporated Deferred Compensation Plan for Directors (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K for the fiscal year ended June 30, 2002, filed with the Commission on September 30, 2002).*

10.11 Amended and Restated Advisory Agreement, dated October 3, 2003, by and among Energy West, Incorporated, D.A. Davidson & Co. and DAMG Capital LLC (filed herewith).

10.12 Letter Agreement dated June 5, 2003 between DAMG Capital LLC and the Company (filed herewith).

10.13 Letter Agreement dated June 5, 2003 between D.A. Davidson & Co. and the Company (filed herewith).

21.1 Subsidiaries of the Company (incorporated by reference to Exhibit 21.1 to the Company's Annual Report on Form 10-K for the fiscal year ended June 30, 2000, filed with the Commission on September 28, 2000).

23.1 Consent of Independent Auditors - Deloitte & Touche LLP (filed herewith).

23.2 Consent of Independent Auditors - Ernst & Young LLP (filed herewith).

31.1 Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

31.2 Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

32.1 Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

32.2 Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

* Represents a management contract or a compensatory plan or arrangement.

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ENERGY WEST, INCORPORATED AND SUBSIDIARIES

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Energy West, Incorporated
Great Falls, Montana

We have audited the accompanying consolidated balance sheets of Energy West, Incorporated and subsidiaries as of June 30, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. Our audits also included the information for the years ended June 30, 2003 and 2002 in the financial statement schedule listed in the Index at Item 14. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Energy West, Incorporated and subsidiaries at June 30, 2003 and 2002, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the information for the years ended June 30, 2003 and 2002, in the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, effective July 1, 2002 the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*.

DELOITTE & TOUCHE LLP

Salt Lake City, Utah
September 30, 2003

Report of Independent Auditors

The Board of Directors
Energy West, Incorporated

We have audited the accompanying consolidated statements of income, stockholders' equity, and cash flows of Energy West, Incorporated and subsidiaries for the year ended June 30, 2001. Our audit also included the information for the year ended June 30, 2001 in the financial statement schedule listed in the index at item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Energy West Incorporated and subsidiaries for the year ended June 30, 2001, in conformity with accounting principles generally accepted in the United States. Also, in our opinion, the related financial statement schedule for the year ended June 30, 2001, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

/s/ Ernst & Young LLP

Salt Lake City, Utah
August 31, 2001

ENERGY WEST, INCORPORATED AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, JUNE 30, 2003 AND 2002

ASSETS	2003	2002
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,938,768	$ 367,657
Accounts receivable (net of allowance of $213,013 and $154,251 at June 30, 2003 and 2002, respectively)	7,971,632	8,244,239
Derivative assets	2,719,640	2,867,717
Natural gas and propane inventories	1,038,690	5,640,660
Materials and supplies	371,490	593,674
Prepayments and other	352,982	445,652
Deferred income taxes	828,698	931,147
Income tax receivable	1,882,889	–
Recoverable cost of gas purchases	1,067,109	–
Total current assets	18,171,898	19,090,746
PROPERTY, PLANT, AND EQUIPMENT, Net	39,576,596	36,518,908
DEFERRED CHARGES	4,388,372	1,935,263
OTHER ASSETS	271,429	324,130
TOTAL ASSETS	$62,408,295	$57,869,047

See notes to consolidated financial statements

(Continued)

ENERGY WEST, INCORPORATED AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, JUNE 30, 2003 AND 2002

CAPITALIZATION AND LIABILITIES	2003	2002
CURRENT LIABILITIES:		
Current portion of long-term debt	$ 532,371	$ 502,072
Lines of credit	6,104,588	3,500,000
Accounts payable	8,841,779	7,413,693
Derivative liabilities	780,703	–
Income taxes payable	–	1,005,975
Refundable cost of gas purchases	–	2,024,159
Accrued and other current liabilities	5,309,254	5,453,304
Total current liabilities	21,568,695	19,899,203
LONG-TERM LIABILITIES:		
Deferred income taxes	5,460,083	4,043,038
Deferred investment tax credits	355,406	376,468
Other long-term liabilities	4,891,200	1,910,571
Total	10,706,689	6,330,077
LONG-TERM DEBT	14,834,452	15,367,424
COMMITMENTS AND CONTINGENCIES (Notes 7, 8, 13, and 14)		
STOCKHOLDERS' EQUITY:		
Preferred stock; $.15 par value, 1,500,000 shares authorized, no shares outstanding		
Common stock; $.15 par value, 3,500,000 shares authorized, 2,595,250 and 2,573,046 shares outstanding at June 30, 2003 and 2002, respectively	389,295	385,964
Capital in excess of par value	5,056,425	4,863,113
Retained earnings	9,852,739	11,023,266
Total stockholders' equity	15,298,459	16,272,343
TOTAL CAPITALIZATION	30,132,911	31,639,767
TOTAL CAPITALIZATION AND LIABILITIES	$62,408,295	$57,869,047

See notes to consolidated financial statements. (Concluded)

ENERGY WEST, INCORPORATED AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED JUNE 30, 2003, 2002, AND 2001

	2003	2002	2001
REVENUES:			
Natural gas operations	$31,627,242	$ 39,515,060	$40,605,105
Propane operations	12,786,918	10,656,152	13,867,232
Gas and electric—wholesale	34,283,190	39,846,739	56,971,747
Pipeline operations	448,681	154,494	168,351
Total revenues	79,146,031	90,172,445	111,612,435
EXPENSES:			
Gas purchased	30,803,655	35,872,169	40,308,604
Gas and electric—wholesale	31,506,103	38,522,409	49,662,361
Cost of goods sold	210,661	195,254	202,775
Distribution, general, and administrative	11,669,028	8,790,183	12,090,515
Maintenance	496,717	465,771	427,767
Depreciation and amortization	2,392,368	2,059,169	1,970,081
Taxes other than income	888,281	946,214	727,076
Total expenses	77,966,813	86,851,169	105,389,179
OPERATING INCOME	1,179,218	3,321,276	6,223,256
NON-OPERATING INCOME	302,110	657,887	281,559
INTEREST EXPENSE:			
Long-term debt	(1,159,502)	(1,187,749)	(1,225,840)
Lines of credit	(473,540)	(516,743)	(870,727)
Total interest expense	(1,633,042)	(1,704,492)	(2,096,567)
INCOME (LOSS) BEFORE INCOME TAXES	(151,714)	2,274,671	4,408,248
INCOME TAX BENEFIT (EXPENSE)	62,835	(873,881)	(1,643,111)
NET INCOME (LOSS)	$ (88,879)	$ 1,400,790	$ 2,765,137
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (0.03)	$ 0.55	$ 1.11
Diluted	$ (0.03)	$ 0.55	$ 1.10
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	2,586,487	2,549,245	2,495,537
Diluted	2,586,487	2,558,782	2,509,738

See notes to consolidated financial statements.

ENERGY WEST, INCORPORATED AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED JUNE 30, 2003, 2002, AND 2001

	Shares	Common Stock	Capital in Excess of Par Value	Retained Earnings	Total
BALANCE AT JUNE 30, 2000	2,475,435	$371,321	$3,906,401	$ 9,508,483	$13,786,205
Exercise of stock options at $9.00 per share	2,300	345	20,355	-	20,700
Sales of common stock at $7.990 to $11.800 per share under the Company's dividend reinvestment plan	21,838	3,277	212,976	-	216,253
Issuance of common stock to ESOP at estimated fair value of $8.012 per share	13,810	2,072	108,578	-	110,650
Net income				2,765,137	2,765,137
Dividends	-	-	-	(1,285,671)	(1,285,671)
BALANCE AT JUNE 30, 2001	2,513,383	377,015	4,248,310	10,987,949	15,613,274
Exercise of stock options at $8.375 to $9.187 per share	24,002	3,600	200,974	-	204,574
Sales of common stock at $8.012 to $11.958 per share under the Company's dividend reinvestment plan	10,698	1,604	118,134	-	119,738
Issuance of common stock to ESOP at estimated fair value of $12.110 per share	20,631	3,095	246,743	-	249,838
Issuance of common stock at $11.450 per share under the Company's deferred board stock compensation plan	4,332	650	48,952	-	49,602
Net income				1,400,790	1,400,790
Dividends	-	-	-	(1,365,473)	(1,365,473)
BALANCE AT JUNE 30, 2002	2,573,046	385,964	4,863,113	11,023,266	16,272,343
Sales of common stock at $6.010 to $9.720 per share under the Company's dividend reinvestment plan	9,820	1,473	77,114	-	78,587
Issuance of common stock to ESOP at estimated fair value of $9.533 per share	12,384	1,858	116,198	-	118,056
Net loss				(88,879)	(88,879)
Dividends	-	-	-	(1,081,648)	(1,081,648)
BALANCE AT JUNE 30, 2003	2,595,250	$389,295	$5,056,425	$ 9,852,739	$15,298,459

See notes to consolidated financial statements.

