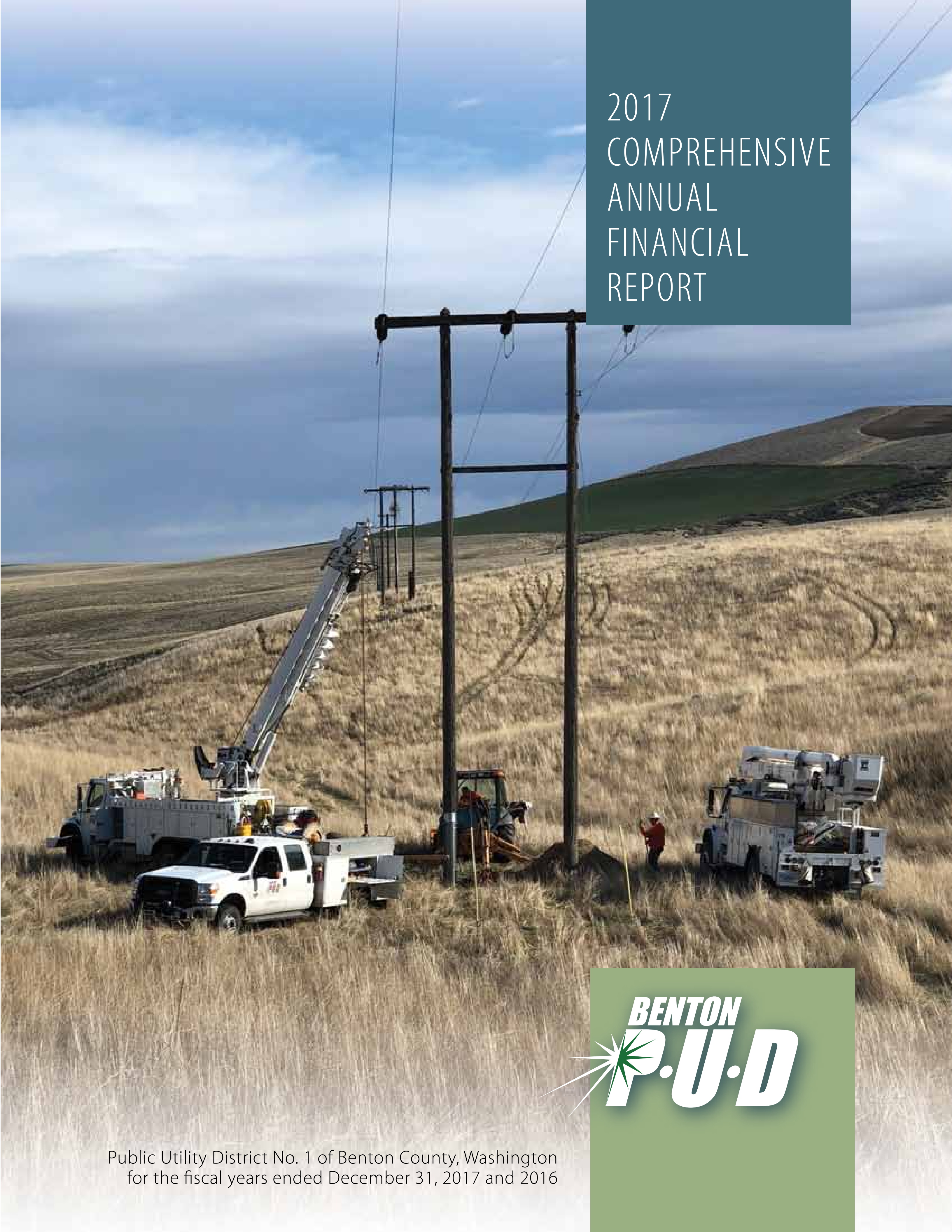
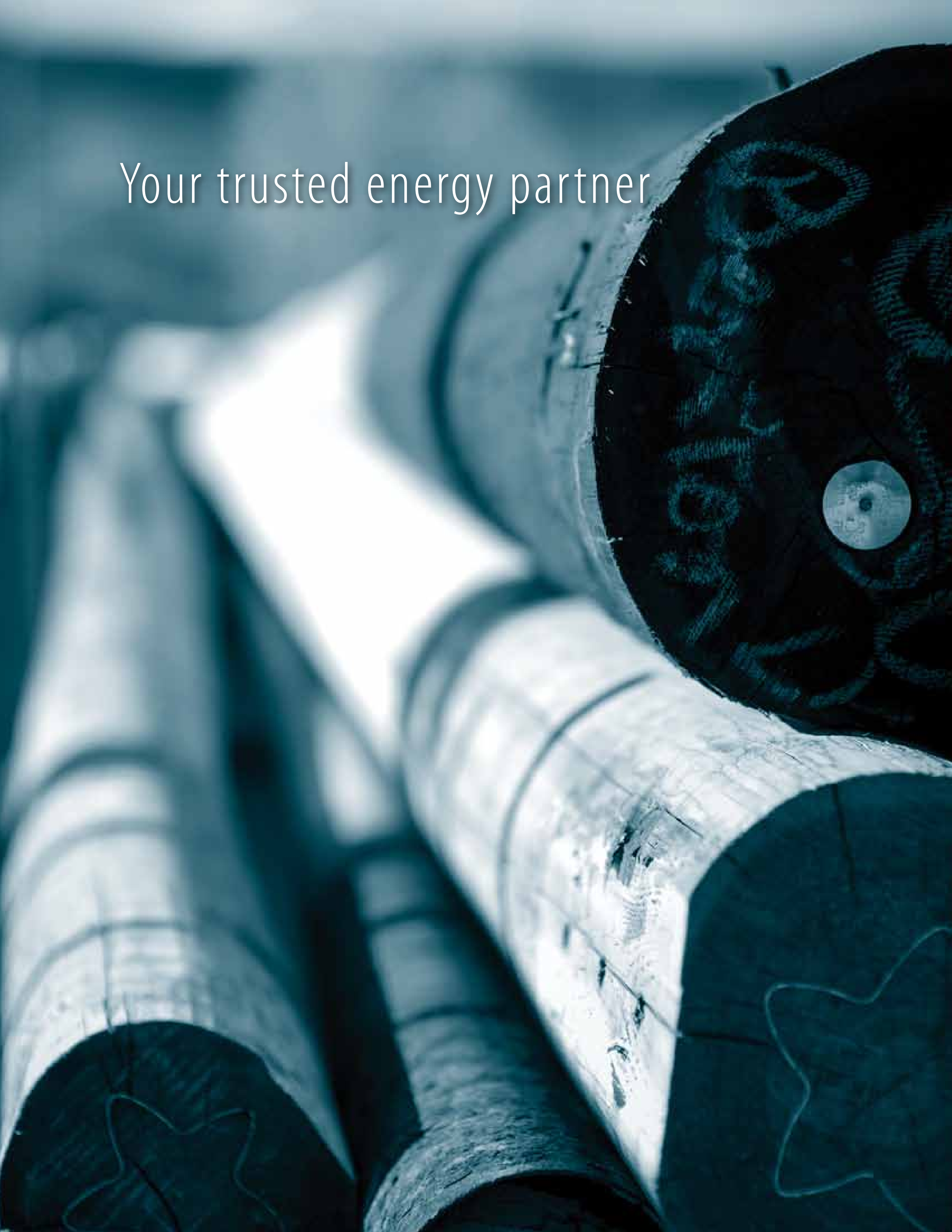


