BENTON PUD 2009 ANNUAL REPORT





THE POWER OF FORWARD THINKING

COMPREHENSIVE ANNUAL

FINANCIAL REPORT

PUBLIC UTILITY DISTRICT NO. 1 OF BENTON COUNTY, WASHINGTON
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2009

BENTON P·U·D





COMPREHENSIVE ANNUAL FINANCIAL REPORT

PUBLIC UTILITY DISTRICT NO.1
OF BENTON COUNTY, WASHINGTON
FOR THE FISCAL YEAR
ENDED DECEMBER 31, 2009

Prepared by Finance and Business Services
Communications and Governmental Relations

CORE PURPOSE

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

M I S S I O N

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

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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.





INTRODUCTORY SECTION

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, 2008

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

COMMISSION AND MANAGEMENT

THE POWER OF THINKING AHEAD

In the late 1800's, Thomas Edison took the mere idea of electric lighting and developed a practical incandescent light bulb. By combining the technology at the time with vision, he made the light bulb convenient, safe, and economical and created a system to bring electricity to homes and businesses.

Today we rely on power in ways even Edison never dreamed of - from charging cell phones to charging cars – electricity is the foundation of our quality of life and economy. But with this growing need for electricity, comes the challenge to meet the demand with reliable low cost power.

While technology has increased the need for power, it is technology that will enable utilities to be prepared for the future. This takes long range planning, vision and innovation.

This past year, after research and planning, Benton PUD began the first steps to integrate the latest technologies needed for smart grid by installing new meters systematically throughout our service area. Once fully deployed, the new meters will be able to provide information on electricity usage, power quality, and signal an outage. In the future, customers will be able to access information about power use to monitor and manage their energy usage resulting in savings for both the customer and Benton PUD. It positions Benton PUD well financially and technically for the evolving requirements of the smart grid and the next generation of equipment and market conditions expected to emerge in the coming years. The project is just one example of Benton PUD's focus on the future.

It takes more than just poles and wires to deliver power to our customers. Benton PUD has made prudent investments in technologies, from meters to software, at the same time balancing costs and customer needs.

The power of thinking ahead was evident in Edison's vision of the light bulb and the power of thinking ahead is evident as Benton PUD embraces technologies today for our customers tomorrow.

2009 BOARD OF COMMISSIONERS

Jim Sanders
General Manager

Lori Kays-Sanders
President

Jeff Hall
Secretary

Bob Bertsch
Vice President

Chad Bartram
Assistant General Manager &
Director of Finance & Business Services

LETTER OF TRANSMITTAL

May 1, 2010

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, 2009 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, 2009.

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, 2009 and 2008. 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 (BPA) and purchases most of its power from BPA. 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 90 miles of 115kV transmission line, 1,582 miles of distribution lines, and other buildings, equipment, stores and related facilities.

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 the District service territory), 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.

While the Tri-Cities is not immune to the country's economic struggles, it has weathered the national recession better than many areas. The federal economic stimulus package is providing $2 billion in funding to Hanford. Through 2009, 3,999 jobs have been saved or created translating to 1,538 full-time equivalents as a result of the stimulus package at Hanford. The funding will help stabilize the local economy and retain the already highly-skilled workforce.

The Tri-Cities gained 3,400 nonfarm jobs during the year with growth in administrative and waste service sectors, health services, financial services, and government. The Tri-Cities continues to be a regional shopping destination for communities throughout southeastern Washington and northeastern Oregon leading to continued growth in the retail service industry. Although housing construction employment is down, the real estate market is stable compared to other communities nationwide.

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 establish 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 provide for maintaining a debt ratio at 38% or less. The financial policies call for developing financial plans to maintain operating reserves sufficient to provide funding for 90 days of non-power expenses, 10% of gross power expenses, and one year average annual debt service.

The District has adopted new policies related to reserve levels that are effective beginning in 2012 that call for developing financial plans to maintain minimum end-of-year unrestricted reserves sufficient to provide funding for the sum of: 1) 12.5% of budgeted operating expenses; 2) the difference between the 75% and 95% probability of attainment of net power expense (the District budgets at the 75% probability of attainment); 3) 2% of the historical investment in assets as recorded in the prior year for catastrophic losses; 4) 83.3% of the annual debt service payment required in the following year; and 5) 30% of the average projected capital requirements based on the projected five-year capital plan. The Commission periodically reviews these policies.

RELEVANT FINANCIAL POLICIES

No rate action was required in 2009 as a result of meeting the requirements of the District's financial policies. However, as a result of projected rising wholesale power costs in future years, the District increased retail rates an average of six percent effective January 1, 2010 and anticipates the need for future retail rate increases in order to meet targets established in financial policies.

MAJOR INITIATIVES

The District is implementing advanced metering infrastructure (AMI) over the next several years. The project involves installing meters that can communicate remotely at all service points. The project started in 2009 with approximately half of residential meters installed at the end of the year. By installing these meters, the District will be able to read meters remotely and perform certain meter functions remotely. These meters will allow the District to achieve cost savings as well as provide a foundation for future smart grid initiatives

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, 2008. This was the seventh 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.

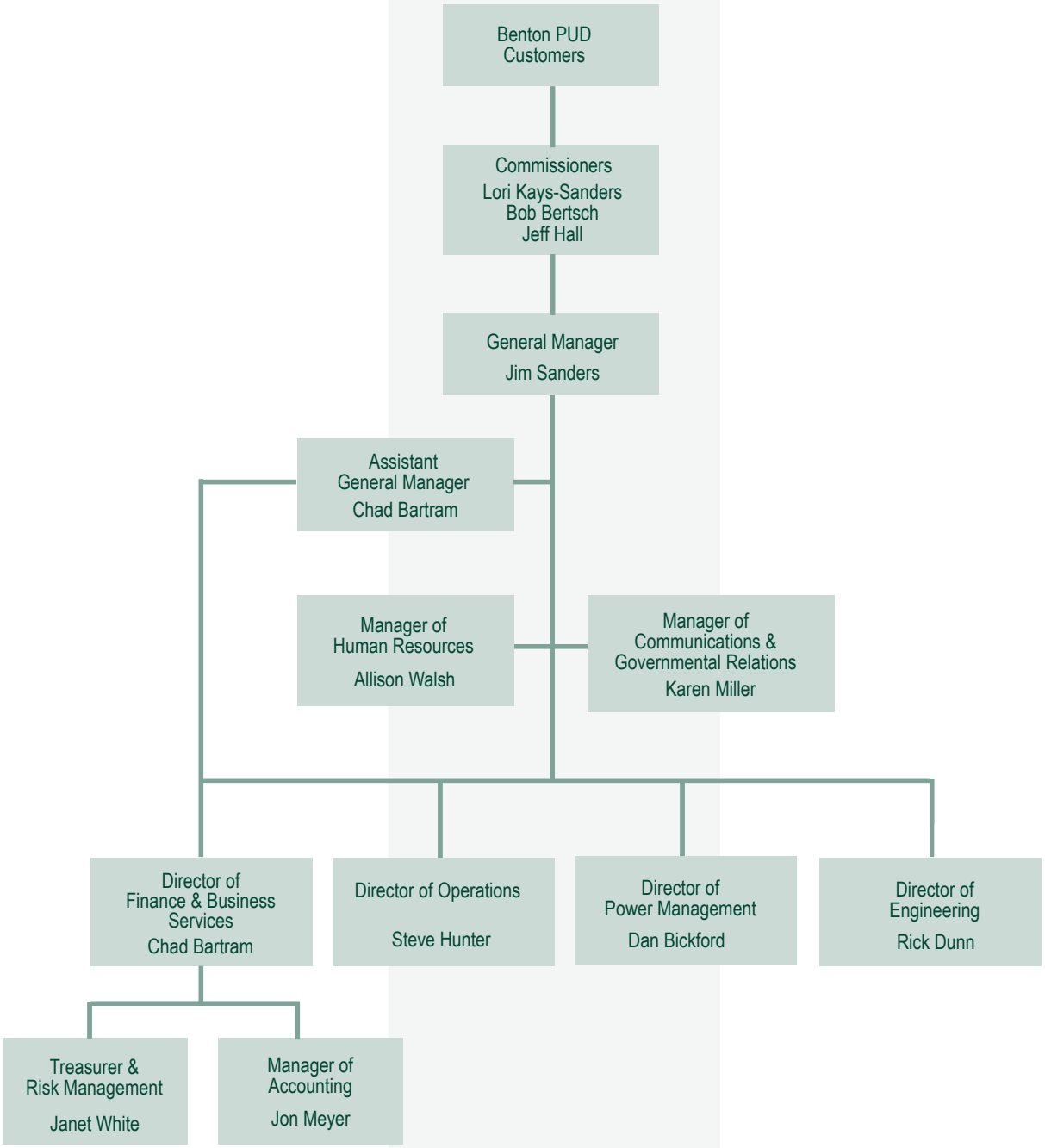
Preparation of the Comprehensive Annual Financial Report was made possible by the dedicated service of the entire staff of the Finance and Business Services and the Communications and Governmental Relations Departments. We wish to express our appreciation to these staff members for their contributions 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
Assistant General Manager
Director of Finance and Business Services

ORGANIZATIONAL CHART







FINANCIAL SECTION

Washington State Auditor
Brian Sonntag

INDEPENDENT AUDITOR'S REPORT

April 27, 2010

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

We have audited the accompanying basic financial statements of Public Utility District No. 1 of Benton County, Washington, as of and for the years ended December 31, 2009 and 2008 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 and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our 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 Public Utility District No. 1 of Benton County, Washington, as of December 31, 2009 and 2008, and the changes in financial position and cash flows thereof for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1, during the year ended December 31, 2009, the District has implemented the Governmental Accounting Standards Board Statement No. 53 - Accounting and Financial Reporting for Derivative Instruments.

In accordance with *Government Auditing Standards*, we will also issue our report dated April 27, 2010, on our consideration of the District's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audit.

The management's discussion and information on post employment benefits other than pensions are not required parts of the basic financial statements but are 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 are presented for purposes of additional analysis and are not required parts 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

Insurance Building, P.O. Box 40021 ⅄ Olympia, Washington 98504-0021 ⅄ (360) 902-0370 ⅄ TDD Relay (800) 833-6388
FAX (360) 753-0646 ⅄ http://www.sao.wa.gov

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, 2009 and 2008, with additional comparative data for 2007. 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, 2009 and 2008, 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, 2008 The District had restricted net assets of $86,955 at December 31, 2009.

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)*

	2009	2008	Increase (Decrease) 2009-2008	% Change 2009-2008	2007
Current & Other Assets	$64,555	$74,233	($9,678)	-13%	$59,576
Capital Assets	115,807	110,029	5,778	5%	109,916
Total Assets	$180,363	$184,262	($3,899)	-2%	$169,492
Other Liabilities	$15,125	$13,853	$1,272	9%	$15,685
Long-Term Liabilities	54,371	71,354	(16,983)	-24%	59,199
Total Liabilities	$69,496	$85,207	($15,711)	-18%	$74,884
Invested in Capital Assets, *net of related debt*	$64,783	$56,393	$8,390	15%	$53,979
Restricted	87	-	87	-	-
Unrestricted	45,997	42,662	3,335	8%	40,629
Total Net Assets	$110,867	$99,055	$11,812	12%	$94,608

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

	2009	2008	Increase (Decrease) 2009-2008	% Change 2009-2008	2007
Operating Revenues					
Retail Energy Sales	$91,942	$86,237	$5,705	7%	$92,388
Sales for Resale	39,115	53,414	(14,299)	-27%	43,202
Other	2,276	2,308	(32)	-1%	2,532
Nonoperating Revenues					
Interest Income	252	1,148	(896)	-78%	1,676
Other Income	107	50	57	114%	87
Total Revenues	133,691	143,157	(9,465)	-7%	139,885
Operating Expenses					
Power Supply	85,809	102,191	(16,382)	-16%	92,885
Operations and Maintenance	17,269	16,951	318	2%	16,231
Taxes/Depreciation/Amortization	19,324	18,567	757	4%	19,969
Nonoperating Expenses					
Interest & Other Nonoperating Expense	2,278	2,443	(165)	-7%	2,533
Debt Discount & Expense Amortization	34	40	(6)	-15%	22
Loss in Joint Venture/Special Assessments	236	403	(166)	-41%	555
Total Expenses	124,952	140,596	(15,644)	-11%	132,195
Income (Loss) before Contributions	8,740	2,561	6,179	241%	7,690
Capital Contributions	3,072	1,885	1,187	63%	6,100
Extraordinary Item					(9,755)
Change in Net Assets	11,812	4,446	7,365	166%	4,035
Beginning Net Assets	99,055	94,608	4,446	5%	90,573
Ending Net Assets	$110,867	$99,055	$11,812	12%	$94,608

Financial Analysis

During 2009, the District's overall financial position and results of operation improved. The District's net assets increased by $11.8 million compared to an increase in net assets of $4.4 million in 2008. 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 2009 and 2008.