ENERGY WEST, INCORPORATED AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2003, 2002, AND 2001

	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (88,879)	$ 1,400,790	$ 2,765,137
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization, including deferred charges and financing costs	2,594,141	2,326,909	2,378,894
Gain on sale of assets	(23,657)	(393,584)	-
Investment tax credit	(21,062)	(21,062)	(21,062)
Deferred gain on sale of assets	(23,628)	(23,628)	(23,628)
Deferred income taxes	1,519,494	(1,354,927)	(883,589)
Changes in assets and liabilities:			
Accounts receivable	272,607	2,087,164	(2,640,452)
Derivative assets	148,077	577,144	(3,405,971)
Natural gas and propane inventories	4,601,970	(873,114)	(2,853,845)
Accounts payable	1,288,920	108,573	945,828
Derivative liabilities	780,703	(3,921,354)	3,921,354
Recoverable/refundable cost of gas purchases	(3,091,268)	8,848,379	(2,110,825)
Prepayments and other	92,670	(44,510)	(40,314)
Other assets and liabilities	(3,503,919)	(1,602,750)	7,976,538
Net cash provided by operating activities	4,546,169	7,114,030	6,008,065
CASH FLOWS FROM INVESTING ACTIVITIES:			
Construction expenditures	(4,040,286)	(5,485,108)	(3,276,251)
Acquisition of producing natural gas reserves, net of settlement (see Note 2)	(90,113)	(956,888)	-
Proceeds from sale of assets	23,958	1,188,458	10,044
Proceeds from notes receivable	3,300	134,627	24,458
Customer advances refunded for construction	(2,131)	(28,078)	(68,869)
Increase (decrease) from contributions in aid of construction	31,360	(2,901)	22,775
Net cash used in investing activities	(4,073,912)	(5,149,890)	(3,287,843)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayments of long-term debt	(502,673)	(490,000)	(494,000)
Proceeds from lines of credit	40,032,623	44,084,650	83,035,477
Repayments of lines of credit	(37,428,035)	(44,370,639)	(84,104,488)
Sale of common stock	78,587	324,312	236,953
Dividends paid	(1,081,648)	(1,365,473)	(1,285,671)
Net cash provided by (used in) financing activities	1,098,854	(1,817,150)	(2,611,729)
NET INCREASE IN CASH AND CASH EQUIVALENTS	1,571,111	146,990	108,493
CASH AND CASH EQUIVALENTS:			
Beginning of year	367,657	220,667	112,174
End of year	$ 1,938,768	$ 367,657	$ 220,667

(Continued)

ENERGY WEST, INCORPORATED AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2003, 2002, AND 2001

	2003	2002	2001
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during the year for interest	$ 1,490,265	$ 2,025,468	$ 2,047,819
Cash paid during the year for income taxes	–	2,937,000	275,000
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Shares issued to satisfy liability to the ESOP	118,056	249,838	110,650
Capital lease	–	13,496	–
Assets acquired for debt issued and liabilities assumed	834,667	–	–

See notes to consolidated financial statements (Concluded)

1. SUMMARY OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Nature of Business—Energy West, Incorporated (the "Company") is a regulated public utility with certain non-utility operations conducted through its subsidiaries. The Company's regulated utility operations involve the distribution and sale of natural gas to the public in and around Great Falls and West Yellowstone, Montana and Cody, Wyoming, and the distribution and sale of propane to the public through underground propane vapor systems in and around Payson, Arizona and Cascade, Montana. The Company's West Yellowstone, Montana operation is supplied by liquefied natural gas.

The Company's non-regulated operations include wholesale distribution of bulk propane in Wyoming, Arizona, and Montana and the retail distribution of bulk propane in Arizona. The Company also markets gas and electricity in Montana and Wyoming through its non-regulated subsidiary, Energy West Resources, Inc. ("EWR").

Principles of Consolidation—The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, Energy West Propane, Inc. ("EWP"), EWR, and Energy West Development, Inc. ("EWD"). The consolidated financial statements also include the Company's proportionate share of the assets, liabilities, revenues, and expenses of certain producing natural gas reserves that were acquired in fiscal years 2003 and 2002 (see Note 2). All intercompany transactions and accounts have been eliminated.

Segments—The Company reports financial results for four business segments: Natural Gas Operations, Propane Operations, EWR, and Pipeline Operations. Summarized financial information for these four segments is set forth in Note 11.

Use of Estimates in Preparing Financial Statements—The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company has used estimates in measuring certain deferred charges and deferred credits related to items subject to approval of the various public service commissions with jurisdiction over the Company. Estimates are also used in the development of discount rates and trend rates related to the measurement of postretirement benefit obligations and accrual amounts, allowances for doubtful accounts, valuing derivative instruments, estimating litigation reserves, and in the determination of depreciable lives of utility plant. Actual results could differ from these estimates.

Natural Gas and Propane Inventories—Natural gas inventory and propane inventory are stated at the lower of weighted average cost or net realizable value except for inventory used in the Great Falls distribution area, which is stated at the rate approved by the Montana Public Service Commission ("MPSC"), which includes transportation and storage costs.

Recoverable/Refundable Costs of Gas and Propane Purchases—The Company accounts for purchased gas and propane costs in accordance with procedures authorized by the MPSC, the Wyoming Public Service Commission ("WPSC"), and the Arizona Corporation Commission. Purchased gas and propane costs that are different from those provided for in present rates, and approved by the applicable commissions, are accumulated and recovered or credited through future rate changes.

In March 2001, the Company was granted an interim order that allowed the addition of $2.12 per Mcf surcharge to recover $6,824,000 of previously unrecovered gas costs. The Company recovered in excess of these costs during fiscal 2002 resulting in a refundable gas obligation totaling $2,024,000 as of June 30, 2002. Such amount has been reflected as a liability in the accompanying financial statements. Effective July 1, 2002, the MPSC approved the Company's application to discontinue this surcharge. The Company has in place an interim order that allows for the recovery of gas costs when there is a gas cost change that exceeds $.10 per Mcf. As of June 30, 2003, the Company has unrecovered purchased gas costs of $1,067,000.

Property, Plant, and Equipment —Property, plant and equipment are recorded at original cost when placed in service. Depreciation and amortization on assets are generally recorded on a straight-line basis over the estimated useful lives, as applicable, at various rates. The average rates of depreciation and amortization were approximately 3.69%, 3.40% and 3.47% during the years ended June 30, 2003, 2002 and 2001, respectively.

Natural Gas Reserves—During fiscal year 2002, EWR acquired an undivided interest in certain producing natural gas reserves on properties located in northern Montana. During fiscal year 2003, EWD purchased additional reserves in northern Montana (see Note 2). As of June 30, 2003, the reserves are estimated to have approximately 3.4 million Mmbtu and 1.3 million Mmbtu, respectively, in remaining natural gas reserves. The Company is depleting these reserves using the units-of-production method. The gas reserves are included in Property, Plant, and Equipment in the accompanying financial statements. The production of the gas reserves is not considered to be significant to the operations of the Company as defined by Statement of Financial Accounting Standard ("SFAS") No. 69, *Disclosures About Oil And Gas Producing Properties.*

Impairment of Long-Lived Assets—The Company evaluates its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets or intangibles may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future undiscounted net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets.

Stock-Based Compensation—The Company has elected to follow the accounting provisions of Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees for Stock-Based Compensation*, for stock options granted to employees and directors and to furnish the pro forma disclosure required under SFAS No. 123, *Accounting for Stock-Based Compensation.* In the fiscal years ended June 30, 2002 and 2001, no options were granted and, accordingly, there was no impact on the accompanying consolidated financial statements from the issuance of options. Additionally, the carryover effect of options granted prior to 2001 was not significant.

