BENTON PUD

2007 ANNUAL REPORT

COMPREHENSIVE ANNUAL

FINANCIAL REPORT

PUBLIC UTILITY DISTRICT NO. 1 OF BENTON COUNTY, WASHINGTON
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007


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BENTON P·U·D

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PUBLIC UTILITY DISTRICT NO.1
OF BENTON COUNTY, WASHINGTON
OF THE FISCAL YEAR
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Prepared by Finance and Business Services
Communications and Governmental Relations

TABLE OF CONTENTS

INTRODUCTORY

FINANCIAL

STATISTICAL


ADVENTURE
ADVENTURE

INTRODUCTORY SECTION

PEOPLE WITH ENERGY WORKING FOR YOU

CORE PURPOSE

To improve the quality of life in our community through leadership, cooperation and stewardship.

MISSION

We contribute high value to our community and customers by providing energy and related services using reliable and efficient delivery systems.

VALUES

EXCELLENCE ... We set high standards, constantly strive to exceed expectations and inspire others.

FORWARD FOCUS ... We anticipate the future, seeking better and more innovative ways to serve our customers.

INTEGRITY ... We are honest, trustworthy, ethical and demonstrate this by our actions.

MUTUAL RESPECT ... We value each individual for who they are, understanding and appreciating their opinion and input.

TEAMWORK ... We work together as an interdependent group of multi-talented people committed to common goals for individual and organizational success.

2007 ANNUAL REPORT FROM THE MANAGER AND COMMISSION

BEHIND THE SCENES

We are pleased to report 2007 was another year of strong financial performance. It also was a year of meeting the demand of growth with construction and customer service projects. We are truly proud of the accomplishments and also proud of our employees behind the scenes who have contributed to achievements such as:

- Decrease in rates,
- A substation built and another expanded,
- Power and broadband reliability outstanding,
- Electronic bill presentment implemented,
- New facility opened in Prosser,
- Broadband growth, and
- Strong financial outlook.

AND MOST IMPORTANT... CUSTOMER SATISFACTION HIGH

Year round, night and day, Benton PUD is working for its customers offering electricity and broadband. Our customers can take for granted their reliable low-cost power because we never do. We embrace new technology to improve customer service, build infrastructure to ensure reliability, add facilities to handle our growing community, and participate in regional issues to protect rates - all to ensure reliable low-cost service today and in the future. What happens behind the scenes year round provides a strong foundation for years to come.

It is the ongoing, behind the scenes work that enables our customers to receive the fifth consecutive rate decrease announced at the end of the year. Benton PUD rates are now below the median and the average of utilities in the Northwest.

At the same time we lowered rates, the District made investments into the system with several major construction projects. The economy of our community and outlying areas continues on a robust track. To handle growth and ensure reliability, a substation was built in the south Kennewick area. In addition, to accommodate the third phase of the Nine Canyon Wind Project, Benton PUD expanded the substation and infrastructure located at the base of the project. Both projects were built safely, efficiently and placed in service on schedule.

Benton PUD celebrated the completion of the new Prosser facility in April. The new facility combined customer service with operations and includes a customer service lobby, offices, conference room as well as a warehouse, garage and pole yard. Improvements for our customers include a drive-through window, easy access to the building, plenty of parking and a public meeting room available to community organizations.

Jim Sanders
General Manager

Broadband experienced growth, too. Benton PUD received HUD grant money from the City of Kennewick for economic development and expansion. The grant was used to expand the fiber backbone in key business areas that are experiencing growth and have potential for future development. Adding high-speed fiber service to the list of assets offered to future developers assists economic growth in our community. At the end of the year, broadband income exceeded expenses and system reliability was outstanding.

Additional customer payment services were implemented. Online payment services were expanded to offer electronic bill presentment in addition to online payment options. Now customers can receive and pay their bill online, saving the District on printing, billing and mailing costs. In six months, Benton PUD experienced a high adoption rate of 8.5 percent exceeding industry standards.

Overall customer satisfaction has improved over the past three years as strides have been made in various areas of customer services. The most recent customer survey, fall quarter, shows customer satisfaction is at 89.3 percent. This is significantly higher than the surveys' historical average of 76.6 percent and is the highest overall satisfaction percentage in the history of the survey.

As this annual report shows, the overall financial outlook remains strong. Simply put, this year Benton PUD lowered rates, reduced bonded debt while maintaining healthy reserves. Investments made this year provide a strong foundation for future years. Benton PUD is prepared for the changing world and growing community and remains committed to the simple idea that public power was founded on – reliable, low-cost power for our customers.

2007 BOARD OF COMMISSIONERS

Jeff Hall
President

Bob Bertsch
Vice President

Lori Kays-Sanders
Secretary

CODE OF ETHICS

As stewards of the public's assets we, the Commission and employees of Benton PUD, have the high duty and responsibility to assure that our actions and deeds are consistent with the trust placed in us. To further these objectives we agree to adhere to legal, moral and professional standards of conduct in the fulfillment of our responsibilities.

This ethical code is designed to uphold our values and enhance the performance of all persons engaged in the business of the District.

PERSONAL AND PROFESSIONAL INTEGRITY

- We abide by approved professional practices and standards and act in accordance with the law.
- We demonstrate our values of mutual respect, forward focus, integrity, teamwork, and excellence.
- We respect the rights, responsibilities and integrity of our customers, colleagues, and public officials with whom we work and associate.

RESPONSIBILITIES TO OUR CUSTOMERS AND COMMUNITY

- We fully dedicate our skills and energy to provide value to our customers.
- We abide by the laws, regulations, and governmental standards to protect the public and the environment.

RESPONSIBILITIES AS EMPLOYEES

- We promote equal employment opportunities and oppose any discrimination, harassment, and other unlawful practices.
- We value the contributions of every employee and treat each individual with respect.
- We maintain a work environment free from pressures that would encourage departure from ethical behavior or acceptable standards of conduct.
- We encourage good faith questioning of our practices and provide a structure within which we report unethical behavior or unacceptable standards of conduct free from retaliation.
- We maintain a work environment that enhances the safety of our employees and customers.
- We maintain confidentiality when required and limit the disclosure to lawful or generally accepted practices.

BUSINESS RESPONSIBILITIES

- We openly provide information to our constituents, allowing them to measure the effectiveness of our performance.
- We ensure financial reports and records are an accurate reflection of the transactions of the District in accordance with generally accepted standards.
- We exercise prudence and integrity in the management of funds in our custody.
- We adhere to all laws applicable to public agencies and exercise good stewardship of public assets.
- We are responsive to public information requests and our Commission meetings are open to the public with opportunities for input.

CONFLICT OF INTEREST

- We refrain from engaging in any outside matters of financial or personal interest incompatible with the impartial, objective, and effective performance of our duties.
- We do not seek or accept favors or items resulting in personal gain, which would influence or appear to influence the conduct of our official duties.
- We do not use District property or resources for personal or political gain.

FAST FACTS

Number Customers: 45,944

Residential Electric Rate:
$0.0602 per kWh*
$8.80 monthly customer charge (single phase)

Average Annual Residential Customer Use: 16,972 kWh

Annual MWh Sales: 2,378,612 (includes sales for resale)

Annual MWh Sales: 1,607,265 (excludes sales for resale)
Residential 40%
General 31%
Large Industrial 3%
Irrigation 25%
Other 1%

System Average Load:
Wholesale - 283.6 aMW
Load at BPA meters - 190.2 aMW
Retail Sales - 183.5 aMW
Sales for Resale - 88.1 aMW

Coincidental System Peak Load:
Summer – 383 MW – July 2007
Winter – 292 MW – Jan 2007

Record System Peaks:
Summer – 387 MW – July 1999
Winter – 392 MW – Feb 1996

Service Territory: 939 square miles in Benton County

Miles of Lines:
89 miles of 115 kV transmission lines
1,469 miles of distribution lines

Substations:
37 Total – 20 of which are on the Columbia River serving large farms
Substation Capacity - 653 MVA

Transformers: 17,050 total

Line Transformer Capacity (MVA): 1,185

Meters: 45,526 total

Employees: 157 Total
Administrative – 86
Operations – 63
Prosser – 8
Average Employee Tenure - 13 years

(as of December 31, 2007)
*Rate reduced to $0.0578 effective January 1, 2008.

Certificate of Achievement for Excellence in Financial Reporting

Presented to

Public Utility District No. 1 of Benton County Washington

For its Comprehensive Annual Financial Report for the Fiscal Year Ended December 31, 2006

A Certificate of Achievement for Excellence in Financial Reporting is presented by the Government Finance Officers Association of the United States and Canada to government units and public employee retirement systems whose comprehensive annual financial reports (CAFRs) achieve the highest standards in government accounting and financial reporting.

President

Executive Director

LETTER OF TRANSMITTAL

April 28, 2008

To the Board of Commissioners and Customers

Public Utility District No. 1 of Benton County, Washington

The Comprehensive Annual Financial Report (CAFR) of the Benton County Public Utility District (District) for the year ended December 31, 2007 is hereby submitted. The report is designed to assess the District's financial condition, educate readers about District services, examine current challenges facing the District, and fulfill legal reporting requirements.

State law requires that every local government submit financial reports to the State Auditor within 150 days after the close of each fiscal year. The District's bond covenants require financial information be provided to each nationally recognized municipal securities information repository in accordance with Section (b)(5) of Securities and Exchange Commission Rule 15c2-12 under the Securities and Exchange Act of 1934. This report is published to fulfill both requirements for the fiscal year ended December 31, 2007.

Management assumes full responsibility for the completeness and reliability of the information contained in this report, based upon a comprehensive framework of internal control that is established for this purpose. Because the cost of internal control should not exceed anticipated benefits, the objective is to provide reasonable, rather than absolute, assurance that the financial statements are free of any material misstatements.

The Washington State Auditor's Office has issued an unqualified ("clean") opinion on the District's financial statements for the years ended December 31, 2007 and 2006. The independent auditor's report is located at the front of the financial section of this report.

Management's discussion and analysis (MD&A) immediately follows the independent auditor's report and provides a narrative introduction, overview, and analysis of the basic financial statements. MD&A complement this transmittal letter and should be read in conjunction with it.

Profile of the District

The District is a municipal corporation of the State of Washington established in 1934 for the purpose of engaging in the purchase, generation, transmission, distribution and sale of electric energy. Additionally, the District is authorized under state law to provide wholesale telecommunication services. The District is governed by an elected three-member board and maintains its administrative offices in the City of Kennewick.

The District is a statutory preference customer of the Bonneville Power Administration and purchases most of its power from Bonneville. The District's remaining power supply requirements are supplied by various contract purchases (see Note 10). The District's contracted power supply is projected to be surplus for most months of the year. The District purchases and sells power within the wholesale markets to balance resources to loads.

The District's properties include 37 substations, approximately 89 miles of 115kV transmission line, 1,469 miles of distribution lines, and other buildings, equipment, stores and related facilities. The District owned and operated a 27 MW natural gas fired simple-cycle combustion turbine (Finley CT) that was constructed during 2001 and sold during 2007 (see Note 16).

The District is located in southeastern Washington, encompassing approximately 939 square miles of Benton County and includes the incorporated cities of Kennewick, Benton City, and Prosser (the Benton County seat). The District's largest city, Kennewick, as well as the City of Richland in Benton County (outside of the District), and the City of Pasco in adjacent Franklin County, make up what is known as the Tri-Cities.

The District records financial transactions within a single proprietary fund. The District has no governmental funds with legally adopted budgets that carry the force of law. Accordingly, the District's budget is not contained within this report.

The District adopts an annual budget for purposes of planning and management control. The budget process involves preparation of a proposed operating and capital budget by District staff for the ensuing year that is presented to the Board of Commissioners. During workshop sessions that are open to the public, the staff and Board review and revise the proposed budget. A public hearing is conducted to obtain ratepayer comments. The budget is approved by the Board and becomes the basis for operations for the next calendar year.

Local Economy

Benton County's economy is based on four major industries: agriculture, food processing, manufacturing, and nuclear-related technology. Farmland comprises the majority of Benton County's land area. Many corporate farms are located in the District encompassing over 100,000 acres of irrigated and dry land crops. Irrigation has led to increased production of a wide variety of crops including potatoes, apples, corn, cherries, wine grapes, hops, wheat, onions, concord grapes, hay, and hard and soft fruits. These crops are shipped to both domestic and export markets.

With the strength of farm production throughout the County, food processing has become a major factor in the Benton County economy. Production and processing of wine grapes is of significant importance to the County's economy. Other food processing industries include frozen potato products, frozen peas and cut corn. Fruit packing and cold storage also provide significant employment.

Manufacturing activities within the County include a large fertilizer and agricultural products plant which distributes its products throughout the Northwest and California. The Tri-Cities is home to the world's largest crane manufacturer, as well as a manufacturer of zirconium and titanium alloy tubing used for the aerospace industry (hydraulic landing gear), the medical industry (human bone surgery), golf clubs, bicycles, ski poles and tennis rackets. Other industries in the region include paper and cardboard container plants and production of nuclear fuel pellets and rods.

The Hanford Reservation, encompassing 560 square miles within Benton County, has evolved into one of the largest nuclear industrial centers in the United States. Today the focus is on energy research, environmental cleanup and related technology. The major employers in Benton County are the Department of Energy and its contractors associated with the Hanford Project.

The Tri-Cities economy remains strong and is one of the fastest growing in the state. The area gained 5,100 nonfarm jobs during the year with growth in food processing, retail trade, business and professional services, leisure and hospitality, and government. The Tri-Cities has become a major retail hub for communities throughout southeastern Washington and northeastern Oregon leading to continued growth in the retail service industry. Tourism and a growing population helped the Tri-Cities outpace the state in retail sales growth. 2007 was also another good year for real estate sales in the area which hasn't experienced the volatility of housing prices seen in areas on the west side of the state and elsewhere in the country.

Long-Term Financial Planning

The Financial Planning Committee, consisting of the General Manager and Directors, meets quarterly to review an updated five-year financial forecast. The forecast includes both operating and capital activity with a focus on reserve levels, debt service coverage levels, and potential rate action. The forecast is then reviewed with the Board of Commissioners on a quarterly basis.

The District has adopted a comprehensive set of financial policies for purposes of managing the District's finances. The policies cover such issues as liquidity, debt service coverage, debt financing, retail rates, power supply risk, credit risk, investment policies and practices, insurance, integrated planning, budgetary and procurement controls, and financial reporting. The financial policies call for developing financial plans to maintain cash reserves sufficient to provide funding for 90 days of non-power expenses and funding for unanticipated power costs based on 10% of gross power expenses for the planned year's budget, a minimum debt service coverage of 2.0 times annual debt service including capital contributions and 1.75 times annual debt service excluding capital contributions, and a long-term goal of financing no more than 40% of gross non-generation capital improvements from bond proceeds over a rolling ten-year period. The Commission periodically reviews these policies.

Cash Management and Investments

The District invests its available funds in a manner that minimizes the District's risk of financial loss, maintains necessary liquidity, and achieves maximum yield consistent with the foregoing criteria. State law and the District policy permit investing in direct obligations of the U.S. government and its agencies, the State Treasurer's Local Government Investment Pool, certificates of deposit with banks that are qualified public depositories of the State of Washington, securities backed by the full faith and credit of the U.S. Government, or other investments allowed by State law. Investments are generally made so that securities can be held to maturity.

Risk Management

The District maintains a comprehensive insurance program that includes liability and standard insurance coverage for personal property, automobile, public officials and equipment, except unemployment insurance for which the District has elected to become self-insured. The District is a member of the Public Utility Risk Management Services Self-Insurance Fund, which is currently composed of 19 members. Additional information on the District's risk management program is included in Note 11 of the notes to the financial statements.

As an integral part of its overall risk management program, the District has instituted an Energy Risk Management Policy designed to manage the price, volume, and credit risk associated with its power supply activities. Primary operational risk oversight of power trading operations is provided by a Risk Management Committee.

Awards and Acknowledgments

The Government Finance Officers Association of the United States and Canada (GFOA) awarded a Certificate of Achievement for Excellence in Financial Reporting to the District for its comprehensive annual financial report for the fiscal year ended December 31, 2006. This was the fifth consecutive year that the District has achieved this prestigious award. In order to be awarded a Certificate of Achievement, a government must publish an easily readable and efficiently organized comprehensive annual financial report. This report must satisfy both generally accepted accounting principles and applicable legal requirements.

A Certificate of Achievement is valid for a period of one year only. We believe that our current comprehensive annual financial report continues to meet the Certificate of Achievement Program's requirements and we are submitting it to the GFOA to determine its eligibility for another certificate.