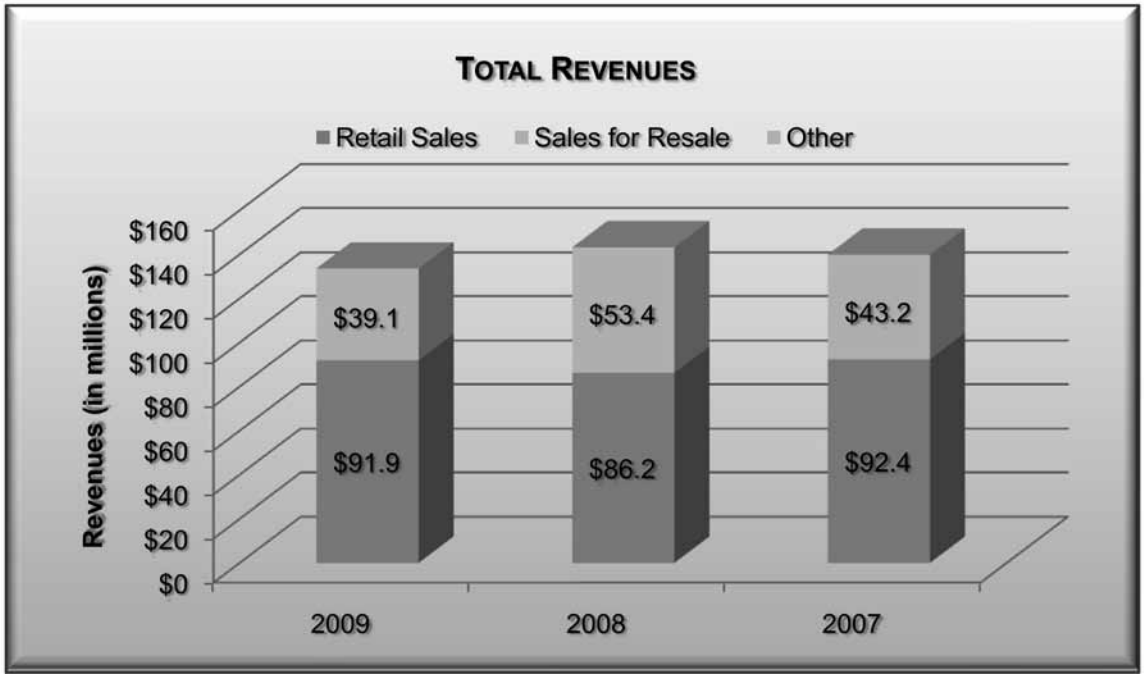
Operating Revenues

2008 to 2009:
Revenues from sales to retail customers (Retail Energy Sales) in 2009 increased $5.7 million (7%) from 2008. This was primarily a result of 5% increase in kilowatt hours sold to customers in 2009 compared to 2008. In addition, a temporary rate credit ended in 2009. The rate credit was designed to return an $8 million residential exchange settlement received from the Bonneville Power Administration (BPA) to District customers over a 12-month period. In 2009, $3.4 million was returned to customers compared with $4.9 million returned in 2008.

Revenues from wholesale energy and natural gas sales (Sales for Resale) decreased by $14.3 million (27%) primarily as a result of higher retail demand than expected. In addition, wholesale market prices were not as favorable in 2009. The average annualized price for Sales for Resale decreased from $63 per MWh in 2008 to $58 per MWh in 2009.

2007 to 2008:
Revenues from sales to retail customers (Retail Energy Sales) in 2008 decreased $6.2 million (7%) from 2007. This was primarily a result of a 4% average retail rate reduction effective January 1, 2008, coupled with a temporary rate credit that returned $4.8 million to customers. The District experienced a 2% increase in kilowatt hours (kWh) sold to customers in 2008 compared to 2007, partially offsetting the rate reductions.

Revenues from wholesale energy and natural gas sales (Sales for Resale) increased by $10.2 million (24%) primarily as a result of strong market prices and an effective hedging strategy. In addition to a 6% increase in megawatt hours (MWh) of sales for resale, the average annualized price increased from $54 per MWh in 2007 to $63 per MWh in 2008.



Operating Expenses

2008 to 2009:

Gross power supply expense decreased by $16.4 million (16%), primarily as a result of less power purchased to meet hedged wholesale power sales due to a decline in market price. In addition, net power expense (gross power supply expense less sales for resale) decreased by $2.1 million (4%) as the decrease in gross power supply expense of $16.4 million was accompanied by a decrease of $14.3 million in Sales for Resale. The District uses net power expense as a means to measure overall financial performance related to power supply management.

Operations and maintenance expense increased by $0.3 million (2%). The District charges internal labor to operations and maintenance activities and capital projects. In 2009, the internal labor required for capital projects increased $0.4 million from 2008, while internal labor performed on operations and maintenance activities increased $0.2 million.

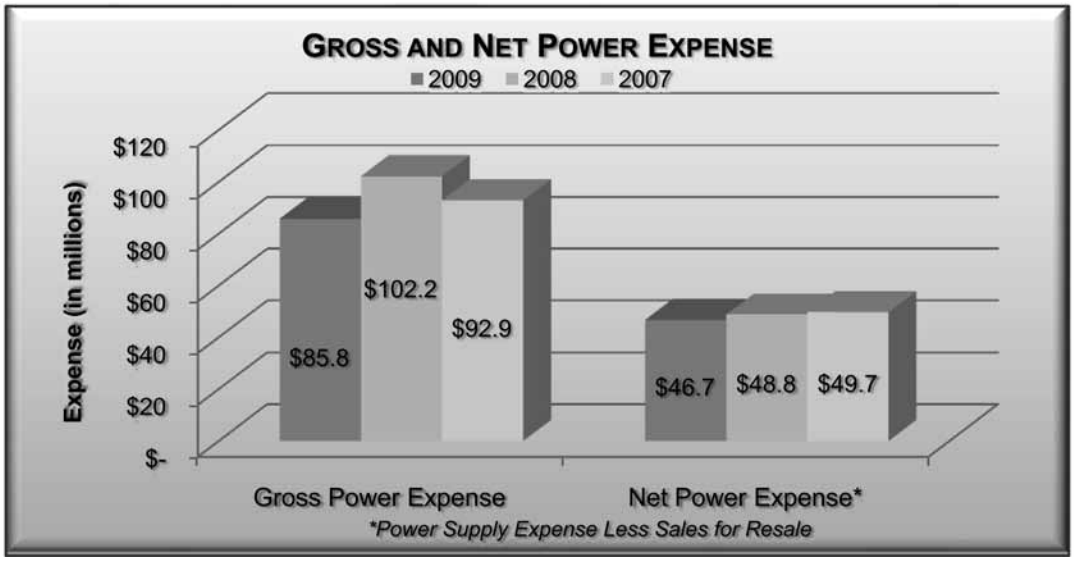
Taxes assessed by state and municipal governments increased by $0.8 million (8%) primarily as a result of an increase in Retail Energy Sales. Depreciation and amortization was unchanged from 2008 primarily as a result of several information systems reaching the end of their depreciable period offsetting increases in depreciation from other capital additions for the year.

2007 to 2008:

Gross power supply expense increased by $9.3 million (10%), primarily as a result of purchasing power in the market when Slice production (see Note 10) was lower than planned during the fall. Despite the increase in gross power supply expense, net power expense (gross power supply expense less sales for resale) decreased by $1.0 million (2%) as a result of the increase in sales for resale.

Operations and maintenance expense increased by $0.7 million (4%). In 2008, the internal labor required for capital projects remained at a level similar to 2007, while internal labor performed on operations and maintenance activities increased $0.4 million. In addition, materials and supplies expense and other purchased services increased by $0.2 million.

Taxes assessed by state and municipal governments decreased by $0.7 million (7%) primarily as a result of a decrease in Retail Energy Sales. Depreciation and amortization decreased by $0.7 million (7%) as a result of decreased plant and equipment in-service due to the sale of the Finley Combustion Turbine (CT) Plant in May 2007.



Other Income & Expense

During 2009, interest income decreased by $0.9 million due to lower investment rates. The average investment rate of the Washington State Treasurer's Local Government Investment Pool (LGIP) decreased from 2.7% in 2008 to 0.7% in 2009. Loss in Joint Ventures/Special Assessments decreased by $0.2 million due to reductions in assessments by GHFB, LLP and NoaNet (see Notes 12 and 13).

From 2007 to 2008, interest income decreased by $0.5 million due to lower investment rates and a reduction in invested balances resulting from the White Creek Wind Project purchase in September. The average investment rate of the Washington State Treasurer's LGIP decreased from 5.1% in 2007 to 2.7% in 2008. Loss in Joint Ventures/Special Assessments decreased by $0.2 million due to reductions in assessments by GHFB, LLP and NoaNet.

Capital Contributions

During 2009, capital contributions increased by $1.2 million (63%) primarily due to completion of a fiber build-out to connect surrounding communities.

From 2007 to 2008, capital contributions decreased $4.2 million (69%) primarily attributable to a one-time $4.3 million contribution billed to Energy Northwest in 2007 for the completion of Phase III of the Nine Canyon Wind Farm.

Summary of Financial Position

The overall financial position of the District improved during 2009 with an increase in net assets of $11.8 million. The District sets retail rates based on conservative assumptions. Through prudent planning and cost control, the District was able maintain rates in 2009 and reduce rates in both 2008 and 2007, while simultaneously reducing outstanding debt and maintaining strong cash and investment reserves.

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 $31.0 million, $28.7 million, and $33.5 million at December 31, 2009, 2008 and 2007, 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 2009, 2008 and 2007, the District's debt service coverage was 4.57, 3.18, and 4.12, respectively. Debt service coverage for 2007 was 3.80 prior to a $2.2 million transfer from the Rate Stabilization account.

Capital Asset and Long-Term Debt Activity

During 2009, gross capital additions excluding construction work-in-progress totaled $10.7 million. Capital contributions associated with these additions totaled $3.1 million. Major capital additions included implementation of an Advanced Metering Infrastructure, as well as capital additions associated with improvements to existing distribution infrastructure, a 1.0% growth in customers served by the District, and internal capital expenditures to meet District needs. Construction work-in-progress totaled $8.5 million at year-end, a net increase of $4.9 million over 2008.

During 2008, gross capital additions excluding construction work-in-progress totaled $10.4 million. Capital contributions associated with these additions totaled $1.9 million. Major capital additions included implementation of a geographical information system workflow management system, vendor selection and the initial implementation phase of a system-wide Advanced Metering Infrastructure, as well as capital additions associated with improvements to existing distribution infrastructure, a 1.7% growth in customers served by the District, and internal capital expenditures to meet District needs. Construction work-in-progress totaled $3.7 million at year-end, a net decrease of $0.4 million over 2007.

There were no long-term debt issuances in 2009 or 2008.

During 2009, the District provided updates to Moody's, Standard & Poor's (S&P) and Fitch Ratings. The District's rating from Moody's was affirmed at A2, stable outlook. The District's rating from Fitch was affirmed at A, stable outlook. S&P did not issue an update to their previous A, stable outlook, rating.

Debt service payments totaled $5.1 million in 2009, $5.1 million in 2008, and $7.0 million in 2007.

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

Other Significant Matters

The District implemented an average 6% retail rate increase effective January 1, 2010 largely as a result of BPA wholesale rate increases. At this time, the District is anticipating the need for additional rate increases over the next several years to offset increased power supply costs.

The District issued $17.3 million of Build America Bonds on March 16, 2010 to fund capital improvements. Standard & Poor's upgraded the District's rating to A+ from A, stable outlook. Fitch and Moody's affirmed their previous ratings. In addition, the District defeased $6.4 million of the 2001A bonds on March 10, 2010 using cash reserves. As a result of the two transactions, the net increase in the District's outstanding bonds was $10.9 million.

The District's financial policies were modified in 2009 to set revised criteria for unrestricted reserve levels effective in 2012. Based on current forecasts, the new policy is expected to increase minimum reserve levels beginning in 2012.