The following table illustrates the effect on net loss and loss per common share for the year ended June 30, 2003 if the fair value based method had been applied to all outstanding and unvested awards in the period:

Net loss, as reported	$ (88,879)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(37,037)
Pro forma net loss	$(125,916)
Loss per common share:	
Basic—as reported	$ (0.03)
Basic—pro forma	$ (0.05)
Diluted—as reported	$ (0.03)
Diluted—pro forma	$ (0.05)

The fair value of the options was estimated at the date of grant using the Black-Scholes option pricing model with the following assumptions for 2003:

1) risk-free interest rate of 3.2 percent;
2) dividend yield of 6.6 percent;
3) no discount for lack of marketability;
4) expected life of 5 years; and
5) a volatility factor of the expected market price of the Company's common stock of 37 percent.

Comprehensive Income—During the years ended June 30, 2003, 2002, and 2001, the Company had no components of comprehensive income other than net income.

Revenue Recognition—Revenues are recognized in the period that services are provided or products are delivered. The Company records gas distribution revenues for gas delivered to residential and commercial customers but not billed at the end of the accounting period. The Company periodically collects revenues subject to possible refunds pending final orders from regulatory agencies. When this occurs, appropriate reserves for such revenues collected subject to refund are established.

Derivatives—The accounting for derivative financial instruments that are used to manage risk is in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities.* Derivatives are recorded at estimated fair value and gains and losses from derivative instruments are included as a component of gas and electric—wholesale revenues in the accompanying consolidated statements of operations. For the years ended June 30, 2003 and 2002, the Company recognized a net loss of $928,000 and a net gain of $2,647,000, respectively. The loss of $928,000 in fiscal year 2003 was offset by gross margin on physical sales of natural gas of approximately the same amount resulting in an immaterial impact on the Company's consolidated statement of operations. The $2,647,000 gain in fiscal year 2002 was offset by additional costs of gas incurred by the Company upon termination of certain gas contracts (see Note 14), resulting in an immaterial impact on the Company's consolidated statement of operations.

Debt Issuance and Reacquisition Costs—Debt premium, discount and issue costs are amortized over the life of each debt issue. Debt reacquisition costs for refinanced debt are amortized over the remaining life of the debt.

Cash and Cash Equivalents—All highly liquid investments with maturities of three months or less at the date of acquisition are considered to be cash equivalents.

Earnings Per Share—Net income per common share is computed by both the basic method, which uses the weighted average number of the Company's common shares outstanding, and the diluted method, which includes the dilutive common shares from stock options, as calculated using the treasury stock method. The only dilutive securities are the stock options described in Note 12. Options to purchase 130,420 shares of common stock were outstanding at June 30, 2003 but were not included in the computation of diluted earnings per shares as their effect would be antidilutive. The dilutive effect of stock options for the years ended June 30, 2002 and 2001 was an increase to basic weighted average common shares outstanding of 9,837 and 14,201, respectively.

Credit Risk—The Company's primary market areas are Montana, Wyoming, and Arizona. Exposure to credit risk may be impacted by the concentration of customers in these areas due to changes in economic or other conditions. Customers include individuals and numerous industries that may be affected differently by changing conditions. Management believes that its credit review procedures, loss reserves, customer deposits, and collection procedures have adequately provided for usual and customary credit related losses.

Effects of Regulation—The Company follows SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* and its consolidated financial statements reflect the effects of the different rate making principles followed by the various jurisdictions regulating the Company. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

Income Taxes—The Company files its income tax returns on a consolidated basis. Rate-regulated operations record cumulative increases in deferred taxes as a regulatory asset for income taxes recoverable from customers. The Company uses the deferral method to account for investment tax credits as required by regulatory commissions. Deferred income taxes are determined using the asset and liability method, under which deferred tax assets and liabilities are measured based upon the temporary differences between the financial statement and income tax bases of assets and liabilities, using current tax rates.

Financial Instruments—The fair value of all financial instruments with the exception of fixed rate long-term debt (see Note 8) approximates carrying value because they have short maturities or variable rates of interest that approximate prevailing market interest rates.

Asset Retirement Obligations—In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations,* which requires asset retirement obligations to be recognized when they are incurred and recorded as liabilities. The Company adopted this statement effective July 1, 2002, and has recorded an estimated asset retirement obligation in the accompanying consolidated balance sheet in "Other long-term liabilities", and in "Property, plant and equipment". The asset retirement obligation of $555,665 represents the Company's estimated future liability as of June 30, 2003, to plug and abandon existing oil and gas wells owned by EWR and EWD. EWR and EWD will depreciate the asset amount and increase the liability over the estimated useful life of these assets. In the future, the Company may have other asset retirement obligations arising from its business operations.

The Company has identified but not recognized ARO liabilities related to gas transmission and distribution assets resulting from easements over property not owned by the Company. These easements are generally perpetual and only require retirement upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as the Company intends to utilize these properties indefinitely. In the event the Company decides to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

Changes in the asset retirement obligation can be reconciled as follows:

Balance—July 1, 2002	$389,880
Accretion	28,969
Additions	172,681
Adjustment	(35,865)
Balance—June 30, 2003	$555,665

In connection with the acquisition of additional natural gas reserves during fiscal year 2003 (see Note 2), the Company recorded an addition to its asset retirement obligation totaling $172,681, which represents the fair value of the estimated costs to plug and abandon the acquired wells.

Had SFAS No. 143 been applied in fiscal year 2002, the resulting asset retirement obligation would not have been significant due to the fact that EWR acquired the natural gas reserves to which the asset retirement obligation applies at the end of fiscal year 2002. The asset retirement obligation at June 30, 2002 would have approximated the amount recorded at July 1, 2002, the effective date of SFAS No. 143 for the Company.

New Accounting Pronouncements—In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. This statement supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.* The statement retains the previously existing accounting requirements related to the recognition and measurement of the impairment of long-lived assets to be held and used but expands the measurement requirements of long-lived assets to be disposed of by sale to include discontinued operations. It also expands the previously existing reporting requirements for discontinued operations to include a component of an entity that either has been disposed of or is classified as held for sale. The Company adopted SFAS No. 144 effective July 1, 2002. Management has determined that there is no current impact from SFAS No. 144 on the consolidated financial statements of the Company.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements Nos. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. This statement eliminates the required classification of gain or loss on extinguishment of debt as an extraordinary item of income and states that such gain or loss be evaluated for extraordinary classification under the criteria of APB Opinion No. 30, *Reporting Results of Operations*. This statement also requires sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions, and makes various other technical corrections to existing pronouncements. The Company adopted SFAS No. 145 effective July 1, 2002. Management has determined that there is no current impact from SFAS No. 145 on the consolidated financial statements of the Company.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. This statement nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*. This statement requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred rather than the date of an entity's commitment to an exit plan. The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. The Company adopted SFAS No. 146 on December 31, 2002. Management has determined that there is no impact from SFAS No. 146 on the consolidated financial statements of the Company.

In December 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"). FIN 45 requires that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee. This interpretation is applicable on a prospective basis to guarantees issued or modified after December 31, 2002. FIN 45 also contains disclosure provisions surrounding existing guarantees, which are effective for financial statements of interim or annual periods ending after December 15, 2002. Management has determined that there is no current impact from FIN 45 on the consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46"), which requires the consolidation of certain entities considered to be variable interest entities ("VIEs"). An entity is considered to be a VIE when it has equity investors who lack the characteristics of having a controlling financial interest, or its capital is insufficient to permit it to finance its activities without additional subordinated financial support. Consolidation of a VIE by an investor is required when it is determined that the investor will absorb a majority of the VIE's expected losses or residual returns if they occur. Management has determined that there is no current impact from FIN 46 on the consolidated financial statements.

In April 2003, the FASB issued SFAS No. 149, *Amendments of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS No. 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities. The Statement is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. Management has determined that there is no current impact from SFAS No. 149 on the consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which provides standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The Statement is effective for financial instruments entered into or modified after May 31, 2003 and for pre-existing instruments as of the beginning of the first interim period beginning after June 15, 2003. Management has determined that there is no current impact from SFAS No. 150 on the consolidated financial statements.