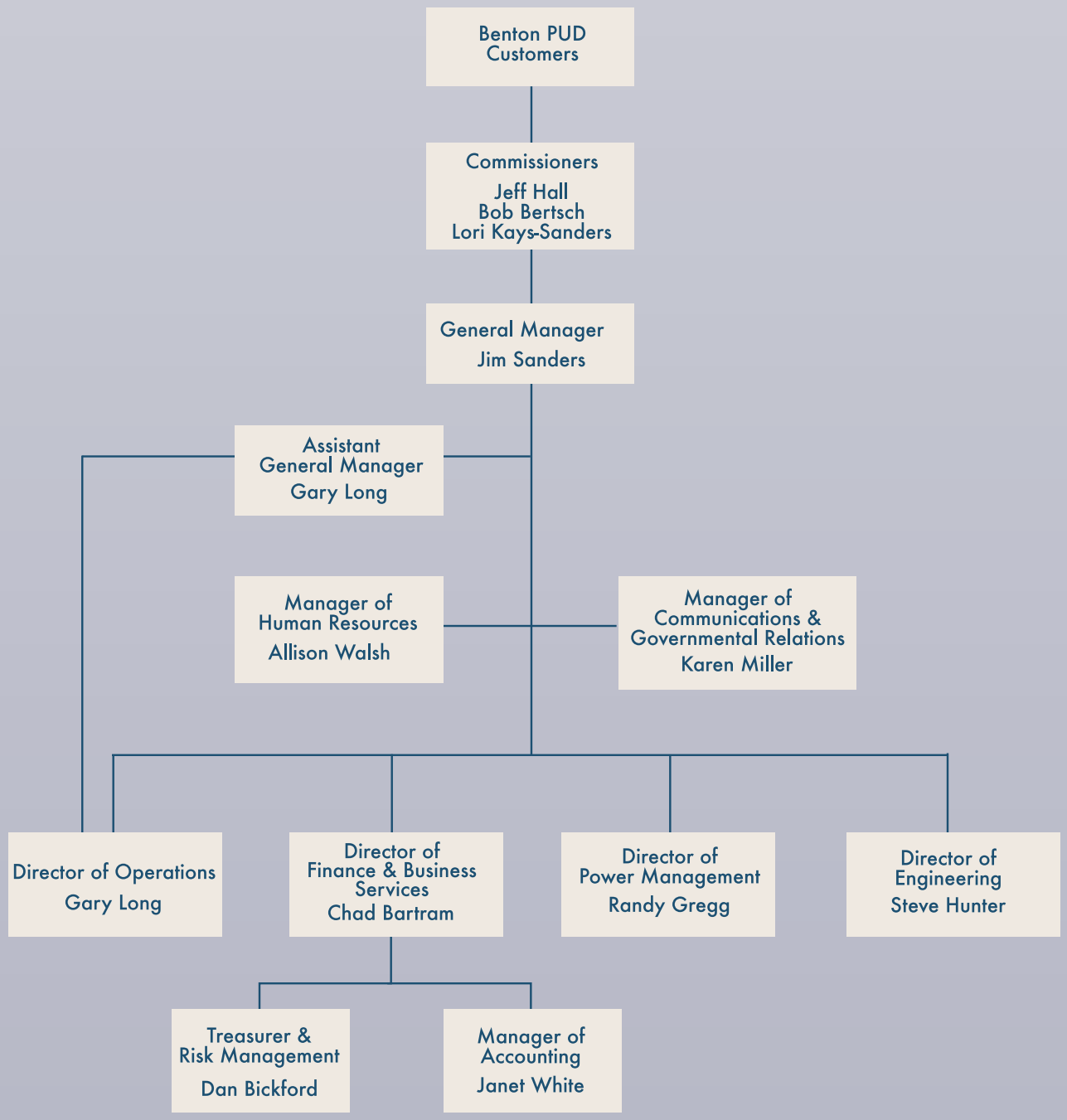
Preparation of the Comprehensive Annual Financial Report was made possible by the dedicated service of the entire staff of the Finance and Business Services and the Communications and Governmental Relations Departments. We wish to express our appreciation to these staff members for their contributions to the development of this report. Further appreciation is extended to the Board of Commissioners for their leadership and support in planning and conducting the financial operations of the District in a responsible and enterprising manner.

Respectfully submitted

James W. Sanders
General Manager

Chad B. Bartram
Director of Finance and Business Services

ORGANIZATIONAL CHART



FINANCIAL SECTION

INDEPENDENT AUDITOR'S REPORT

Washington State Auditor
Brian Sonntag

INDEPENDENT AUDITOR'S REPORT

April 18, 2008

Board of Commissioners
Public Utility District No. 1 of Benton County
Kennewick, Washington

We have audited the accompanying basic financial statements of the Public Utility District No. 1 of Benton County, Washington, as of and for the years ended December 31, 2007 and 2006, as listed in the table of contents. These financial statements are the responsibility of the District's management. Our responsibility is to express an opinion on these financial statements 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, the financial statements referred to above present fairly, in all material respects, the financial position of the Public Utility District No. 1 of Benton County, Washington, as of December 31, 2007 and 2006, and the changes in financial position and, where applicable, cash flows thereof for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The management's discussion and analysis is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

The information identified in the table of contents as the Introductory and Statistical Sections is presented for purposes of additional analysis and is not a required part of the basic financial statements of the District. Such information has not been subjected to the auditing procedures applied in the audit of the basic financial statements and, accordingly, we express no opinion on it.

Sincerely,

BRIAN SONNTAG, CGFM
STATE AUDITOR

Management's Discussion and Analysis

This section provides an overview and analysis of key data presented in the basic financial statements for the years ended December 31, 2007 and 2006, with additional comparative data for 2005. Information within this section should be used in conjunction with the basic financial statements and accompanying notes.

Overview of the Financial Statements

Public Utility District No. 1 of Benton County (District) accounts for its financial activities within a single proprietary fund titled the Electric System. The Electric System is used to account for the purchase, generation, transmission, distribution and sale of electric energy, as well as the sale of wholesale telecommunication services.

In accordance with requirements set forth by the Governmental Accounting Standards Board, the District's financial statements employ the accrual basis of accounting in recognizing increases and decreases in economic resources. Accrual accounting recognizes all revenues and expenses during the year, regardless of when cash is received or paid.

The basic financial statements, presented on a comparative format for the years ended December 31, 2007 and 2006, are comprised of:

- Balance Sheets: The District presents its statement of position using the balance sheet format. The Balance Sheets reflect the assets, liabilities and net assets (equity) of the District at year-end. The net assets section of the Balance Sheets is separated into three categories: net assets invested in capital assets, net of related debt; restricted net assets; and unrestricted net assets. The District had no restricted net assets at December 31, 2007 or 2006.

- Statements of Revenues, Expenses, and Changes in Net Assets: These statements reflect the transactions and events that have increased or decreased the District's total economic resources during the period. Revenues are presented net of allowances and are summarized by major source. Revenues and expenses are classified as operating or nonoperating based on the nature of the transaction.

- Statements of Cash Flows: The Statements of Cash Flows reflect the sources and uses of cash separated into four categories of activities: operating, noncapital financing, capital and related financing, and investing. The District does not include cash equivalents within its definition of cash.

The notes to the financial statements, presented at the end of the basic financial statements, are considered an integral part of the District's presentation of financial position, results of operations, and changes in cash flows.

Condensed Comparative Financial Information

Provided below is a three year comparison of key financial information:

Balance Sheet *(in thousands)*

	2007	2006	Increase (Decrease) 2007-2006	% Change 2007-2006	2005
Current & Other Assets	$59,576	$56,795	$2,781	5%	$66,863
Capital Assets	109,916	119,839	(9,923)	-8%	118,503
Total Assets	$169,492	$176,634	($7,142)	-4%	$185,366
Other Liabilities	$15,685	$25,450	($9,765)	-38%	$25,393
Long-Term Liabilities	59,199	60,611	(1,412)	-2%	77,412
Total Liabilities	$74,884	$86,061	($11,177)	-13%	$102,805
Invested in Capital Assets, *Net of Related Debt*	$53,979	$60,652	($6,673)	-11%	$47,804
Unrestricted	40,629	29,921	10,708	36%	34,757
Total Net Assets	$94,608	$90,573	$4,035	4%	$82,561

Statement of Revenues, Expenses, and Changes in Net Assets *(in thousands)*

	2007	2006	Increase (Decrease) 2007-2006	% Change 2007-2006	2005
Operating Revenues					
Retail Energy Sales	$92,388	$95,550	($3,162)	-3%	$101,112
Sales for Resale	43,202	46,842	(3,641)	-8%	39,589
Other	2,532	2,588	(56)	-2%	1,951
Non-operating Revenues					
Interest Income	1,676	1,961	(285)	-15%	1,123
Other Income	87	-	87	-	552
Total Revenues	139,885	146,941	(7,056)	-5%	144,327
Operating Expenses					
Power Supply	92,885	98,556	(5,671)	-6%	102,442
Operations and Maintenance	16,231	16,826	(596)	-4%	15,647
Taxes/Depreciation/Expenses	19,969	20,253	(284)	-1%	20,591
Non-operating Expenses					
Other Expense	-	9	(9)	-100%	419
Interest Expense	2,533	3,310	(776)	-23%	3,389
Debt Discount & Expense Amortization	22	553	(532)	-96%	209
Loss in Joint Venture	555	912	(358)	-39%	449
Total Expenses	132,195	140,420	(8,225)	-6%	143,146
Income (Loss) Before Contributions	7,690	6,521	1,169	18%	1,181
Capital Contributions	6,100	1,491	4,609	309%	1,951
Extraordinary Item	(9,755)	-	(9,755)	-	-
Change in Net Assets	4,035	8,012	(3,977)	-50%	3,132
Beginning Net Assets	90,573	82,561	8,012	10%	79,429
Ending Net Assets	$94,608	$90,573	$4,035	4%	$82,561

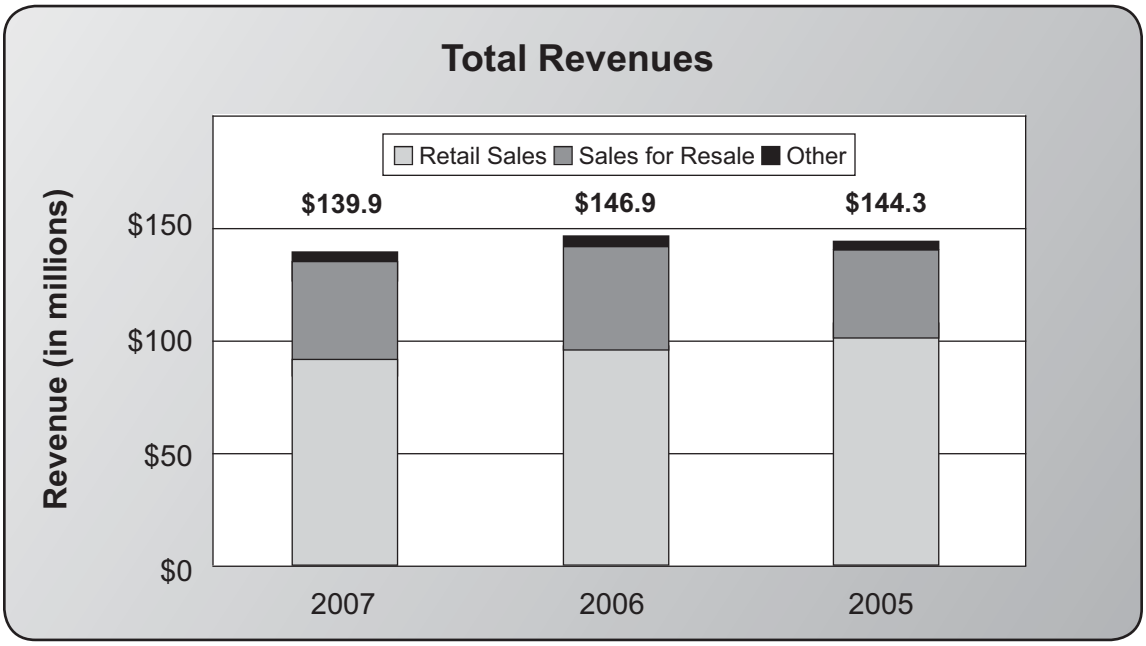
Financial Analysis

During 2007, the District's overall financial position and results of operation improved. The District's net assets increased by $4.0 million compared to an increase in net assets of $8.0 million in 2006. Provided below is a year-over-year analysis of the change in net assets by major component of income, with a primary focus on changes between 2007 and 2006.

Operating Revenues

2006 to 2007:
Revenues from sales to retail customers (Retail Energy Sales) in 2007 decreased $3.2 million (3%) from 2006. This was primarily a result of a 6% average retail rate reduction effective January 1, 2007 coupled with a 4% average retail rate reduction effective September 1, 2006. The District experienced a 3% increase in kWh sold to customers in 2007 compared to 2006, partially offsetting the rate reduction.

Revenues from wholesale energy and natural gas sales (Sales for Resale) decreased by $3.6 million (8%) primarily as a result of less power available to sell due to fewer kWh received from BPA and an increase in customer load.



2005 to 2006:
Retail Energy Sales in 2006 decreased $5.6 million from 2005. This was primarily a result of a 3% average retail rate reduction effective November 1, 2005 followed by a 4% average retail rate reduction effective September 1, 2006, as well as a 3% decrease in kWh sold to customers in 2006 compared to 2005.

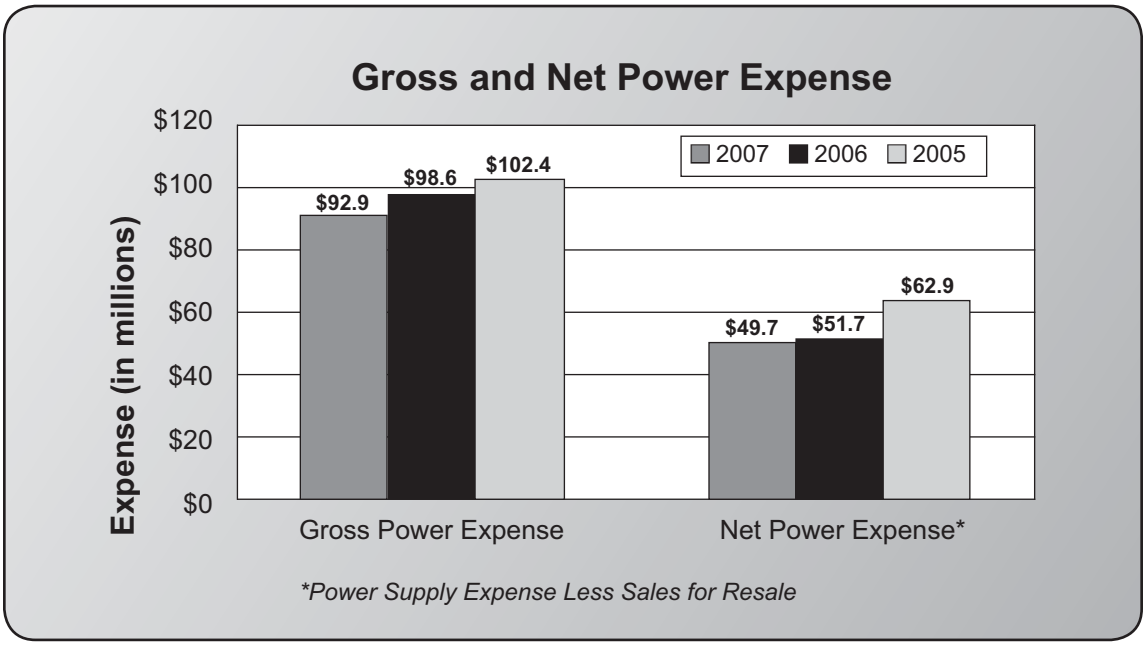
Sales for Resale increased by $7.3 million (18%) primarily as a result of a 12% increase in kWh generated over 2005 from the District's share of Slice output (see Note 10) contributing to a greater level of excess power.

Operating Expenses

2006 to 2007:
Gross power supply expense decreased by $5.7 million (6%), primarily as a result of a decrease in BPA rates and a decrease of $2.9 million in the Bonneville Power Administration (BPA) net Slice True-up and prior year settlements from 2007 to 2006, as well as a reduction in both Retail Energy Sales and Sales for Resale. Net power expense (power supply expense less sales for resale) decreased by $2.0 million (4%) as a result of the decreased BPA rates and True-up expense. The District uses net power expense as a means to measure overall financial performance related to power supply management.

Operations and maintenance expense decreased by $0.6 million (4%). The District charges internal labor to operations and maintenance activities and capital projects. In 2007, there was an increase in the amount of internal labor required for capital projects resulting in less work performed on operations and maintenance activities. Capitalized labor increased $0.4 million from 2007 to 2006. In addition, charges related to assisting other utilities during power outages caused by storms decreased by $0.2 million from 2007 to 2006. Those utilities were subsequently billed and revenues were recorded for those charges.

Taxes assessed by state and municipal governments decreased by $0.2 million (2%) primarily as a result of a decrease in Retail Energy Sales. Depreciation and amortization decreased by $0.1 million (1%) as a result of decreased plant and equipment in-service due to the sale of the Finley CT Plant in May 2007.



2005 to 2006:
Gross power supply expense decreased by $3.9 million (4%), primarily as a result of $2.0 million accrued for the 2002 Slice True-Up settlement, and $1.8 million accrued from BPA under Exhibit N. Net power expense decreased by $11.1 million (18%) as a result of higher Sales for Resale.

Operations and maintenance expense increased by $1.2 million (8%). In 2006, there was a decrease in the amount of internal labor required for capital projects resulting in more work performed on operations and maintenance activities. The increase in operations and maintenance expense was primarily a result of a 10% increase in the amount of labor charged to operations and maintenance activities, as well as wage and benefit escalation. Operations and maintenance also included $0.3 million in charges related to assisting other utilities during power outages caused by storms (subsequently billed).

Taxes assessed by state and municipal governments decreased by $0.5 million (5%) primarily as a result of a decrease in Retail Energy Sales. Depreciation and amortization increased by $0.2 million (2%) as a result of increased plant and equipment in-service.

Other Income & Expense

During 2007, interest income decreased by $0.3 million due to lower invested balances due to a cash defeasance of $7.9 million of the District's outstanding revenue bonds in December 2006. The average rate of the Washington State Treasurer's Local Government Investment Pool (LGIP) increased from 4.9% in 2006 to 5.1% in 2007. Loss in Joint Ventures/Special Assessments decreased $0.4 million primarily due to an assessment in 2006 paid to the Washington Public Utility District Association, of which the District is a member, to provide funding for a new building. Debt Discount & Expense Amortization decreased by $0.5 million primarily due to the bond defeasance in 2006.

The District sold its Finley CT plant in May 2007 and an Extraordinary Loss of $9.8 million was recorded (See Note 16).

From 2005 to 2006, interest income increased by $0.8 million due to higher invested balances and an increase in interest rates. The average rate of the LGIP increased from 3.2% in 2005 to 4.9% in 2006. Loss in Joint Ventures/Special Assessments increased $0.5 million primarily due to a $0.4 million building assessment paid to the Washington Public Utility District Association. Debt Discount & Expense Amortization increased by $0.3 million primarily due to a loss on the defeasance of Electric Revenue Refunding Bonds, Series 1997.