BALANCE SHEET

As of December 31, 2009 and 2008

ASSETS	2009	2008
CURRENT ASSETS		
Cash & Working Funds	$1,398,280	$1,324,573
Investments (Note 3)	29,557,119	27,382,270
Restricted Fund (Note 1)	86,955	-
Restricted Bond Fund - Principal & Interest	855,875	855,280
Note Receivable, Current Portion	-	650,000
Accounts Receivable, net	8,263,389	8,319,372
Accrued Unbilled Revenues	3,491,000	3,410,000
Inventory - Materials & Supplies	3,007,526	3,027,405
Prepaid Expenses	229,743	46,139
Accrued Electric Revenue	2,585,355	2,062,359
Total Current Assets	**49,475,242**	**47,077,398**
NONCURRENT ASSETS		
Other Receivables (Note 1)	100,000	50,000
Ownership Interest - GHFB (Note 12)	-	25,390
Deferred Charges (Note 4)	14,980,151	27,080,324
Subtotal Noncurrent Assets	**15,080,151**	**27,155,714**
Utility Plant (Note 2)		
Land and Intangible Plant	3,035,413	3,026,677
Electric Plant in Service	224,649,450	216,419,414
Construction Work in Progress	8,520,861	3,653,703
Less: Accumulated Depreciation	(120,398,468)	(113,070,438)
Net Utility Plant	115,807,257	110,029,356
Total Noncurrent Assets	**130,887,408**	**137,185,070**
TOTAL ASSETS	**$180,362,650**	**$184,262,468**
NET ASSETS AND LIABILITIES		
CURRENT LIABILITIES		
Warrants Outstanding	$323,784	$339,728
Accounts Payable	6,669,317	5,782,764
Customer Deposits	992,451	999,109
Accrued Taxes Payable	2,659,671	2,433,229
Other Accrued Liabilities	1,432,001	1,335,832
Accrued Interest Payable	417,542	433,613
Revenue Bonds, Current Portion (Note 6)	2,630,000	2,530,000
Total Current Liabilities	**15,124,765**	**13,854,275**
NONCURRENT LIABILITIES		
Revenue Bonds (Note 6)	48,235,000	50,865,000
Unamortized Premium & Discount & Loss on Defeasance	597,829	663,277
Deferred Credits & Other Liabilities (Note 4)	5,538,551	19,825,308
Total Noncurrent Liabilities	**54,371,380**	**71,353,585**
Total Liabilities	**69,496,145**	**85,207,860**
NET ASSETS		
Invested in Capital Assets, Net of Related Debt	64,782,761	56,392,746
Restricted (Note 1)	86,955	-
Unrestricted	45,996,788	42,661,862
Total Net Assets	**110,866,505**	**99,054,608**
TOTAL NET ASSETS AND LIABILITIES	**$180,362,650**	**$184,262,468**

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, 2009 and 2008

	2009	2008
OPERATING REVENUES		
Sales of Electric Energy - Retail	$91,942,100	$86,236,604
Energy Sales for Resale	38,885,352	53,188,137
Transmission of Power for Others	229,429	225,908
Broadband Revenue	927,041	858,566
Other Revenue	1,348,716	1,449,381
Total Operating Revenues	**133,332,638**	**141,958,596**
OPERATING EXPENSES		
Power Supply & Generation	85,809,370	102,190,931
Transmission Operation & Maintenance	30,026	20,449
Distribution Operation & Maintenance	7,092,143	6,998,119
Broadband Expense	577,958	662,267
Customer Accounting, Collection and Information	4,011,243	3,850,215
Administrative & General Expense	5,557,985	5,420,309
Taxes	9,956,874	9,197,531
Depreciation & Amortization	9,367,272	9,369,594
Total Operating Expenses	**122,402,872**	**137,709,415**
OPERATING INCOME (LOSS)	**10,929,766**	**4,249,181**
NONOPERATING REVENUES & EXPENSES		
Interest Income	251,814	1,148,196
Other Income	106,997	50,048
Other Expense	(18,374)	(460)
Interest Expense	(2,259,809)	(2,442,913)
Debt Discount & Expense Amortization	(34,128)	(40,312)
Gain (Loss) in Joint Ventures	(236,393)	(402,707)
Total Nonoperating Revenues & Expenses	**(2,189,894)**	**(1,688,148)**
INCOME (LOSS) BEFORE CONTRIBUTIONS & EXTRAORDINARY ITEMS	**8,739,872**	**2,561,033**
CAPITAL CONTRIBUTIONS	**3,072,025**	**1,885,387**
CHANGE IN NET ASSETS	**11,811,897**	**4,446,420**
TOTAL NET ASSETS, BEGINNING OF YEAR	**99,054,608**	**94,608,188**
TOTAL NET ASSETS, END OF YEAR	**$110,866,505**	**$99,054,608**

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

STATEMENT OF CASH FLOWS

For the years ended December 31, 2009 and 2008

	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash Received from Customers and Counterparties	$133,469,621	$142,552,454
Cash Paid to Suppliers and Counterparties	(93,251,285)	(115,950,031)
Cash Paid to Employees for Services	(12,052,204)	(11,210,456)
Taxes Paid	(9,730,432)	(9,360,676)
Net Cash Provided by Operating Activities	**18,435,701**	**6,031,291**
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES		
Other Income	20,042	50,048
Other Expense	(18,374)	(460)
Net Cash Provided (Used) by Noncapital Financing Activities	**1,668**	**49,588**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Acquisition of Capital Assets	(15,047,623)	(9,285,604)
Bond Principal Paid	(2,546,667)	(2,434,167)
Bond Interest Paid	(2,585,608)	(2,696,180)
Capital Contributions	3,072,025	1,885,387
Proceeds from Sale of Assets	878,249	706,187
Net Cash Used by Capital and Related Financing Activities	**(16,229,624)**	**(11,824,377)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest Income	251,814	1,148,196
Proceeds from Sale of Investments	38,309,166	59,147,009
Purchase of Investments	(40,484,015)	(58,308,628)
Assessments to Joint Venture	(211,003)	(361,583)
Net Cash Provided (Used) by Investing Activities	**(2,134,038)**	**1,624,994**
NET INCREASE (DECREASE) IN CASH	**73,707**	**(4,118,504)**
CASH BALANCE, BEGINNING OF YEAR	**1,324,573**	**5,443,077**
CASH BALANCE, END OF YEAR	**$1,398,280**	**$1,324,573**

	2009	2008
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating Income	$10,929,766	$4,249,181
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation & Amortization	9,367,272	9,369,594
Unbilled Revenues	(81,000)	(215,000)
Decrease (Increase) in Accounts Receivable	55,983	378,858
Decrease (Increase) in Inventories	19,879	(382,547)
Decrease (Increase) in Prepaid Expenses	(183,604)	15,172
Decrease (Increase) in Accrued Electric Revenue	(522,996)	978,357
Decrease (Increase) in Miscellaneous Assets	(81,037)	96,654
Decrease (Increase) in Deferred Purchased Power Costs	11,606,518	(21,861,389)
Decrease (Increase) in Deferred Derivative Charges	425,116	579,859
Increase (Decrease) in Deferred Derivative Credits	(10,783,818)	14,440,773
Increase (Decrease) in Deferred Regulatory Credits	(3,152,120)	-
Increase (Decrease) in Warrants Outstanding	(15,944)	101,373
Increase (Decrease) in Accounts Payable	886,553	(677,155)
Increase (Decrease) in Accrued Taxes Payable	226,442	(163,145)
Increase (Decrease) in Customer Deposits	(6,658)	(83,288)
Increase (Decrease) in Other Current Liabilities	96,169	(1,104,022)
Increase (Decrease) in Deferred Credits	(350,820)	308,016
Net Cash Provided by Operating Activities	**$18,435,701**	**$6,031,291**

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

NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2009 & 2008

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.

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 67,180, Prosser, population 5,110, and Benton City, population 2,955. 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 90 miles of 115kV transmission line, 1,582 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	4 - 14 years

Initial depreciation on utility plant is recorded in the month 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 4.31% in 2009 and 4.49% in 2008. 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 $325,799 and $253,267 in 2009 and 2008, 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 pronouncements on *Accounting for Asset Retirement Obligations.* This 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 this standard.

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. In addition, the District also received $86,932 as part of a settlement from the Washington State Attorney General against energy companies from power market manipulation in 2000 and 2001. According to the terms of the settlement, the funds are to be placed in an interest-bearing account and can only be used for residential low-income energy assistance or residential weatherization programs. The balance in the account at December 31, 2009 was $86,955. This amount is also reported as a restricted net asset.

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). No transfers were made during 2009 or 2008 to the Rate Stabilization Account.

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 $650,000 outstanding balance of the note at December 31, 2008 is classified as current. The final balance of the note was paid in 2009. Interest at a rate of 5% per year was imputed and was amortized over the term of the note.

i) Other Receivables: Other receivables include a $100,000 Rural Economic Development Revolving Fund which was established during 2008 pursuant to Revised Code of Washington (RCW) 82.16.0491. The District contributed $50,000 to fund in 2008 and an additional $50,000 in 2009. Each contribution to the fund was partially offset by a $25,000 public utility tax credit. The District appointed Benton-Franklin Council of Governments to oversee and direct activities of the fund. One loan of $12,500 had been issued as of December 31, 2009.

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

k) Derivative Instruments: The District has adopted GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*. Subject to certain exceptions GASB Statement No. 53 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 such derivatives meet specific hedge accounting criteria to be determined as effective. Effective hedges qualify for hedge accounting and such changes in fair values are deferred. The District uses FASB pronouncements on *Accounting for the Effects of Certain Types of Regulation* to defer unrecognized gains or losses for derivatives that are not deemed to be effective.

It is the District's policy to document and apply as appropriate the normal purchase and normal sales exception under GASB Statement No. 53. 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." These transactions are excluded under GASB Statement No. 53 and therefore are not required to be recorded at fair value in the financial statements. Certain put and call options and financial swaps for electricity and natural gas are considered to be derivatives under GASB Statement No. 53, but do not generally meet the "normal purchases and normal sales" criteria.

At December 31, 2009, the District had the following derivative instruments outstanding:

	Changes in Fair Value		Fair Value at December 31, 2009		
	Classification	Amount	Classification	Amount	Notional
Cash Flow Hedges:					
Commodity Forward	Deferred Credit	$ (3,293,277)	Derivative Asset	$ 3,293,277	179,400 MWh
Commodity Forward	Deferred Charge	$ 647,977	Derivative Liability	$ (647,977)	156,000 MWh
Call Option	Deferred Credit	$ (2,629)	Derivative Asset	$ 2,629	10,000 MWh

At December 31, 2008, the District had the following derivative instruments outstanding:

	Changes in Fair Value		Fair Value at December 31, 2008		
	Classification	Amount	Classification	Amount	Notional
Cash Flow Hedges:					
Commodity Forward	Deferred Credit	$(14,046,069)	Derivative Asset	$ 14,046,069	517,680 MWh
Commodity Forward	Deferred Charge	$ 977,093	Derivative Liability	$ (977,093)	673,440 MMBtu
Put Option	Deferred Credit	$ (33,655)	Derivative Asset	$ 33,655	10,000 MWh
Call Option	Deferred Charge	$ 96,000	Derivative Liability	$ (96,000)	20,400 MWh

The fair values of the commodity swap contracts were based on the futures price curve for the Mid-Columbia Intercontinental Exchange for electricity and the Sumas index for natural gas. The fair value of the options were calculated using the Black-Scholes-Merten options pricing model.

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 Turbine* – The District purchases gas for future periods to generate electricity when the Frederickson Plant (See Note 10) 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 next calendar 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 is economically viable for the period, by buying gas). 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 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

The following table displays the terms of the District's hedging derivative instruments outstanding at December 31, 2009, along with the credit rating of the associated counterparty or parent company guarantor, as applicable. All of these instruments presented in the table are commodity forward contracts with the objective to hedge changes in cash flows due to market price fluctuations related to expected sales of electricity. In addition, all of the instruments settle at expiration using the Mid-Columbia Intercontinental Exchange as the index.