2017 COMPREHENSIVE ANNUAL FINANCIAL REPORT

BENTON P·U·D

Public Utility District No. 1 of Benton County, Washington
for the fiscal years ended December 31, 2017 and 2016


Your trusted energy partner

2017 COMPREHENSIVE ANNUAL FINANCIAL REPORT

Public Utility District No. 1 of

Benton County, Washington

for the fiscal years ended

December 31, 2017 and 2016

Prepared by Financial & Business Services and Communications & Governmental Relations of Benton PUD

Your trusted energy partner

OUR PURPOSE

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

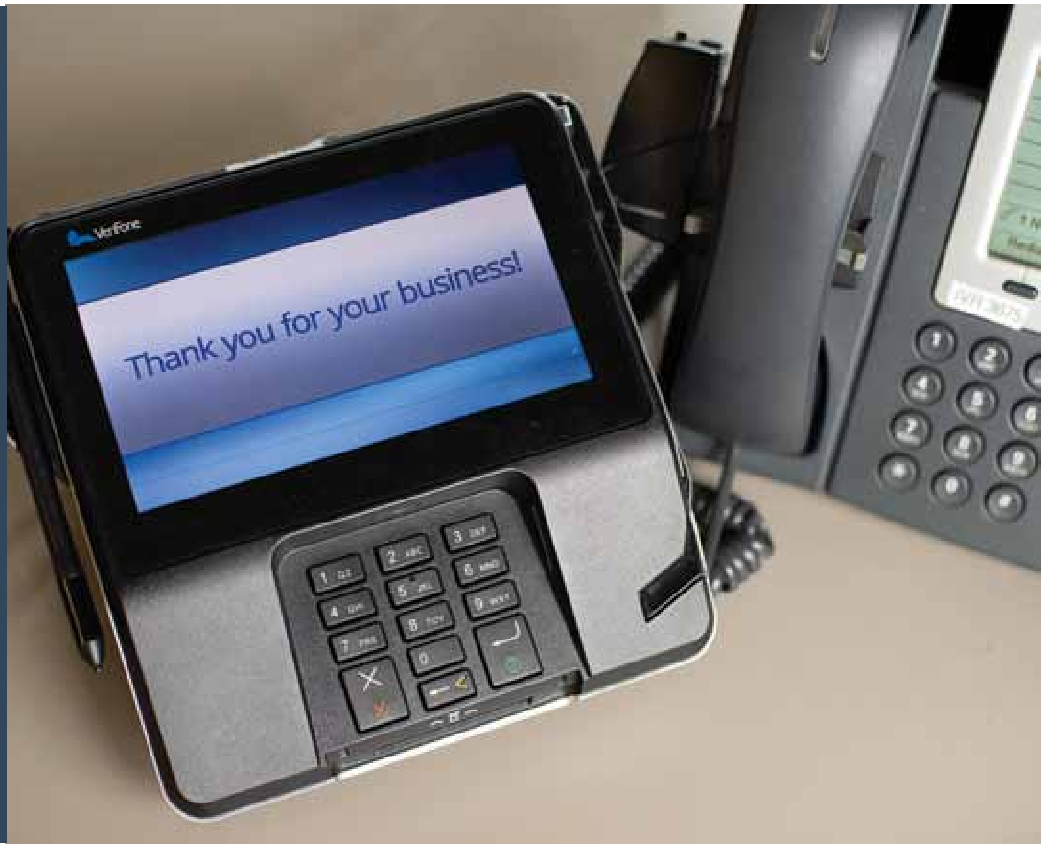
OUR MISSION

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

OUR VALUES

Excellence
Forward Focus
Integrity
Mutual Respect
Teamwork
Safety

TABLE OF CONTENTS


Thank you for your business!

INTRODUCTORY SECTION

Your trusted energy partner

Your trusted energy partner

Government Finance Officers Association

Certificate of Achievement for Excellence in Financial Reporting

Presented to

Public Utility District No. 1 of Benton County Washington

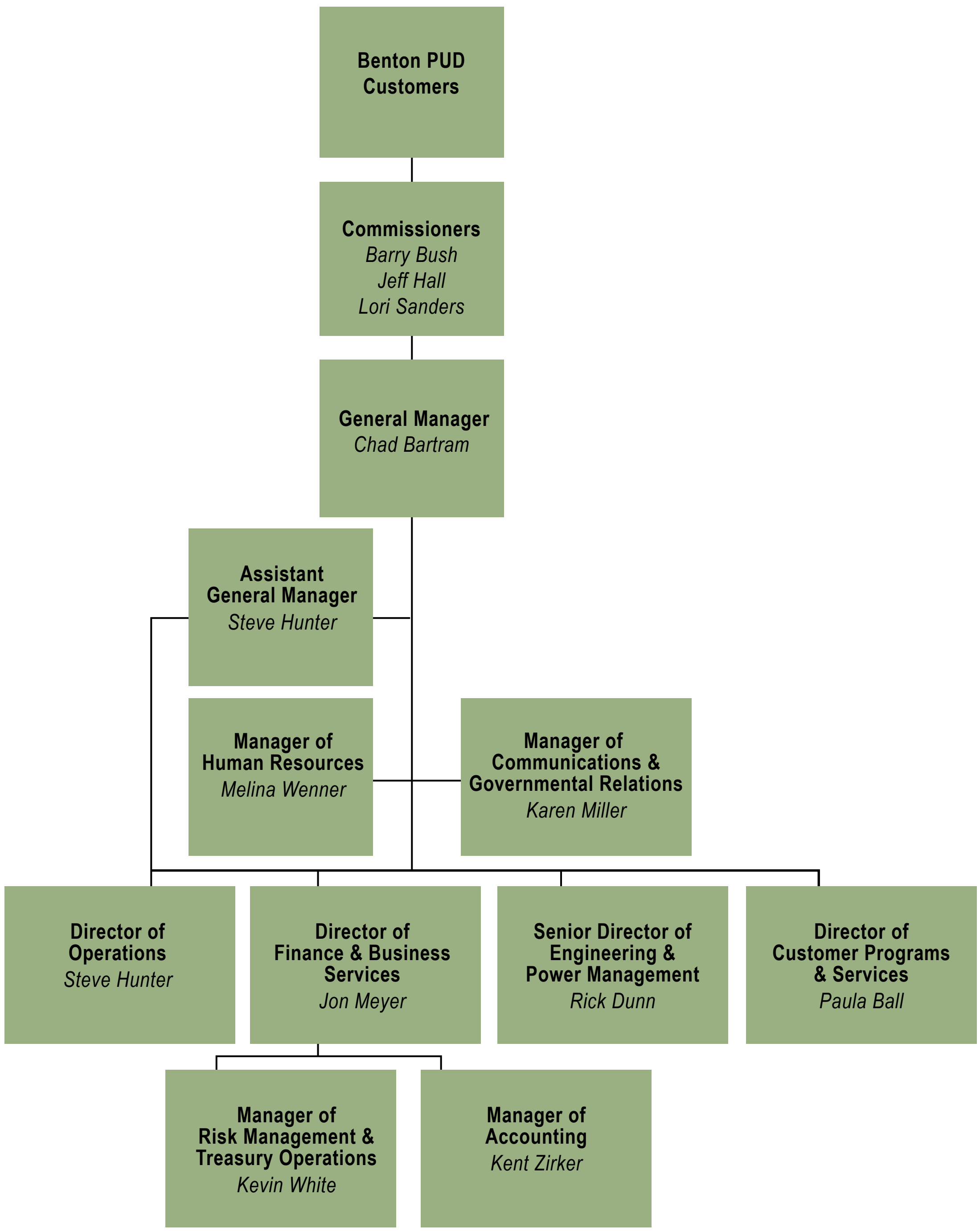
For its Comprehensive Annual Financial Report for the Fiscal Year Ended