Capital Contributions

During 2007, capital contributions increased $4.6 million (309%) primarily attributable to $4.3 million billed to Energy Northwest for the completion of Phase III of the Nine Canyon Wind Farm.

From 2005 to 2006, capital contributions decreased $0.5 million (24%) primarily as a result of an increase in the deferral of revenues for payments received from customers for projects not completed at year-end.

Summary of Financial Position

The overall financial position of the District improved during 2007 with an increase in net assets of $4.0 million. The District sets retail rates based on conservative assumptions. Through prudent planning and cost control, the District was able to reduce rates in both 2006 and 2007 while simultaneously reducing outstanding debt and maintaining strong cash and investment reserves. In 2007, although lower than planned power production from the Federal Columbia River Power System, from which the District receives a share through its Slice Contract with BPA, resulted in lower Sales for Resale, the Slice Contract True-Up and Exhibit N contributed to lower power costs.

District financial policies require that financial plans be developed to maintain minimum end-of-year cash and investment balances contained within unrestricted accounts sufficient to: 1) provide funding for 90 days of non-power expenses based on the planned year's operating budget, and 2) provide funding for unanticipated power costs based on 10% of gross power expenses for the planned year's budget. The District's unrestricted cash and investment balances totaled $33.5 million, $26.3 million, and $33.7 million at December 31, 2007, 2006 and 2005, respectively. Actual balances exceeded the minimum required level per District financial policies for each year.

In accordance with District financial policies and covenants established within the District's bond resolutions, the District is required to maintain and collect rates and charges sufficient to provide Net Revenues (defined as net income less depreciation, amortization, and interest expense) in each fiscal year in an amount at least equal to 1.25 times the Annual Debt Service. For the years ended 2007, 2006 and 2005, the District's debt service coverage was 4.12, 2.97, and 3.17, respectively. Debt service coverage for 2007 was 3.80 prior to a $2.2 million transfer from the Rate Stabilization account and was 3.49 in 2005 prior to a $1.5 million transfer to the Rate Stabilization account.

Capital Asset and Long-Term Debt Activity

During 2007, gross capital additions excluding construction work-in-progress totaled $15.6 million. Capital contributions associated with these additions totaled $6.1 million. Major capital additions include $3.1 million for the construction of a new Prosser office, $2.1 million for Phase III of the Nine Canyon Wind Farm, and $1.8 million for the completion of a new substation. Other capital additions were associated with improvements to existing distribution infrastructure, a 1.6% growth in customers served by the District, and internal capital expenditures to meet District needs. The District reduced capital assets by $19.3 million due to the sale of the Finley CT. Construction work-in-progress totaled $4.0 million at year-end, a net decrease of $1.3 million over 2006.

During 2006, gross capital additions excluding construction work-in-progress totaled $7.5 million. Capital contributions associated with these additions totaled $1.5 million. Capital additions were associated with improvements to existing distribution infrastructure, a 1% growth in customers served by the District, and internal capital expenditures to meet District needs. Construction work-in-progress totaled $5.3 million at year-end, a net increase of $3.9 million over 2005.

There were no long-term debt issuances in 2007 or 2006. In December 2006, the District used reserves to defease $7.9 million of certain Electric Revenue Refunding Bonds, Series 1997.

During 2007, the District sought updates to its existing credit ratings with Moody's, Standard & Poor's (S&P) and Fitch Ratings. The District's rating from Moody's was upgraded from A3, stable outlook to A2 stable. The District's rating outlook from S&P was upgraded from A- positive to A stable. The District's rating from Fitch was upgraded from A- stable to A stable.

Debt service payments totaled $7.0 million in 2007, $7.4 million in 2006, and $5.6 million in 2005 (not reduced for capitalized interest).

Additional information about the District's capital assets and long-term debt is presented in Notes 2 and 6.

Other Significant Matters

As a result of ongoing conservative planning, effective hedging of power supply risk, and strong financial reserves, the District was able to implement its fifth consecutive rate decrease, a 4% average retail rate reduction effective January 1, 2008, while maintaining a strong financial position.

BALANCE SHEET

As of December 31, 2007 and 2006

ASSETS	2007	2006
CURRENT ASSETS		
Cash & Working Funds	$5,443,077	$2,808,366
Investments (Note 3)	28,022,638	23,512,114
Restricted Bond Fund - Principal & Interest	855,013	1,159,617
Restricted Construction Account	198,013	-
Note Receivable, Current Portion	650,000	650,000
Accounts Receivable, net	8,698,230	9,702,114
Accrued Unbilled Revenues	3,195,000	3,224,000
Inventory - Materials & Supplies	2,644,858	3,681,449
Prepaid Expenses	61,311	38,135
Accrued Interest Receivable	-	16,313
Accrued Electric Revenue	3,040,716	2,128,100
Total Current Assets	**52,808,856**	**46,920,208**
NONCURRENT ASSETS		
Restricted Bond Reserve	-	812,537
Note Receivable (Note 1)	650,000	1,300,000
Other Receivables (Note 1)	-	1,828,099
Ownership Interest - GHFB/PRM (Note 12)	66,514	189,500
Deferred Charges (Note 4)	6,050,076	5,744,640
Subtotal Noncurrent Assets	6,766,590	9,874,776
Utility Plant (Note 2)		
Land and Intangible Plant	3,016,319	2,710,660
Electric Plant in Service	207,174,625	212,486,859
Construction Work in Progress	4,028,943	5,345,157
Less: Accumulated Depreciation	(104,303,619)	(100,703,710)
Net Utility Plant	109,916,268	119,838,966
Total Noncurrent Assets	**116,682,858**	**129,713,742**
TOTAL ASSETS	**$169,491,714**	**$176,633,950**
NET ASSETS AND LIABILITIES		
CURRENT LIABILITIES		
Warrants Outstanding	$238,355	$1,124,266
Accounts Payable	6,459,920	13,463,427
Customer Deposits	1,082,397	1,138,020
Accrued Taxes Payable	2,596,374	2,749,069
Other Accrued Liabilities	2,439,854	2,407,805
Accrued Interest Payable	452,513	521,799
Revenue Bonds, Current Portion	2,415,000	4,045,000
Total Current Liabilities	**15,684,413**	**25,449,386**
NONCURRENT LIABILITIES		
Revenue Bonds (Note 6)	53,395,000	55,810,000
Unamortized Premium & Discount & Loss on Defeasance	727,593	782,504
Deferred Credits & Other Liabilities (Note 4)	5,076,520	4,018,630
Total Noncurrent Liabilities	**59,199,113**	**60,611,134**
Total Liabilities	**74,883,526**	**86,060,520**
NET ASSETS		
Invested in Capital Assets, Net of Related Debt	53,979,188	60,651,818
Unrestricted	40,629,000	29,921,612
Total Net Assets	**94,608,188**	**90,573,430**
TOTAL NET ASSETS AND LIABILITIES	**$169,491,714**	**$176,633,950**

The accompanying notes are an integral part of the financial statements.

STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET ASSETS

For the years ended December 31, 2007 and 2006

	2007	2006
OPERATING REVENUES		
Sales of Electric Energy - Retail	$92,388,210	$95,549,937
Energy Sales for Resale	42,922,151	46,585,675
Transmission of Power for Others	279,687	256,781
Broadband Revenue	787,589	461,276
Other Revenue	1,745,868	2,126,721
Total Operating Revenues	**138,123,505**	**144,980,390**
OPERATING EXPENSES		
Power Supply & Generation	92,885,438	98,556,099
Transmission Operation & Maintenance	24,376	53,432
Distribution Operation & Maintenance	6,254,249	6,883,927
Broadband Expense	692,390	582,999
Customer Accounting, Collection and Information	3,854,630	4,062,499
Administrative & General Expense	5,405,180	5,243,565
Taxes	9,884,911	10,096,882
Depreciation & Amortization	10,084,084	10,156,431
Total Operating Expenses	**129,085,258**	**135,635,834**
OPERATING INCOME (LOSS)	**9,038,247**	**9,344,556**
NONOPERATING REVENUES & EXPENSES		
Interest Income	1,675,710	1,960,710
Other Income	86,500	-
Other Expense	-	(9,359)
Interest Expense	(2,533,496)	(3,309,699)
Debt Discount & Expense Amortization	(21,519)	(553,124)
Gain (Loss) in Joint Ventures	(555,095)	(912,323)
Total Nonoperating Revenues & Expenses	**(1,347,900)**	**(2,823,795)**
INCOME (LOSS) BEFORE CONTRIBUTIONS & EXTRAORDINARY ITEMS	**7,690,347**	**6,520,761**
CAPITAL CONTRIBUTIONS	**6,099,714**	**1,491,180**
EXTRAORDINARY ITEMS	**(9,755,303)**	**-**
CHANGE IN NET ASSETS	**4,034,758**	**8,011,941**
TOTAL NET ASSETS, BEGINNING OF YEAR	**90,573,430**	**82,561,489**
TOTAL NET ASSETS, END OF YEAR	**$94,608,188**	**$90,573,430**

The accompanying notes are an integral part of the financial statements.

STATEMENT OF CASH FLOWS

For the years ended December 31, 2007 and 2006

	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash Received from Customers and Counterparties	$139,156,390	$142,431,749
Cash Paid to Suppliers and Counterparties	(104,076,852)	(105,371,090)
Cash Paid to Employees for Services	(10,937,897)	(11,079,876)
Taxes Paid	(10,037,606)	(10,200,241)
Net Cash Provided by Operating Activities	**14,104,035**	**15,780,542**
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES		
Grant Revenue	1,500	-
Washington Consumer Energy Fund Expense	-	(9,359)
Net Cash Provided (Used) by Noncapital Financing Activities	**1,500**	**(9,359)**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Acquisition of Capital Assets	(14,347,091)	(10,915,864)
Bond Defeasance	-	(7,890,000)
Bond Principal Paid	(3,773,333)	(3,903,333)
Bond Interest Paid	(2,879,766)	(3,513,937)
Conservation Incentives Paid	-	(554,065)
Broadband Capital Grant Revenue	85,000	-
Capital Contributions	6,099,714	1,491,180
Proceeds from Sale of Assets	5,980,737	713,421
Net Cash Used by Capital and Related Financing Activities	**(8,834,739)**	**(24,572,598)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest Income	1,692,023	2,257,129
Proceeds from Sale of Investments	49,664,074	56,162,529
Purchase of Investments	(53,560,074)	(48,350,406)
Assessments to Joint Venture	(432,108)	(824,496)
Net Cash Provided (Used) by Investing Activities	**(2,636,085)**	**9,244,756**
NET INCREASE (DECREASE) IN CASH	**2,634,711**	**443,341**
CASH BALANCE, BEGINNING OF YEAR	**2,808,366**	**2,365,025**
CASH BALANCE, END OF YEAR	**$5,443,077**	**$2,808,366**
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating Income	$9,038,247	$9,344,556
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation & Amortization	10,084,084	10,156,431
Unbilled Revenues	29,000	404,000
Decrease (Increase) in Accounts Receivable	2,831,983	(4,780,740)
Decrease (Increase) in Inventories	1,036,591	(188,217)
Decrease (Increase) in Prepaid Expenses	(23,176)	49,818
Decrease (Increase) in Accrued Electric Revenue	(912,616)	928,350
Decrease (Increase) in Miscellaneous Assets	(152,550)	(29,560)
Decrease (Increase) in Deferred Purchased Power Costs	673,145	1,118,874
Decrease (Increase) in Deferred Regulatory Charges	(1,492,875)	3,934,428
Increase (Decrease) in Deferred Regulatory Credits	(469,985)	(1,253,124)
Increase (Decrease) in Warrants Outstanding	(885,911)	667,012
Increase (Decrease) in Accounts Payable	(7,003,508)	(880,606)
Increase (Decrease) in Accrued Taxes Payable	(152,695)	(103,359)
Increase (Decrease) in Customer Deposits	(55,623)	202,361
Increase (Decrease) in Other Current Liabilities	32,049	68,435
Increase (Decrease) in Deferred Credits	1,527,875	(3,858,117)
Net Cash Provided by Operating Activities	**$14,104,035**	**$15,780,542**

The accompanying notes are an integral part of the financial statements.

NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2007 & 2006

NOTE 1 - SUMMARY OF OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Public Utility District No. 1 of Benton County, Washington (the District) is a municipal corporation of the State of Washington established in 1934 for the purpose of engaging in the purchase, generation, transmission, distribution and sale of electric energy. Additionally, the District is authorized under state law to provide wholesale telecommunication services. The District owned and operated a 27 MW natural gas fired simple-cycle combustion turbine (Finley CT) that was constructed during 2001 and sold during 2007 (see Note 16).

The District serves Benton County exclusive of most of the City of Richland, the U.S. Department of Energy's operations on the Hanford Reservation, the City of West Richland and those rural areas of the County which are served by the Benton Rural Electric Association. Cities in the District's service area include Kennewick, population 62,520, Prosser, population 5,075, and Benton City, population 2,860. The District maintains its administrative offices in the City of Kennewick. The District is governed by an elected three-member board.

The District's service area comprises approximately 939 square miles of Benton County. The District's properties include 37 substations, approximately 89 miles of 115kV transmission line, 1,469 miles of distribution lines, and other buildings, equipment, stores and related facilities.

As required by generally accepted accounting principles, management has considered all potential component units in defining the reporting entity and has no component units.

The accounting policies of the District conform to generally accepted accounting principles applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. The District has applied all applicable GASB pronouncements and elected to apply Financial Accounting Standards Board (FASB) statements and interpretations issued after November 30, 1989, except for those that conflict with or contradict GASB pronouncements. The following is a summary of the more significant policies:

a) Basis of Accounting and Presentation: The accounting and reporting policies of the District are regulated by the Washington State Auditor's Office and are based on the Uniform System of Accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission (FERC). The District uses the full accrual basis of accounting where revenues are recognized when earned and expenses are recognized when incurred. Revenues and expenses related to the District's principal operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing and investing activities are considered to be nonoperating revenues and expenses.

b) Utility Plant and Depreciation: Utility plant is recorded at original cost which includes both direct costs of construction or acquisition and indirect costs. The District's capitalization threshold is $5,000 for non-infrastructure capital. All costs related to infrastructure are capitalized. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and improvements is capitalized.

   Property, plant and equipment is depreciated using the straight-line method over the following estimated useful lives:

Buildings and Improvements	33 - 40 years
Generation Plant	20 years
Electric Plant - Transmission	25 - 33 years
Electric Plant - Distribution	10 - 33 years
Electric Plant/Equipment - Broadband	5 - 20 years
Transportation Equipment	16 years
General Plant & Equipment	3 - 14 years

   Initial depreciation on utility plant is recorded in the year subsequent to purchase or completion of construction. Composite rates are used for asset groups and, accordingly, no gain or loss is recorded on the disposition of an asset unless it represents a major retirement. The composite depreciation rate was approximately 4.89% in 2007 and 4.85% in 2006. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation.

   Preliminary survey and investigation costs incurred for proposed projects are deferred pending a final decision to develop the project. Costs relating to projects ultimately constructed are reclassified to utility plant. If the project is abandoned, the costs are expensed.

c) Allowance for Funds Used During Construction (AFUDC): AFUDC represents the estimated costs of financing construction projects and is computed using the District's long-term borrowing rate. The allowance totaled $346,269 and $155,621 in 2007 and 2006, respectively, and is capitalized as part of the cost of the project and reflected as a reduction of interest expense.

d) Asset Retirement Obligation: The District has adopted FASB Statement of Financial Accounting Standard (SFAS) No. 143, *Accounting for Asset Retirement Obligations.* This statement requires the District to recognize the fair value of a liability associated with the retirement of a long-lived asset, such as the Finley CT, in the period in which it is incurred. See Note 5 for discussion regarding the impact of adopting SFAS No. 143.

e) Restricted Assets: In accordance with bond resolutions, related agreements and laws, separate restricted accounts have been established. These assets are restricted for specific uses including debt service, bond reserve and capital additions and are classified as current or noncurrent assets, as appropriate.

f) Cash and Investments: For purposes of the Statement of Cash Flows, cash includes unrestricted and restricted cash balances. Short-term highly liquid investments are not considered to be cash equivalents (see Note 3). The District transferred $2,244,474 from the Rate Stabilization Account to its general account in 2007.

g) Accounts Receivable: The percentage-of-sales allowance method is used to estimate uncollectible accounts. The reserve is then reviewed for adequacy against an aging schedule of accounts receivable. Accounts deemed uncollectible are transferred to the provision for uncollectible accounts on a monthly basis.

h) Notes Receivable: Notes receivable include amounts related to the sale of electric plant to the City of Richland. On June 1, 2005, the District sold electric plant and transferred service territory representing approximately 1.7% of the District's annual revenues for $3,250,000 to the City of Richland to be paid in five annual installments of $650,000. The first payment of $650,000 was received June 2005, a second payment was received June 2006, and a third payment was received June 2007. The balance of the note at December 31, 2007 is $1,300,000 of which $650,000 is classified as current. Interest at a rate of 5% per year was imputed and is being amortized over the term of the note.

i) Other Receivables: Other receivables include the long-term portion of the note receivable from the City of Richland. In addition, $1.8 million at December 31, 2006 was due from BPA for the recall of energy under Exhibit N of the Block and Slice Agreement (see Note 10).

j) Inventories: Inventories are valued at average cost, which approximates the market value.

k) Derivative Instruments: The District has adopted FASB SFAS No. 133, *Accounting for Derivative Instrument and Hedging Activities*, as amended. Subject to certain exceptions SFAS No. 133 requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value, and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

It is the District's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS No. 133, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, related Derivative Implementation Group (DIG) guidance, and SFAS No. 149, *Amendment of Statement No. 133 on Derivative Instruments and Hedging Activities*. Collectively, these statements are referred to as "SFAS No. 133."