Notional Amount (MWh)	Effective Date	Maturity Date	Counterparty Credit Rating	Price Received
10,000 MWh	07/08/08	01/31/10	A+/Aa3	$ 97.50
10,000 MWh	02/12/09	01/31/10	AAA/Aaa	$ 51.00
8,600 MWh	05/13/09	01/31/10	AAA/Aaa	$ 42.50
9,600 MWh	07/08/08	02/28/10	A+/Aa3	$ 97.50
9,600 MWh	02/12/09	02/28/10	AAA/Aaa	$ 51.00
7,200 MWh	05/13/09	02/28/10	AAA/Aaa	$ 42.50
10,800 MWh	07/08/08	03/31/10	A+/Aa3	$ 97.50
10,800 MWh	12/09/09	03/31/10	AA-/Aa3	$ 40.25
10,800 MWh	07/28/09	03/31/10	AA/Aa2	$ 38.25
10,800 MWh	02/12/09	03/31/10	AAA/Aaa	$ 51.00
7,800 MWh	05/13/09	03/31/10	AAA/Aaa	$ 42.50
10,400 MWh	12/09/09	04/30/10	AA-/Aa3	$ 64.50
10,400 MWh	07/28/09	04/30/10	AA/Aa2	$ 38.25
10,400 MWh	02/12/09	04/30/10	AAA/Aaa	$ 38.50
7,600 MWh	06/11/09	04/30/10	AAA/Aaa	$ 25.50
10,000 MWh	12/09/09	05/31/10	AA-/Aa3	$ 64.50
10,000 MWh	07/28/09	05/31/10	AA/Aa2	$ 38.25
10,000 MWh	02/12/09	05/31/10	AAA/Aaa	$ 38.50
8,600 MWh	06/11/09	05/31/10	AAA/Aaa	$ 25.50
10,400 MWh	12/09/09	06/30/10	AA-/Aa3	$ 64.50
10,400 MWh	02/12/09	06/30/10	AAA/Aaa	$ 38.50
7,600 MWh	06/11/09	06/30/10	AAA/Aaa	$ 25.50
10,400 MWh	05/19/08	10/31/10	BBB+/Baa1	$ 89.50
10,400 MWh	02/18/09	10/31/10	A-/A2	$ 54.50
10,000 MWh	05/19/08	11/30/10	BBB+/Baa1	$ 89.50
10,000 MWh	02/18/09	11/30/10	A-/A2	$ 54.50
10,400 MWh	05/19/08	12/31/10	BBB+/Baa1	$ 89.50
10,400 MWh	02/18/09	12/31/10	A-/A2	$ 54.50
10,400 MWh	10/14/09	01/31/11	AA-/Aa3	$ 59.65
9,600 MWh	10/14/09	02/28/11	AA-/Aa3	$ 59.65
10,800 MWh	10/14/09	03/31/11	AA-/Aa3	$ 59.65
10,400 MWh	08/12/09	04/30/11	A/A2	$ 41.00
10,400 MWh	08/12/09	05/31/11	A/A2	$ 41.00
10,400 MWh	08/12/09	06/30/11	A/A2	$ 41.00

In addition, the District had one call option outstanding at December 31, 2009. The option has an effective date of 12/9/09, a maturity date of 1/31/10, a notional amount of 10,000 MWh and a strike price of $55.00/MWh based on the Mid-Columbia Intercontinental Exchange. The objective was to hedge changes in cash flows due to market price fluctuations for expected purchases. The counterparty is rated A/A1.

The following table displays the terms of the District's electricity commodity forward hedging derivative instruments outstanding at December 31, 2008, along with the credit rating of the associated counterparty or parent company guarantor, as applicable. All of these instruments presented in the table are commodity forward contracts with the objective to hedge changes in cash flows due to market price fluctuations related to expected sales of electricity. In addition, all of the instruments settle at expiration using the Mid-Columbia Intercontinental Exchange as the index.

Notional Amount (MWh)	Effective Date	Maturity Date	Counterparty Credit Rating	Price Received
10,400 MWh	4/10/2008	1/31/2009	BBB/Baa3	$89.65
10,400 MWh	7/11/2008	1/31/2009	AAA/Aaa	$99.00
8,200 MWh	7/11/2008	1/31/2009	BBB+/Baa1	$86.00
4,160 MWh	5/16/2008	1/31/2009	A-/A2	$97.75
9,600 MWh	4/10/2008	2/28/2009	BBB/Baa3	$89.65
9,600 MWh	7/11/2008	2/28/2009	AAA/Aaa	$99.00
7,800 MWh	7/11/2008	2/28/2009	BBB+/Baa1	$86.00
3,840 MWh	5/16/2008	2/28/2009	A-/A2	$97.75
10,400 MWh	4/10/2008	3/31/2009	BBB/Baa3	$89.65
10,400 MWh	7/11/2008	3/31/2009	AAA/Aaa	$99.00
8,775 MWh	7/11/2008	3/31/2009	BBB+/Baa1	$86.00
4,160 MWh	5/16/2008	3/31/2009	A-/A2	$97.75
4,160 MWh	6/27/2008	4/30/2009	AA-/Aa2	$74.75
8,200 MWh	6/27/2008	4/30/2009	AA-/Aa2	$49.50
20,800 MWh	10/9/2007	4/30/2009	BBB/Baa3	$49.00
8,200 MWh	12/5/2008	4/30/2009	AAA/Aaa	$28.50
4,000 MWh	6/27/2008	5/31/2009	AA-/Aa2	$74.75
9,200 MWh	6/27/2008	5/31/2009	AA-/Aa2	$49.50
20,000 MWh	10/9/2007	5/31/2009	BBB/Baa3	$49.00
9,200 MWh	12/5/2008	5/31/2009	AAA/Aaa	$28.50
4,160 MWh	6/27/2008	6/30/2009	AA-/Aa2	$74.75
8,200 MWh	6/27/2008	6/30/2009	AA-/Aa2	$49.50
20,800 MWh	10/9/2007	6/30/2009	BBB/Baa3	$49.00
10,400 MWh	4/22/2008	7/31/2009	A+/Aa1	$91.00
10,400 MWh	10/19/2006	7/31/2009	BBB+/Baa1	$75.50
10,400 MWh	10/26/2006	7/31/2009	A+/Aa2	$77.50
10,400 MWh	4/22/2008	8/31/2009	A+/Aa1	$91.00
10,400 MWh	10/19/2006	8/31/2009	BBB+/Baa1	$75.50
10,400 MWh	10/26/2006	8/31/2009	A+/Aa2	$77.50
10,000 MWh	4/22/2008	9/30/2009	A+/Aa1	$91.00
10,000 MWh	10/19/2006	9/30/2009	BBB+/Baa1	$75.50
10,000 MWh	10/26/2006	9/30/2009	A+/Aa2	$77.50
8,400 MWh	4/16/2008	10/31/2009	AA-/Aa2	$70.25
21,600 MWh	10/9/2007	10/31/2009	AA/Aa2	$69.00
10,800 MWh	1/29/2007	10/31/2009	A-/A2	$68.00
9,025 MWh	4/16/2008	11/30/2009	AA-/Aa2	$70.25
19,200 MWh	10/9/2007	11/30/2009	AA/Aa2	$69.00
9,600 MWh	1/29/2007	11/30/2009	A-/A2	$68.00
8,800 MWh	4/16/2008	12/31/2009	AA-/Aa2	$70.25
20,800 MWh	10/9/2007	12/31/2009	AA/Aa2	$69.00
10,400 MWh	1/29/2007	12/31/2009	A-/A2	$68.00
10,000 MWh	7/8/2008	1/31/2010	AA-/Aa2	$97.50
9,600 MWh	7/8/2008	2/28/2010	AA-/Aa2	$97.50
10,800 MWh	7/8/2008	3/31/2010	AA-/Aa2	$97.50
10,400 MWh	5/19/2008	4/30/2010	AA-/Aa2	$64.50
10,000 MWh	5/19/2008	5/31/2010	AA-/Aa2	$64.50
10,400 MWh	5/19/2008	6/30/2010	AA-/Aa2	$64.50
10,400 MWh	5/19/2008	10/31/2010	BBB+/Baa1	$89.50
10,000 MWh	5/19/2008	11/30/2010	BBB+/Baa1	$89.50
10,400 MWh	5/19/2008	12/31/2010	BBB+/Baa1	$89.50

The following table displays the terms of the District's natural gas commodity forward hedging derivative instruments outstanding at December 31, 2008, along with the credit rating of the associated counterparty or parent company guarantor, as applicable. All of these instruments presented in the table are commodity forward contracts with the objective to hedge changes in cash flows due to market price fluctuations related to expected purchases of natural gas. In addition, all of the instruments settle at expiration using the Sumas index.

Notional Amount (MMBtu)	Effective Date	Begin Date	Maturity Date	Counterparty Credit Rating	Price Received
75,640 MMBtu	10/26/2006	7/1/2009	9/30/2009	AA/Aa2	$7.29
75,640 MMBtu	10/19/2006	7/1/2009	9/30/2009	BBB+/Baa1	$7.12
75,640 MMBtu	10/26/2006	7/1/2009	9/30/2009	AA/Aa2	$7.29
75,640 MMBtu	10/19/2006	7/1/2009	9/30/2009	BBB+/Baa1	$7.12
73,200 MMBtu	10/26/2006	7/1/2009	9/30/2009	AA/Aa2	$7.29
73,200 MMBtu	10/19/2006	7/1/2009	9/30/2009	BBB+/Baa1	$7.12
75,640 MMBtu	1/29/2007	10/1/2009	12/31/2009	A-/A2	$7.665
73,200 MMBtu	1/29/2007	10/1/2009	12/31/2009	A-/A2	$7.665
75,640 MMBtu	1/29/2007	10/1/2009	12/31/2009	A-/A2	$7.665

The District had two call options outstanding at December 31, 2008. The first option had an effective date of 9/11/08, a maturity date of 1/31/09, a notional amount of 20,800 MWh and a strike price of $125.00/MWh based on the Mid-Columbia Intercontinental Exchange. The second option had an effective date of 9/11/08, a maturity date of 2/28/09, a notional amount of 19,200 MWh and a strike price of $125.00/MWh based on the Mid-Columbia Intercontinental Exchange. The objective was to hedge changes in cash flows due to market price fluctuations for expected purchases. Both call options were with the same counterparty. The counterparty was rated A/A2.

The District had two put options outstanding at December 31, 2008. The first option had an effective date of 11/12/08, a maturity date of 4/30/09, a notional amount of 10,400 MWh and a strike price of $40.00/MWh based on the Mid-Columbia Intercontinental Exchange. The second option had an effective date of 11/12/08, a maturity date of 5/31/09, a notional amount of 10,000 MWh and a strike price of $40.00/MWh based on the Mid-Columbia Intercontinental Exchange. The objective was to hedge changes in cash flows due to market price fluctuations for expected sales. Both call options were with the same counterparty who was rated BBB/Baa3.

Risks

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.

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, 2009, and 47 counterparties at December 31, 2008. Counterparty credit limits are based on TEA's proprietary credit rating system 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.

Prior to March 2008, the maximum credit exposure with any counterparty as set by the Commission in the Risk Management Policy was $2.25 million. In March 2008, to allow for TEA trading as principal, the Commission approved a $7 million credit exposure limit to TEA

consistent with the owner's guarantee. In October 2008, the Commission approved a temporary increase in the maximum credit exposure the District could incur with specific counterparties to $3 million through January 14, 2009. This increase was necessary as a result of a significant decrease in forward market prices and consequently an increase in the fair value of existing forward contracts. In December 2008, the Commission waived the individual counterparty credit limit of $2.25 million to allow TEA to trade under its credit limits pending a revision to the Risk Management Policy. This mitigates the District's credit exposure by netting and setting off the District's sales with purchases made by other TEA members. In May 2009, the Commission approved a $3 million credit limit for specific counterparties that meet certain criteria of TEA. Credit concentration limits based on market conditions and available qualified counterparties are established by the Risk Management Committee.

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.

Forward 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.

The aggregate fair value of hedging derivative instruments in asset positions was $3,295,905 and $14,079,724 at December 31, 2009 and 2008 respectively. There was no collateral held or liabilities included in netting arrangements.

Although the District executes hedging derivative instruments with various counterparties, three contracts, comprising approximately 44% of the net exposure to credit risk, are held with one counterparty as of December 31, 2009. That counterparty is rated A+/Aa3. This District did not have a net exposure to any single counterparty over 20% at December 31, 2008.

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, 2009 or 2008. 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, 2009 and 2008, 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, 2009 or 2008.

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 FASB

pronouncements for *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 for those derivatives that are not deemed to be effective. In addition, the District recorded a deferred regulatory credit of $3,152,120 related to undistributed residential exchange settlement funds (see Note 10) at December 31, 2008. The remaining deferred regulatory credit was amortized during 2009.

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 GA*SB 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 $251,000 and $203,000 at December 31, 2009 and 2008, 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 $3.5 million at December 31, 2009 and $3.4 million at December 31, 2008.

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. Capital contributions are recorded as deferred revenues when received and reclassified to revenue when the related project is completed.

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 and 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 $89,687 and $110,473 at December 31, 2009 and 2008, 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 $2,100,498 and $2,144,214 at December 31, 2009 and 2008, respectively. Current liabilities of $955,444 and $919,143 at December 31, 2009 and 2008, respectively were classified as a current liability and the remainder as a long-term liability (see Note 4).