Reclassifications—Certain prior year amounts have been reclassified to conform to the current year presentation.

2. PROVED NATURAL GAS RESERVES

In November 1999, EWR entered into a contract with a seller of natural gas whereby the seller agreed to supply and EWR agreed to purchase a minimum fixed quantity of natural gas at an agreed-upon price. During the term of the contract, the seller was unable to supply EWR with the quantities specified in the contract, and, accordingly, EWR was required to purchase natural gas from other suppliers at prices that exceeded the contract price. For remedies in the event of a breach on the part of the seller, the contract required payment by the seller to EWR of an amount equal to the difference between the contract quantity and the actual quantity delivered multiplied by the difference between the contract price and the spot price of natural gas during the term of the breach.

During fiscal year 2001, EWR notified the seller of its intention to pursue collection and demanded payment of damages for the breach by the seller. During December 2001, EWR and the seller agreed to terms whereby the seller would convey an undivided interest in proved natural gas reserves to EWR for a price that was reduced by an amount agreed upon by the two parties to cure damages for the seller's breach under the natural gas supply contract. In May 2002, EWR paid the seller approximately $956,000, which consists of an agreed-upon price for the reserves and associated support equipment of $1,257,000 reduced by $300,000 to cure damages under the supply contract. The agreed-upon price for the reserves is supported by an independent third-party valuation and the contemporaneous purchase of interests in the same reserves by two independent third parties.

EWR recorded the acquisition of the natural gas reserves and the settlement of the breach by the seller as two separate and distinct transactions in fiscal year 2002. Accordingly, EWR recorded the cost of the interest in the proved natural gas reserves and associated support equipment at $1,257,000 and recorded a $300,000 settlement as non-operating income in the accompanying consolidated statement of operations for the year ended June 30, 2002.

In March 2003, EWD acquired a 75% undivided ownership interest in natural gas production properties located in Montana that will provide a portion of the gas requirements of EWR. The total purchase price of the interest was $924,780, which consists of cash paid totaling $90,113, the issuance of a promissory note totaling $800,917 that was paid in full on September 30, 2003, and the assumption of liabilities of $33,750.

3. PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consists of the following as of June 30, 2003 and 2002:

	2003	2002
Gas transmission and distribution facilities	$ 49,617,786	$ 47,204,701
Non-depreciable property	567,011	395,996
Buildings and leasehold improvements	3,317,535	2,922,911
Transportation equipment	2,541,367	2,515,574
Computer equipment	4,642,657	4,008,767
Other equipment	3,909,996	3,788,845
Construction work-in-progress	1,523,660	1,001,449
Producing natural gas reserves	1,858,601	933,821
	67,978,613	62,772,064
Accumulated depreciation, depletion, and amortization	(28,402,017)	(26,253,156)
Total	$ 39,576,596	$ 36,518,908

4. DEFERRED CHARGES

Deferred charges consist of the following as of June 30, 2003 and 2002:

	2003	2002
Regulatory asset for property tax settlement (see Note 13)	$2,430,000	$ –
Regulatory asset for income taxes	638,619	458,754
Regulatory assets for deferred environmental remediation costs	541,196	617,069
Unamortized debt issue costs	778,557	859,440
Total	$4,388,372	$1,935,263

5. ACCRUED AND OTHER CURRENT LIABILITIES

Accrued and other current liabilities consist of the following as of June 30, 2003 and 2002:

	2003	2002
Litigation reserve for PPLM settlement (see Note 13)	$2,200,000	$2,000,000
Property tax settlement—current portion	243,000	
Payable to employee benefit plans	568,133	870,132
Accrued vacation	429,333	433,043
Customer deposits	576,917	341,276
Accrued compensation	464,394	1,615,524
Accrued interest	106,860	112,512
Accrued taxes other than income	219,853	
Other	500,764	80,817
Total	$5,309,254	$5,453,304

6. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following as of June 30, 2003 and 2002:

	2003	2002
Asset retirement obligation	$ 555,665	$ –
Contribution in aid of construction	1,066,804	1,013,789
Customer advances for construction	538,010	561,801
Accumulated postretirement obligation	209,800	157,300
Deferred gain on sale leaseback of assets	70,895	94,520
Regulatory liability for income taxes	263,026	83,161
Property tax settlement (see Note 13)	2,187,000	
Total	$4,891,200	$1,910,571

7. LINES OF CREDIT

At June 30, 2003, the Company had approximately $1,939,000 of cash on hand and a $10,595,000 unsecured bank credit facility, of which approximately $6,105,000 had been borrowed under the credit agreement. At June 30, 2003, the Company had outstanding letters of credit totaling $4,400,000 related to electricity and gas purchase contracts. These letters of credit are netted against the Company's bank lines of credit, resulting in net availability of approximately $90,000 under the lines of credit at June 30, 2003.

Following an adverse ruling in the lawsuit with PPL Montana, LLC ("PPLM") on March 7, 2003 (see Note 13), the Company's bank lender, Wells Fargo Bank Montana, National Association ("Wells Fargo") and the Company began negotiations with respect to the Company's credit facility which was set to expire in May 2003. Wells Fargo granted a series of extensions of the credit facility through September 5, 2003.

On September 5, 2003, the Company reached an agreement with Wells Fargo for a new credit facility through October 15, 2003 (the "Wells Fargo Facility"). The terms of the Wells Fargo Facility established a term loan of approximately $10,400,000, the proceeds of which were used to repay the prior Wells Fargo credit facility and to establish a reserve of approximately $2,600,000 for letters of credit that remained outstanding from the prior facility. In addition, the Wells Fargo Facility established a revolving line of credit under which the Company could borrow up to $3,000,000 for working capital and certain other expenses. Borrowings under the Wells Fargo Facility were secured by liens on substantially all of the assets of the Company used in its regulated operations in Arizona, and by substantially all of the assets of the Company's subsidiaries. As required under the terms of the Company's outstanding long-term notes and bonds (the "Long Term Debt"), the Company's obligations under the Long Term Debt were secured on an equal and ratable basis with Wells Fargo in the collateral granted to secure the Wells Fargo Facility with the exception of the first $1,000,000 of debt under the Wells Fargo Facility.

On September 30, 2003, the Company established a $23,000,000 revolving credit facility (the "LaSalle Facility") with LaSalle Bank, National Association, as Agent for certain banks (collectively the "Lender"). The LaSalle Facility replaced the Wells Fargo Facility and the amount due under the Wells Fargo Facility was paid in full out of the proceeds of the LaSalle Facility. Borrowings under the LaSalle Facility are secured by liens on substantially all of the assets of the Company and its subsidiaries. As required under the terms of the Long Term Debt, the Company's obligations under the Long Term Debt are secured on an equal and ratable basis with the Lender in the collateral granted to secure the LaSalle Facility with the exception of the first $1,000,000 of debt under the LaSalle Facility.

Under applicable law,the Company was required to obtain approval from the MPSC and the WPSC to enter into the LaSalle Facility. Both commissions gave the necessary approval. The MPSC order granting approval imposed several requirements on the Company including restrictions on the use of the proceeds of the LaSalle Facility for anything other than utility purposes, and requirements that the Company provide ongoing reports to the MPSC with respect to the financial condition of the Company and its non-regulated subsidiaries and certain other matters. The MPSC order provided that the Company could fund the remaining $2.2 million settlement payment owed by EWR to PPLM. The settlement payment was made on September 30, 2003, ending the litigation between the two parties.

The LaSalle Facility provides that the maximum availability under the facility will be reduced from $23,000,000 to $15,000,000 no later than March 31, 2004. From and after the date on which the amount of availability under the LaSalle Facility is reduced, the LaSalle Facility is to be secured by a senior priority lien in the accounts receivable and inventory of the Company and its subsidiaries. As a result of the provisions providing for the reduction in the maximum availability under the LaSalle Facility, the Company will be required to refinance or restructure the Long Term Debt by March 31, 2004. The Company anticipates that such refinancing or restructuring will involve providing a senior priority lien in the fixed assets of the Company and its subsidiaries to secure the Long Term Debt or any long-term debt that the Company issues to replace the current Long Term Debt. The Company also anticipates that it will increase the total amount of long-term debt outstanding in connection with such refinancing or restructuring. The Company presently anticipates that the amount of such increase in long-term debt will be approximately $8,000,000. The Company believes that it will be able to accomplish the Long Term Debt restructuring or refinancing by March 31, 2004.