The District has reviewed its various contractual arrangements to determine applicability of these standards. Purchases and sales of forward electricity, natural gas and option contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under SFAS No. 133. These transactions are excluded under SFAS 133 and therefore are not required to be fair valued in the financial statements. Certain put and call options, and financial swaps for electricity and natural gas, are considered to be derivatives under SFAS No. 133, but do not generally meet the "normal purchases and normal sales" criteria under SFAS No. 133.

The District has adopted GASB Technical Bulletin (TB) 2003-01, *Disclosure Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets*, effective for 2003. The following disclosures are provided for derivatives not reported at fair value in conformity with this guidance.

Objective & Strategies:
The District enters into derivative energy transactions to hedge its known or expected positions within its approved risk management policy. Decisions are made to enter into forward transactions to protect its financial position, specifically to deal with expected long and short positions as determined by projected load and resource balance positions. Generally, several strategies are employed to hedge the District's resource portfolio, including:

- Combustion Turbines – The District purchases gas for future periods to generate electricity when the plant is economically viable on a marginal basis for that period based on parameters set by the Risk Management Committee. If load projections indicate that the District does not require the electricity to serve its customers, an equivalent quantity of power will concurrently be sold or otherwise hedged for the same period.

- Surplus Purchased Power Resources – The District hedges projected surpluses in future periods by selling power or by purchasing put options. Surplus power is generally sold forward at a fixed-price, either physically or financially, when the probability of surplus is very high; surplus power is hedged through the purchase of physical or financial put options when the projected surplus is less certain, but nevertheless expected to be available under expected scenarios. From time to time the District will sell physical power forward in the prompt month at a price based on the Mid-Columbia index to perfect financial forward sales which settle based on the same index.

- Deficit Power Resources – The District hedges projected power resource deficits in future periods by purchasing power or by purchasing power call options (or if the Frederickson Project (see Note 10) is economically viable for the period, by buying gas or gas call options). Power is generally purchased to cover projected deficits at a fixed price, either physically or financially, when the probability of the deficit position is very high; such deficit positions are hedged through the purchase of physical or financial call options when the projected deficits are less certain, but nevertheless expected under the approved planning conditions.

Derivatives authorized under the Risk Management Policy and employed by the District include:

- Physical power and natural gas forward purchases and sales
- Monthly and daily power and gas physical calls and puts
- Power and natural gas fixed for floating swaps
- Currency swaps relating to managing US/Canadian exchange rate risk resulting from transactions denominated in Canadian dollars
- Monthly financial Asian power and gas put and call options
- Financial daily power and gas put and call options
- Monthly power and natural gas swaptions

As of December 31, 2007 and 2006, the following derivative products were outstanding:

- Physical power and natural gas forward purchases and sales
- Physical daily power puts
- Fixed for floating financial power and natural gas swaps

The fair value of these derivative instruments is provided in Note 10. There is no associated debt for these instruments at December 31, 2007 or 2006.

GASB TB 2003-01 mandates disclosures for six different types of risk that can arise in connection with derivatives to the extent these risks are actually present.

- Credit Risk – The District has developed a credit policy that establishes guidelines for setting credit limits and monitoring credit exposure on a continuous basis. The policy addresses frequency of counterparty credit evaluations, credit limits per specific counterparty and counterparty credit concentration limits. A summary of counterparty credit exposure related to derivatives is provided in Note 10.

  The District has entered into master enabling agreements with various counterparties, which enable hedging transactions. Such agreements include the Western Systems Power Pool (WSPP) form of agreement for physical power transactions, various forms of enabling agreements for physical gas transactions and International Swaps and Derivatives Association Agreements (ISDA) for financial transactions. All of the enabling agreements have provisions addressing credit exposure and provide for various remedies to assure financial performance, including the ability to call on additional collateral as conditions warrant, generally as determined by the exposed party. The District also uses netting provisions in the agreements to diffuse a portion of the risk.

Transactions under the physical enabling agreements are used to deal with long and short physical positions under the direction of the Risk Management Committee and pursuant to the risk management policy. Transactions under the ISDA agreements are used to financially hedge long or short positions so that the District will pay or receive the equivalent of a fixed or known price for energy purchased or sold. The agreements also permit the District to hedge the risk of an underlying physical position by using call options, put options, runoff insurance and weather insurance.

- Basis Risk - The District proactively works to eliminate or minimize basis risk on energy transactions by entering into derivative transactions that settle pursuant to an index derived from market transactions at the point physical delivery is expected to take place. There are no derivative transactions outstanding that carry basis risk as of December 31, 2007 or 2006. As applicable, all power related transactions are to be settled on the relevant Mid-Columbia index, and all gas transactions are to be settled on the relevant Sumas/Huntingdon index. The District has ready access to electric transmission and natural gas transportation capacity at those respective trading points.

- Termination Risk - As of December 31, 2007 and 2006, no termination events have occurred, and there are no outstanding transactions with material termination risk. None of the outstanding transactions have early termination provisions except in the event of default by either counterparty. Events of default are generally related to (i) failure to make payments when due, (ii) failure to provide and maintain suitable credit assurances as required, (iii) bankruptcy or other evidence of insolvency, or (iv) failure to perform under any material provision of the agreement. Failure to provide or receive energy or natural gas under physical commodity transactions does generally not fall under the events of default provisions, unless the non-performing party fails to pay the resulting liquidated damages as they become due.

- There is no rollover, interest rate, or market access risk for these derivative products at December 31, 2007 or 2006.

l) Deferred Regulatory Charges/Credits: The Board of Commissioners establishes rates for the District designed to recover the costs of providing services. As a result, the District qualifies for the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, which allows for the deferral of unrecognized gains or losses. The Board approved a resolution that allows the change in the fair value of derivative instruments during the period to be deferred and recorded as regulatory assets and/or liabilities. As of December 31, 2007, the District recorded unrealized net gains of $1,138,118 related to derivative instruments. As of December 31, 2006, the District recorded unrealized net gains of $3,261,056 and unrealized net losses of $160,077 related to derivative instruments. All other power supply contracts are considered to be normal purchases and sales under SFAS No. 133 and, as such, were not subject to the fair value recording requirements of these statements.

m) Debt Premium, Discount and Expense: Original issue and reacquired bond premiums, discounts and expenses relating to revenue bonds are amortized over the terms of the respective bond issues using the bonds outstanding method. In accordance with GASB Statement No. 23, *Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities*, losses on debt refundings have been deferred and amortized over the shorter of the remaining life of the old or new debt.

n) Revenue Recognition: Revenues from retail sales of electricity are recognized when billed and reported net of bad debt expense of $196,500 and $329,623 at December 31, 2007 and 2006, respectively. Revenues include an estimate for energy delivered to customers between the last billing date and the end of the year. This amount is reflected in the accompanying financial statements as Accrued Unbilled Revenue in the amount of $3.2 million at December 31, 2007 and $3.2 million at December 31, 2006.

o) Capital Contributions: Capital contributions for the District consist mainly of line extension fees. Line extension fees represent amounts collected to recover the costs of installing new lines.

p) Compensated Absences: The District consolidated its vacation and sick leave program to a personal leave program May 1, 1993. Accrued unused sick leave balances for active employees as of April 30, 1993 were frozen and converted to a supplemental leave benefit (SLB). The SLB may be used by employees to make up the difference between a short-term disability benefit and 100% of gross pay or on a one-time basis, restore work hours required for short-term disability eligibility. At death, the District is obligated to pay 100% of the SLB cash value to the employee's beneficiary. At retirement, the District is obligated to deposit 30% of the SLB cash value into the retiring employee's Voluntary Employee Beneficiary Association Trust account. The liability for unpaid supplemental leave benefits was $110,286 and $116,420 at December 31, 2007 and 2006, respectively.

Employees earn personal leave in accordance with length of service. The District accrues the cost of personal leave in the year when earned. Personal leave may accumulate to a maximum of 1,200 hours and is payable upon separation of service, retirement or death. The liability for unpaid leave benefits and related payroll taxes was $1,909,008 and $1,789,642 at December 31, 2007 and 2006, respectively, and is recorded as a current liability.

q) Use of Estimates: The preparation of the financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results may differ from those estimates.

r) Significant Risk and Uncertainty: The District is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include prices on the wholesale market for short-term power, interest rates, water conditions, weather and natural disaster-related disruptions, collective bargaining labor disputes, fish and other Endangered Species Act issues, Environmental Protection Agency regulations, federal government regulations or orders concerning the operation, maintenance, and/or licensing of facilities, other governmental regulations, and the deregulation of the electrical utility industry.

The District's accounts receivable are concentrated with a diverse group of customers and counterparties who have purchased energy or other products and services. These customers generally do not represent a significant concentration of credit risk. The District mitigates credit risk by requiring large customers to provide an acceptable means of payment assurance and by an ongoing financial review of counterparties and establishment of credit limits based on the results of that review.

s) Reclassifications: Certain 2006 account balances may have been reclassified to conform to the 2007 presentation. Such reclassifications would have no effect on previously reported results of operations and cash flows.

NOTE 2 – UTILITY PLANT

Utility plant activity for the years ended December 31 was as follows:

Activity for 2007

Electric Plant Assets	Balance Dec. 31, 2006	Increase	Decrease	Balance Dec. 31, 2007
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	$2,710,660	$315,929	($10,270)	$3,016,319
Construction Work in Progress	5,345,157	11,494,651	(12,810,865)	4,028,943
Capital Assets Being Depreciated:				
Transmission	7,131,591	335,303	-	7,466,894
Generation	20,673,493	-	(19,269,643)	1,403,850
Distribution	147,758,550	10,384,997	(606,832)	157,536,715
General	36,923,225	4,542,708	(698,767)	40,767,166
Subtotal	**212,486,859**	**15,263,008**	**(20,575,242)**	**207,174,625**
Less Accumulated Depreciation for:				
Transmission	(3,482,027)	(256,404)	-	(3,738,431)
Generation	(5,162,680)	(472,457)	5,212,610	(422,527)
Distribution	(78,044,447)	(6,287,182)	732,765	(83,598,864)
General	(14,014,556)	(3,219,942)	690,701	(16,543,797)
Total Accumulated Depreciation	**(100,703,710)**	**(10,235,985)**	**6,636,076**	**(104,303,619)**
Net Utility Plant	**$119,838,966**	**$16,837,603**	**($26,760,301)**	**$109,916,268**

Activity for 2006

Electric Plant Assets	Balance Dec. 31, 2005	Increase	Decrease	Balance Dec. 31, 2006
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	$2,615,199	$95,461	$ -	$2,710,660
Construction Work in Progress	1,417,699	9,210,906	(5,283,448)	5,345,157
Capital Assets Being Depreciated:				
Transmission	7,125,902	10,829	(5,140)	7,131,591
Generation	20,673,493	-	-	20,673,493
Distribution	143,350,352	5,183,978	(775,780)	147,758,550
General	34,881,418	2,194,240	(152,433)	36,923,225
Subtotal	**206,031,165**	**7,389,047**	**(933,353)**	**212,486,859**
Less Accumulated Depreciation for:				
Transmission	(3,225,851)	(256,176)	-	(3,482,027)
Generation	(4,128,193)	(1,034,487)	-	(5,162,680)
Distribution	(72,784,531)	(5,963,940)	704,024	(78,044,447)
General	(11,422,234)	(2,728,931)	136,609	(14,014,556)
Total Accumulated Depreciation	**(91,560,809)**	**(9,983,534)**	**840,633**	**(100,703,710)**
Net Utility Plant	**$118,503,254**	**$6,711,880**	**($5,376,168)**	**$119,838,966**

NOTE 3 – DEPOSITS AND INVESTMENTS

As of December 31, 2007, the District had the following investments:

Investment Type	Maturities	Fair Value
State Treasurer's Local Government Investment Pool	50 days - average	$29,075,664
Total Investments		$29,075,664

As of December 31, 2006, the District had the following investments:

Investment Type	Maturities	Fair Value
State Treasurer's Local Government Investment Pool	36 days - average	$24,286,500
Federal Home Loan Mortgage Corporation	2/15/2007	1,197,768
Total Investments		$25,484,268

Interest rate risk. In accordance with its investment policy, the District manages its exposure to declines in fair values by matching investment maturities to meet anticipated cash flow requirements. The policy limits investment maturities to less than five years from the date of the purchase, unless the maturities coincide as nearly as practicable with the expected use of the funds.

Credit risk. The District's investment policy conforms with State law which restricts investments of public funds to debt securities and obligations of the U.S. Treasury, U.S. Government agencies, and certain other U.S. Government sponsored corporations, certificates of deposit and other evidences of deposit at financial institutions qualified by the Washington Public Deposit Protection Commission (PDPC), bankers' acceptances, investment-grade general obligation debt of state and local governments and public authorities, and the Washington State Treasurer's Local Government Investment Pool (LGIP). The LGIP is an unrated 2a7-like pool and investments in the LGIP are reported based on the pool's share price. The reported value of the pool is the same as the fair value of the pool shares. The LGIP is governed by the State Finance Committee and is administered by the State Treasurer. The District's investment in the Federal Home Loan Mortgage Corporation were rated AAA by Moody's Investor Services and AAA by Standard & Poor's.

Concentration of credit risk. The District's investment policy limits investments at the time of purchase to a percent of the total investment portfolio in the following manner:

- Direct obligations of the U.S. Government, up to 100%
- Washington State Treasurer's Local Government Investment Pool, up to 100%
- U.S. Government agency debt, up to 30% for any single agency
- Certificate of Deposit, up to 50% from any single bank provided they are PDPC approved.

Custodial credit risk – Deposits. For a deposit, this is the risk that in the event of a bank failure, the District's deposits may not be returned to it. The District's deposits and certificates of deposit are entirely covered by federal depository insurance (FDIC) or by collateral held in a multiple financial institution collateral pool administered by the PDPC. Under State law, public depositories under the PDPC may be assessed on a prorated basis if the pool's collateral is insufficient to cover a loss. As a result, deposits covered by collateral held in the multiple financial institution collateral pool are considered to be insured. State law requires that deposits may only be made with institutions that are approved by the PDPC.

NOTE 4 – DEFERRED CHARGES AND DEFERRED CREDITS

Deferred charges and deferred credits as of December 31 consisted of the following:

Deferred Charges	**2007**	**2006**
Unamortized Debt Expense	$ 790,511	$ 903,289
Deferred Regulatory Charges	1,652,952	160,077
Derivative Asset	2,791,071	3,261,056
Deferred Purchased Power Costs	633,432	836,592
Deferred Conservation Costs	-	554,066
Preliminary Surveys	182,110	29,560
Total	**$6,050,076**	**$5,744,640**

Deferred charges include programmatic conservation and weatherization costs incurred for purposes of load reduction and energy efficiency. These costs are being recovered over five years to coincide with credits on the District's power bill from the Bonneville Power Administration.

Deferred Credits & Other Liabilities	**2007**	**2006**
Customer Advances – Line Extensions	$ -	$ 3,869
Unclaimed Property	21,005	18,114
Deferred Regulatory Credits	2,791,071	3,261,056
Derivative Liability	1,652,952	160,077
Deferred Revenue	485,481	405,413
Asset Retirement Obligation – Finley CT	116,432	170,101
Other Postemployment Benefits	9,579	-
Total	**$5,076,520**	**$4,018,630**

See Note 1(l) for an explanation of deferred regulatory charges and credits.

NOTE 5 – ASSET RETIREMENT OBLIGATION (ARO)

The District adopted SFAS No. 143, *Accounting for Asset Retirement Obligations* in 2003. This statement requires the District to recognize the fair value of a liability for an ARO for legal obligations related to the retirement of tangible long-lived assets. Upon initial recognition of a measurable ARO, the asset retirement cost is capitalized by increasing the carrying amount of the related long-lived asset by the same amount as the liability. The asset retirement cost is subsequently allocated to expense over its useful life. In periods subsequent to initial measurement, changes are recognized in the liability for an ARO resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

The District has identified a legal obligation related to the retirement of the Finley CT. Upon termination of the agreement with the landowner of the Finley CT site, the District is obligated to remove equipment and systems from the site and surrender the site in the same condition as received. During 2003, the District recorded an ARO of $190,380 at its net present value of $146,940, and increased depreciable assets by $146,940. In 2006, the net present value of the ARO increased to $170,101 resulting in accretion expense of $8,100. The District sold the Finley CT during 2007, and the plant was dismantled and removed, however, the land is still being leased by the District according to the original terms of the agreement. The District spent $56,464 for site restoration in 2007 and reduced the ARO obligation by this amount. The District will perform the remainder of the site restoration upon termination of the lease. After reducing the ARO for the partial restoration cost, the net present value of the ARO increased to $116,432, resulting in accretion expense of $5,544.