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 2008 account balances may have been reclassified to conform to the 2009 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 2009

Electric Plant Assets	Balance Dec. 31, 2008	Increase	Decrease	Balance Dec. 31, 2009
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	$3,026,677	$8,736	-	$3,035,413
Construction Work in Progress	3,653,703	9,597,989	(4,730,832)	8,520,860
Capital Assets Being Depreciated:				
Transmission	7,415,978	157,752	(34,921)	7,538,809
Generation	1,403,850	-	-	1,403,850
Distribution	164,604,999	8,049,796	(1,961,497)	170,693,298
General	42,994,587	2,520,331	(501,425)	45,013,493
Subtotal	**216,419,414**	**10,727,879**	**(2,497,843)**	**224,649,450**
Less Accumulated Depreciation for:				
Transmission	(3,968,374)	(268,471)	35,038	(4,201,807)
Generation	(492,194)	(65,259)	-	(557,453)
Distribution	(89,528,039)	(7,090,623)	2,248,862	(94,369,800)
General	(19,081,831)	(2,598,018)	410,443	(21,269,406)
Total Accumulated Depreciation	**(113,070,438)**	**(10,022,371)**	**2,694,343**	**(120,398,466)**
Net Utility Plant	**$110,029,356**	**$10,312,233**	**($4,534,332)**	**$115,807,257**

Activity for 2008

Electric Plant Assets	Balance Dec. 31, 2007	Increase	Decrease	Balance Dec. 31, 2008
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	$3,016,319	$10,358	-	$3,026,677
Construction Work in Progress	4,028,943	7,514,334	(7,889,574)	3,653,703
Capital Assets Being Depreciated:				
Transmission	7,466,894	(13,525)	(37,391)	7,415,978
Generation	1,403,850	-	-	1,403,850
Distribution	157,536,715	7,888,435	(820,151)	164,604,999
General	40,767,166	2,473,485	(246,064)	42,994,587
Subtotal	**207,174,625**	**10,348,395**	**(1,103,606)**	**216,419,414**
Less Accumulated Depreciation for:				
Transmission	(3,738,431)	(269,512)	39,569	(3,968,374)
Generation	(422,527)	(69,667)	-	(492,194)
Distribution	(83,598,864)	(6,898,875)	969,700	(89,528,039)
General	(16,543,797)	(2,784,098)	246,064	(19,081,831)
Total Accumulated Depreciation	**(104,303,619)**	**(10,022,152)**	**1,255,333**	**(113,070,438)**
Net Utility Plant	**$109,916,268**	**$7,850,935**	**($7,737,847)**	**$110,029,356**

NOTE 3 – DEPOSITS AND INVESTMENTS

As of December 31, 2009, the District had the following investments:

Investment Type	Maturities	Fair Value
State Treasurer's Local Government Investment-Pool	55 days average	$30,412,994

As of December 31, 2008, the District had the following investments:

Investment Type	Maturities	Fair Value
State Treasurer's Local Government Investment Pool	50 days average	$28,237,550

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.

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 as of December 31 consisted of the following:

Deferred Charges	2009	2008
Unamortized Debt Expense	$586,307	$685,884
Deferred Derivative Charge	647,977	1,073,093
Derivative Asset	3,295,906	14,079,724
Deferred Purchased Power Costs	20,000	264,300
White Creek Wind Project	10,363,468	10,941,867
Preliminary Surveys	35,912	35,456
Other Deferred Charges	30,581	-
Total	**$14,980,151**	**$27,080,324**

During the year ended December 31, 2009, the following changes occurred in deferred credits:

Deferred Credits & Other Liabilities	Balance Dec. 31, 2008	Additions	Reductions	Balance Dec. 31, 2009
Unclaimed Property	$20,919	-	$294	$20,625
Deferred Regulatory Credits	3,152,120	-	3,152,120	-
Deferred Derivative Credit	14,079,724	3,295,906	14,079,724	3,295,906
Derivative Liability	1,073,093	647,977	1,073,093	647,977
Deferred Revenue	134,901	990,989	846,128	279,762
Asset Retirement Obligation - Finley CT	121,908	6,095	-	128,003
Other Postemployment Benefits	17,573	15,081	11,430	21,224
Personal Leave and Benefits*	1,225,071	-	80,017	1,145,054
Total	**$19,825,309**	**$4,956,048**	**$19,242,806**	**$5,538,551**

** In addition to this amount, $955,444 is recorded as a current liability for personal leave and related benefits.*

During the year ended December 31, 2008, the following changes occurred in deferred credits:

Deferred Credits & Other Liabilities	Balance Dec. 31, 2007	Additions	Reductions	Balance Dec. 31, 2008
Unclaimed Property	$21,005	$4,505	$4,591	$20,919
Deferred Regulatory Credits	-	$3,152,120	-	3,152,120
Deferred Derivative Credit	2,791,071	14,079,724	2,791,071	14,079,724
Derivative Liability	1,652,952	1,073,093	1,652,952	1,073,093
Deferred Revenue	485,481	1,231,639	1,582,219	134,901
Asset Retirement Obligation - Finley CT	116,432	5,805	329	121,908
Other Postemployment Benefits	9,579	10,058	2,064	17,573
Personal Leave and Benefits*	-	1,225,071	-	1,225,071
Total	**$5,076,520**	**$20,782,015**	**$6,033,226**	**$19,825,309**

** In addition to this amount, $919,143 is recorded as a current liability for personal leave and related benefits.*

NOTE 5 – ASSET RETIREMENT OBLIGATION (ARO)

The District adopted FASB pronouncements on 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. 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 $59,213 for site restoration in 2007 and $329 in 2008 and reduced the ARO obligation by this amount. The District will perform the remainder of the site restoration upon termination of the lease. In 2008, the net present value of the ARO increased to $121,908, resulting in accretion expense of $5,805 for 2008. In 2009, the net present value of the ARO increased to $128,003 resulting in accretion expense of $6,095.

NOTE 6 – LONG-TERM DEBT

During the year ended December 31, 2009, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Amounts Due Within One Year
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%.	$27,800,000		$1,535,000	$26,265,000	$1,605,000
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%	8,290,000	-	995,000	7,295,000	1,025,000
Subtotal	$53,395,000	-	$2,530,000	$50,865,000	$2,630,000
Plus: Unamortized discount & premium	984,091	-	137,497	846,594	-
Less: Unamortized loss on refundings	(320,814)	-	(72,048)	(248,766)	-
Total Long-Term Debt	**$54,058,277**	-	**$2,595,449**	**$51,462,829**	**$2,630,000**

During the year ended December 31, 2008, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Amounts Due Within One Year
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%.	$29,270,000		$1,470,000	$27,800,000	$1,535,000
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%	9,235,000	-	945,000	8,290,000	995,000
Subtotal	$55,810,000	-	$2,415,000	$53,395,000	$2,530,000
Plus: Unamortized discount & premium	1,128,788	-	144,697	984,091	-
Less: Unamortized loss on refundings	(401,195)	-	(80,381)	(320,814)	-
Total Long-Term Debt	**$56,537,593**	-	**$2,479,316**	**$54,058,277**	**$2,530,000**

Future debt service requirements on these bonds are as follows:

Year	Principal	Interest	Total
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	4,245,000	2,093,355	6,338,355
2014	4,450,000	1,901,774	6,351,774
2015-2019	21,365,000	6,296,757	27,661,757
2020-2022	11,370,000	1,026,170	12,396,170
Total	**$50,865,000**	**$18,489,481**	**$69,354,481**

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.

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 that was extended for additional one-year terms until the final maturity of March 31, 2008. In March 2008, the District replaced this one-year agreement with a three-year $10 million revolving line of credit, the Electric System Revenue Note, 2008, with Bank of America maturing May 15, 2011. 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 expired on June 30, 2009 and was a condition of participation to guarantee performance in the Flexible Priority Firm 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 and GASB Statement No. 50, Pension Disclosures, an Amendment of GASB Statements No. 25 and No. 27.

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 defined benefit plan with a defined contribution component.

Membership in the system includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior Courts (other than judges currently 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; 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 irrevocable 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. Notwithstanding, PERS Plan 2 and Plan 3 members may opt out of plan membership if terminally ill, with less than five years to live.

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 members are vested after the completion of five years of eligible service. Plan 1 members are eligible for retirement after 30 years of service, or at the age of 60 with five years of service, or at the age of 55 with 25 years of service. The annual benefit is two percent of the average final compensation (AFC) per year of service, capped at 60 percent. The AFC is based on the greatest compensation during any 24 eligible consecutive compensation months. This annual benefit is subject to a minimum for Plan 1 retirees who have 25 years of service and have been retired 20 years, or who have 20 years of service and have been retired 25 years. Plan 1 members who retire from inactive status prior to the age of 65 may receive actuarially reduced benefits. The benefit is actuarially reduced to reflect the choice of a survivor option. A cost-of living allowance (COLA) is granted at age 66 based upon years of service times the COLA amount, increased by three

percent annually. Plan 1 members may also elect to receive an additional COLA amount that provides an automatic adjustment based on the Consumer Price Index. The adjustment is capped at three percent annually. To offset the cost of this annual adjustment, the benefit is reduced.

Plan 2 members are vested after the completion of five years of eligible service. Plan 2 members may retire at age 65 with five years of service with an allowance of 2 percent of the AFC per year of service. The AFC is based on the greatest compensation during any eligible consecutive 60-month period. Plan 2 members who retire 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 three 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 a cost-of-living allowance is granted based on the 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 AFC per year of service. The AFC is based on the greatest compensation during any eligible consecutive 60-month period. 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 of service, 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 they may retire at age 55 with 10 years of service. Plan 3 members who retire 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 three 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 1,192 participating employers in PERS. Membership in PERS consisted of the following as of the latest actuarial valuation date for the plans of June 30, 2008:

Retirees and Beneficiaries Receiving Benefits…….73,122
Terminated Plan Members Entitled to
but not yet Receiving Benefits… …… 27,267
Active Plan Member Vested……...105,212
Active Plan Members Non-vested…….. 56,456
Total……262,057

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 for state agencies and local government. 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. Under PERS Plan 3, employer contributions finance the defined benefit portion of the plan, and member contributions finance the defined contribution portion. The Employee Retirement Benefits Board sets Plan 3 employee contribution rates. Six rate options are available ranging from 5 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 Chapters 41.40 and 41.45 RCW.

The required contribution rates expressed as a percentage of current year covered payroll, as of December 31, 2009, were as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer *	5.31%	5.31%	5.31%**
Employee	6.00%	3.90%	***

* *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 as follows:

Year	PERS Plan 1	PERS Plan 2	PERS Plan 3
2009	$46,118	$664,540	$54,509
2008	$41,675	$667,757	$50,363
2007	$45,465	$517,263	$33,536

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 AFC. 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, 2009 and 2008 was $157,404 and $219,703.

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. 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 contributed 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. Effective August 1, 2008, the District contribution was increased to 1%. 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 no financial report is issue. 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, 2018, must enroll in retiree medical insurance or COBRA from the Central Washington Public Utilities Unified Insurance Trust Program (See Note 11) within the enrollment period following retirement and must remain continuously enrolled in medical insurance from the Trust.

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 employees who retire between August 1, 2006 and July

31, 2007 the monthly contributions will be equal to the lesser of actual medical premiums or nine dollars for each year of PERS-eligible service. For employees who retire between August 1, 2007 and July 31, 2011 the monthly contributions will be equal to the lesser of actual medical premiums or eight dollars for each year of PERS-eligible service. 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, 2018.

Funding Policy

The District pays the contributions when required and does prefund the plan based on an actuarial calculation. The District made no retiree medical insurance premium contributions in 2005, 2006, and 2007. The District contributed $11,430 and $2,065 in 2009 and 2008, respectively.

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, the amount actually contributed to the plan, and changes in the District's net OPEB obligation to the Plan for the years ending December 31, 2009 and 2008.

OPEB Cost and Obligation	2009	2008
Annual required contribution	$15,081	$10,058
Interest on net OPEB obligation	-	-
Adjustment to annual required contribution	-	-
Annual OPEB cost (expense)	$15,081	$10,058
Contributions made	(11,430)	(2,065)
Increase in net OPEB obligation	$3,651	$7,993
Net OPEB obligation – beginning of year	17,572	9,579
Net OPEB obligation – end of year	$21,223	$17,572

The District's annual OPEB cost, the percentage of annual OPEB cost contributed to the plan and the net OPEB obligation for 2009 and the preceding year were as follows:

Fiscal Year Ended	Annual OPEB Cost	Percentage of Annual OPEB Cost Contributed	Net OPEB Obligation
12/31/07	$9,579	0.00%	$9,579
12/31/08	$10,058	20.53%	$17,572
12/31/09	$15,081	75.79%	$21,223

Funded Status and Funding Progress

The actuarial accrued liability is unfunded. The funded status as of December 31, 2009 using actuarial valuation from December 31, 2007 is as follows:

Actuarial accrued liability (AAL)	$160,491
Actuarial value of the plan	0
Unfunded actuarial accrued liability (UAAL)	**$160,491**
Funded ratio (actuarial value of plan assets/AAL)	0%
Covered payroll (active plan members)	$11,029,641
UAAL as a percentage of covered payroll	1.46%

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 multi-year trend information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the actuarial accrued liabilities for benefits.

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 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. A modification was made in 2009 to update the benefit amounts based on the updated benefit as required by the Collective Bargaining Agreement. 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 which expires September 30, 2011. 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. BPA increased the rate for the Slice product by 4.4% effective October 1, 2009 through September 30, 2011 period.