During the period prior to the refinancing or restructuring of the Company's Long-Term Debt, the terms of the LaSalle Facility provide that the Company cannot pay dividends to its shareholders. The LaSalle Facility also requires that the Company maintain compliance with a number of financial covenants and ratios including limitations on capital expenditures.

The LaSalle Facility allows the Company to pay interest at the option of either the London Interbank Offered Rate (LIBOR) plus 250 basis points ("bps") or the higher of (a) the rate publicly announced from time to time by LaSalle as its "prime rate" or (b) the Federal Funds Rate plus 0.5% per annum. The facility also has a commitment fee of 35 bps due on the daily unutilized portion of the facility.

8. LONG-TERM DEBT

Long-term debt at June 30, 2003 and 2002 consists of the following:

	2003	2002
Series 1997 notes payable	$ 7,925,444	$ 7,926,000
Series 1993 notes payable	6,280,000	6,700,000
Series 1992B industrial development revenue obligations	1,150,000	1,230,000
Capital lease	11,379	13,496
Total long-term debt	15,366,823	15,869,496
Current portion of long-term debt	(532,371)	(502,072)
Long-term debt	$ 14,834,452	$ 15,367,424

Series 1997 Notes Payable—On August 1, 1997, the Company issued $8,000,000 of Series 1997 notes bearing interest at the rate of 7.5%, payable semiannually on June 1 and December 1 of each year. All principal amounts of the 1997 notes then outstanding, plus accrued interest will be due and payable on June 1, 2012. At the Company's option, beginning June 1, 2002, the notes may be redeemed at any time prior to maturity, in whole or part, at redemption prices declining from 103% to 100% of face value, plus accrued interest. As of June 30, 2003, the Company had not redeemed any of the notes under this issue.

Series 1993 Notes Payable—On June 24, 1993, the Company issued $7,800,000 of Series 1993 notes bearing interest at rates ranging from 6.20% to 7.60%, payable semiannually on June 1 and December 1 of each year. The 1993 notes mature serially in increasing amounts on June 1 of each year beginning in 1999 and extending to June 1, 2013. At the Company's option, beginning June 1, 2003, notes maturing subsequent to 2003 may be redeemed at any time prior to maturity, in whole or part, at redemption prices declining from 104% to 100% of face value, plus accrued interest. As of June 30, 2003, the Company had not redeemed prior to their scheduled maturity any of the notes under this issue.

Series 1992B Industrial Development Revenue Obligations—On September 15, 1992, Cascade County, Montana issued $1,800,000 of Series 1992B Industrial Development Revenue Bonds (the "1992B Bonds") bearing interest at rates ranging from 3.35% to 6.50%, and loaned the proceeds to the Company. The Company is required to pay the loan, with interest, in amounts and on a schedule to repay the 1992B Bonds. Interest is payable semiannually on April 1 and October 1 of each year. The 1992B Bonds mature serially in increasing amounts on October 1 of each year beginning in 1993 and extending to October 1, 2012. At the Company's option, beginning on October 1, 2002, 1992B Bonds maturing in 2003 and later years may be redeemed in whole or in part on any interest payment date at redemption prices declining from 102% to 100% of face value, plus accrued interest. As of June 30, 2003, the Company had not redeemed prior to their scheduled maturity any of the 1992B Bonds.

Aggregate Annual Maturities—The scheduled maturities of long-term debt at June 30, 2003 are as follows:

	Series 1997	Series 1993	Series 1992B	Capital Lease	Total Long-Term Debt
Year ending June 30:					
2004	$ –	$ 445,000	$ 85,000	$ 2,371	$ 532,371
2005		480,000	90,000	2,706	572,706
2006		515,000	95,000	3,088	613,088
2007		550,000	105,000	3,214	658,214
2008		590,000	110,000		700,000
Thereafter	7,925,444	3,700,000	665,000		12,290,444
Total	$7,925,444	$6,280,000	$1,150,000	$11,379	$15,366,823

Under the terms of the Long Term Debt obligations, the Company is subject to certain restrictions, including restrictions on total dividends and distributions, liens and secured indebtedness, and asset sales, and the Company is restricted from incurring additional long-term indebtedness if it does not meet certain financial debt and interest ratios. Management believes that the Company is in compliance with all Long-Term Debt covenants as of June 30, 2003. For the fiscal year ended June 30, 2003, the Company's ratio of earnings to fixed charges was less than 1.5. Under the terms of the Long Term Debt, the Company must achieve a 1.5 ratio of earnings to fixed charges by the end of fiscal year 2004, or the Company will be restricted from incurring additional debt with a maturity of one year or longer. As required under the terms of the Long Term Debt, the Company's obligations under the Long Term Debt are secured on an equal and ratable basis with the Lender in the collateral granted to secure the LaSalle Facility with the exception of the first $1,000,000 of debt under the LaSalle Facility.

The estimated fair value of the Company's fixed rate long-term debt, based on quoted market prices for the same or similar issues, is approximately $16,580,495 and $17,380,158 as of June 30, 2003 and 2002, respectively.

9. EMPLOYEE BENEFIT PLANS

The Company has a defined contribution plan (the "Pension Plan") which covers substantially all of the Company's employees. Under the Pension Plan, the Company contributes annually 10% of each participant's eligible compensation to the Pension Plan. Total contributions to the plan for the years ended June 30, 2003, 2002, and 2001 were $568,133, $617,275, and $509,372, respectively.

The Company also sponsors a defined postretirement health benefit plan (the "Retiree Health Plan") providing health and life insurance benefits to eligible retirees. The Company has elected to pay eligible retirees (post-65 years of age) $125 per month in lieu of contracting for health and life insurance benefits. The amount of this payment is fixed and will not increase with medical trends or inflation. The Company's Retiree Health Plan allows retirees between the ages of 60 and 65 and their spouses to remain on the same medical plan as active employees by contributing 125% of the current COBRA rate to retain this coverage.

The following table sets forth the funded status of the Retiree Health Plan and amounts recognized in the consolidated financial statements as of June 30, 2003 and 2002 and for the years ended June 30, 2003, 2002, and 2001:

	2003	2002
Change in benefit obligation:		
Projected benefit obligation		
Benefit obligation at beginning of year	$ 602,800	$ 743,200
Service costs	31,100	26,000
Interest costs	44,300	39,200
Actuarial (gain) losses	123,400	(182,900)
Benefits paid	(19,300)	(22,700)
Benefit obligation at end of year	782,300	602,800
Change in plan assets:		
Fair value of plan assets at beginning of year	470,800	482,400
Actual return on plan assets	5,300	11,100
Benefits paid	(19,300)	(22,700)
Fair value of plan assets at end of year	456,800	470,800
Benefit obligation in excess of plan assets	325,500	132,000
Unrecognized transition obligation	(196,200)	(215,800)
Unrecognized prior service cost	(144,500)	(162,400)
Unrecognized gain	225,000	403,500
Net amount recognized	$ 209,800	$ 157,300

	2003	2002	2001
Service costs	$ 31,100	$ 26,000	$ 34,900
Interest costs	44,300	39,200	52,000
Expected return on plan assets	(39,000)	(42,400)	(39,500)
Amortization of transition obligation	19,600	19,600	19,600
Amortization of unrecognized prior service costs	17,900	17,900	17,900
Actuarial gain	(21,400)	(28,300)	(13,500)
Postretirement benefit expense	$ 52,500	$ 32,000	$ 71,400

	2003	2002
Weighted-average assumptions as of June 30:		
Discount rate	6.00 %	7.50 %
Expected return on plan assets	8.50 %	9.00 %
Health care inflation rate	8.50 %	9.50 %
	Grading to 5.5%	Grading to 5.5%

A one-percentage-point increase in the assumed health care cost trend rate would increase interest and service cost by $2,900 and the accumulated postretirement benefit obligation by $23,200. A one-percentage-point decrease in the assumed health care cost trend rate would decrease interest and service cost by $2,500 and the accumulated postretirement benefit obligation by $20,100.