December 31, 2016

Christopher P. Morrill

Executive Director/CEO

ORGANIZATION CHART



COMMISSION MESSAGE

Meeting the needs of our community and our customers' expectations
In the last ten years, population in Benton County has grown by 18 percent, second only to Franklin County located adjacent to Benton PUD's service area. Since 2013, Tri-City employment has grown nearly 12 percent or over 12,000 new jobs, according to TRIDEC, the local economic development organization.

In 2017, Benton PUD accomplishments were focused on the growth of our community and meeting the expectations of our customers. Investment in our electric infrastructure was a priority. There were a number of capital projects last year to meet the anticipated demand, improve the overall reliability of our distribution system and help reduce the risk of prolonged outages.

Benton PUD completed a transmission project in south Benton County to meet the growing needs of the agriculture community. To meet residential growth, we partnered with a neighboring utility to install new transmission lines in the south Badger Mountain area and began construction on a new substation.

Smart move for our customers
In March, Benton PUD customers were introduced to SmartHub®. The new system is one of the components of the National Information Solutions Cooperative (NISC) utility software used to integrate customer service, accounting, engineering and operations. SmartHub, an online tool available on a computer, tablet or smart phone, provides customers an easy way to manage their accounts, make payments, access billing and payment history and monitor their electric usage.

Jeff Hall Commissioner — Barry Bush Commissioner — Lori Sanders Commissioner

In December, a near-real-time outage map and enhanced outage notification capabilities were added to Benton PUD's SmartHub app and website. Benton PUD's advanced meters coupled with SmartHub provide automatic outage detection that enables a proactive dispatch of crews and helps us determine where the cause of the outage may be located. It also provides information on the distribution system performance which can help prevent problems before they occur.

In less than a year, over a third of Benton PUD customers enrolled in SmartHub and are now using the many tools it offers. Overall the implementation of SmartHub was a big success for both our customers and for Benton PUD.

Driving forward to support electric vehicles
Benton PUD joined forces with local utilities and community partners to form the Electric Vehicles Infrastructure Transportation Alliance (EVITA) to advocate for electric transportation infrastructure. EVITA was awarded a Washington State Department of Transportation grant for nine fast-charging stations in eastern Washington. As one of the EVITA members, Benton PUD partnered with the City of Kennewick and Greenlots to build a charging station in the Southridge area.

Electric vehicles represent an opportunity for Benton PUD to grow revenues to offset declining load growth, due in part to successful energy efficiency programs. They also help achieve carbon reduction objectives being discussed by state and federal legislators.

These are a few examples of Benton PUD accomplishments in 2017 with the ultimate goal to be our customers' trusted energy partner.

LETTER OF TRANSMITTAL

May 18, 2018

To the Board of Commissioners and Customers
Public Utility District No.1 of Benton County, Washington

The Comprehensive Annual Financial Report (CAFR) of the Public Utility District (District) No.1 of Benton County, Washington for the year ended December 31, 2017 is hereby submitted. The report is designed to assess the District's financial position, 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, 2017.

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 certified public accounting firm of Moss Adams has issued an unmodified ("clean") opinion on the District's financial statements for the years ended December 31, 2017 and 2016. 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 complements 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 Kennewick, WA.

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 8). 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 load.

The District's properties include 37 substations, approximately 98 miles of 115 kV transmission lines, 1,688 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 five major industries: agriculture and food processing, manufacturing, retail, technology, and healthcare. 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, sweet corn, onions, grapes, cherries, wheat, 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 and region, food processing continues to be a major factor in the local 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 racquets. Other industries in the region include paper and cardboard container plant 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 Batelle, PNNL, and the Department of Energy and its contractors associated with the Hanford Project.

LETTER OF TRANSMITTAL

The local economy continues to be strong and steady. Tri-Cities nonfarm employment was up 2.2 percent in December 2017 as compared to December 2016. The Tri-Cities gained approximately 2,400 jobs during the year primarily as a result of expanding construction, educational and health services, and local government. In addition, private service industries such as food, financial activity, and transportation services continued to be strong. The Tri-Cities is a regional shopping destination for communities throughout southeastern Washington and northeastern Oregon leading to continued growth in the retail service industry.

Long-Term Financial Planning

The District's Leadership Team meets at least quarterly to review an updated five-year financial forecast. The forecast includes both operating (including power supply costs) 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 polícies cover such issues as liquidity, debt service coverage, debt financing, retail rates, enterprise risk management, power supply risk, credit risk, investment policies and practices, insurance, integrated planning, budgetary and procurement controls, and financial reporting.

The financial policies call for the development of financial plans to achieve a minimum debt service coverage ratio 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 related to reserve levels call for minimum operating reserves to be no less than 90 days cash on hand. In addition, the policies establish financial plans to maintain total unrestricted reserves that are expected to achieve or maintain the targeted bond rating that is the median for public power utilities. The Commission periodically reviews these policies.

Relevant Financial Policies

As a result of rising wholesale net power costs during the period and future years, the District increased retail rates an average of 1.9% effective October 1, 2017. The District will continue to evaluate the need for future retail rate increases in order to meet targets established in financial policies.

Major Initiatives

The District completed implementation of it's integrated utility software solution in early 2017, completing a major initiative of its Customer Engagement Strategic Plan and IT Strategic Technology Plan. Included in the implementation were a customer portal, mobile device-enhanced services, meter data management system and mobile workforce management. Looking forward, the District will be installing kiosks for customers to make payments and will also have prepaid services to improve customer payment options.

LETTER OF TRANSMITTAL

The District also has substantial transmission, substation, and distribution projects planned over the next several years to continue to ensure reliable electric service while accommodating growth. This includes nearly $3.1 million in the 2018 budget for substation projects that include construction of a new substation, replacing equipment that has reached the end of its useful life, and installing or upgrading equipment with more advanced, reliable, and safe technology. Additional 115 kilovolt transmission lines are planned for the southern part of the county to improve reliability for agricultural customers. In addition, a new line is being constructed to improve reliability for rapidly expanding residential areas. The District, in conjunction with the City of Richland, is constructing a new substation to be completed in 2019 and will be utilized by both utilities which will improve system reliability for an area with substantial growth in recent years. The District is proactively planning projects to meet the needs of expanding growth in its service territory which include expanding substations and increasing distribution reliability to these areas.

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 31,2016. This was the fifteenth consecutive year 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.