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. BPA increased its rate for the Block product by 6.95% effective October 1, 2009 through September 30, 2011. BPA has put in place a Cost Recovery Adjustment Clause (CRAC) which applies to the District's Block purchases during the rate period of 10/1/06 – 9/30/11. The CRAC can be triggered when BPA's forecasted Accumulated Modified Net Revenues (AMNR) is lower than expected. AMNR represents the Power Services net revenues, modified by certain items, as accumulated since 1999 through the end of each year for FY 2006 through 2010. The amount of the CRAC is determined by the amount AMNR is forecasted to be greater than certain values 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 CRAC 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 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 for the fiscal year ending September 2007, 19.8 annual aMW for the fiscal year ending September 2008 and 13.4 annual aMW for the fiscal year ending September 2009. 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(l)). The reimbursement of $4.2 million for the fiscal year ending September 2008 was received in January 2009, and the

reimbursement of $3.3 million for the fiscal year ending September 2009 was received in January 2010.

The District has executed a Slice/Block Power Sales Agreement with BPA for the period commencing October 1, 2011 and expiring September 30, 2028.

Compared to current product, the new Slice would have changes in operational flexibility, and clarification of with-in hour capacity rights as shown below:

- The Slice Product is a system sale of power that includes requirements power, surplus power, and hourly scheduling rights, all of which are indexed to the variable output capability of the FCRPS resources that comprise the Slice System, and to the extent such capability is available to Power Services after System Obligations and Operating Constraints are met. These capabilities are accessed by the District through the Slice Computer Application, which will reasonably represent and calculate the capabilities available to BPA Power Services from such FCRPS resources after System Obligations and Operating Constraints are met, including energy production, peaking, storage and ramping capability, and which the Slice Computer Application applies the District's Selected Slice Percentage to such capabilities.
- No ability to self-supply ancillary services such as operating reserves, energy imbalance, or dynamic scheduling.
- Slice schedules continue to be firm across the hour of delivery.
- The District's new slice percentage is projected to be 1.38126%.

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 Rate Program. This program allowed 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 reimbursed the cost of each participating utility to maintain a line of credit for this purpose. This liquidity tool resulted in a reduction to the CRAC threshold making it significantly less likely to trigger in 2008 and 2009. This program ended June 30, 2009.

In March 2008, the District entered into a Standstill and Interim Relief Payment Agreement with BPA. During the year, the District received a settlement in the amount of $8 million related to residential exchange benefits in FY 2007 and FY 2008 and established a temporary customer rate credit to return these funds to ratepayers over a twelve-month period beginning June 2008. Under FASB pronouncements for Accounting for the Effects of Certain Types of Regulation, the District deferred the settlement payment as a regulatory credit which is being amortized over the period of the temporary customer rate credit. At December 31, 2008, $4.8 million had been returned to customers and credited against power expense, and $3.2 million was recorded as a deferred regulatory credit (see Note 4). At December 31, 2009, an additional $3.4 million had been returned to customers. The remaining regulatory credit was fully amortized during 2009.

BPA also determined that it had over collected from its public customers in providing payments to IOU's for residential exchange benefits in 2002-2006. In the WP-10 power rate case, BPA decided to credit the District $2.29M per year for FY 2010 and 2011 to reimburse the District for these over collections. This credit will continue into the future, but the amount will be reviewed in each successor rate case.

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 (2 aMW) from the Phase III expansion (see Note 15).

White Creek Project

In September 2008, the District entered into an Assignment Agreement with Klickitat PUD under which Klickitat PUD assigned the District a 3% share of its Energy Purchase Agreement with White Creek Wind I, LLC for $11.1 million. The purchase is part of the District's strategy for meeting renewable resource requirements of Initiative 937. The purchase cost is being amortized on a straight-line basis over a 19-year term. This 3% share of the 204.7 MW project represents 6.14 MW (2 aMW). The District also entered into an agreement to sell energy and environmental attributes back to Klickitat PUD through March 2011 to satisfy obligations under an agreement with Powerex related to Klickitat PUD's original share of the White Creek project. The sale will expire before the need to meet Initiative 937 requirements beginning in 2012.

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 2008 was $40.20/MWh. The agreement was not extended and terminated on September 30, 2008. This power was 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 2009 or 2008, as gains are being held for relicensing expenses.

In November 2002, the District began purchasing 57% of Packwood's capacity. The agreement expired October 1, 2008 and the entire output was sold to Snohomish PUD through September 30, 2010.

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 Resource Management Agreement (RMA) with The Energy Authority (TEA) on July 1, 2006 to provide scheduling, dispatching, fuel management and other power management services. 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. Under the agreement, TEA began trading real time and day ahead transactions as principal on behalf of the District in April 2008. This arrangement allows a financial benefit to the District with TEA trading in aggregated larger power blocks and passing the resulting transaction pricing on to the District. It also provides the advantages of simplified settlement, lower operational and settlement risk, and rigorous documentation and equitable allocation of pricing for like transactions across PUDs. In December 2008, the RMA was amended to allow these transactions to be traded utilizing TEA's credit and contracts as discussed in Note 1(k).

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 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, 2009, the District had entered into various short-term financial forward sales and purchase contracts committing the District through June 2011. Financial forward contracts for electricity had a net positive fair value of $2.6 million at December 31, 2009 and are reflected in the financial statements as deferred credits and charges, respectively.

At December 31, 2009, the District had an outstanding call option enabling the District to buy and sell electricity at a specific price. These agreements will expire in the first quarter of 2010. The net market value of these options as of December 31, 2009 was $2,629 more than the original premium paid. Accordingly, the premiums paid for the options were amortized by this amount and recognized as deferred charges and credits.

At December 31, 2008, the District had entered into various short-term financial forward sales and purchase contracts committing the District through December 2010. Financial forward contracts for electricity had a net positive fair value of $14 million, and financial forward contracts for gas had a negative fair value of $977,000 at December 31, 2008 and are reflected in the financial statements as deferred credits and charges.

At December 31, 2008, the District had outstanding call and put options enabling the District to buy and sell electricity at various prices. These agreements will expire in the first two quarters of 2009. The net market value of these options as of December 31, 2008 was $62,345 less than the original premium paid. Accordingly, the premiums paid for the options were amortized by this amount and recognized as deferred charges and credits.

NOTE 11 – SELF-INSURANCE

Public Utility Risk Management Services Self-Insurance Fund

The District is a member of the Public Utility Risk Management Services (PURMS) Self-Insurance Fund. PURMS is a public entity risk pool organized on December 30, 1976 in the State of Washington under RCW 54.16.200 and interlocal governmental agreements. It currently operates under RCW 48.62. Its members include 18 public utility districts and one non-profit mutual corporation. The objectives of PURMS are to formulate, develop and administer a program of self-insurance in order to obtain lower costs for the various coverages provided to its members and to develop a comprehensive loss control program.

The risks shared by the members are defined in the Self-Insurance Agreement (SIA). The fund consists of three pools for liability, property, and health and welfare coverage. The pools operate independently of one another. All members do not participate in all pools. The District does not participate in the health and welfare pool.

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.

PURMS engages an independent qualified actuary on an annual basis to determine the claim financing levels, liabilities for unpaid claims and claims adjustment expenses for the Liability Pool and the Property Pool. A copy of these reports is provided to the Washington State Risk Manager and to the Washington State Auditor's Office. Audit reports for the Trust are available from the Washington State Auditor's Office (Report Nos. 1002749 and 1002748).

The pools are fully funded by its current and former members. Members that withdraw from PURMS are responsible for their share of contributions to the pools for any unresolved, unreported and in-process claims for the period they were signatory to the SIA. Claims are filed by members with the Administrator, Pacific Underwriters, Seattle, WA, which serves by contract as the fund's Administrator and provides claims adjustment and loss prevention services.

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

Liability Risk Pool - The liability pool has a $1 million liability coverage limit per occurrence. In addition, the fund maintains $35 million of excess general liability insurance and $10 million of professional liability insurance over the $1 million retention. A second layer of excess general liability insurance of $25 million is also maintained over the first layer of $35 million. The fund maintains $35 million in directors and officers liability coverage with a retention of $500,000. The deductible is $250.

The Board approved increasing the liability pool reserve balance from $2 million to $3 million effective January 1, 2009. This increase is being funded over three years by two additional assessments per year in the years 2009 through 2011. Liability assessments are levied at the beginning of each calendar year to replenish the reserves to the designated level and at any time during the year that the actual reserves drop to $500,000 less than the designated level.

Property Risk Pool - The majority of the property in the property pool has a self-insured retention of $250,000 per property loss. Certain classes of property have higher retention requirements up 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.

The designated property pool reserve balance is $750,000. Property assessments are levied at the beginning of each calendar year to replenish the reserves to the designated level and at any time during the year that the actual reserves drop below $500,000.

Central Washington Public Utilities Unified Insurance Program Trust

The District is a member of the Central Washington Public Utilities Unified Insurance Program 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 and Alternate 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. Effective January 1, 2009, the Trust established a self-insured dental plan. Both plans are approved by the State Risk Office. The audit report for the Trust is available from the Washington State Auditor's Office (Report Nos. 1000680 and 1000681).

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

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 $41,124 related to operations of GHFB for the year ended December 31, 2008, resulting in an equity interest in GHFB of $25,390 at December 31, 2008. In 2009, GHFB was dissolved and the District received payment for the remaining equity and recognized a loss of $15,538 clearing the equity interest. GHFB's primary purpose is to fund services previously performed by Power Resource Managers 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 may be obtained by writing to: Franklin PUD, P.O. Box 2407, Pasco, WA 99302.

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.

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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 $220,855 and $361,583 for 2009 and 2008, respectively.

NoaNet recorded a decrease in net assets (excluding member assessments) of $763,789 (unaudited) for 2009 and a decrease of $71,912 for 2008. 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 $8,641,053 as of December 31, 2009 (unaudited) and $9,449,020 as of December 31, 2008.

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, 2009 and 2008 follows:

Broadband	2009	2008
Operating Revenues		
Ethernet	$425,555	$318,448
TDM	132,403	101,108
Wireless	3,414	3,544
Co-Location	129	2,580
Internet Transport Service	235,060	309,927
Fixed Wireless	130,743	119,745
Other Revenue	903	2,656
NoaNet Maintenance Revenue	2,304	3,988
Bad Debt Expense	(3,470)	(3,430)
Total Operating Revenues	**$927,041**	**$858,566**
Operating Expenses		
Marketing & Business Development	$83,533	$61,624
NoaNet Maintenance Expense	2,004	2,927
General Expenses	370,096	455,943
Other Maintenance	35,686	59,282
Network Operating Center Maint.	60,671	59,989
Wireless Maintenance	25,968	22,502
Subtotal before depreciation	$577,958	$662,267
Depreciation	734,397	685,099
Total Operating Expenses	**$1,312,355**	**$1,347,366**
Nonoperating Revenues (Grant Proceeds)	-	-
Nonoperating Expenses	$223,629	$366,295
Capital Investment (Annual)	$3,427,502	$728,038
Capital Investment (Cumulative)	$11,759,940	$8,332,438

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 $16,550,000 and $18,360,000 at December 31, 2009 and 2008, respectively.

Current and former Members of NoaNet have entered into a Repayment Agreement to guarantee the debt of NoaNet. Under the Repayment Agreement, each guarantor 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 $2,326,930 and $2,581,416 as of December 31, 2009 and 2008, respectively.

In the event of a failure by any guarantor to pay such amounts when due, NoaNet may bill from time to time as necessary, and each guarantor 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 $2,907,835 and $3,225,852 as of December 31, 2009 and 2008, 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. The Combined balance was $2,706,418 as of December 31, 2008. The 2003 Line of Credit was paid off in 2009. The 2006 Line of Credit balance was $1,487,221 at December 31, 2009. 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.

In September 2008, NoaNet opened a $1.5 million line of credit with Bank of America to fund capital expenditures. This Note is guaranteed by the Members. The outstanding balance on the 2008 Line of Credit was $1,200,000 and $1,500,000 at December 31, 2009 and 2008 respectively.

The District's guarantee is 14.17% of the outstanding balance or $170,040 and $212,550 at December 31, 2009 and 2008 respectively.

In August 2009, NoaNet opened a $1.5 million line of credit with Bank of America to fund capital expenditures. This Note is guaranteed by the Members. The outstanding balance on the 2009 Line of Credit was $1,500,000 at December 31, 2009. The District's guarantee is 14.17% of the outstanding balance or $212,550 as of December 31, 2009.

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 is obligated to pay an amended percentage share effective May 2008 when Phase III achieved commercial operation. 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 % Share	District % 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%	5.90%
O&M Costs – Post Phase III Commercial Operation	9.39%	11.74%

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, 2009 and 2008, the District has entered into renewable energy contracts that total 3.2% of its retail load, exceeding the Initiative's initial renewable target of 3% by 2012.

Operating Leases

The District leases electrical testing equipment on an annual basis. The annual rental cost was $22,375 and $21,714 for 2009 and 2008, 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 non-cancellable operating lease of more than one year.

The annual rental cost for the land was $51,104 and $50,275 for 2009 and 2008, respectively.