Included in the postretirement benefit expense amounts were $40,260 in 2003, $26,100 in 2002 and $29,400 in 2001 related to regulated operations. The MPSC allows for recovery of these costs over a 20-year period beginning on November 4, 1997 for the utility operations in Montana. Management believes it is probable that its regulators in Wyoming will allow recovery of these costs based upon recent industry rate decisions addressing this issue. The plan assets are held in a VEBA trust fund into which all the Company's contributions are made.

10. INCOME TAXES

Significant components of the Company's deferred tax assets and liabilities as of June 30, 2003 and 2002 are as follows:

	2003		2002	
	Current	Long-Term	Current	Long-Term
Deferred tax asset:				
Allowances for doubtful accounts	$ 62,824	$ –	$ 30,917	$ –
Unamortized investment tax credit	–	45,887	–	54,470
Contributions in aid of construction	–	216,957	–	209,885
Other nondeductible accruals	168,033	173,769	991,465	147,141
Deferred gain on sale of assets	–	28,890	–	38,518
Recoverable purchase gas costs	–	–	783,554	–
Derivatives	378,478	–	–	–
Deferred incentive and pension accrual	–	60,983	–	556,198
Other	219,363	396,368	203,735	227,649
Total	828,698	922,854	2,009,671	1,233,861
Deferred tax liabilities:				
Recoverable purchase gas costs	–	494,631	–	–
Property, plant, and equipment	–	5,667,489	–	5,011,672
Debt issue costs	–	121,944	–	136,983
Deferred rate case costs	–	39,531	–	52,034
Derivatives	–	–	1,078,524	–
Other	–	59,342	–	76,210
Total	–	6,382,937	1,078,524	5,276,899
Net deferred tax assets (liabilities)	$ 828,698	$ (5,460,083)	$ 931,147	$ (4,043,038)

Income tax expense (benefit) for the years ended June 30, 2003, 2002, and 2001 consists of the following:

	2003	2002	2001
Current:			
Federal	$(1,474,595)	$ 1,857,616	$ 2,249,626
State	(86,672)	395,487	428,125
Total	(1,561,267)	2,253,103	2,677,751
Deferred:			
Federal	1,440,933	(1,119,762)	(811,901)
State	78,561	(238,398)	(201,677)
Total	1,519,494	(1,358,160)	(1,013,578)
Total income taxes before credits	(41,773)	894,943	1,664,173
Investment tax credit, net	(21,062)	(21,062)	(21,062)
Income tax expense (benefit)	$ (62,835)	$ 873,881	$ 1,643,111

Income tax expense (benefit) differs from the amount computed by applying the federal statutory rate to pre-tax income for the following reasons:

	2003	2002	2001
Income tax expense (benefit) at statutory rate of 34%	$(51,583)	$866,995	$1,498,804
State income tax expense (benefit), net of federal tax benefit	(5,353)	103,679	182,930
Amortization of deferred investment tax credits	(21,062)	(21,062)	(21,062)
Other	15,163	(75,731)	(17,561)
Total	$(62,835)	$873,881	$1,643,111

11. SEGMENTS OF OPERATIONS

Effective July 1, 2002, the Company changed the structure of its internal organization such that the Pipeline Operations segment was established as a new segment. The results of this segment reflect operations of oil and gas gathering systems placed into service in fiscal year 2002, and transferred from EWR to EWD. For fiscal year 2002 and prior years, EWD consisted primarily of real estate holding and incurred minimal expenses. The financial operations of EWD's pipeline assets and real estate holding are now being reported as pipeline operations.

Summarized financial information for the Company's Natural Gas Operations, Propane Operations, EWR and Pipeline Operations segments (before inter-company eliminations between segments primarily consisting of gas sales from EWR to Natural Gas Operations, inter-company accounts receivable, accounts payable, equity, and subsidiary investment) is as follows:

Year Ended June 30, 2003	Natural Gas Operations	Propane Operations	EWR	Pipeline Operations	Eliminations	Consolidated
Operating revenue:						
Natural gas operations	$31,927,242	$ -	$ -	$ -	$ (300,000)	$31,627,242
Propane operations		12,984,676			(197,758)	12,786,918
Gas and electric—wholesale			50,371,419		(16,088,229)	34,283,190
Pipeline operations				448,681		448,681
Total operating revenue	31,927,242	12,984,676	50,371,419	448,681	(16,585,987)	79,146,031
Gas purchased	22,054,365	8,959,974		287,074	(497,758)	30,803,655
Gas and electric—wholesale			47,594,332		(16,088,229)	31,506,103
Cost of goods sold			210,661			210,661
Distribution, general, and administrative	6,006,710	2,693,842	2,827,549	140,927		11,669,028
Maintenance	410,829	85,888				496,717
Depreciation and amortization	1,486,754	622,156	168,537	114,921		2,392,368
Taxes other than income	637,635	198,369	43,977	8,300		888,281
Operating expenses	30,596,293	12,560,229	50,845,056	551,222	(16,585,987)	77,966,813
Operating income (loss)	1,330,949	424,447	(473,637)	(102,541)		1,179,218
Non-operating income	93,850	187,329	19,632	1,299		302,110
Interest on long-term debt	(689,969)	(297,115)	(166,173)	(6,245)		(1,159,502)
Interest on lines of credit	(308,681)	(106,045)	(57,879)	(935)		(473,540)
Income (loss) before income taxes	426,149	208,616	(678,057)	(108,422)		(151,714)
Income tax benefit (expense)	(245,182)	(68,833)	359,886	16,964		62,835
Net income (loss)	$ 180,967	$ 139,783	$ (318,171)	$ (91,458)	$ -	$ (88,879)
Capital expenditures	$ 2,660,788	$ 878,356	$ 80,776	$1,345,146	$ -	$ 4,965,066
Total assets	$36,177,289	$12,630,662	$12,184,332	$2,643,483	$ (1,227,471)	$62,408,295

Year Ended June 30, 2002	Natural Gas Operations	Propane Operations	EWR	Pipeline Operations	Eliminations	Consolidated
Operating revenue:						
Natural gas operations	$39,823,393	$ –	$ –	$ –	$ (308,333)	$39,515,060
Propane operations		10,870,327			(214,175)	10,656,152
Gas and electric—wholesale			56,819,550		(16,972,811)	39,846,739
Pipeline operations				154,494		154,494
Total operating revenue	39,823,393	10,870,327	56,819,550	154,494	(17,495,319)	90,172,445
Gas purchased	29,773,507	6,621,170			(522,508)	35,872,169
Gas and electric—wholesale			55,495,220		(16,972,811)	38,522,409
Cost of goods sold			195,254			195,254
Distribution, general, and administrative	5,033,521	2,157,761	1,543,738	55,163		8,790,183
Maintenance	387,468	78,303				465,771
Depreciation and amortization	1,388,254	622,039	34,150	14,726		2,059,169
Taxes other than income	687,819	207,086	50,284	1,025		946,214
Operating expenses	37,270,569	9,686,359	57,318,646	70,914	(17,495,319)	86,851,169
Operating income (loss)	2,552,824	1,183,968	(499,096)	83,580		3,321,276
Non-operating income	153,935	199,477	304,878	(403)		657,887
Interest on long-term debt	(799,889)	(305,859)	(80,207)	(1,794)		(1,187,749)
Interest on lines of credit	(370,837)	(121,109)	(24,101)	(696)		(516,743)
Income (loss) before income taxes	1,536,033	956,477	(298,526)	80,687		2,274,671
Income tax benefit (expense)	(600,339)	(351,271)	110,112	(32,383)		(873,881)
Net income (loss)	$ 935,694	$ 605,206	$ (188,414)	$ 48,304	$ –	$ 1,400,790
Capital expenditures	$ 3,122,484	$ 1,221,971	$ 1,279,549	$ 831,453	$ –	$ 6,455,457
Total assets	$35,103,259	$12,110,629	$10,411,234	$1,067,308	$ (823,383)	$57,869,047