Jon L. Meyer Chad B. Bartram

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,

Chad B. Bartram
Chad B. Bartram
General Manager

Jon L. Meyer
Jon L. Meyer
Director of Finance and Business Services

FINANCIAL SECTION

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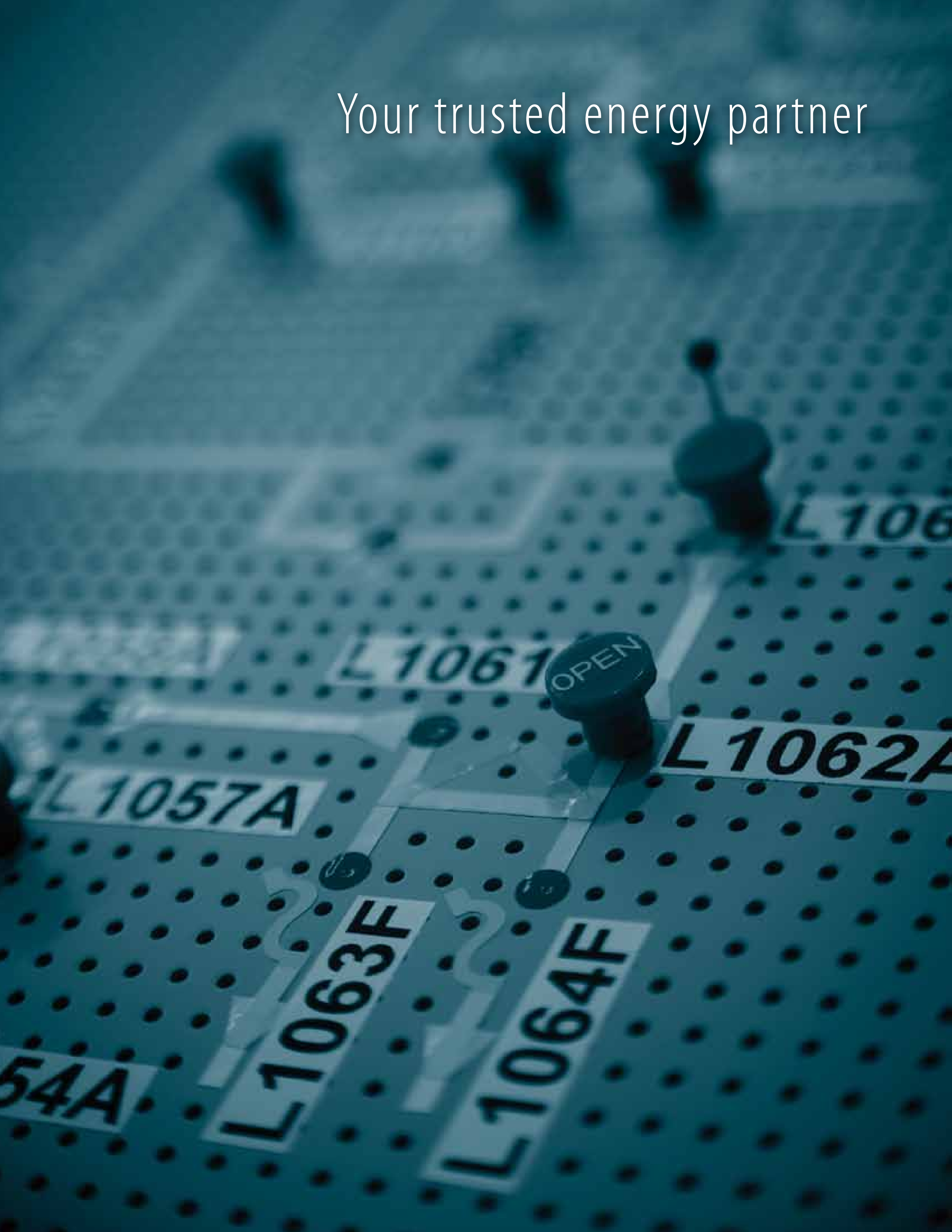
Your trusted energy partner



INDEPENDENT AUDITOR'S REPORT

MOSS ADAMS

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

Report on the Financial Statements

We have audited the accompanying financial statements of Public Utility District No. 1 of Benton County, Washington (the "District"), which comprise the statements of net position as of December 31,2017 and 2016, and the related statements of revenues, expenses, and changes in net position and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as wellas evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the District as of December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matter

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the accompanying management's discussion and analysis preceding the financial statements and the schedules of proportionate share of net pension liability and schedules of employer contributions subsequent to the notes to the financial statements be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board, who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming opinions on the financial statements that collectively comprise the District's financial statements. The statistical section is presented for purposes of additional analysis and is not a required part of the financial statements.
The statistical section has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Moss Adams LLP

Portland, Oregon
May 16, 2018

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, 2017 and 2016, with additional comparative data for 2015. 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 (GASB), 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 incurred 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, 2017 and 2016, consist of:

Statement of Net Position: The District presents its Statement of Net Position using the balance sheet format. The Statement of Net Position reflects the assets, liabilities, deferred outflows and inflows of resources, and net position (equity) of the District at year-end. The net position section is separated into three categories: net investment in capital assets, net position - restricted, and net position - unrestricted.

Statement of Revenues, Expenses, and Changes in Net Position: This statement reflects 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.

Statement of Cash Flows: The Statement of Cash Flows reflects the sources and uses of cash separated into four categories of activities: operating, noncapital financing, capital and related financing, and investing.

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 3-year comparison of key financial information:

Statement of Net Position *(in thousands)*

	2017	2016	Increase (Decrease) 2017-2016	% Change 2017-2016	2015
Assets and Deferred Outflows of Resources					
Current & Noncurrent Assets	$92,286	$92,043	$243	0%	$83,118
Utility Plant	125,666	123,470	2,196	2%	120,791
Subtotal Assets	217,952	215,513	2,439	1%	203,909
Deferred Outflows of Resources	2,552	3,937	(1,385)	-35%	3,893
Total Assets and Deferred Outflows of Resources	220,504	219,450	1,054	0%	207,802
Liabilities and Deferred Inflows of Resources					
Current Liabilities	20,875	20,515	360	2%	18,507
Noncurrent Liabilities	72,448	80,576	(8,128)	-10%	68,152
Subtotal Liabilities	93,323	101,091	(7,768)	-8%	86,659
Deferred Inflows of Resources	3,026	2,323	703	30%	4,836
Total Liabilities and Deferred Inflows of Resources	96,349	103,414	(7,065)	-7%	91,495
Net Position					
Net Investment in Capital Assets	64,407	58,672	5,735	10%	68,040
Restricted for Debt Service	1,108	1,108	-	0%	1,084
Unrestricted	58,640	56,256	2,384	4%	47,183
Total Net Position	$124,155	$116,036	$8,119	7%	$116,307

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

	2017	2016	Increase (Decrease) 2017-2016	% Change 2017-2016	2015
Operating Revenues					
Retail Energy Sales	$130,811	$120,439	$10,372	9%	$116,820
Secondary Market Sales	15,828	15,723	105	1%	18,370
Other	3,504	3,700	(196)	-5%	3,695
Nonoperating Revenues					
Interest Income	605	326	279	86%	245
Other Income	562	321	241	75%	504
Unrealized Gain/(Loss) on Investments	(33)	(4)	(29)	>300%	25
Total Revenues	151,277	140,505	10,772	8%	139,659
Operating Expenses					
Power Supply	96,775	94,193	2,582	3%	95,574
Operations, Maintenance and A&G	21,760	19,966	1,794	9%	21,179
Taxes/Depreciation/Amortization	24,197	25,261	(1,064)	-4%	25,472
Nonoperating Expenses					
Interest Expense	2,910	2,665	245	9%	2,757
Debt Premium Amortization & (Gain) on Defeased Debt	(493)	(144)	(349)	242%	(420)
Total Expenses	145,149	141,941	3,208	2%	144,562
Income/(Loss) before Contributions	6,128	(1,436)	7,564	>-300%	(4,903)
Capital Contributions	1,991	1,165	826	71%	2,472
Change in Net Position	8,119	(271)	8,390	>-300%	(2,431)
Beginning Net Position	$116,036	$116,307	($271)	0%	$118,738
Ending Net Position	$124,155	$116,036	$8,119	7%	$116,307