The future minimum rental payments are:

Year	Minimum Rental Payment
2010	$50,738
2011	50,738
2012	50,738
2013	50,738
2014	50,738
2015-2019	253,690
2020-2021	71,879
Total	**$579,259**

NOTE 16 – SUBSEQUENT EVENTS

The District issued $17.3 million of Build America Bonds on March 16, 2010 to fund capital improvements and a debt service reserve. In addition, the District defeased $6.4 million of the 2001A bonds on March 10, 2010 using cash reserves. As a result of the two transactions, the net increase of the District's outstanding bonds was $10.9 million.

Required Supplementary Information

Retiree Medical Insurance Benefit
Schedule of Funding Progress

Actuarial Valuation Date	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) – Unit (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	-	$9,972,796	1.09%
12/31/08	-	$113,657	$113,657	-	$10,478,784	1.08%
12/31/09	-	$160,491	$160,491	-	$11,029,641	1.46%





STATISTICAL SECTION

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

	2009	2008	2007	2006
OPERATING REVENUES				
Sales of Electric Energy - Retail [1]	$91,942,100	$86,236,604	$92,388,210	$95,549,937
Energy Sales for Resale	38,885,352	53,188,137	42,922,151	46,585,675
Transmission of Power for Others	229,429	225,908	279,687	256,781
Broadband Revenue	927,041	858,566	787,589	461,276
Other Revenue	1,348,716	1,449,381	1,745,868	2,126,721
Total Operating Revenues	$133,332,638	141,958,596	138,123,505	144,980,390
OPERATING EXPENSES				
Purchased Power	75,055,153	91,764,877	83,330,863	88,171,300
Purchased Transmission & Ancillary Services	10,074,811	10,295,990	9,385,236	9,713,193
Conservation Program	679,406	130,064	-	-
Generation	-	-	169,339	671,606
Transmission Operations & Maintenance	30,026	20,449	24,376	53,432
Distribution Operations & Maintenance	7,092,143	6,998,119	6,254,249	6,883,927
Broadband Expense	577,958	662,267	692,390	582,999
Customer Accounting, Collection and Information	4,011,243	3,850,215	3,854,630	4,062,499
Administrative & General	5,557,985	5,420,309	5,405,180	5,243,565
Taxes	9,956,874	9,197,531	9,884,911	10,096,882
Depreciation & Amortization	9,367,272	9,369,594	10,084,084	10,156,431
Total Operating Expenses	122,402,872	137,709,415	129,085,258	135,635,834
OPERATING INCOME (LOSS)	**10,929,766**	**4,249,181**	**9,038,247**	**9,344,556**
NONOPERATING REVENUES & EXPENSES				
Interest & Other Nonoperating Income	358,811	1,198,244	1,762,210	1,960,710
Interest Expense & Other Nonoperating Expense	(2,278,183)	(2,443,373)	(2,533,496)	(3,319,058)
Debt Discount & Expense Amortization	(34,128)	(40,312)	(21,519)	(553,124)
Gain (Loss) in Joint Venture	(236,393)	(402,707)	(555,095)	(912,323)
Total Nonoperating Revenues & Expenses	(2,189,894)	(1,688,148)	(1,347,900)	(2,823,795)
INCOME (LOSS) BEFORE CONTRIBUTIONS AND EXTRAORDINARY ITEM	**8,739,872**	**2,561,033**	**7,690,347**	**6,520,761**
CAPITAL CONTRIBUTIONS [2]	**3,072,025**	**1,885,387**	**6,099,714**	**1,491,180**
EXTRAORDINARY ITEM	**-**	**-**	**(9,755,303)**	**-**
CHANGE IN NET ASSETS	**$11,811,897**	**$4,446,420**	**$4,034,758**	**$8,011,941**

NET ASSETS

For the years ended December 31

	2009	2008	2007	2006
Invested in Capital Assets, Net of Related Debt	$64,782,761	$56,392,746	$53,979,188	$60,651,818
Restricted	$86,955	-	-	-
Unrestricted	45,996,788	42,661,862	40,629,000	29,921,612
Total Net Assets	**$110,866,505**	**$99,054,608**	**$94,608,188**	**$90,573,430**

(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 capital contributions as revenue. Calendar year 2000 was restated for comparative purposes.

2005	2004	2003	2002	2001	2000
$101,111,740	$101,177,165	$99,074,832	$92,900,867	$69,513,163	$72,254,487
39,350,618	32,452,008	33,065,979	13,629,442	11,455,832	10,027,175
238,040	198,591	268,955	419,896	1,001,978	807,972
315,469	161,447	52,876	6,538	-	-
1,635,971	1,379,005	1,196,174	1,223,392	1,031,762	854,573
142,651,838	135,368,216	133,658,816	108,180,135	83,002,735	83,944,207
92,225,135	84,134,802	85,034,770	65,573,174	43,291,151	40,973,729
8,776,993	8,336,489	9,319,269	9,746,736	8,378,725	6,381,077
-	-	-	-	-	-
1,440,302	1,319,742	2,678,635	8,436,576	2,034,379	-
17,321	154,426	216,643	174,812	95,395	52,242
6,358,739	6,291,634	5,991,928	5,063,932	5,567,616	5,091,473
471,082	404,573	288,320	159,489	47,757	-
3,700,101	3,358,095	3,250,414	3,269,614	3,497,386	2,726,404
5,098,364	4,875,823	4,502,408	4,756,135	5,444,556	4,330,378
10,638,538	10,022,182	10,315,133	9,415,620	7,386,595	7,203,783
9,951,985	9,270,588	8,800,473	7,038,619	5,714,137	5,331,998
138,678,560	128,168,354	130,397,993	113,634,707	81,457,697	72,091,084
3,973,278	**7,199,862**	**3,260,823**	**(5,454,572)**	**1,545,038**	**11,853,123**
1,674,427	569,733	248,093	551,108	1,051,003	1,227,833
(3,807,972)	(4,198,458)	(3,887,870)	(3,111,569)	(2,315,586)	(2,383,234)
(209,324)	(113,865)	(245,253)	(135,733)	(35,962)	(66,177)
(449,138)	(574,560)	(444,361)	(368,388)	57,189	-
(2,792,007)	(4,317,150)	(4,329,391)	(3,064,582)	(1,243,355)	(1,221,578)
1,181,271	**2,882,712**	**(1,068,568)**	**(8,519,154)**	**301,683**	**10,631,545**
1,951,640	**1,841,166**	**2,930,868**	**6,951,770**	**1,325,750**	**1,122,378**
-	**-**	**-**	**-**	**-**	**418,840**
$3,132,911	**$4,723,878**	**$1,862,300**	**($1,567,384)**	**$1,627,433**	**$12,172,763**

2005	2004	2003	2002	2001	2000
$47,804,295	$48,450,170	$46,564,150	$54,257,706	$48,668,840	$51,455,113
-	-	-	-	-	-
34,757,194	30,978,408	28,140,550	18,584,694	25,740,944	21,327,238
$82,561,489	**$79,428,578**	**$74,704,700**	**$72,842,400**	**$74,409,784**	**$72,782,351**

REVENUES AND CONSUMPTION BY CUSTOMER CLASS

For the years ended December 31

	2009	2008	2007	2006
AVERAGE NUMBER OF CUSTOMERS				
Residential	39,220	38,855	37,969	37,418
General Service	5,289	5,192	5,077	4,931
Industrial	3	3	3	3
Irrigation	746	736	717	713
Miscellaneous	1,816	1,814	1,804	1,790
Total	47,074	46,600	45,570	44,855
RETAIL ELECTRIC SALES (IN THOUSANDS) (1)				
Residential	$43,704	$41,116	$42,765	$44,778
General Service	25,605	24,750	27,282	29,259
Industrial	1,483	1,662	1,790	1,444
Irrigation	16,290	13,936	15,764	15,485
Miscellaneous	733	690	744	824
Total	$87,815	$82,154	$88,345	$91,790
RETAIL ELECTRIC SALES IN MWh				
Residential	721,719	666,418	644,392	632,213
General Service	530,255	510,144	503,551	510,052
Industrial	38,909	47,760	49,045	37,456
Irrigation	427,269	407,432	402,251	368,048
Miscellaneous	8,188	8,102	8,026	7,941
Total	1,726,341	1,639,856	1,607,265	1,555,710
AVERAGE REVENUE PER kWh (CENTS) (1)				
Residential	6.06	6.17	6.64	7.08
General Service	4.83	4.85	5.42	5.74
Industrial	3.81	3.48	3.65	3.86
Irrigation	3.81	3.42	3.92	4.21
Miscellaneous	8.95	8.51	9.27	10.38
Average - All Classes	5.09	5.01	5.50	5.90

(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.

2005	2004	2003	2002 (2)	2001	2000
36,963	36,285	35,576	34,872	34,854	34,678
4,903	4,869	4,761	4,649	4,567	4,484
3	3	3	3	3	3
718	729	739	739	733	727
1,802	1,823	1,797	1,681	1,664	1,647
44,389	43,709	42,876	41,944	41,821	41,539
$46,461	$47,664	$46,335	$41,277	$32,177	$30,749
30,478	30,651	29,043	25,961	20,291	19,464
1,995	2,483	2,291	3,044	1,772	7,382
17,136	16,294	16,375	15,061	11,851	11,393
832	827	794	699	602	623
$96,902	$97,919	$94,838	$86,042	$66,693	$69,612
622,639	621,386	604,618	622,196	617,763	636,952
521,308	523,388	509,057	496,949	500,356	530,430
53,286	69,479	58,054	80,551	70,897	220,913
397,651	375,363	401,868	382,551	375,683	385,753
7,625	7,438	7,154	5,432	5,284	5,208
1,602,508	1,597,054	1,580,751	1,587,678	1,569,982	1,779,257
7.46	7.67	7.66	6.63	5.21	4.83
5.85	5.86	5.71	5.22	4.06	3.67
3.74	3.57	3.95	3.78	2.50	3.34
4.31	4.34	4.07	3.94	3.15	2.95
10.92	11.11	11.10	12.88	11.39	11.96
6.05	6.13	6.00	5.42	4.25	3.91

RETAIL RATES (1)

As of December 31

	2009	2008	2007	2006
Residential				
Monthly Base Charge (single phase)	$8.80	$8.80	$8.80	$9.15
Energy Charge (cents/kWh)	5.78	5.78	6.02	6.28
Small General Service				
Monthly Base Charge (single phase)	$10.70	$10.70	$11.25	$11.75
Energy Charge Effective 2001 (cents/kwh)				
First 20,000 kwh	5.13	5.13	5.39	5.64
Over 20,000 kwh	3.35	3.35	3.46	3.62
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 (single phase)	$13.20	$13.20	$13.90	$14.55
Energy Charge (cents/kwh)				
Summer Effective 2001				
First 20,000 kwh	4.46	4.46	4.69	4.81
Over 20,000 kwh	2.74	2.74	2.88	2.95
Summer Prior to 2001				
First 2,500 kwh	-	-	-	-
Next 17,500 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter Effective 2001				
First 20,000 kwh	5.24	5.24	5.52	5.66
Over 20,000 kwh	3.33	3.33	3.49	3.58
Winter Prior to 2001				
First 2,500 kwh	-	-	-	-
Next 17,500 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Demand Charge	$6.60	$6.60	$7.20	$8.08
Large General Service				
Monthly Charge (multi phase)	$17.40	$17.40	$18.45	$19.10
Energy Charge (cents/kwh)				
Summer				
First 20,000 kwh	4.33	4.33	4.62	4.78
Over 20,000 kwh	2.89	2.89	3.07	3.18
Winter				
First 20,000 kwh	4.72	4.72	5.03	5.21
Over 20,000 kwh	3.56	3.56	3.77	3.9
Demand Charge	$5.60	$5.60	$5.92	$6.13

(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.