NOTE 6 – LONG-TERM DEBT

During the year ended December 31, 2007, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Amounts Due Within One Year
1995 Electric Revenue Bonds, due in annual installments of $365,000 - $830,000 through November 1, 2015; interest at 4.2% - 5.625%.	$545,000	-	$545,000	-	-
1997 Electric Revenue and Refunding Bonds, due in annual installments of $180,000 - $2,455,000 through November 1, 2017, interest at 4.5% - 5.8%.	1,995,000	-	1,995,000	-	-
2001A Revenue and Refunding Bonds, due in annual installments of $1,130,000 - $2,900,000 through November 1, 2021; interest at 3.75% - 5.625%.	30,685,000	-	1,415,000	29,270,000	1,470,000
2002 Revenue Bonds, due in annual installments of $1,220,000 - $2,005,000 through November 1, 2022; interest at 3.60% - 5.25%.	17,305,000	-	-	17,305,000	-
2005 Revenue Refunding Bonds, due in annual installments of $90,000 –$1,185,000 through November 1, 2017; interest at 2.1% - 4.0%	9,325,000	-	90,000	9,235,000	945,000
Subtotal	$59,855,000	-	$4,045,000	$55,810,000	$2,415,000
Plus: Unamortized discount & premium	1,278,609	-	149,821	1,128,788	-
Less: Unamortized loss on refundings	(496,105)	-	(94,910)	(401,195)	-
Total Long-Term Debt	**$60,637,504**	-	**$4,099,911**	**$56,537,593**	**$2,415,000**

During the year ended December 31, 2006, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Amounts Due Within One Year
1995 Electric Revenue Bonds, due in annual installments of $365,000 - $830,000 through November 1, 2015; interest at 4.2% - 5.625%.	$1,065,000	-	$520,000	$545,000	$545,000
1997 Electric Revenue and Refunding Bonds, due in annual installments of $180,000 - $2,455,000 through November 1, 2017, interest at 4.5% - 5.8%.	11,785,000	-	9,790,000	1,995,000	1,995,000
2001A Revenue and Refunding Bonds, due in annual installments of $1,130,000 - $2,900,000 through November 1, 2021; interest at 3.75% - 5.625%.	32,050,000	-	1,365,000	30,685,000	1,415,000
2002 Revenue Bonds, due in annual installments of $1,220,000 - $2,005,000 through November 1, 2022; interest at 3.60% - 5.25%.	17,305,000	-	-	17,305,000	-
2005 Revenue Refunding Bonds, due in annual installments of $90,000 –$1,185,000 through November 1, 2017; interest at 2.1% - 4.0%	9,415,000	-	90,000	9,325,000	90,000
Subtotal	$71,620,000	-	$11,765,000	$59,855,000	$4,045,000
Plus: Unamortized discount & premium	1,418,541	-	139,932	1,278,609	-
Less: Unamortized loss on refundings	(881,213)	-	(385,108)	(496,105)	-
Total Long-Term Debt	**$72,157,328**	-	**$11,519,824**	**$60,637,504**	**$4,045,000**

Future debt service requirements on these bonds are as follows:

Year	Principal	Interest	Total
2008	$ 2,415,000	$ 2,715,080	$ 5,130,080
2009	2,530,000	2,601,680	5,131,680
2010	2,630,000	2,505,250	5,135,250
2011	2,735,000	2,394,119	5,129,119
2012	4,070,000	2,272,056	6,342,056
2013-2017	21,650,000	8,437,718	30,087,718
2018-2022	19,780,000	2,880,339	22,660,339
Total	**$55,810,000**	**$23,806,242**	**$79,616,242**

In December 2006, the District used $7,890,000 of reserves to cash defease certain Electric Revenue Refunding Bonds, Series 1997. This bond defeasance resulted in a net present value savings of $91,333. The aggregate reduction in debt service was $9,450,595.

In March 2005, the District issued $9,655,000 of Electric Revenue Refunding Bonds, Series 2005. The proceeds were used to refund certain of the District's outstanding 1995 Bonds, the callable 1997 Bonds and to pay issuance costs. This bond refunding resulted in a net present value savings of $808,265 to the District, or 9% of the refunded bonds. The aggregate reduction in debt service between the refunded debt and the refunding debt was $987,953. Proceeds from the refunding bonds and the District were placed in separate irrevocable trusts to provide for all future debt service payments on the defeased bonds. Accordingly, the trust account assets and liabilities for the defeased bonds are not reflected in the District's financial statements.

The remaining principal balance of the 1995 and 1997 bond issues was retired by the District in November 2007.

The District's debt service reserve requirement for issues prior to 2002 was satisfied by a surety policy issued by Ambac Assurance Corporation. Reserve requirements for the 2002 and 2005 bond issues were satisfied through the funding of a reserve account in an amount equal to the average annual debt service or $812,537, in addition to a surety bond issued by MBIA Insurance Corporation. With the retirement of the final maturity of the 1995 bonds, the surety policy expired, and the method of calculating the debt service reserve requirement changed.

In October 2007, the District purchased a municipal bond debt service reserve insurance policy issued by Financial Security Assurance, Inc. to satisfy the reserve requirement for the outstanding 2001A bonds and a debt service reserve surety bond issued by MBIA Insurance Corporation to satisfy the reserve requirement for the outstanding 2002 and 2005 bonds. These actions allowed the District to release $812,537 held in the restricted debt service reserve account.

In March 2004, the District established a one-year $10 million revolving line of credit, the Electric System Revenue Note, 2004, with Bank of America. In March of 2006 and March of 2007, this line of credit was extended for additional one-year terms with a maturity of March 31, 2008 (see Note 17). The line of credit was established in support of District financial policies that require additional liquidity be maintained above minimum cash and investment reserve levels for the purpose of meeting unforeseen short-term cash needs. Specifically, the line of credit can be used in support of general District operations or for irrevocable letters of credit as may be required to satisfy collateral posting requirements under contracts and agreements within the ordinary course of business. Draws on the Note will bear interest based on a pricing grid and formula using the bank's prime rate or the LIBOR rate. This Note is a special obligation of the District payable solely out of a special fund and has a lien on revenues junior to the payment of operating expenses of the electric system and outstanding electric system bonds. No draws on the line of credit have been made, and the District does not anticipate any draws on the line of credit for the next twelve months.

In August 2006, the District established a standby irrevocable letter of credit with Bank of America in favor of BPA in the amount of $4.5 million. This letter of credit expires on September 30, 2009 and was a condition of participation to guarantee performance in the Flexible PF Rate Program (see Note 10).

NOTE 7 - PENSION PLANS

Substantially all District regular full-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing multiple-employer public employee defined benefit and defined contribution retirement plans. The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to: Department of Retirement Systems, Communications Unit, P. O. Box 48380, Olympia, WA 98504-8380. The following disclosures are made pursuant to GASB Statement No. 27, *Accounting for Pensions by State and Local Government Employers*.

Public Employees' Retirement System (PERS) Plans 1, 2, and 3

Plan Description

PERS is a cost-sharing multiple employer cost-sharing retirement system comprised of three separate plans for membership purposes: Plans 1 and 2 are defined benefit plans and Plan 3 is a combination defined benefit/defined contribution plan. Membership in the system includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior Courts (other than judges in a judicial retirement system); employees of legislative committees; community and technical colleges, college and university employees (not in national higher education retirement programs); judges of district and municipal courts; non-certificated employees of school districts; and employees of local governments. PERS participants who joined the system by September 30, 1977, are Plan 1 members. Those who joined on or after October 1, 1977 and by either, February 28, 2002 for state and higher education employees, or August 31, 2002 for local government employees, are Plan 2 members unless they exercise an option to transfer their membership to Plan 3. PERS participants joining the system on or after March 1, 2002 for state and higher education employees, or September 1, 2002 for local government employees have the option of choosing membership in either PERS Plan 2 or PERS Plan 3. The option must be exercised within 90 days of employment. An employee is reported in Plan 2 until a choice is made. Employees who fail to choose within 90 days default to PERS Plan 3. PERS defined benefit retirement benefits are financed from a combination of investment earnings and employer and employee contributions. PERS retirement benefit provisions are established in state statute and may be amended only by the State Legislature.

Plan 1 retirement benefits are vested after an employee completes five years of eligible service. Plan 1 members are eligible for retirement at any age after 30 years of service, or at age 60 with five years of service, or at age 55 with 25 years of service. The annual pension is two percent of the average final compensation per year of service, capped at 60 percent. The average final compensation is based on the greatest compensation during any 24 eligible consecutive compensation months. If qualified, after reaching age 66, a cost-of-living allowance is granted based on years of service credit and is capped at three percent annually.

Plan 2 retirement benefits are vested after an employee completes five years of eligible service. Plan 2 members may retire at age 65 with five years of service, or at age 55 with 20 years of service, with an allowance of two percent per year of service of the average final compensation. The average final compensation is based on the greatest compensation during any 60 eligible consecutive compensation months excluding any type of severance pay. Plan 2 retirements prior to age 65 are actuarially reduced. If retirement is at age 55 or older with at least 30 years of service, a three percent per year reduction applies; otherwise an actuarial reduction will apply. There is no cap on years of service credit and a cost-of-living allowance is granted (indexed to the Seattle Consumer Price Index), capped at three percent annually.

Plan 3 has a dual benefit structure. Employer contributions finance a defined benefit component, and member contributions finance a defined contribution component. The defined benefit portion provides a benefit calculated at one percent of the average final compensation per year of service. The average final compensation is based on the greatest compensation during any 60 eligible consecutive compensation months. Effective June 7, 2006, Plan 3 members are vested in the defined benefit portion of their plan after ten years of service; or after five years if twelve months of that service are earned after age 44; or after five service credit years earned in PERS Plan 2 prior to June 1, 2003. Plan 3 members are immediately vested in the defined contribution portion of their plan. Vested Plan 3 members are eligible to retire with full benefits at age 65, or at age 55 with 10 years of service. Retirements prior to the age of 65 receive reduced benefits. If retirement is at age 55 or older with at least 30 years of service, a 3 percent per year reduction applies; otherwise an actuarial reduction will apply.

The benefit is also actuarially reduced to reflect the choice of a survivor option. There is no cap on years of service credit; and Plan 3 provides the same cost-of-living allowance as Plan 2. The defined contribution portion can be distributed in accordance with an option selected by the member, either as a lump sum or pursuant to other options authorized by the Employee Retirement Benefits Board.

There are 1,188 participating employers in PERS. Membership in PERS consisted of the following as of the latest actuarial valuation date for the plans of September 30, 2006:

Retirees and Beneficiaries Receiving Benefits 70,201
Terminated Plan Members Entitled To but Not Yet Receiving Benefits 25,610
Active Plan Member Vested 105,215
Active Plan Members Nonvested 49,812
Total 250,838

Funding Policy

Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates, Plan 2 employer and employee contribution rates, and Plan 3 employer contribution rates. Employee contribution rates for Plan 1 are established by statute at six percent and do not vary from year to year. The employer and employee contribution rates for Plan 2 and the employer contribution rate for Plan 3 are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. All employers are required to contribute at the level established by the Legislature. PERS Plan 3 defined contribution is a non-contributing plan for employers. Employees who participate in the defined contribution portion of PERS Plan 3 do not contribute to the defined benefit portion of PERS Plan 3. The Employee Retirement Benefits Board sets Plan 3 employee contribution rates. Six rate options are available ranging from five to 15 percent; two of the options are graduated rates dependent on the employee's age. The methods used to determine the contribution requirements are established under state statute in accordance with the Revised Code of Washington (RCW) Chapters 41.40 and 41.45.

The required contribution rates expressed as a percentage of current year covered payroll, as of December 31, 2007, were:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer *	6.13%	6.13%	6.13%**
Employee	6.00%	4.15%	***

* The employer rates include the administrative expense fee currently set at 0.16%.
** Plan 3 defined benefit portion only.
*** Variable from 5.0% minimum to 15.0% maximum based on rate selected by the PERS 3 member.

Both the District and the employees made the required contributions. The District's required contributions for the years ended December 31 were:

Year	PERS Plan 1	PERS Plan 2	PERS Plan 3
2007	$41,465	$517,263	$33,536
2006	$31,880	$275,044	$17,186
2005	$18,882	$158,935	$10,188

Excess Compensation

A cash-out of accrued personal leave at termination in excess of 240 hours qualifies as "excess compensation" for PERS Plan 1 members. Excess compensation is included as part of a participant's average final compensation. When a payment is made that qualifies as excess compensation, the employer is billed for the resulting increase to the retiree's benefit to offset the increased cost to the Department of Retirement Systems. The bill is based on the present value of the increase to retiree's benefit. Present value is calculated using actuarial tables developed by the Office of the State Actuary and adopted into Washington Administrative Code by the Department of Retirement Systems. Beginning in 2003, the District accrued a liability for future "excess compensation" bills based on personal leave bank balances of PERS Plan 1 employees and actuarial numbers provided by the Office of the State Actuary. The liability for PERS Plan 1 excess compensation at December 31, 2007 and 2006 was $300,450 and $375,510.

NOTE 8 - DEFERRED COMPENSATION PLANS

The District offers its employees deferred compensation plans created in accordance with Internal Revenue Code Sections 457 and 401(a) permitting employees to defer a portion of their salary until future years. Prior to January 1, 2007, the District provided a 50% match of employee contributions calculated at a percentage of employee regular straight-time wages for the pay period equal to 7.32% less the PERS 2 employer contribution percentage less 1.5%. The District match was locked at a maximum rate of 2% on January 1, 2007. The deferred compensation is not available to employees until separation from service through termination, retirement, death, or unforeseeable emergency. The plan assets are held in trust for the exclusive benefit of plan participants and beneficiaries.

Effective August 1, 2005, the District contributes 0.5% of an employee's regular straight-time wages for the pay period into a health reimbursement arrangement (HRA) intended to help employees pay for health insurance premiums upon retirement. In addition, employees may elect to participate in a District provided wellness program and receive an additional 1% contribution of regular straight-time wages each pay period into an HRA. The plan assets are held in trust for the exclusive benefit of plan participants and beneficiaries.

The District established the Retirement Health Savings Plan for its non-bargaining employees during 2003, and amended the plan effective August 1, 2005 to include bargaining employees. This plan is an employer-sponsored health benefit saving plan that allows employees to accumulate assets to pay for eligible medical expenses at retirement on a tax-free basis. The District ended employee contributions to this plan in 2007 based on guidance from the administrator of the trust. Assets already contributed by employees to the trust will remain in the trust and can continue to be used for eligible expenses.

NOTE 9 – OTHER POSTEMPLOYMENT BENEFITS

Plan Description

The District offers a postemployment benefit plan to pay a portion of medical insurance premiums for certain retirees between the ages of 60 through 64. The plan was established as part of the Collective Bargaining Agreement and is offered to all employee types. The plan may be amended as part of the bargaining process. The plan is administered by the District and does not issue a stand alone report. To be eligible to receive plan benefits, an employee must have worked in a PERS-eligible position while actively employed, must retire between August 1, 2005 and July 31, 2015, must enroll in retiree medical insurance or COBRA from the Central Washington Public Utilities Unified Insurance Trust (See Note 11) within the enrollment period following retirement and must remain continuously enrolled in medical insurance from the Trust.

The plan provides that employees who retire during the initial plan year between August 1, 2005 and July 31, 2006 will have monthly contributions equal to the lesser of actual medical premiums or ten dollars for each year of PERS-eligible service at the District paid toward their medical insurance premium during the time they are between the ages of 60 through 64 for each month they remain enrolled in medical insurance from the Trust. For each successive year ending July 31, the dollar amount per month for each year of service will be reduced by one dollar until the benefit reaches zero on August 1, 2015.

Funding Policy
The District will pay the required contributions on a pay-as-you-go basis and not fund the plan. The District made no retiree medical insurance premium contributions in 2005, 2006, and 2007.

Annual OPEB Cost and Net OPEB Obligation
The District's annual other postemployment benefit (OPEB) cost (expense) is calculated based on the annual required contribution of the employer (ARC), an amount actuarially determined in accordance with the parameters of GASB Statement 45. The District implemented GASB Statement 45 in 2007 (transition year). The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year and amortize any unfunded actuarial liabilities (or excess funding) over a period not to exceed thirty years. The following table shows the components of the District's annual OPEB cost for the year, the amount actually contributed to the plan, and changes in the District's net OPEB obligation to the Plan.

Annual required contribution	$9,579
Interest on net OPEB obligation	-
Adjustment to annual required contribution	-
Annual OPEB cost (expense)	$9,579
Contributions made	-
Increase in net OPEB obligation	$9,579
Net OPEB obligation – beginning of year	-
Net OPEB obligation – end of year	$9,579

The District's annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net OPEB obligation for 2007 (transition year) were as follows:

Fiscal Year Ended	Annual OPEB Cost	Percentage of Annual OPEB Cost Contributed	Net OPEB Obligation
12/31/07	$9,579	0%	$9,579

Funded Status and Funding Progress
The funded status of the plan as of December 31, 2007, the most recent actuarial valuation date was as follows:

Actuarial accrued liability (AAL)	$108,245
Actuarial value of the plan	0
Unfunded actuarial accrued liability (UAAL)	$108,245
Funded ratio (actuarial value of plan assets/AAL)	0%
Covered payroll (active plan members)	$9,972,796
UAAL as a percentage of covered payroll	1.09%

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and probability a retiree will meet the eligibility requirements of the Plan. Amounts determined regarding the funded status of the plan and the annual required contributions of the employer are subject to continual revision as actual results are compared with past expectations and new estimates are made about the future. The schedule of funding progress, presented as required supplementary information following the notes to the financial statements, presents trend information for the transition year that shows whether the actuarial value of plan assets is increasing or decreasing over time relative to the actuarial accrued liabilities for benefits.

Actuarial Methods and Assumptions
Projections of benefits for financial reporting purposes are based on the substantive plan (the plan as understood by the employer and plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the employer and plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations.

In the actuarial valuation of December 31, 2007, the unit credit actuarial cost method was used. The actuarial assumptions include projected ages of retirement by employee based on years of service and pension plan eligibility, a 5.0% investment rate of return, and a 50% participation rate of retired employees. The UAAL is being amortized as a level percentage of projected payroll on a closed basis over thirty years. The remaining amortization period at December 31, 2007 was twenty-nine years.

NOTE 10 – LONG-TERM PURCHASED POWER COMMITMENTS

Bonneville Power Administration (BPA)

Commencing October 1, 2001, the District entered into a ten-year Block and Slice Power Sales Agreement with the United States Department of Energy BPA. The Slice product provides the District 1.7641% of the actual output of the Federal Columbia River Power System (FCRPS) and will require the District to pay that same percentage of actual costs of the system. The District's share of output is expected to be 165 average megawatts (aMW) in an average year, but may vary considerably based on water conditions within the Northwest. The Block product provides power in monthly amounts ranging between 47 megawatts (MW) and 83 MW for the first five-year term. In the second five-year term, the monthly Block entitlements increase to a range of 85 MW to 158 MW.

During the previous BPA power rate period (10/1/01 – 9/30/06), BPA periodically examined the forecast and actual loads, market prices and expenses and selectively imposed three Cost Recovery Adjustment Clauses (CRACs) designed to assure that full cost recovery was maintained. The three CRACs were the (1) Load-Based (LB) CRAC which was designed to capture the costs of purchasing sufficient power to serve the loads that are placed on BPA; (2) Financial-Based (FB) CRAC which triggered if the Power Business Line's forecast accumulated net revenues fell below a preset threshold; and (3) Safety Net (SN) CRAC which triggered if BPA missed a payment to Treasury or other creditor, or if BPA forecast a 50% probability that it would miss such a payment during the current fiscal year.