Year Ended June 30, 2001	Natural Gas Operations	Propane Operations	EWR	Pipeline Operations	Eliminations	Consolidated
Operating revenue:						
Natural gas operations	$41,008,435	$ –	$ –	$ –	$ (403,330)	$ 40,605,105
Propane operations		14,005,549			(138,317)	13,867,232
Gas and electric—wholesale			77,668,732		(20,696,985)	56,971,747
Pipeline operations				168,351		168,351
Total operating revenue	41,008,435	14,005,549	77,668,732	168,351	(21,238,632)	111,612,435
Gas purchased	31,139,176	9,711,075			(541,647)	40,308,604
Gas and electric—wholesale			70,359,346		(20,696,985)	49,662,361
Cost of goods sold			202,775			202,775
Distribution, general, and administrative	5,593,537	2,517,222	3,978,294	1,462		12,090,515
Maintenance	339,527	88,240				427,767
Depreciation and amortization	1,337,620	605,501	19,757	7,203		1,970,081
Taxes other than income	507,927	162,786	56,363			727,076
Operating expenses	38,917,787	13,084,824	74,616,535	8,665	(21,238,632)	105,389,179
Operating income	2,090,648	920,725	3,052,197	159,686		6,223,256
Non-operating income	131,382	128,122	22,055			281,559
Interest on long-term debt	(732,850)	(286,472)	(196,402)	(10,116)		(1,225,840)
Interest on lines of credit	(521,390)	(199,805)	(141,997)	(7,535)		(870,727)
Income before income taxes	967,790	562,570	2,735,853	142,035		4,408,248
Income taxes	(355,856)	(221,446)	(1,001,962)	(63,847)		(1,643,111)
Net income	$ 611,934	$ 341,124	$ 1,733,891	$ 78,188	$ –	$ 2,765,137
Capital expenditures	$ 1,773,357	$ 1,192,655	$ –	$310,239	$ –	$ 3,276,251
Total assets	$39,874,297	$12,833,470	$11,805,637	$546,094	$ (2,781,863)	$ 62,277,635

12. STOCK OPTIONS AND OWNERSHIP PLANS

Stock Options—The Energy West, Incorporated 2002 Stock Option Plan is an incentive stock option plan (the "2002 Option Plan") that provides for the issuance of up to 200,000 shares of the Company's common stock pursuant to options issuable to certain key employees. Additionally, the Company's 1992 Stock Option Plan (the "1992 Option Plan"), which expired in September 2002, provided for the issuance of up to 100,000 shares of the Company's common stock pursuant to options issuable to certain key employees. Under the 2002 Option Plan and the 1992 Option Plan (collectively, the "Option Plans"), the option price may not be less than 100% of the common stock fair market value on the date of grant (110% of the fair market value if the employee owns more than 10% of the Company's outstanding common stock). Pursuant to the Option Plans, the options vest over four years and are exercisable over a five-year period from date of issuance. When the 1992 Option Plan expired in September 2002, 12,600 shares remained unissued and were no longer available for issuance.

A summary of activity under the Option Plans for the years ended June 30, 2003, 2002, and 2001 is as follows:

	2003		2002		2001	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding at beginning of year	32,420	$9.089	56,420	$8.894	62,720	$8.894
Granted	114,500	8.491	–		–	
Exercised	–		(24,000)	8.523	(2,300)	9.000
Forfeited	(16,500)	8.614	–		(4,000)	9.187
Outstanding at end of year	130,420	8.624	32,420	9.089	56,420	8.849
Options exercisable at year end	48,820	8.846	19,452	9.089	30,568	8.733

At June 30, 2003, exercise prices range from $8.49 to $9.19 per share. The weighted-average remaining contractual life of stock options is three years. At June 30, 2003, there were approximately 98,000 shares available for grant under the 2002 Option Plan.

Employee Stock Ownership Plan—The Company has an Employee Stock Ownership Plan ("ESOP") that covers most of the Company's employees. The ESOP receives contributions of the Company's common stock from the Company each year as determined by the Board of Directors. The contribution is recorded based on the current market price of the Company's common stock. The Company has recognized as expense $-0-, $129,802, and $240,812 for the years ended June 30, 2003, 2002, and 2001, respectively, related to the common stock contributions.

13. COMMITMENTS AND CONTINGENCIES

Commitments—The Company has entered into long-term, take or pay natural gas supply contracts which expire at varying times through 2008. The contracts generally require the Company to purchase specified minimum volumes of natural gas at fixed prices over periods ranging from one to six years. The prices per MMBtu for these contracts average approximately $3.30. Based on these fixed prices, the minimum take or pay obligation at June 30, 2003 is as follows:

Year ending June 30:	
2004	$3,426,573
2005	1,539,152
2006	1,539,753
2007	900,873
2008	577,731
Total	$7,984,082

Natural gas purchases under these contracts for the years ended June 30, 2003, 2002, and 2001 approximated $1,973,242, $920,475, and $1,141,000, respectively.

In 2000, the Company entered into a 10-year transportation agreement with NorthWestern Energy that fixes the cost of pipeline and storage capacity.

Environmental Contingency—The Company owns property on which it operated a manufactured gas plant from 1909 to 1928. The site is currently used as an office facility for Company field personnel and storage location for certain equipment and materials. The coal gasification process utilized in the plant resulted in the production of certain by-products, which have been classified by the federal government and the State of Montana as hazardous to the environment.

Several years ago the Company initiated an assessment of the site to determine if remediation of the site was required. That assessment resulted in a submission of a proposed remediation plan to the Montana Department of Environmental Quality ("MDEQ") in 1994. The Company has worked with the MDEQ since that time to obtain the data that would lead to a remediation action acceptable to the MDEQ. In the summer of 1999 the Company received final approval from the MDEQ for its plan for remediation of soil contaminants. The Company has completed its remediation of soil contaminants and in April of 2002 received a closure letter from MDEQ approving the completion of such remediation program.

The Company and its consultants continue their work with the MDEQ relating to the remediation plan or water contaminants. The MDEQ has established regulations that allow water contaminants at a site to exceed standards if it is technically impracticable to achieve them. Although the MDEQ has not established guidance to attain a technical waiver, the U.S. Environmental Protection Agency ("EPA") has developed such guidance. The EPA guidance lists factors which render mediations technically impracticable. The Company has filed a request for a waiver respecting compliance with certain standards with the MDEQ.

At June 30, 2003, the Company had incurred cumulative costs of approximately $2,034,000 in connection with its evaluation and remediation of the site. The Company also estimates that it will incur at least $60,000 in additional expenses in connection with its investigation and remediation for this site. On May 30, 1995, the Company received an order from the MPSC allowing for recovery of the costs associated with the evaluation and remediation of the site through a surcharge on customer bills. As of June 30, 2003, the Company had recovered approximately $1,443,000 through such surcharges.

On April 15, 2003, the MPSC issued an Order to Show Cause Regarding the Environmental Surcharge. The MPSC required the Company to show cause why it was not in violation of the 1995 order by failing to seek renewal of the surcharge at the conclusion of the initial two year recovery period. The Company responded to the MPSC and an interim order been issued by the MPSC suspending the collection by the Company of the surcharge until further investigation can be conducted and requiring a new application from the Company respecting the surcharge. Company management believes the Company's application will be approved. The Company currently has an unrecovered balance of $590,000 awaiting recovery through this mechanism. In the event that the MPSC does not approve the Company's revised application, in addition to potentially being unable to recover the unrecovered balance of $590,000, the Company could be required to refund to customers a portion of the $1,430,000 previously collected through surcharge.

Litigation—From time to time the Company is involved in litigation relating to claims arising from its operations in the normal course of business. The Company utilizes various risk management strategies, including maintaining liability insurance against certain risks, employee education and safety programs and other processes intended to reduce its exposure.

In addition to other litigation referred to above, the Company or its subsidiaries are involved in the following described litigation:

EWR has been involved in a lawsuit with PPLM which was filed on July 2, 2001, and involves a wholesale electricity supply contract between EWR and PPLM dated March 17, 2000 and a confirmation letter thereunder dated June 13, 2000. On June 17, 2003, EWR and PPLM reached agreement on a settlement of the lawsuit. Under the terms of the settlement, EWR paid PPLM a total of $3,200,000, consisting of an initial payment of $1,000,000 on June 17, 2003, and a second payment of $2,200,000 on September 30, 2003, terminating all proceedings in the case. EWR had established reserves in fiscal year 2002 of approximately $3,032,000 to pay a potential settlement with PPLM and the remaining $168,000 was charged to operating expenses in fiscal year 2003.