2005	2004	2003	2002	2001	2000
$9.55	$10.05	$10.65	$9.00	$9.00	$6.90
6.54	6.87	7.27	6.12	6.12	4.40
$12.25	$12.51	$12.51	$10.75	$10.75	$7.50
5.87	5.98	5.98	5.14	5.14	-
3.77	3.84	3.84	3.30	3.30	-
-	-	-	-	-	3.73
-	-	-	-	-	3.56
-	-	-	-	-	2.12
-	-	-	-	-	3.73
-	-	-	-	-	3.56
-	-	-	-	-	2.12
$15.15	$15.28	$15.28	$13.85	$13.85	$10.65
5.01	5.06	5.06	4.49	4.49	-
3.07	3.10	3.10	2.74	2.74	-
-	-	-	-	-	3.41
-	-	-	-	-	3.36
-	-	-	-	-	1.84
5.90	5.96	5.96	5.28	5.28	-
3.73	3.77	3.77	3.34	3.34	-
-	-	-	-	-	3.78
-	-	-	-	-	3.74
-	-	-	-	-	2.26
$8.42	$8.50	$8.50	$8.50	$8.50	$6.00
$19.90	$20.41	$20.41	$17.75	$17.75	$13.15
4.98	5.11	5.11	4.45	4.45	3.16
3.31	3.39	3.39	2.95	2.95	1.66
5.43	5.57	5.57	4.48	4.48	3.55
4.06	4.16	4.16	3.62	3.62	2.33
$6.39	$6.55	$6.55	$5.70	$5.70	$5.70

PRINCIPAL RATEPAYERS

For the years ended December 31

2009

Ratepayer's Rate Class [1]	kWh	Rank	Percentage of Total kWh	Retail Sales	Percentage of Total Retail Electric Sales
Large Irrigation Customer 1	188,534,878	1	10.9%	$6,829,342	7.4%
Large Irrigation Customer 2	71,045,636	2	4.1%	2,581,574	2.8%
Large Irrigation Customer 3	39,863,383	3	2.3%	1,390,527	1.5%
Large Industrial Customer 1	38,899,317	4	2.3%	1,478,543	1.6%
Large Irrigation Customer 4	35,467,244	5	2.1%	1,310,959	1.4%
Large Irrigation Customer 5	33,573,722	6	1.9%	1,177,696	1.3%
Large General Customer 1	25,646,657	7	1.5%	1,096,953	1.2%
Large General Customer 2	23,156,692	8	1.3%	1,172,963	1.3%
Large Irrigation Customer 6	22,788,000	9	1.3%	814,742	0.9%
Large General Customer 3	21,564,477	10	1.2%	1,006,737	1.1%
Large General Customer 4	-	-	-	-	-
	500,540,006		29.0%	$18,860,036	20.5%
Total All Ratepayers	**1,726,340,980**			**$91,942,100**	

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

(2) Revenues for 2000 are estimated based on kWh consumption.

2000

kWh	Rank	Percentage of Total kWh	Retail Sales[2]	Percentage of Total Retail Electric Sales
172,862,000	2	9.7%	$5,401,105	7.5%
64,262,000	3	3.6%	2,014,176	2.8%
30,448,000	7	1.7%	916,136	1.3%
219,753,000	1	12.4%	7,382,000	10.2%
36,762,000	5	2.1%	1,172,079	1.6%
35,487,000	6	2.0%	1,073,740	1.5%
47,821,000	4	2.7%	1,547,749	2.1%
22,438,000	9	1.3%	860,035	1.2%
21,348,000	10	1.2%	658,365	0.9%
-	-	-	-	-
25,620,000	8	1.4%	614,880	0.9%
676,801,000		38.0%	$21,640,265	30.0%
1,779,257,048			**$72,254,487**	

RATIOS OF OUTSTANDING DEBT

For the years ended December 31

	2009	2008	2007	2006
Revenue Bonds	$50,865,000	$53,395,000	$55,810,000	$59,855,000
Unamortized Premium & Discount and Loss on Defeasance	597,829	663,277	727,593	782,504
Total Outstanding Revenue Debt	$51,462,829	$54,058,277	$56,537,593	$60,637,504
Total Revenue Debt to Operating Revenues	39%	38%	41%	42%
Total Revenue Debt to Total Assets	29%	29%	33%	34%
Total Revenue Debt per Ratepayer	$1,093	$1,160	$1,241	$1,352

DEBT MARGIN INFORMATION (1)

For the year ended December 31, 2009

Net Revenues January 2009 - December 2009 (2)	$23,473,107
Maximum Future Annual Debt Service (2015)	$6,372,489
Maximum Allowable Annual Debt Service per Bond Covenants (2)	$18,778,486
Allowable Additional Annual Debt Service	$12,405,997

(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%.

2005	2004	2003	2002	2001	2000
$71,620,000	$74,830,000	$79,105,000	$79,105,000	$65,840,000	$39,800,000
537,328	984,226	1,009,884	916,871	786,137	(689,161)
$72,157,328	$75,814,226	$80,114,884	$80,021,871	$66,626,137	$39,110,839
51%	56%	60%	74%	80%	47%
39%	44%	47%	46%	42%	31%
$1,626	$1,735	$1,869	$1,908	$1,593	$942

DEBT SERVICE COVERAGE

For the years ended December 31

	2009	2008	2007	2006
DEBT SERVICE CALCULATION				
Change in Net Assets	$11,811,897	$4,446,420	$4,034,758	$8,011,941
Adjustments to (from) Change in Net Assets				
Depreciation & Amortization	9,367,272	9,369,594	10,084,084	10,156,431
Interest Expense	2,259,809	2,442,913	2,533,496	3,309,699
Debt Discount & Expense Amortization	34,128	40,312	21,519	553,124
Extraordinary Item	-	-	9,755,303	-
Transfer (to) from Rate Stabilization	-	-	2,244,474	-
REVENUE AVAILABLE FOR DEBT SERVICE	**$23,473,107**	**$16,299,239**	**$28,673,634**	**$22,031,195**
DEBT SERVICE (2)	**$5,131,680**	**$5,130,080**	**$6,957,703**	**$7,407,225**
DEBT SERVICE COVERAGE RATIO	**4.57**	**3.18**	**4.12**	**2.97**

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

(2) Reduced by capitalized interest.

2005	2004	2003	2002	2001 [1]	2000
$3,132,911	$4,723,878	$1,862,300	($1,567,384)	$1,627,433	$12,172,763
9,951,985	9,270,588	8,800,473	7,038,619	5,714,137	5,331,998
3,389,240	3,992,266	3,887,870	3,111,569	2,315,586	2,383,234
209,324	113,865	245,253	135,733	35,962	66,177
-	-	-	-	-	(418,840)
(1,500,000)	(3,000,000)	-	-	-	536,406
$15,183,460	**$15,100,597**	**$14,795,896**	**$8,718,537**	**$9,693,118**	**$20,071,738**
$4,783,721	**$7,599,395**	**$3,324,395**	**$3,396,911**	**$5,739,255**	**$5,740,030**
3.17	**1.99**	**4.45**	**2.57**	**1.69**	**3.50**

PRINCIPAL EMPLOYERS - TRI-CITIES METROPOLITAN STATISTICAL AREA

For the years ended December 31

		2009		
Employer	**Product/Service**	**Employees**	**Rank**	**Percentage of Total MSA Nonfarm Employment**
Battelle Pacific NW National Laboratory	Research/National Laboratory	4,033	1	4.2%
Fluor Hanford Inc.	Environmental Engineering	3,630	2	3.7%
Bechtel National, Inc.	Engineering Services	2,130	3	2.2%
ConAgra/Lamb Weston Inc.	Food Processing	2,128	4	2.2%
Pasco School District	Education	1,900	5	2.0%
Tyson Fresh Meats/Iowa Beef	Meat Packing	1,800	6	1.9%
Kennewick School District	Education	1,750	7	1.8%
Kadlec Medical Center	Health Care	1,535	8	1.6%
Richland School District	Education	1,350	9	1.4%
CH2MHill Hanford Group Inc./CHG	Environmental Engineering	1,170	10	1.2%
Energy Northwest	Electrical Power	-	-	-
Framatome ANP	Nuclear Fuel	-	-	-
Total		21,426		22.1%

Source: Tri-City Development Council

2000		
Employees	Rank	Percentage of Total MSA Nonfarm Employment
3,500	2	4.6%
4,637	1	6.1%
-	-	-
1,854	4	2.4%
1,000	8	1.3%
1,450	5	1.9%
2,000	3	2.6%
-	-	-
981	9	1.3%
1,240	6	1.6%
1,020	7	1.3%
750	10	1.0%
18,432		24.2%

DEMOGRAPHIC STATISTICS

For the years ended December 31

	2009	2008	2007	2006
Population [1]				
Tri-Cities Metropolitan Statistical Area	242,000	235,700	230,300	224,800
Benton County	169,300	165,500	162,900	160,600
City of Kennewick	67,180	65,860	62,520	61,770
Prosser	5,110	5,075	5,075	5,045
Benton City	2,955	2,855	2,860	2,840
Total Personal Income - Benton County [2]	N/A	N/A	$5,469,683	$5,017,697
Per Capita Income - Benton County [2]	N/A	N/A	$34,448	$32,337
Unemployment Rate - Benton County [3]	7.4%	6.5%	5.1%	5.8%
Building Permits Issued [4]				
Kennewick	1,868	1,649	1,963	1,851
Benton County (Unincorporated)	604	562	662	753
Taxable Retail Sales - All of Benton County [5]	N/A	$2,601,911,391	$2,574,398,245	$2,303,245,278

(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

2005	2004	2003	2002	2001	2000
218,600	212,100	205,200	198,900	195,200	191,822
158,100	155,100	151,600	147,600	144,800	142,475
60,410	58,970	57,900	56,280	55,780	54,693
5,045	4,985	4,940	4,905	4,865	4,838
2,840	2,815	2,790	2,725	2,720	2,624
$4,895,653	$4,762,477	$4,536,705	$4,344,335	$4,124,077	$3,801,367
$31,329	$30,815	$29,707	$28,998	$28,318	$26,564
6.5%	5.8%	6.9%	6.7%	6.9%	5.4%
1,813	1,859	1,981	1,999	1,711	1,622
819	945	1,018	1,076	919	876
$2,226,436,260	$2,081,376,797	$2,020,400,388	$1,916,804,636	$1,801,558,310	$1,606,308,596

OPERATING INDICATORS

For the years ended December 31

	2009	2008	2007	2006
Operating Expenses / Revenues	91.8%	97.0%	93.5%	93.6%
Total Electric Sales in MWh				
Retail Sales	1,726,341	1,639,856	1,607,265	1,555,710
Sales for Resale	667,758	818,485	771,347	845,768
Total MWh Sales	2,394,099	2,458,341	2,378,612	2,401,478
Average Annual kWh per Customer				
Residential	18,402	17,151	16,972	16,896
General Service	100,256	98,256	99,183	103,438
Industrial	12,969,692	15,920,098	16,348,383	12,485,305
Irrigation	572,747	553,576	561,019	516,196
Miscellaneous	4,509	4,466	4,449	4,436
Average Annual kWh per Customer - All Classes	36,673	35,190	35,270	34,683
Average Revenue per Customer				
Residential	$1,114	$1,058	$1,126	$1,197
General Service	4,841	4,767	5,374	5,934
Industrial	494,424	554,015	596,832	481,482
Irrigation	21,836	18,934	21,986	21,718
Miscellaneous	403	380	412	460
Average Revenue per Customer - All Classes	$1,865	$1,763	$1,939	$2,046
Additions to Electric Plant, excluding work-in-progress (1)	$10,736,615	$10,358,753	$15,578,938	$7,484,509
Net Electric Utility Plant	$115,807,257	$110,029,356	$109,916,268	$119,838,966
Capitalized Payroll	$2,363,236	$2,008,050	$1,998,843	$1,570,018
Total Payroll Expense	$11,585,291	$11,041,774	$10,583,678	$10,769,446
Full Time Equivalent Employees (2)	159	156	156	162
Power Outages	342	342	356	315
Power Outages Caused by Squirrels	53	61	55	38
Cooling Degree Days (3)	1,235	991	1,070	1,166
Heating Degree Days (3)	5,679	5,581	5,223	5,140
Annual Precipitation (inches) (3)	5.47	5.49	5.48	8.46

(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. Full time equivalents reported beginning in 2006. Average number of employees reported prior to 2006.

(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.

2005	2004	2003	2002	2001	2000
97.2%	94.7%	97.6%	105.4%	98.5%	86.7%
1,602,508	1,597,054	1,580,751	1,587,678	1,569,982	1,779,257
563,061	723,913	819,435	615,694	200,639	50,426
2,165,569	2,320,967	2,400,186	2,203,372	1,770,621	1,829,683
16,845	17,125	16,995	17,842	17,724	18,368
106,324	107,494	106,922	106,894	109,571	118,294
17,761,932	23,159,528	19,351,268	26,850,190	23,632,237	73,637,600
553,832	514,901	543,800	517,660	512,528	530,610
4,231	4,080	3,981	3,231	3,176	3,162
36,101	36,538	36,868	37,852	37,541	42,833
$1,257	$1,314	$1,302	$1,184	$923	$887
6,216	6,295	6,100	5,584	4,443	4,341
664,988	827,817	763,762	1,014,690	590,735	2,460,655
23,866	22,352	22,158	20,380	16,168	15,672
462	453	442	416	362	378
$2,183	$2,240	$2,212	$2,051	$1,595	$1,676
$8,296,645	$9,107,460	$10,023,480	$17,607,642	$27,548,676	$10,040,300
$118,503,253	$122,188,107	$123,699,242	$121,809,610	$111,672,899	$89,980,118
$1,806,542	$1,968,011	$2,017,656	$1,486,016	$1,530,209	$1,273,076
$10,133,591	$9,687,480	$9,321,808	$9,112,720	$8,759,127	$8,179,105
162	160	159	161	157	154
331	336	295	343	406	449
40	35	42	58	72	83
989	1,135	1,331	1,131	1,092	903
5,145	4,930	4,742	4,954	4,966	5,399
6.37	7.96	8.14	5.41	6.66	8.08

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