During the current BPA power rate period (10/1/06 - 9/30/09), BPA has put in place new CRACs which apply to the District's Block purchases, but not the Slice purchases. The CRACs can be triggered when BPA's forecasted Accumulated Modified Net Revenues (AMNR) is lower than expected. AMNR represents the generation function net revenues, modified by certain items, as accumulated since 1999 through the end of each year for FY 2006 through 2008. The amount of the CRAC is determined by the amount AMNR is forecasted to be greater than certain values (roughly equivalent to the amount that BPA generation function reserves drop below $750 million) and is capped at $300 million per year. If triggered, the CRAC amount would be converted to a percentage and would increase the Block rates charged to the District.

The $300 million per year cap can be increased if BPA triggers a NFB (National Marine Fisheries Service FCRPS BiOp) adjustment. The NFB adjustment could be triggered if a court orders additional expenditures for Fish and Wildlife mitigation, an Endangered Species Act (ESA) litigation settlement occurs which results in higher costs, a new, more expensive, Biological Opinion (BiOp) is implemented, or BPA commits to implement a recovery plan under the ESA. The NFB adjustment could begin at the start of a fiscal year, or during the fiscal year if an emergency is declared.

The rates also contain a Dividend Distribution Clause (DDC) which would operate similar to the CRACs but would lower the Block rates charged to the District. The DDC would be triggered when generation function reserves exceed $1.05 billion. There is no cap on the DDC.

The District has entered into two other contracts with BPA for block-type purchases at fixed rates. The first contract allowed access to up to 20 MW and must be used to serve a large industrial customer of the District. The second contract was for approximately 10 aMW during the April through October time period. These agreements expired on August 31, 2006 and September 30, 2006, respectively.

The Block and Slice agreement contains a provision (Exhibit N) which allows BPA to recall energy if the sum of Block and Slice energy in a critical water year exceeds District firm loads less declared resources. BPA triggered this provision in August 2006. BPA and the District entered into a letter agreement whereby BPA is recalling 24 annual aMW over the period of October 2006 through September 2007 and 19.8 annual aMW over the period of October 2007 through September 2008. BPA will reimburse the District for this energy based on BPA's weighted average firm power rates. The reimbursement of $6.1 million for the fiscal year ending September 2007 was received in December 2007 as part of the annual Slice true-up process (see Note 1(i)). The reimbursement for the fiscal year ending September 2008 estimated at $5 million is expected in late December 2008 or early January 2009.

To obtain needed transmission services, the District entered into a service agreement with BPA for point-to-point transmission services commencing May 31, 1997 and terminating on the earlier of September 30, 2031 or the date of termination established pursuant to BPA's Open Access Transmission Tariff. Effective October 1, 2000, the District obtained transmission demand of 468 MW. It was reduced to 428 MW on October 1, 2003 and 423 MW on October 1, 2005. This service level exceeds requirements needed to meet projected retail loads.

In August 2006, the District entered into an agreement to participate in BPA's Flexible Priority Firm (PF) Rate Program. This program allows BPA to request participating utilities to pay up to three months in advance for power when BPA's reserve levels drop to a certain point; in turn, BPA pays the cost of each participating utility to maintain a line of credit for this purpose and pays the utility interest for amounts prepaid. This liquidity tool resulted in a reduction to the CRAC threshold making it significantly less likely to trigger in 2008 and 2009.

Energy Northwest

The District, Energy Northwest and BPA have entered into separate agreements with respect to certain Energy Northwest projects. Under these agreements, the District has purchased 4.965%, 5.350%, and 4.295% of the project capability of Project No. 1, Columbia Generating Station, and Energy Northwest's 70% share of Project No. 3, respectively. All project participants, including the District, have assigned their respective rights to the capability of these projects to BPA under contracts referred to as net-billing agreements. Project participants are obligated to pay Energy Northwest their pro rata share of total project costs, and BPA in turn is obligated to pay the participants identical amounts by reducing amounts due to BPA under power sales agreements. The net-billing agreements provide that participants and BPA are obligated to make such payments whether or not the projects are completed, operable, or operating and notwithstanding the suspension, interruption, interference, reduction, or curtailment of the projects' output.

BPA and Energy Northwest received a favorable private letter ruling from the IRS allowing for direct-pay agreements effective June 2006. The ruling assures that the proposed direct-pay agreements do not adversely affect the existing Federal income tax-exemption on the BPA-backed bonds issued by Energy Northwest for three nuclear projects. Under the direct-pay agreements, BPA pays amounts directly to Energy Northwest to cover the costs of the projects. This enables Energy Northwest to reduce to zero the amounts it bills to project participants and also reduces to zero the amount of net-billing credits BPA provides. The direct-pay agreements improve BPA's cash flows and provide an opportunity for rate relief for the region. The District began participation in the direct-pay program in June 2006.

Additionally, the District entered into a Nine Canyon Wind Project Power Purchase Agreement with Energy Northwest for the purchase of 3 MW of the project generating capacity (1 aMW) of Phase I through July 1, 2023. The project reached commercial operation in late 2002. The District on October 30, 2006, signed an Amended and Restated Agreement with ENW and the other purchasers which extended the term of the Agreement through July 1, 2030 (with rights to extend the agreement for five year terms) and provided the District with 6 MW (2aMW) from the Phase III expansion (see Note 15).

Lakeview Light and Power (LL&P) Wind Energy, Inc.

In April 2007, the District entered into a twenty-year Energy and Environmental Attributes Purchase Agreement with LL&P to purchase 3 MW of peak capacity (1 aMW) at the White Creek Wind Project. This project is a new wind generation facility with anticipated capacity of 204.7 MW upon system completion. It is located in Klickitat County and was declared in commercial operation date in November, 2007. The purchase price for this project begins at $51.97 per MWh escalating 2% per year. The District pays for only the energy and associated environmental attributes generated by the project.

Klickitat PUD Landfill Gas Project

The District extended its agreement to purchase 1 aMW per month from Klickitat PUD's Landfill Gas Project through 2008. The price of this power in January 2008 will be $40.20/MWh. Benton PUD is discussing options to renew the contract for an additional 5 years. This power is marketed to District customers as green power.

Packwood Lake Hydroelectric Project (Packwood)

The District is a 14% participant in Energy Northwest's 27 MW Packwood Project, located in the Cascade Mountains south of Mount Rainier. The Packwood Agreement with Energy Northwest obligates participants to pay annual costs and receive excess revenues. Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized, and no equity is accumulated. Accordingly, no investment for the joint venture is reflected on the District's balance sheet. No distributions were made in 2007 or 2006, as gains are being held for relicensing expenses.

In November 2002, the District began purchasing 57% of Packwood's capacity. The agreement, which was extended to expire October 1, 2008, allows the District to receive power at costs below the average BPA Block rate.

Frederickson Project

In March 2001, the District entered into a twenty-year agreement with Frederickson Power LP for the purchase of 50 MW of contract capacity from the 249 MW Frederickson combined-cycle natural gas fired combustion turbine project near Tacoma, Washington. The agreement includes firm gas transportation from the Canadian border to the project. Power deliveries and variable energy charges are based on a deemed heat rate of 7,100 British thermal units (Btu) per kilowatt-hour (kWh). Up to 40% of the contract capacity may be displaced regardless of the dispatch decisions of other purchasers. Power costs include a capacity charge and fixed and variable operation and maintenance charges indexed to performance and escalation factors. The District received fuel management services for the Frederickson Project from Power Resource Managers (PRM) through June 2006 and from The Energy Authority (TEA) beginning in July 2006 (see Note 12).

Other Power Supply Contracts and Purchases

The District entered into a contract with TEA on July 1, 2006 to provide scheduling, dispatching, and fuel management services to the District. The agreement expires on June 30, 2012. The District has the unilateral right to terminate the agreement upon 30 days written notice. The agreement also provides for annual consulting task orders to provide for a variety of power management services.

In June 2001, the District entered into a long-term agreement through October 2018 with Westcoast Energy for natural gas pipeline transportation capacity to serve its share of the Frederickson Power generating facility. The transportation capacity is dedicated to provide natural gas for Frederickson operations when the Frederickson plant is economically viable and the transportation capacity is economically viable. In April 2004, the District assigned the transportation capacity agreement to Louis Dreyfus Energy Canada LP. This agreement expired on October 31, 2006. In January 2006, the District executed a permanent assignment of most of this capacity, transferring its right, title, and interest to Terasen Gas, Inc., for the period November 1, 2006 through October 31, 2018. In October 2007, the District executed an agreement to assign the remaining pipeline capacity to Terasen, Gas, Inc. for the period November 1, 2007 through October 31, 2018. No financial commitments remain for the District.

At December 31, 2007, the District had entered into various short-term financial forward sales and purchase contracts committing the District through December 2009. Financial forward contracts for electricity had a net positive fair value of $572,778, and financial forward contracts for gas had a net positive fair value of $517,323 at December 31, 2007 and were reflected in the financial statements as deferred regulatory credits and charges, respectively, in accordance with SFAS No. 71.

At December 31, 2007, the District had outstanding put options enabling the District to sell electricity at various prices. These agreements will expire in the first two quarters of 2008. The market value of these options as of December 31, 2007 was $48,017 higher than the original premium paid. Accordingly, the premiums paid for the options were amortized by this amount and recognized as a deferred regulatory credit in accordance with SFAS No. 71.

At December 31, 2006, the District had entered into various short-term physical and financial forward sales and purchase contracts committing the District through September 2009. The physical forward contracts call for delivery of power at fixed prices in various block increments. The fair value of physical forward contracts totals a gain of $381,650 for electricity transactions and a loss of $246,864 for gas transactions. These contracts have been designated as normal purchases and sales under SFAS No. 133 (see Note 1(k)). Accordingly, the fair value of these contracts has not been recorded on the balance sheet. The District has also entered into several financial forward contracts. Financial forward contracts for electricity had a net positive fair value of $3,189,459, and financial forward contracts for gas had a net negative fair value of $160,077 at December 31, 2006, and are reflected in the financial statements as deferred regulatory credits and charges, respectively, in accordance with SFAS No. 71.

At December 31, 2006, the District had outstanding put and call options enabling the District to sell and buy electricity at various prices. The agreements expired in the first two quarters of 2007. Due to declining prices, the market value of these options at year-end was $71,597 higher than the original premium paid. Accordingly, a derivative asset was recorded for this amount and recognized as a deferred regulatory credit in accordance with SFAS No. 71.

Commodity transactions, both physical and financial, are entered into only with counterparties approved by the District's Risk Management Committee for creditworthiness. The District had 47 counterparties with approved credit limits for electric power and natural gas sales and purchases as of December 31, 2007, and 42 counterparties at December 31, 2006. Counterparty credit limits are based on credit ratings and other factors. Credit ratings for counterparties range from "not-rated" to AA+, with a majority of counterparties rated between BBB- and AA+. Not-rated counterparties either provide additional security or are assigned credit limits of $25,000 or less. The maximum credit exposure with any counterparty is set by the Commission at $2.25 million. In February 2006, the Commission approved a temporary increase in the maximum credit exposure the District could incur with any counterparty to $4.5 million through September 30, 2006. This increase was necessary as a result of strong hydroelectric generation increasing the volume of surplus power available to sell to counterparties, along with a corresponding decrease in forward market prices and consequently an increase in the fair value of existing forward contracts. Credit concentration limits based on market conditions and available qualified counterparties are established by the Risk Management Committee.

NOTE 11 – SELF-INSURANCE

Public Utility Risk Management Services Self-Insurance Fund

The District is a member of the Public Utility Risk Management Services Self-Insurance Fund (PURMS). RCW Chapter 48.62 authorizes the governing body of any one or more governmental entities to form together into or join a pool or organization for the joint purchasing of insurance, and/or joint self-insuring, and/or joint hiring or contracting for risk management services to the same extent that they may individually purchase insurance, self insure, or hire or contract for risk management services. An agreement to form a pooling arrangement was made pursuant to the provisions of RCW Chapter 54.16. The liability pool was formed on December 31, 1976 when certain PUDs in the State of Washington joined together by signing an Agreement to pool their self-insured losses and jointly purchase insurance and administrative services. Nineteen members currently belong to PURMS.

Additional pools for property and health and welfare coverage were added in March 1997 and April 2000, respectively, under the same agreements and with the same membership. All members do not participate in all pools. The District does not participate in the PURMS health and welfare pool.

The liability pool has a $1 million self-insured retention with $2.0 million of reserves. In addition, the fund purchases $60 million of excess general liability insurance and $10 million of professional liability insurance over the $1 million retention. The fund also purchases $35 million in directors and officers liability coverage with a retention of $500,000. The deductible is $250.

The majority of the property in the property pool has a $250,000 self-insured retention. Certain classes of property have higher retention requirements up to $750,000. In response to the changes in retention, PURMS members have increased the reserve from $500,000 to $750,000. In addition, the fund purchases $150 million of excess insurance over the $250,000 (or higher) retention level. The deductible varies but for most classes of property it is $250.

Members of each pool are assessed to maintain the designated self-insured retention.

After termination, a member is still responsible for their share of contributions to the pools for any unresolved, unreported, and in-process claims for the period they were a signatory to the agreement.

The pools are fully funded by its current and former members. Claims are filed by members with the Administrator, Pacific Underwriters, Seattle, WA, which has been contracted to perform claims adjustment and loss prevention services.

The pools are governed by a Board of Directors which is comprised of one designated representative from each participating member. The Administrator and an elected Administrative Committee are responsible for conducting the business affairs of the Pool.

Settled claims have not exceeded insurance coverage in any of the past three fiscal years.

Central Washington Public Utilities Unified Insurance Program Trust

The District is a member of the Central Washington Public Utilities Unified Insurance Trust (Trust). The Trust was organized October 1, 1982 pursuant to the provisions of RCW Title 54 and interlocal governmental agreements. The Trust's general objectives are to provide a central fund for the collection and disbursement of employee benefit premiums and claims involving medical, dental, life and long-term disability coverage. The Trust is administered by a Board of Trustees comprised of an appointed Trustee from each of the seven member Districts. The Trustees are authorized to negotiate, obtain, maintain insurance policies, and authorize disbursements made from the Trust to Third Party Administrators or other entities. Effective August 1, 2002, the Trust established a self-insured medical plan approved by the State Risk Office. The audit report for the Trust is available from the Washington State Auditor's Office (Report Nos. 72121 and 72122).

Unemployment Claims

The District pays unemployment claims on a reimbursement basis with claims administered by the Washington State Department of Employment Security.

Short-Term Disability Insurance

The District self-pays short-term disability benefits through a 70% salary continuation program from the 41st consecutive scheduled hour of inability to work until the employee either recovers and returns to work or completes the waiting period required for long-term disability insurance eligibility, whichever is earlier. Certification of illness or injury by a licensed, competent medical authority is required. The District utilizes a Third Party Administrator who provides medical oversight and advice-to-pay for all disability claims.

NOTE 12 – JOINT VENTURES

Power Resource Managers, LLP (PRM)
PRM was a partnership of Benton, Grays Harbor, and Franklin public utility districts. The partnership was authorized by the Interlocal Cooperation Act, RCW 39.34.010, and by the Uniform Partnership Act as enacted in RCW 25.04.010. The partnership was formed in June 1998 to insure continued use of the power/scheduling, dispatching, power brokerage and energy consulting expertise of PRM. The District's initial investment to purchase the assets was $600,000. Effective June 30, 2006, Benton, Grays Harbor, and Franklin public utility districts sold certain assets of PRM to The Energy Authority and authorized the cessation of PRM's active business operations.

Grays Harbor Franklin Benton, LLP (GHFB)
GHFB is a Limited Liability Partnership formed under RCW 25.05.500 pursuant to an interlocal cooperation agreement and began doing business under the name GHFB, LLP on July 1, 2006. The proceeds from the sale of certain assets to The Energy Authority were retained as startup funds for GHFB. The District recognized a loss of $87,841 related to operations of PRM through June 30, 2006 and a loss of $122,986 related to operations of GHFB through December 31, 2007 resulting in an equity interest in GHFB of $66,514 at December 31, 2007. GHFB's primary purpose at this time is to fund services previously performed by PRM but not being performed by The Energy Authority, for example, receiving and analyzing information related to federal legislation that may impact the three partner PUDs.

Financial statements for GHFB and PRM may be obtained by writing to: Franklin PUD, 1411 W Clark Avenue, Pasco, WA 99301.

NOTE 13 - PARTICIPATION IN NORTHWEST OPEN ACCESS NETWORK, INC. (NoaNet)

The District, along with 13 other Washington State public entities, is a member of NoaNet, a Washington nonprofit mutual corporation. NoaNet was incorporated in February 2000 to provide a broadband communications backbone over public benefit fibers leased from BPA throughout Washington. The network began commercial operation in January 2001.

As a member of NoaNet, the District has guaranteed certain portions of NoaNet debt based on its proportionate share (see Note 15). The District's membership interest in NoaNet is 14.17%. The management of NoaNet anticipates meeting debt obligations through profitable operations, but it is expected that it will be necessary for NoaNet to assess members to cover deficits during the initial years of operation. The District recorded as expense member assessments of $432,109 and $431,999 for 2007 and 2006, respectively.

NoaNet recorded a decrease in net assets (excluding member assessments) of $784,661 (unaudited) and $2,046,523 for 2007 and 2006, respectively. In accordance with Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock,* as well as a position statement issued by the Washington State Auditor concerning the appropriate accounting treatment for NoaNet, a proportionate share of these losses has not been recorded by the District since NoaNet had negative net assets of $11,501,043 as of December 31, 2007 (unaudited) and $13,815,982 as of December 31, 2006.

Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, Chief Financial Officer, 616 State St., Centralia, WA 98351.