By letter dated August 30, 2002, the Montana Department of Revenue ("DOR") notified the Company that the DOR had completed a property tax audit of the Company for the period January 1, 1997 through and including December 31, 2001, and had determined that the Company had willfully under-reported its personal property and that additional property taxes and penalties should be assessed.

On August 8, 2003, the Company reached an agreement with the DOR to pay $2,430,000 in back taxes (without interest or penalty) as a settlement for the underpayment of property taxes for tax years 1992 through and including 2002. The settlement amount will be paid in ten equal annual installments of $243,000, on or before November 30 of each year, beginning November 30, 2003.

Under Montana law, the Company believes it is entitled to recover the amounts paid in connection with the DOR settlement through future rate adjustments without seeking approval from the MPSC. The amended rates will go into effect on January 1 following the date of each tax payment. The amended rate schedules must be filed with the MPSC on or before the effective date of the changes in taxes paid, and the commission has 45 days to act on the adjusted rates submitted. If the commission determines that the rates were adjusted in error, then refunds must be paid to the customers.

The Company has included $2,187,000 in other long-term liabilities and $243,000 in accrued and other current liabilities related to the DOR settlement in the accompanying consolidated balance sheet at June 30, 2003. As discussed above, management believes that Montana law permits the Company to recover the DOR settlement through rates. Accordingly, the Company has recorded a regulatory asset equal to the settlement amount.

Operating Leases—The Company leases certain properties including land, office buildings, and other equipment under non-cancelable capital and operating leases through fiscal year 2010. The future minimum lease payments are as follows:

Year ended June 30:	
2004	$ 183,765
2005	152,599
2006	142,599
2007	90,624
2008	90,624
Thereafter	85,800
Total	$ 746,011

Lease expense resulting from operating leases for the years ended June 30, 2003, 2002, and 2001 totaled $189,906, $189,906, and $189,615, respectively.

Letters of Credit—Outstanding letters of credit totaled $4,400,000 $4,150,000, and $6,000,000 at June 30, 2003, 2002, and 2001, respectively. The letters of credit guarantee the Company's performance to third parties for gas and electric purchases and gas transportation services. Subsequent to June 30, 2003, third parties drew $1,610,864 on the letters of credit to satisfy obligations of the Company.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Management of Risks Related to Derivatives—The Company and its subsidiaries are subject to certain risks related to changes in certain commodity prices and risks of counter-party performance. The Company has established certain policies and procedures to manage such risks. The Company has a Risk Management Committee ("RMC") comprised of Company officers and management to oversee the Company's risk management program as defined in its risk management policy. The purpose of the risk management program is to minimize adverse impacts on earnings resulting from volatility of energy prices, counter-party credit risks, and other risks related to the energy commodity business.

General—From time to time the Company or its subsidiaries may use financial derivative contracts to mitigate the risk of commodity price volatility related to firm commitments to purchase and sell natural gas or electricity. Conversely, such arrangements may be used to hedge against future market price declines where the Company or a subsidiary enters into an obligation to purchase a commodity at a fixed price in the future. The Company accounts for such financial instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*.

In accordance with SFAS No. 133, contracts that do not qualify as normal purchase and sale contracts must be reflected in the Company's financial statements at fair value, determined as of the date of the balance sheet. This accounting treatment is also referred to as "mark-to-market" accounting. Mark-to-market accounting treatment can result in a disparity between reported earnings and realized cash flow, because changes in the value of the financial instrument are reported as income or loss even though no cash payment may have been made between the parties to the contract. If such contracts are held to maturity, the cash flow from the contracts, and their hedges, is realized over the life of the contract.

Quoted market prices for natural gas derivative contracts of the Company or its subsidiaries generally are not available. Therefore, to determine the fair value of natural gas derivative contracts, the Company uses internally developed valuation models that incorporate independently available current and historical pricing information.

During the third quarter of fiscal year 2002, Energy West Resources, Inc. ("EWR") terminated its existing derivative contracts with Enron Canada Corporation ("ECC"), a subsidiary of Enron Corp. Most of these contracts were commodity swaps that EWR had entered into to mitigate the effects of fluctuations in the market price of natural gas. The derivative contracts with ECC were entered into at various times in order to lock in margins on certain contracts under which EWR had commitments to other parties to sell natural gas at fixed prices (the "Future Sale Agreements"). EWR made the decision to terminate these ECC contracts because of concerns relating to the bankruptcy of Enron Corp. At the date of termination, the market price of natural gas was substantially lower than the price had been when EWR entered into the contracts, resulting in a net amount due from EWR to ECC of approximately $5,400,000. EWR paid this amount to ECC upon the termination of the contracts, and thereby discharged the liability related to the contracts. The costs related to such termination were reflected in the Company's consolidated statement of operations as adjustments to gas purchased for the fiscal year ended June 30, 2002. At the time the Company terminated the ECC derivative contracts, the Company entered into new gas purchase contracts (the "Future Purchase Agreements") at prices much lower than those provided for under the ECC contracts. The Company recognized income as a result of the mark-to-market accounting treatment of the Future Purchase Agreements, and therefore the termination of the ECC derivative contracts did not have a material impact on the Company's consolidated statement of operations.

The Future Purchase Agreements and the Future Sale Agreements continue to be valued on a mark-to market basis. As of June 30, 2003, these agreements were reflected on the Company's consolidated balance sheet as derivative assets and liabilities at an approximate fair value as follows:

	Assets	Liabilities
Contracts maturing during fiscal year 2004	$ 880,240	$285,610
Contracts maturing during fiscal years 2005 and 2006	1,431,154	236,795
Contracts maturing during fiscal years 2007 and 2008	352,849	221,052
Contracts maturing during fiscal years 2009 and beyond	55,397	37,246
Total	$2,719,640	$780,703

During fiscal year 2003, the Company did not enter into any new contracts that would be accounted for using mark-to-market accounting under SFAS No. 133.

15. SUBSEQUENT EVENTS

Certain assets related to the Company's propane operations were sold effective August 21, 2003. At the date of the sale, the assets had a net book value totaling $1,118,303. In connection with the sale, the Company recognized a gain of $252,030.

16. QUARTERLY INFORMATION (UNAUDITED)

Quarterly results (unaudited) for the years ended June 30, 2003 and 2002 are as follows (in thousands, except per share data):

Fiscal Year 2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 10,363	$ 23,189	$ 28,913	$ 16,681
Operating income (loss)	(1,312)	471	3,345	(1,325)
Net income (loss)	(1,021)	121	1,779	(968)
Basic earnings (loss) per common share	(0.40)	0.05	0.69	(0.37)
Diluted earnings (loss) per share	(0.40)	0.05	0.69	(0.37)
Fiscal Year 2002				
Revenues	$ 15,894	$ 22,689	$ 35,534	$ 16,055
Operating income (loss)	437	1,593	2,238	(947)
Net income (loss)	(433)	623	1,174	37
Basic earnings (loss) per common share	(0.17)	0.25	0.46	0.01
Diluted earnings (loss) per share	(0.17)	0.25	0.46	0.01

During the fourth quarter of fiscal year 2003, the Company had approximately $440,000 of expenses related to obtaining new short-term financing. Also during the fourth quarter of fiscal year 2003, the Company incurred approximately $201,000 in additional legal fees and approximately $168,000 in settlement costs related to the PPLM litigation.

Effective January 1, 2002, the Company changed its policy regarding the classification of net gains from derivative instruments to include those net gains in revenues rather than in non-operating income. Accordingly, net gains from derivative instruments for quarters ended prior to January 1, 2002 have been restated to reflect the classification of net gains from derivative instruments as a component of revenues. The reclassification impacted amounts previously reported for revenues and operating income (loss), but had no impact on net income (loss).

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Comments Welcome

The Company welcomes your questions, comments and requests for financial information. Please direct your communications to:

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Local: 406-791-7500
Fax: 406-791-7560
E-mail: jshogan@ewst.com

Annual Meeting

The Annual Meeting of Company Shareholders will be held October 31, 2003, at 9:00 am, Mountain Standard Time, in the Missouri Room of the Civic Center located at Park Drive and Central Avenue in Great Falls, Montana.

Transfer Agent

Inquiries concerning change of address and other matters relating to ownership of securities should be directed to Shareholder Services at:

Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden Co 80401
Local: 303-262-0600
Toll free: 1-800-962-4284

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