Financial Analysis

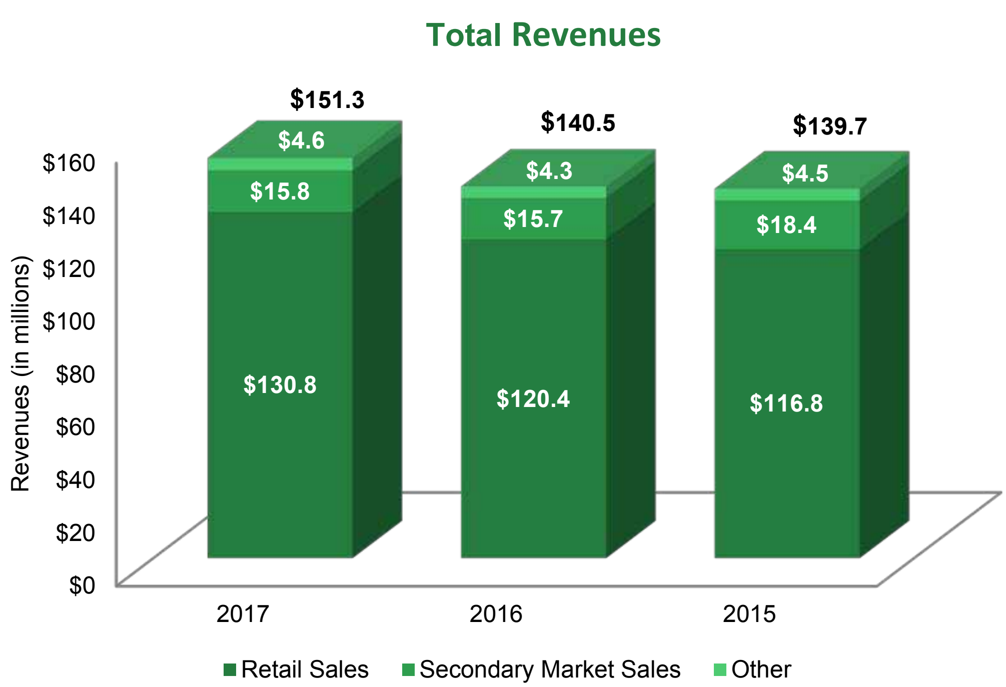
During 2017, the District's overall financial position and results of operations improved over last year. The District's net position increased by $8.1 million compared to a decrease of $271,000 in 2016. Provided below is a year-over-year analysis of the change in net position by major component of income, with a primary focus on changes between 2017 and 2016.

Operating Revenues
2016 to 2017:
Revenues from sales to retail customers (retail energy sales) in 2017 increased $10.4 million (9%) from 2016. Colder than average winter and warmer than average summer weather contributed to an increase in kilowatt hours (kWh) sold to customers of 5.4%. In addition, active service agreements increased by 1.2% and the District had rate increases of 1.9% effective October 1, 2017 and 4.9% effective September 1, 2016.

Revenues from wholesale energy and natural gas sales increased by $105,000 (0.7%), primarily as a result of increased sales despite a decrease in wholesale prices of about 7%.

2015 to 2016:
Revenues from sales to retail customers in 2016 increased $3.6 million (3%) from 2015. Continued milder weather contributed to a decrease in kilowatt hours (kWh) sold to customers of 2.5%. However, revenues increased as a result of a September 1, 2015 retail revenue rate increase of 3.9% and a September 1, 2016 retail revenue rate increase of 4.9%.

Revenues from wholesale energy and natural gas sales decreased by $2.6 million (-14%), primarily as a result of a decrease in wholesale prices of about 9%.



Operating Expenses
2016 to 2017:
Power supply expense increased by $2.6 million (2.7%), primarily as a result of weather and increased purchase transactions by The Energy Authority (TEA) to manage daily loads. In addition, net power expense (power supply expense less secondary market sales) increased by $2.5 million (3.2%), primarily attributable to increased retail energy sales and a rate increase from BPA that became effective October of 2017. The District uses net power expense as a means to measure overall financial performance related to power supply management.

Total operations, maintenance and administrative and general (A&G) expenses increased by $1.8 million (9.0%). The increase was primarily due to 2016 had included $700,000 in temporary budget reductions (see 2015 to 2016 analysis), and 2017 labor and benefits charged to operations and maintenance expense from resources previously dedicated to capital projects The District charges internal labor to operations, maintenance, A&G activities, and capital projects. In 2017, the internal labor required for operations and maintenance activities increased $1.1 million from 2016 while internal labor performed on capital projects decreased $777,000.

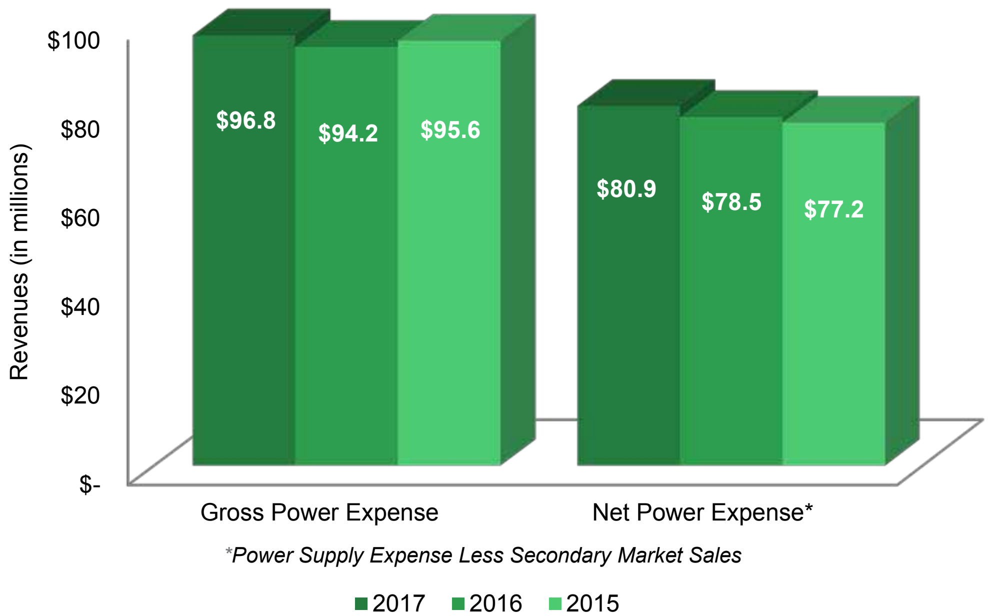
Taxes assessed by state and municipal governments increased by $1.4 million (11%), primarily as a result of higher retail sales. Depreciation and amortization decreased $2.5 million as a result of assets becoming fully depreciated and updating useful lives to better match the service life of certain assets.