NOTE 14 - TELECOMMUNICATIONS SERVICES

The District has installed and continues to build out a fiber optic backbone system in its service area to provide wholesale telecommunication services and for internal use by the electric system. The District has connected its fiber optic system to NoaNet's fiber optic communications system. Broadband coverage is also being extended through the development of a wireless network to deliver high-speed Internet service.

Broadband operations and capital activity for the years ended December 31, 2007 and 2006 follows:

Broadband	2007	2006
Operating Revenues		
Ethernet	$265,192	$206,628
TDM	161,227	134,910
Wireless	4,535	6,832
Co-Location	6,780	6,780
Internet Transport Service	243,335	32,260
Fixed Wireless	101,773	76,513
Other Revenue	3,843	1,415
NoaNet Maintenance Revenue	4,963	7,628
Bad Debt Expense	(4,060)	(11,690)
Total Operating Revenues	**$787,589**	**$461,276**
Operating Expenses		
Marketing & Business Development	$71,258	$70,721
NoaNet Maintenance Expense	3,928	7,329
General Expenses	472,699	390,289
Other Maintenance	70,274	59,728
Network Operating Center Maintenance	58,536	32,204
Wireless Maintenance	15,695	22,728
Subtotal before depreciation	$692,390	$582,999
Depreciation	626,088	578,688
Total Operating Expenses	**$1,318,478**	**$1,161,687**
Nonoperating Revenues (Grant Proceeds)	$85,000	-
Nonoperating Expenses	$448,597	$458,284
Capital Investment (Annual)	$768,529	$577,151
Capital Investment (Cumulative)	$7,604,400	$6,835,871

The above amounts are included in summarized line items on the income statement.

NOTE 15 - OTHER COMMITMENTS AND CONTINGENT LIABILITIES

Repayment Agreement Relating to NoaNet Line of Credit (see Note 13)

In July 2001, NoaNet issued $27 million in Telecommunications Network Revenue Bonds (Bonds) to finance the repayment of the founding members and the costs of initial construction, operations and maintenance. The Bonds became due beginning in December 2003 through December 2016 with interest due semi-annually at rates ranging from 5.05% to 7.09%. The amount of outstanding Bonds was $20,065,000 and $21,675,000 at December 31, 2007 and 2006, respectively.

Each Member of NoaNet has entered into a Repayment Agreement to guarantee the debt of NoaNet. Under the Repayment Agreement, each Member acknowledges and agrees that it is a guarantor of the payment of the principal of and interest on the Bonds and is liable by assessment or otherwise to repay NoaNet for amounts due and owing with respect to such principal and interest up to each Member's percentage interest. The District's guarantee is 14.06% of the outstanding Bonds, or $2,821,139 and $3,047,505 as of December 31, 2007 and 2006, respectively.

In the event of a failure by any Member or Members to pay such amounts when due, NoaNet may bill from time to time as necessary, and each Member is obligated to pay 30 days after receipt of the bill, an additional amount up to a maximum of 25% of such Member's percentage interest (the "Step-Up"), up to the maximum percentage interest, in order to cover the deficiency caused by such Member's or Members' failure to pay. Any Member that pays an additional amount to cover a deficiency reserves all rights to seek reimbursement from the Member or Members that failed to pay. The District's maximum percentage interest is 17.57% or $3,525,421 and $3,808,830 as of December 31, 2007 and 2006, respectively.

In January 2003, NoaNet opened a $5 million line of credit (Note) with Bank of America to fund capital expenditures, and opened a second $5 million line of credit with Bank of America in June 2006. Combined balances of $4,034,835 and $5,500,000 were outstanding on the Notes as of December 31, 2007 and 2006, respectively. NoaNet may assess its Members for their percentage share of principal and interest on the Note to the extent that NoaNet does not have sufficient funds to pay the Note.

Energy Northwest – Nine Canyon Wind Project

The Nine Canyon Wind Energy Project is owned and operated by Energy Northwest. The District, along with nine other public utilities, is a participant in Phases I and III of the Project. Under its Power Purchase Agreement, the District is obligated to pay its percentage share of the annual debt service of each project Phase and the operation and maintenance costs of the project in return for its percentage share of project output, whether or not the project is operating or capable of operating. Under the agreement, the District will be obligated to pay an amended percentage share when Phase III is in commercial operation, which is expected in February, 2008. Under a step-up provision, the District could be required to pay up to a maximum of 125% of its percentage share in the event of default by another purchaser. The Agreement limits Energy Northwest's total annual operation and maintenance cost to $4 million prior to Phase III Commercial Operation, and to $7 million post Phase III Commercial Operation. These limits will change annually based on certain inflation indexes. The agreement terminates July 1, 2030. The District's applicable percentage share obligations are:

Allocation of Cost	District Percentage Share	District Percentage Share under Step-up Provision
Debt Service – Phase I	6.25%	7.81%
Debt Service – Phase III	18.63%	23.29%
O&M Costs – Prior to Phase III Commercial Operation	4.72%	5.9%
O&M Costs – Post Phase III Commercial Operation	9.39%	11.74%

Conservation and Renewable Energy Systems (CARES)

The District is a member of CARES, a joint operating agency of the State of Washington. CARES was formed to develop, finance and acquire conservation, renewable and high efficiency resources for the benefit of its members.

The District entered into a loan program through CARES and the Wisconsin Energy Conservation Corporation (WECC) in 1997 to offer weatherization loans to customers for terms of three, five, seven and ten years. WECC sold the loans to Federal National Mortgage Association, and the program ended in 1999. The District is responsible for any loan defaults. At December 31, 2007, there were 10 active loans with an outstanding balance of $6,256. At December 31, 2006, there were 18 active loans with an outstanding balance of $25,217. All loans were current with the exception of a $287 outstanding loan that is approximately 13 months delinquent as of December 31, 2007.

Initiative 937

With the passage of Initiative 937 by Washington voters in November 2006, all electric utilities with more than 25,000 customers are required to purchase additional renewable energy from new sources in gradually increasing percentages until a total of 15% of its total retail load is reached by the year 2020. As of December 31, 2007, the District has entered into renewable energy contracts that total 2.7% of retail load. The initiative's initial renewable target is 3% by 2012.

Operating Leases

The District leases electrical testing equipment on an annual basis. The annual rental cost was $21,151 and $20,122 for 2007 and 2006, respectively.

The District has entered into an agreement with Agrium U.S. Inc., to lease a parcel of land upon which the District constructed the Finley CT in 2001. The agreement is in effect from June 1, 2001 to June 1, 2021. The agreement may be extended up to an additional twenty years with the consent of both parties. The agreement is classified as a noncancellable operating lease of more than one year.

The annual rental cost for the land was $48,355 and $46,662 for 2007 and 2006, respectively.

The future minimum rental payments are:

Year	Minimum Rental Payment
2008	$ 49,080
2009	49,080
2010	49,080
2011	49,080
2012	49,080
2013-2017	245,400
2018-2021	166,278
Total	**$657,078**

NOTE 16 – EXTRAORDINARY ITEM

The Finley CT Plant was constructed in 2001 to provide insurance against high market prices; however, as a result of a relatively high heat rate and the high cost of natural gas fuel, the facility rarely operated. During 2006, the District evaluated alternatives to maximize the value of the plant including its use as an emergency power supply for critical community infrastructure during a disaster. The analysis resulted in a recommendation to sell the plant and in November 2006, the Commission declared the Finley CT surplus to the District's needs. A Request for Proposals to purchase the plant was issued in late January 2007 with responses due in mid-February. The plant was declared unavailable for use in late February. The sale of the plant was finalized in May 2007 and an extraordinary loss of $9.8 million was recorded.

NOTE 17 – SUBSEQUENT EVENTS

The District intends to replace or renew the $10 million revolving line of credit. It is planned that this renewal/replacement Note will have a maturity of March 31, 2011 (see Note 6).

Required Supplementary Information

Retiree Medical Insurance Benefit
Schedule of Funding Progress

Actuarial Valuation Date	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) – Unit Credit Cost Method (b)	Unfunded AAL (UAAL) (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAAL as a Percentage of Covered Payroll [(b-a)/c]
12/31/07	-	$108,245	$108,245	0	$9,972,796	1.09%

STATISTICAL

SECTION


Altec

STATISTICAL SECTION

This part of the District's comprehensive annual financial report presents detailed information as a context for understanding what the information in the financial statements, note disclosures, and required supplementary information says about the District's overall financial health.

FINANCIAL TRENDS

These schedules contain trend information to help the reader understand how the District's financial performance and well-being have changed over time.

REVENUE CAPACITY

These schedules contain information to help the reader assess the District's most significant revenue source, electric sales.

DEBT CAPACITY

These schedules present information to help the reader assess the affordability of the District's current levels of outstanding debt and the ability of the District to issue additional debt in the future.

DEMOGRAPHIC AND ECONOMIC INFORMATION

These schedules offer demographic and economic indicators to help the reader understand the environment within which the District's financial activities take place.

OPERATING INFORMATION

These schedules contain service and infrastructure data to help the reader understand how the information in the District's financial report relates to the services the District provides and the activities it performs.

STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET ASSETS

For the years ended December 31

	2007	2006	2005	2004
OPERATING REVENUES				
Sales of Electric Energy - Retail [1]	$92,388,210	$95,549,937	$101,111,740	$101,177,165
Energy Sales for Resale	42,922,151	46,585,675	39,350,618	32,452,008
Transmission of Power for Others	279,687	256,781	238,040	198,591
Broadband Revenue	787,589	461,276	315,469	161,447
Other Revenue	1,745,868	2,126,721	1,635,971	1,379,005
Total Operating Revenues	138,123,505	144,980,390	142,651,838	135,368,216
OPERATING EXPENSES				
Purchased Power	83,330,863	88,171,300	92,225,135	84,134,802
Purchased Transmission & Ancillary Services	9,385,236	9,713,193	8,776,993	8,336,489
Generation	169,339	671,606	1,440,302	1,319,742
Transmission Operations & Maintenance	24,376	53,432	17,321	154,426
Distribution Operations & Maintenance	6,254,249	6,883,927	6,358,739	6,291,634
Broadband Expense	692,390	582,999	471,082	404,573
Customer Accounting, Collection and Information	3,854,630	4,062,499	3,700,101	3,358,095
Administrative & General	5,405,180	5,243,565	5,098,364	4,875,823
Taxes	9,884,911	10,096,882	10,638,538	10,022,182
Depreciation & Amortization	10,084,084	10,156,431	9,951,985	9,270,588
Total Operating Expenses	129,085,258	135,635,834	138,678,560	128,168,354
OPERATING INCOME (LOSS)	**9,038,247**	**9,344,556**	**3,973,278**	**7,199,862**
NON-OPERATING REVENUES & EXPENSES				
Interest & Other Non-Operating Income	1,762,210	1,960,710	1,674,427	569,733
Interest Expense & Other Non-Operating Expense	(2,533,496)	(3,319,058)	(3,807,972)	(4,198,458)
Debt Discount & Expense Amortization	(21,519)	(553,124)	(209,324)	(113,865)
Gain (Loss) in Joint Venture	(555,095)	(912,323)	(449,138)	(574,560)
Total Non-Operating Revenues & Expenses	(1,347,900)	(2,823,795)	(2,792,007)	(4,317,150)
INCOME (LOSS) BEFORE CONTRIBUTIONS AND EXTRAORDINARY ITEM	**7,690,347**	**6,520,761**	**1,181,271**	**2,882,712**
CAPITAL CONTRIBUTIONS [2]	**6,099,714**	**1,491,180**	**1,951,640**	**1,841,166**
EXTRAORDINARY ITEM	**(9,755,303)**	**-**	**-**	**-**
CHANGE IN NET ASSETS	**$4,034,758**	**$8,011,941**	**$3,132,911**	**$4,723,878**

NET ASSETS

For the years ended December 31

	2007	2006	2005	2004
Invested in Capital Assets, Net of Related Debt	$53,979,188	$60,651,818	$47,804,295	$48,450,170
Unrestricted	40,629,000	29,921,612	34,757,194	30,978,408
Total Net Assets	$94,608,188	$90,573,430	$82,561,489	$79,428,578

(1) Governmental Accounting Standards Board Statement No. 34 was implemented effective 2002 reclassifying bad debt expense as a direct deduction of Retail Sales. All prior years have been restated for comparative purposes.

(2) Governmental Accounting Standards Board Statement No. 33 was implemented effective 2001 reclassifying contributions in aid of construction as revenue. Calendar year 2000 was restated for comparative purposes.

2003	2002	2001	2000	1999	1998
$99,074,832	$92,900,867	$69,513,163	$72,254,487	$67,931,121	$66,044,368
33,065,979	13,629,442	11,455,832	10,027,175	225,602	207,860
268,955	419,896	1,001,978	807,972	606,318	339,124
52,876	6,538	-	-	-	-
1,196,174	1,223,392	1,031,762	854,573	840,824	810,856
133,658,816	108,180,135	83,002,735	83,944,207	69,603,865	67,402,208
85,034,770	65,573,174	43,291,151	40,973,729	34,656,326	34,097,982
9,319,269	9,746,736	8,378,725	6,381,077	5,799,104	4,855,605
2,678,635	8,436,576	2,034,379	-	-	-
216,643	174,812	95,395	52,242	8,385	17,515
5,991,928	5,063,932	5,567,616	5,091,473	4,561,544	5,154,186
288,320	159,489	47,757	-	-	-
3,250,414	3,269,614	3,497,386	2,726,404	2,447,479	1,795,429
4,502,408	4,756,135	5,444,556	4,330,378	4,393,632	4,198,933
10,315,133	9,415,620	7,386,595	7,203,783	7,513,308	7,223,701
8,800,473	7,038,619	5,714,137	5,331,998	5,050,523	4,665,747
130,397,993	113,634,707	81,457,697	72,091,084	64,430,301	62,009,098
3,260,823	**(5,454,572)**	**1,545,038**	**11,853,123**	**5,173,564**	**5,393,110**
248,093	551,108	1,051,003	1,227,833	842,071	1,416,336
(3,887,870)	(3,111,569)	(2,315,586)	(2,383,234)	(2,564,897)	(2,730,145)
(245,253)	(135,733)	(35,962)	(66,177)	(66,177)	(102,858)
(444,361)	(368,388)	57,189	-	-	-
(4,329,391)	(3,064,582)	(1,243,355)	(1,221,578)	(1,789,003)	(1,416,667)
(1,068,568)	**(8,519,154)**	**301,683**	**10,631,545**	**3,384,561**	**3,976,443**
2,930,868	**6,951,770**	**1,325,750**	**1,122,378**	**-**	**-**
-	**-**	**-**	**418,840**	**-**	**-**
$1,862,300	**($1,567,384)**	**$1,627,433**	**$12,172,763**	**$3,384,561**	**$3,976,443**

2003	2002	2001	2000	1999	1998
$46,564,150	$54,257,706	$48,668,840	$51,455,113	$43,040,684	$34,901,135
28,140,550	18,584,694	25,740,944	21,327,238	17,568,905	19,788,167
$74,704,700	$72,842,400	$74,409,784	$72,782,351	$60,609,589	$54,689,302

REVENUES AND CONSUMPTION BY CUSTOMER CLASS

For the years ended December 31

	2007	2006	2005	2004
Average Number of Customers				
Residential	37,969	37,418	36,963	36,285
General Service	5,077	4,931	4,903	4,869
Industrial	3	3	3	3
Irrigation	717	713	718	729
Miscellaneous	1,804	1,790	1,802	1,823
Total	45,570	44,855	44,389	43,709
Retail Electric Sales (in thousands) (1)				
Residential	$42,765	$44,778	$46,461	$47,664
General Service	27,282	29,259	30,478	30,651
Industrial	1,790	1,444	1,995	2,483
Irrigation	15,764	15,485	17,136	16,294
Miscellaneous	744	824	832	827
Total	$88,345	$91,790	$96,902	$97,919
Retail Electric Sales in MWh				
Residential	644,392	632,213	622,639	621,386
General Service	503,551	510,052	521,308	523,388
Industrial	49,045	37,456	53,286	69,479
Irrigation	402,251	368,048	397,651	375,363
Miscellaneous	8,026	7,941	7,625	7,438
Total	1,607,265	1,555,710	1,602,508	1,597,054
Average Revenue per kWh (cents) (1)				
Residential	6.64	7.08	7.46	7.67
General Service	5.42	5.74	5.85	5.86
Industrial	3.65	3.86	3.74	3.57
Irrigation	3.92	4.21	4.31	4.34
Miscellaneous	9.27	10.38	10.92	11.11
Average - All Classes	5.50	5.90	6.05	6.13

(1) Includes total retail revenue (per kWh charge and base charge); excludes city utility occupation tax, bad debt expense, and accrued unbilled revenue.

(2) Changed methodology for customer counts in 2002 due to new Customer Information System. 2001 customer counts for General Service, Irrigation, and Miscellaneous classes represent an average of counts for 2000 and 2002.

2003	2002 [2]	2001	2000	1999	1998
35,576	34,872	34,854	34,678	33,625	33,162
4,761	4,649	4,567	4,484	4,369	4,272
3	3	3	3	3	3
739	739	733	727	723	724
1,797	1,681	1,664	1,647	1,596	1,557
42,876	41,944	41,821	41,539	40,316	39,718
$46,335	$41,277	$32,177	$30,749	$28,862	$28,842
29,043	25,961	20,291	19,464	18,617	18,170
2,291	3,044	1,772	7,382	5,728	6,064
16,375	15,061	11,851	11,393	11,600	9,828
794	699	602	623	608	617
$94,838	$86,042	$66,693	$69,612	$65,414	$63,521
604,618	622,196	617,763	636,952	594,533	597,305
509,057	496,949	500,356	530,430	502,753	491,150
58,054	80,551	70,897	220,913	219,640	232,546
401,868	382,551	375,683	385,753	400,394	336,626
7,154	5,432	5,284	5,208	5,085	4,912
1,580,751	1,587,678	1,569,982	1,779,257	1,722,405	1,662,540
7.66	6.63	5.21	4.83	4.85	4.83
5.71	5.22	4.06	3.67	3.70	3.70
3.95	3.78	2.50	3.34	2.61	2.61
4.07	3.94	3.15	2.95	2.90	2.92
11.10	12.88	11.39	11.96	11.95	12.55
6.00	5.42	4.25	3.91	3.80	3.82

RETAIL RATES (1)

For the years ended December 31

	2007	2006	2005	2004
Residential				
Monthly Base Charge (Single Phase)	$8.80	$9.15	$9.55	$10.05
Energy Charge (cents/kWh)	6.02	6.28	6.54	6.87
Small General Service				
Monthly Base Charge	$11.25	$11.75	$12.25	$12.51
Energy Charge Effective 2001 (cents/kwh)				
First 20,000 kwh	5.39	5.64	5.87	5.98
Over 20,000 kwh	3.46	3.62	3.77	3.84
Summer Prior to 2001				
First 2,500 kwh	-	-	-	-
Next 17,500 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter Prior to 2001				
First 2,500 kwh	-	-	-	-
Next 17,500 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Medium General Service (New Class Effective 1997)				
Monthly Charge	$13.90	$14.55	$15.15	$15.28
Energy Charge (cents/kwh)				
Summer Effective 2001				
First 20,000 kwh	4.69	4.81	5.01	5.06
Over 20,000 kwh	2.88	2.95	3.07	3.10
Summer Prior to 2001				
First 2,500 kwh	-	-	-	-
Next 17,500 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter Effective 2001				
First 20,000 kwh	5.52	5.66	5.90	5.96
Over 20,000 kwh	3.49	3.58	3.73	3.77
Winter Prior to 2001				
First 2,500 kwh	-	-	-	-
Next 17,500 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Demand Charge	$7.20	$8.08	$8.42	$8.50
Large General Service				
Monthly Charge	$18.45	$19.10	$19.90	$20.41
Energy Charge (cents/kwh)				
Summer				
First 20,000 kwh	4.62	4.78	4.98	5.11
Over 20,000 kwh	3.07	3.18	3.31	3.39
Winter				
First 20,000 kwh	5.03	5.21	5.43	5.57
Over 20,000 kwh	3.77	3.9	4.06	4.16
Demand Charge	$5.92	$6.13	$6.39	$6.55

(1) These rates represent the typical customer. Other Monthly Charges may apply.
Other rate schedules also in effect are small irrigation, large irrigation, industrial, and miscellaneous.

2003	2002	2001	2000	1999	1998
$10.65	$9.00	$9.00	$6.90	$6.90	$6.90
7.27	6.12	6.12	4.3994	4.3994	4.3994
$12.51	$10.75	$10.75	$7.50	$7.50	$7.50
5.98	5.14	5.14	-	-	-
3.84	3.30	3.30	-	-	-
-	-	-	3.7260	3.7260	3.7260
-	-	-	3.5566	3.5566	3.5566
-	-	-	2.1189	2.1189	2.1189
-	-	-	3.7260	3.7260	3.7260
-	-	-	3.5566	3.5566	3.5566
-	-	-	2.1189	2.1189	2.1189
$15.28	$13.85	$13.85	$10.65	$10.65	$10.65
5.06	4.49	4.49	-	-	-
3.10	2.74	2.74	-	-	-
-	-	-	3.4120	3.4120	3.4120
-	-	-	3.3581	3.3581	3.3581
-	-	-	1.8370	1.8370	1.8370
5.96	5.28	5.28	-	-	-
3.77	3.34	3.34	-	-	-
-	-	-	3.7840	3.7840	3.7840
-	-	-	3.7409	3.7409	3.7409
-	-	-	2.2636	2.2636	2.2636
$8.50	$8.50	$8.50	$6.00	$6.00	$6.00
$20.41	$17.75	$17.75	$13.15	$13.15	$13.15
5.11	4.45	4.45	3.1605	3.1605	3.1605
3.39	2.95	2.95	1.6642	1.6642	1.6642
5.57	4.48	4.48	3.5475	3.5475	3.5475
4.16	3.62	3.62	2.3342	2.3342	2.3342
$6.55	$5.70	$5.70	$5.70	$5.70	$5.70

PRINCIPAL RATEPAYERS

For the years ended December 31

	2007				
Ratepayer's Rate Class [1]	**kWh**	**Rank**	**Percentage of Total kWh**	**Retail Sales**	**Percentage of Total Retail Electric Sales**
Large Irrigation Customer 1	177,254,300	1	11.0%	$6,603,956	7.1%
Large Irrigation Customer 2	64,717,089	2	4.0%	2,452,815	2.7%
Large Industrial Customer 1	49,177,986	3	3.1%	2,368,695	2.5%
Large Irrigation Customer 3	37,022,051	4	2.3%	1,447,361	1.5%
Large Irrigation Customer 4	32,165,136	5	2.0%	1,143,463	1.2%
Large General Customer 1	29,614,404	6	1.8%	1,221,277	1.3%
Large Irrigation Customer 5	22,860,000	7	1.4%	1,073,840	1.1%
Large General Customer 2	21,990,805	8	1.4%	1,697,707	1.8%
Large Irrigation Customer 6	21,869,736	9	1.4%	826,214	0.9%
Large General Customer 3	21,562,738	10	1.3%	1,434,178	1.5%
Large Irrigation Customer 7	-	-	-	-	-
	478,234,245		29.8%	$19,520,358	21.1%
Total All Ratepayers	1,607,264,815			$92,388,210	

(1) To preserve confidentiality, individual ratepayer names are not disclosed.

(2) Revenues for 1998 are estimated based on kWh consumption.

1998				
kWh	Rank	Percentage of Total kWh	Retail Sales[2]	Percentage of Total Retail Electric Sales
136,968,000	2	8.2%	$3,730,466	5.6%
59,582,000	3	3.6%	1,536,789	2.3%
232,584,000	1	14.0%	6,418,059	9.7%
28,654,000	6	1.7%	753,875	1.1%
34,717,000	5	2.1%	822,761	1.2%
44,383,000	4	2.7%	1,634,866	2.5%
18,744,000	9	1.1%	444,216	0.7%
16,276,000	-	1.0%	574,980	0.9%
16,580,000	10	1.0%	426,298	0.6%
22,084,000	7	1.3%	780,158	1.2%
18,987,000	8	1.1%	449,975	0.7%
629,559,000		37.9%	$17,572,442	26.6%
1,662,540,000			$66,044,368	

RATIOS OF OUTSTANDING DEBT

For the years ended December 31

	2007	2006	2005	2004
Revenue Bonds	$55,810,000	$59,855,000	$71,620,000	$74,830,000
Unamortized Premium & Discount & Loss on Defeasance	727,593	782,504	537,328	984,226
Total Outstanding Debt	$56,537,593	$60,637,504	$72,157,328	$75,814,226
Total Revenue Debt to Operating Revenues	41%	42%	51%	56%
Total Revenue Debt to Total Assets	32%	34%	39%	44%
Total Revenue Debt per Ratepayer	$1,241	$1,352	$1,626	$1,735

DEBT MARGIN INFORMATION (1)

For the year ended December 31, 2007

Net Revenues February 2006 - January 2007 (2)	$22,626,308
Maximum Future Annual Debt Service (2015)	$6,372,489
Maximum Allowable Annual Debt Service per Bond Covenants (2)	$18,101,046
Allowable Additional Annual Debt Service	$11,728,557

(1) As a proprietary fund, the District does not have a legal debt limitation. However, the District's bond resolutions establish restrictions on the issuance of additional debt based on a defined formula.

(2) The bond covenants state that new parity bonds may be issued if the amount of net revenue for any twelve consecutive months in the prior 24 month period divided by the maximum annual debt service in any future year is not less than 125%.

2003	2002	2001	2000	1999	1998
$79,105,000	$79,105,000	$65,840,000	$39,800,000	$43,125,000	$46,275,000
1,009,884	916,871	786,137	(689,161)	(690,832)	(692,504)
$80,114,884	$80,021,871	$66,626,137	$39,110,839	$42,434,168	$45,582,496
60%	74%	80%	47%	61%	68%
47%	46%	42%	31%	37%	41%
$1,869	$1,908	$1,593	$942	$1,053	$1,148

DEBT SERVICE COVERAGE

For the years ended December 31

	2007	2006	2005	2004
DEBT SERVICE CALCULATION				
Change in Net Assets	$4,034,758	$8,011,941	$3,132,911	$4,723,878
Adjustments to (from) Change in Net Assets				
Depreciation & Amortization	10,084,084	10,156,431	9,951,985	9,270,588
Interest Expense	2,533,496	3,309,699	3,389,240	3,992,266
Debt Discount & Expense Amortization	21,519	553,124	209,324	113,865
Extraordinary Item	9,755,303	-	-	-
Transfer (to) from Rate Stabilization	2,244,474	-	(1,500,000)	(3,000,000)
REVENUE AVAILABLE FOR DEBT SERVICE	**$28,673,634**	**$22,031,195**	**$15,183,460**	**$15,100,597**
DEBT SERVICE (2)	**$6,957,703**	**$7,407,225**	**$4,783,721**	**$7,599,395**
DEBT SERVICE COVERAGE RATIO	**4.12**	**2.97**	**3.17**	**1.99**

(1) GASB Statement No. 33 was implemented in 2001 reclassifying capital contributions as revenue.

(2) Reduced by capitalized interest.

2003	2002	2001[1]	2000	1999	1998
$1,862,300	($1,567,384)	$1,627,433	$12,172,763	$3,384,561	$3,976,443
8,800,473	7,038,619	5,714,137	5,331,998	5,050,523	4,665,747
3,887,870	3,111,569	2,315,586	2,383,234	2,564,897	2,730,145
245,253	135,733	35,962	66,177	66,177	102,858
-	-	-	(418,840)	-	-
-	-	-	536,406	-	-
$14,795,896	**$8,718,537**	**$9,693,118**	**$20,071,738**	**$11,066,158**	**$11,475,193**
$3,324,395	**$3,396,911**	**$5,739,255**	**$5,740,030**	**$5,744,870**	**$5,572,200**
4.45	**2.57**	**1.69**	**3.50**	**1.93**	**2.06**

PRINCIPAL EMPLOYERS - TRI-CITIES METROPOLITAN STATISTICAL AREA

For the years ended December 31

		2007		
Employer	Product/Service	Employees	Rank	Percentage of Total MSA Nonfarm Employment
Battelle Pacific NW National Laboratory	Research and Development	4,033	1	4.4%
Fluor Hanford Inc.	Environmental Engineering	3,630	2	4.0%
Bechtel National, Inc.	Engineering Services	2,129	3	2.3%
ConAgra/Lamb Weston Inc.	Food Processing	2,129	3	2.3%
Tyson Fresh Meats/Iowa Beef	Meat Packing	1,800	5	2.0%
Kennewick School District	Education	1,700	6	1.9%
Pasco School District	Education	1,538	7	1.7%
Kadlec Medical Center	Health Care	1,436	8	1.6%
Richland School District	Education	1,350	9	1.5%
CH2MHill Hanford Group Inc./CHG	Environmental Engineering	1,170	10	1.3%
Energy Northwest	Electrical Power	-	-	-
Our Lady of Lourdes Health Center	Health Care	-	-	-
Total		20,915		22.8%

Source: TRIDEC list of Tri-Cities Major Employers, November 2007 and November 1998

1998		
Employees[1]	Rank	Percentage of Total MSA Nonfarm Employment
3,057	2	4.3%
7,437	1	10.5%
780	10	1.1%
1,750	3	2.5%
1,300	5	1.8%
1,700	4	2.4%
1,000	7	1.4%
-	-	-
950	8	1.3%
-	-	-
1,066	6	1.5%
800	9	1.1%
19,840		27.9%

DEMOGRAPHIC STATISTICS

For the years ended December 31

	2007	2006	2005	2004
Population [1]				
Tri-Cities Metropolitan Statistical Area	230,300	224,800	218,600	212,100
Benton County	162,900	160,600	158,100	155,100
City of Kennewick	62,520	61,770	60,410	58,970
Prosser	5,075	5,045	5,045	4,985
Benton City	2,860	2,840	2,840	2,815
Total Personal Income - Benton County [2]	N/A	N/A	$4,963,840	$4,766,205
Per Capita Income - Benton County [2]	N/A	N/A	$31,433	$30,572
Unemployment Rate - Benton County [3]	5.2%	5.8%	6.2%	6.5%
Building Permits Issued [4]				
Kennewick	1,963	1,851	1,813	1,859
Benton County (Unincorporated)	639	753	819	945
Taxable Retail Sales - All of Benton County [5]	N/A	$2,303,245,278	$2,226,436,260	$2,081,376,797

(1) Source: Washington State Office of Financial Management
(2) Source: U.S. Bureau of Economic Analysis
(3) Source: Labor Market and Economic Analysis, Washington Employment Security Department
(4) Source: City of Kennewick and Benton County Building Departments
(5) Source: Washington State Department of Revenue

2003	2002	2001	2000	1999	1998
205,200	198,900	195,200	191,822	186,800	183,965
151,600	147,600	144,800	142,475	138,900	137,500
57,900	56,280	55,780	54,693	50,950	50,390
4,940	4,905	4,865	4,838	4,901	4,854
2,790	2,725	2,720	2,624	2,208	2,171
$4,568,266	$4,372,108	$4,103,136	$3,801,367	$3,537,105	$3,358,499
$29,689	$29,086	$28,141	$26,566	$25,152	$24,227
7.2%	6.3%	6.6%	6.5%	5.6%	6.6%
1,981	1,999	1,711	1,622	1,707	1,3302
1,018	1,076	919	876	959	931
$2,020,400,388	$1,916,804,636	$1,801,558,310	$1,606,308,596	$1,572,739,733	$1,433,840,783

OPERATING INDICATORS

For the years ended December 31

	2007	2006	2005	2004
Operating Expenses / Revenues	93.5%	93.6%	97.2%	94.7%
Total Electric Sales in MWh				
Retail Sales	1,607,265	1,555,710	1,602,508	1,597,054
Sales for Resale	771,347	845,768	563,061	723,913
Total MWh Sales	2,378,612	2,401,478	2,165,569	2,320,967
Average Annual kWh per Customer				
Residential	16,972	16,896	16,845	17,125
General Service	99,183	103,438	106,324	107,494
Industrial	16,348,383	12,485,305	17,761,932	23,159,528
Irrigation	561,019	516,196	553,832	514,901
Miscellaneous	4,449	4,436	4,231	4,080
Average Annual kWh per Customer - All Classes	35,270	34,683	36,101	36,538
Average Revenue per Customer				
Residential	$1,126	$1,197	$1,257	$1,314
General Service	5,374	5,934	6,216	6,295
Industrial	596,832	481,482	664,988	827,817
Irrigation	21,986	21,718	23,866	22,352
Miscellaneous	412	460	462	453
Average Revenue per Customer - All Classes	$1,939	$2,046	$2,183	$2,240
Additions to Electric Plant, excluding work-in-progress (1)	$15,578,938	$7,484,509	$8,296,645	$9,107,460
Net Utility Plant	$109,916,268	$119,838,966	$118,503,253	$122,188,107
Capitalized Payroll	$1,998,843	$1,570,018	$1,806,542	$1,968,011
Total Payroll Expense	$10,583,678	$10,769,446	$10,133,591	$9,687,480
Average Number of Employees(2)	159	163	162	160
Power Outages	355	313	330	333
Power Outages Caused by Squirrels	54	38	42	37
Cooling Degree Days (3)	1,070	1,166	989	1,135
Heating Degree Days (3)	5,223	5,140	5,145	4,930
Annual Precipitation (inches) (3)	5.48	8.46	6.37	7.96

(1) The Nine Canyon Wind Farm Generating Facility Substation, completed at a cost of $5.3 million, was added to the Electric Plant account in 2002. Additonal capital of $2.1 million was added in 2007.

(2) Includes regular and temporary employees.

(3) Source: Hanford Meteorological Station.
Heating degree days are indicators of household energy consumption for space heating. When the average outdoor temperature is less than 65 degrees Fahrenheit, most buildings require heat to maintain a temperature of 70 degrees inside. Similarily, when the average outdoor temperature is 65 degrees or more, most buildings require air-conditioning to maintain a temperature of 70 degrees inside.

2003	2002	2001	2000	1999	1998
97.6%	105.4%	98.5%	86.7%	93.5%	92.2%
1,580,751	1,587,678	1,569,982	1,779,257	1,722,405	1,662,540
819,435	615,694	200,639	50,426	33,171	15,364
2,400,186	2,203,372	1,770,621	1,829,683	1,755,576	1,677,904
16,995	17,842	17,724	18,368	17,681	18,012
106,922	106,894	109,571	118,294	115,073	114,970
19,351,268	26,850,190	23,632,237	73,637,600	73,213,460	77,515,367
543,800	517,660	512,528	530,610	553,795	464,954
3,981	3,231	3,176	3,162	3,186	3,155
36,868	37,852	37,541	42,833	42,723	41,859
$1,302	$1,184	$923	$887	$858	$870
6,100	5,584	4,443	4,341	4,261	4,253
763,762	1,014,690	590,735	2,460,655	1,909,431	2,021,406
22,158	20,380	16,168	15,672	16,044	13,575
442	416	362	378	381	396
$2,212	$2,051	$1,595	$1,676	$1,623	$1,599
$10,023,480	$17,607,642	$27,548,676	$10,040,300	$9,881,730	$10,798,495
$123,699,242	$121,809,610	$111,672,899	$89,980,118	$84,920,685	$80,258,631
$2,017,656	$1,486,016	$1,530,209	$1,273,076	$1,162,695	$1,002,952
$9,321,808	$9,112,720	$8,759,127	$8,179,105	$7,665,655	$7,235,118
159	161	157	154	151	144
292	342	400	448	563	732
41	59	71	83	147	254
1,331	1,131	1,092	903	932	1,377
4,742	4,954	4,966	5,399	4,731	4,508
8.14	5.41	6.66	8.08	3.75	6.45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