2015 to 2016:
Power supply expense decreased by $1.4 million (-1.4%), primarily as a result of weather and decreased purchase transactions by TEA to manage daily loads. However, net power expense increased by $1.3 million (1.6%), primarily attributable to lower secondary market sales and a rate increase from BPA that became effective October of 2015. The District uses net power expense as a means to measure overall financial performance related to power supply management.

Total operations, maintenance and administrative and general (A&G) expenses decreased by $1.2 million (-6%). The decrease was largely comprised of: temporary budget reductions of $700,000 that involved some risk but were determined to be acceptable for one year, reduction in pension expense of about $308,000, and a decrease in labor charged to operations and maintenance expense as a result of resources dedicated to capital projects. The District charges internal labor to operations, maintenance, A&G activities, and capital projects. In 2016, the internal labor required for operations and maintenance activities decreased $468,000 from 2015 while internal labor performed on capital projects increased $1,000,000.

Taxes assessed by state and municipal governments increased by $367,000 (3%), primarily as a result of higher retail sales. Depreciation and amortization decreased $577,000 as a result of assets becoming full depreciated and updating useful lives to better match the service life of certain assets.

Gross and Net Power Expenses



Other Income & Expense

During 2017, interest income increased by $279,000 (86%) due to higher interest rates on longer term investments as compared to previous investment purchases. In addition, the average investment rate of the Washington State Treasurer's Local Government Investment Pool (LGIP) increased from 0.47% in 2016 to 0.97% in 2017. At year-end, the District's investments had an unrealized loss of $33,000.

During 2016, interest income increased by $81,000 (33%) due to higher interest rates on longer term investments as compared to previous investment purchases. In addition, the average investment rate of the Washington State Treasurer's Local Government Investment Pool (LGIP) increased from 0.16% in 2015 to 0.47% in 2016. At year-end, the District's investments had an unrealized loss of $4,000.

There were no significant restrictions, commitments, or other limitations that would affect the availability of resources for future use in 2017, 2016, and 2015.

Capital Contributions

During 2017, capital contributions increased by $826,000 (71%), primarily due to a few larger distribution projects.

During 2016, capital contributions decreased by $1.3 million (-53%), primarily due to 2015 including larger one-time projects related to broadband and community solar.

Summary of Financial Position

The overall financial position of the District increased $8.1 million, primarily due to higher retail loads. Other financial areas of the District remained stable as the District maintained solid cash and investment reserves and achieved a debt service coverage ratio well above policy limits. With rising power costs, the District had an average rate increase of 4.9% effective September 1, 2016 and an increase of 1.9% effective October 1, 2017.

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 provide funding for a specified amount of operating expenses, power supply expenses, catastrophic loss, debt service, and capital improvements. The District's unrestricted cash and investment balances totaled $56.8 million, $54.2 million, and $45.5 million at December 31, 2017, 2016 and 2015, 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 position 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 2017, 2016 and 2015, the District was in compliance with such policies and covenants.

Capital Asset and Long-Term Debt Activity

During 2017, gross capital additions totaled $13.2 million. Capital contributions associated with these additions totaled $2.0 million. Major capital additions included completion of additions and improvements to existing distribution infrastructure and substations, installation of electric facilities along new major road expansions, and a 1.2% growth in customers served by the District, as well as internal capital expenditures to meet District needs. Construction work-in-progress totaled $4.6 million at year-end, a net decrease of $1.1 million from 2016.

During 2016, gross capital additions totaled $15.7 million. Capital contributions associated with these additions totaled $1.2 million. Major capital additions included completion of additions and improvements to existing distribution infrastructure and substations, installation of electric facilities along new major road expansions, and a 1.8% growth in customers served by the District, as well as internal capital expenditures to meet District needs. Construction work-in-progress totaled $5.7 million at year-end, a net increase of $3.0 million over 2015.

In September 2016, the District issued $22,470,000 of Electric Revenue and Refunding Bonds, Series 2016. The bond proceeds were used to fund $15.1 million of improvements and replacements of the District's electric utility system and to refund the 2011 bonds maturing on or after November 1, 2023. (See Note 5)

The Bonds, as well as the District's credit ratings, were affirmed by three rating agencies: Standard & Poor's at A+, Fitch Ratings at A+, and Moody's at Aa3.

Debt service payments totaled $6.2 million in 2017, $5.4 million in 2016, and $4.8 million in 2015.

Additional information about the District's capital assets and long-term debt is presented in Notes 2 & 5.

STATEMENT OF NET POSITION

As of December 31, 2017 and 2016

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	2017	2016
ASSETS		
CURRENT ASSETS		
Cash & Cash Equivalents		
Unrestricted Cash & Cash Equivalents	$44,190,936	$42,306,649
Investments (Note 3)	12,616,525	11,916,120
Accounts Receivable, Net	8,579,629	8,725,320
BPA Prepay Receivable (Note 8)	600,000	600,000
Accrued Interest Receivable	59,654	32,102
Wholesale Power Receivable	1,407,401	870,436
Accrued Unbilled Revenues	4,800,000	5,400,000
Inventory - Materials & Supplies	5,544,372	5,660,664
Prepaid Expenses & Option Premiums	491,064	434,673
Total Current Assets	**78,289,581**	**75,945,964**
NONCURRENT ASSETS		
Restricted Bond Reserve Fund	1,107,865	1,107,865
BPA Prepay Receivable (Note 8)	5,850,000	6,450,000
Other Receivables (Note 1)	96,778	96,895
Other Charges (Note 4)	6,941,230	8,441,979
Subtotal Noncurrent Assets	13,995,873	16,096,739
Utility Plant (Note 2)		
Land and Intangible Plant	3,493,641	3,474,031
Electric Plant in Service	305,931,426	302,719,921
Construction Work in Progress	4,599,287	5,697,524
Less: Accumulated Depreciation	(188,357,607)	(188,421,328)
Net Utility Plant	125,666,747	123,470,148
Total Noncurrent Assets	**139,662,620**	**139,566,887**
TOTAL ASSETS	**217,952,201**	**215,512,851**
DEFERRED OUTFLOWS OF RESOURCES		
Pension Deferred Outflow	1,429,022	2,019,756
Accumulated Decrease in Fair Value of Hedging Derivatives	1,122,842	1,919,445
Total Deferred Outflows of Resources	**2,551,864**	**3,939,201**
TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	**$220,504,065**	**$219,452,052**

NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES		
LIABILITIES		
CURRENT LIABILITIES		
Accounts Payable	$9,922,995	$10,311,190
Customer Deposits	1,667,840	1,477,457
Accrued Taxes Payable	3,652,731	3,382,660
Other Accrued Liabilities	1,569,509	1,765,047
Accrued Interest Payable	491,664	533,772
Revenue Bonds, Current Portion (Note 5)	3,570,000	3,045,000
Total Current Liabilities	**20,874,739**	**20,515,126**
NONCURRENT LIABILITIES		
Revenue Bonds (Note 5)	57,671,311	61,750,315
Pension Liability (Note 6)	9,884,887	13,019,386
BPA Prepay Incentive Credit	1,733,533	1,894,789
Other Credits & Liabilities (Note 4)	3,158,625	3,911,262
Total Noncurrent Liabilities	**72,448,356**	**80,575,752**
TOTAL LIABILITIES	**93,323,095**	**101,090,878**
DEFERRED INFLOWS OF RESOURCES		
Unamortized Gain on Defeased Debt	18,389	2,344
Pension Deferred Inflow	1,866,603	245,673
Accumulated Increase in Fair Value of Hedging Derivatives	1,140,955	2,077,305
Total Deferred Inflows of Resources	**3,025,947**	**2,325,322**
NET POSITION		
Net Investment in Capital Assets	64,407,047	58,672,489
Restricted for Debt Service	1,107,865	1,107,865
Unrestricted	58,640,111	56,255,498
Total Net Position	**124,155,023**	**116,035,852**
TOTAL NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	**$220,504,065**	**$219,452,052**

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

STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

For the years ended December 31, 2017 and 2016

	2017	2016
OPERATING REVENUES		
Retail Energy Sales	$130,811,427	$120,438,526
Secondary Market Sales	14,542,756	14,808,281
Transmission of Power for Others	1,284,536	915,169
Broadband Revenue	2,164,500	2,046,068
Other Revenue	1,338,933	1,653,580
Total Operating Revenues	**150,142,152**	**139,861,624**
OPERATING EXPENSES		
Power Supply (Includes Prepaid Power Amortization, See Note 8)	96,774,565	94,193,294
Transmission Operation & Maintenance	199,419	260,519
Distribution Operation & Maintenance	9,799,347	9,029,751
Broadband Expense	844,688	931,789
Customer Accounting, Collection & Information	3,735,098	3,411,338
Administrative & General Expense	7,181,596	6,331,749
Taxes	14,018,894	12,630,500
Depreciation	10,177,574	12,630,490
Total Operating Expenses	**142,731,181**	**139,419,430**
OPERATING INCOME	**7,410,971**	**442,194**
NONOPERATING REVENUES & EXPENSES		
Interest Income	605,664	325,895
Other Income	562,073	321,466
Interest Expense, net of amounts capitalized	(2,910,007)	(2,664,442)
Debt Premium Amortization & Gain on Defeased Debt	492,959	143,522
Unrealized (Loss) on Investments	(33,130)	(4,170)
Total Nonoperating Revenues & Expenses	**(1,282,441)**	**(1,877,729)**
INCOME/(LOSS) BEFORE CAPITAL CONTRIBUTIONS	**6,128,530**	**(1,435,535)**
CAPITAL CONTRIBUTIONS	1,990,641	1,164,819
CHANGE IN NET POSITION	**8,119,171**	**(270,716)**
TOTAL NET POSITION, BEGINNING OF YEAR	**116,035,852**	**116,306,568**
TOTAL NET POSITION, END OF YEAR	**$124,155,023**	**$116,035,852**

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

STATEMENT OF CASH FLOWS

For the years ended December 31, 2017 and 2016

	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash Received from Customers and Counterparties	$150,946,386	$137,809,943
Cash Paid to Suppliers and Counterparties	(104,413,811)	(98,491,760)
Cash Paid to Employees for Services	(14,331,940)	(14,038,554)
Taxes Paid	(13,748,825)	(12,551,371)
Net Cash Provided by Operating Activities	**18,451,810**	**12,728,258**
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES		
Other Interest Expense	(40,556)	(49,300)
Net Cash Used by Noncapital Financing Activities	**(40,556)**	**(49,300)**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Acquisition of Capital Assets	(12,572,631)	(15,329,337)
Proceeds from Sale of Revenue Bonds	-	15,099,327
Reimbursement of Bond Expense	10,205	-
Bond Principal Paid	(3,045,000)	(2,920,000)
Bond Interest Paid	(2,831,526)	(2,314,477)
Capital Contributions	1,990,642	1,164,818
Proceeds from Sale of Assets	76,766	59,233
Net Cash Used by Capital and Related Financing Activities	**(16,371,544)**	**(4,240,436)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest Income	578,112	327,490
Proceeds from Sale of Investments	8,008,658	11,984,822
Purchase of Investments	(8,742,193)	(5,933,352)
Net Cash Provided (Used) by Investing Activities	**(155,423)**	**6,378,960**
NET INCREASE (DECREASE) IN CASH	**1,884,287**	**14,817,482**
CASH & CASH EQUIVALENTS BALANCE, BEGINNING OF YEAR	**43,414,514**	**28,597,032**
CASH & CASH EQUIVALENTS BALANCE, END OF YEAR	**$45,298,801**	**$43,414,514**

	2017	2016
RECONCILIATION OF OPERATING INCOME TO NET CASH		
PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating Income	$7,410,971	$442,194
Adjustments to reconcile net operating income to net cash provided by operating activities:		
Depreciation	10,177,575	12,630,490
BPA Prepaid & Power Contracts Amortization	1,178,400	1,178,400
(Increase) Decrease in Unbilled Revenues	600,000	(1,000,000)
Misellaneous Other Revenue & Receipts	216,085	22,741
Pension Expense/(Credit)	(593,733)	(308,366)
Decrease (Increase) in Accounts Receivable	194,030	(1,051,681)
Decrease (Increase) in Inventories	116,293	(493,958)
Decrease (Increase) in Wholesale Power Receivable	(536,965)	251,239
Decrease (Increase) in Miscellaneous Assets	(13,884)	13,805
Decrease (Increase) in Prepaid Expense & Option Premiums	(56,391)	(38,606)
Increase (Decrease) in Warrants Outstanding	-	(250,248)
Increase (Decrease) in Accounts Payable	(388,195)	1,453,322
Increase (Decrease) in Accrued Taxes Payable	270,069	79,129
Increase (Decrease) in Customer Deposits	190,383	58,139
Increase (Decrease) in BPA Prepay Incentive Credit	(161,256)	(161,256)
Increase (Decrease) in Other Current Liabilities	(474,658)	390,324
Increase (Decrease) in Other Credits	323,086	(487,410)
Net Cash Provided by Operating Activities	**$18,451,810**	**$12,728,258**

NONCASH OPERATING, INVESTING, CAPITAL, AND FINANCING ACTIVITIES

The District's investments had an unrealized loss of $33,130 at December 31, 2017 and an unrealized loss of $4,170 at December 31, 2016.

Bond Interest Paid does not include subsidy payments on Series 2010 Revenue Build America Bonds made directly by the US Treasury to the Fiscal Paying Agent of $345,985 in 2017 and $298,726 in 2016 (see Note 5).

The net effect of accumulated increases and decreases in the fair value of hedging derivates had no effect on cash flows for 2017 and 2016. For accumulated decreases in fair value, $1,122,842, the District records an offsetting liability. For accumulated increases in fair value, $1,140,955, the District records an offsetting asset.

The deferred inflows and outflows relating to GASB 68 had no effect on cash flows for 2017 and 2016. The pension deferred outflow was $1,429,022, and $2,019,756 as of December 31, 2017 and 2016 respectively. The pension deferred inflow was $1,866,603, and $245,673 as of December 31, 2017 and 2016, respectively.

During 2016, the District issued $22,470,000 of Electric Revenue and Refunding Bonds and retired various oustanding bonds (see Note 5).

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

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 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 that are served by the Benton Rural Electric Association. Cities in the District's service area include Kennewick, population 80,280, Prosser, population 5,965, and Benton City, population 3,360. 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 98 miles of 115kV transmission lines, 1,675 miles of distribution lines, and other buildings, equipment, stores, and related facilities.

As required by generally accepted accounting principles (GAAP), management has considered all potential component units in defining the reporting entity and has no component units. The following is a summary of the more significant policies:

a) Basis of Accounting and Presentation: The accounting policies of the District conform to GAAP applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. In 2016, the District implemented GASB statements No. 72 Fair Value Measurement and Application, No. 76 Hierarchy of Generally Accepted Accounting Principles for State and Local Governments, and No. 79 Certain External Investment Pools and Pool Participants. In 2017, the District implemented GASB statement No.82 Pension Issues – an amendment of GASB Statements No. 67, No. 68, and No. 73.

Accounting records are maintained in accordance with methods prescribed by the Washington State Auditor's Office under the authority of Revised Code of Washington (RCW) 43.09 and the Uniform System of Accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission (FERC). The financial statements are reported using the economic resources measurement focus and the accrual basis of accounting where revenues are recognized when incurred, regardless of the timing of the related cash flows. 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 noninfrastructure 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 are depreciated using the straight-line method over these 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 3.4% in 2017 and 4.7% in 2016. 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 $207,413 and $150,380 in 2017 and 2016, respectively, and is capitalized as part of the cost of the project and reflected as a reduction of interest expense.

d) 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 bond reserve and capital additions and are classified as current or noncurrent assets, as appropriate.

e) Cash and Cash Equivalents: For purposes of the statement of cash flows, the District considers all short-term highly liquid investments with a maturity of 3-months or less when purchased to be cash equivalents.

f) 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. The reserve for uncollectible accounts totaled $553,178 and $400,000 in 2017 and 2016, respectively.

g) Other Receivables: Other receivables include a Rural Economic Development Revolving Fund, which was established during 2008 pursuant to RCW 82.16.0491. The District contributed to the fund in 2008 and 2009. Each contribution to the fund was partially offset by a public utility tax credit. The District appointed Benton-Franklin Council of Governments to oversee and direct activities of the fund. The District does not have a reserve for uncollectible accounts related to Other Receivables.

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

i) 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 every derivative instrument be recorded on the statement of net position as an asset or liability measured at its fair value, and changes in the derivative's fair value be recognized 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.

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.

As of December 31, 2017, the District had the following derivative instruments outstanding:

	Changes in Fair Value		Fair Value at December 31, 2017		Notional
	Classification	Amount	Classification	Amount	(MWh/MMB
Cash Flow Hedges:					
Financial Swap Forward	Deferred Inflow	($1,140,955)	Derivative Asset	$1,140,955	936,975
Financial Swap Forward	Deferred Outflow	$1,122,842	Derivative Liability	($1,122,842)	2,612,120

These derivative instruments were entered into between July 2016 and December 2017 with maturities between January 2018 and December 2019. The District paid or received no cash to enter into these transactions.

As of December 31, 2016, the District had the following derivative instruments outstanding:

	Changes in Fair Value		Fair Value at December 31, 2016		Notional
	Classification	Amount	Classification	Amount	(MWh/MMB
Cash Flow Hedges:					
Financial Swap Forward	Deferred Inflow	($2,060,583)	Derivative Asset	$2,060,583	2,292,860
Financial Swap Forward	Deferred Outflow	$1,888,788	Derivative Liability	($1,888,788)	1,794,100
Put Option	Deferred Inflow	($16,722)	Derivative Asset	$16,722	18,575
Put Option	Deferred Outflow	$30,657	Derivative Liability	($30,657)	16,800

These derivative instruments were entered into between October 2015 and December 2016 with maturities between January 2017 and February 2019. The District paid $115,783 to enter into these transactions.

The fair values of the commodity swap contracts were based on the futures price curve for the Mid-Columbia Intercontinental Exchange (ICE) index for electricity and the Sumas index for natural gas; additionally, all instruments close at the same index, respectively. The fair value of the options was calculated using the Black-76 options pricing model. The District categorizes its fair value measurements within the fair value hierarchy established by GAAP. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. All of the District's fair market measurements are classified as Level 2.

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 8) is economically viable on a marginal basis for that period based on parameters set by the Risk Management Committee. If load projections indicate 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 ICE index to perfect financial forward sales that 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 Plant 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
- Quarterly and monthly financial power and gas put and call options
- Financial daily power and gas put and call options
- Quarterly and monthly power and natural gas swaptions
- Financial natural gas swing and basis swaps

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 8.

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 46 counterparties with approved credit limits for electric power and natural gas sales and purchases as of

December 31, 2017, and 48 counterparties at December 31, 2016. Counterparty credit limits are based on The Energy Authority's (TEA) (see Note 8) proprietary credit rating system and other factors. Credit ratings for counterparties range from "not-rated" to AAA, with a majority of counterparties rated between BBB- and AAA. Not-rated counterparties either provide additional security or are assigned credit limits of $25,000 or less.

The District's counterparty credit limits are scaled against TEA credit limits with a maximum credit limit of $3 million. This mitigates the District's credit exposure by netting and setting off the District's sales with purchases made by other TEA clients. 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 $1,140,955 and $2,077,305 at December 31, 2017 and 2016, respectively. There was no collateral held or liabilities included in the netting arrangements.

Although the District executes hedging derivative instruments with various counterparties, four counterparties comprise 99% of the net exposure to credit risk as of December 31, 2017. These counterparties are rated BBB+/Baa1 (19 contracts comprising 23% of net exposure), Not Rated/Baa2 (11 contracts comprising 25% of net exposure), A/A2 (18 contracts comprising 30% of net exposure, and BBB+/A3 (9 contracts comprising 21% of net exposure). At December 31, 2016, three counterparties comprise 93% of the net exposure to credit risk. These counterparties are rated BBB/Baa1 (11 contracts comprising 24% of net exposure), Not Rated/Baa2 (26 contracts comprising 38% of net exposure) and BBB+/A3 (28 contracts comprising 31% of net exposure).

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, 2017 or 2016. 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 or be converted to the Sumas/Huntingdon index within 6 months of delivery. The District has ready access to electric transmission and natural gas transportation capacity at those respective trading points.

Termination Risk - As of December 31, 2017 and 2016, no termination events have occurred, and there are no outstanding transactions with material 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 generally does not fall under the events of default provisions, unless the nonperforming party fails to pay the resulting liquidated damages when due.

There is no rollover, interest rate, or market access risk for these derivative products at December 31, 2017 or 2016.

j) Debt Premium Amortization and Gain on Defeased Debt: Original issue and reacquired bond premiums relating to revenue bonds are amortized over the terms of the respective bond issues using the bonds outstanding method. In accordance with GASB Statement No. 23*, Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities*, gains on debt refundings have been deferred and amortized over the shorter of the remaining life of the old or new debt. Effective with GASB 65, bond issuance costs are expensed in the period incurred.

k) Revenue Recognition: Revenues from retail sales of electricity are recognized when billed and reported net of bad debt expense of $219,000 and $103,660 at December 31, 2017 and 2016, 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 $4.8 million at December 31, 2017, and $5.4 million at December 31, 2016.

l) 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.

m) Pensions: For purposes of measuring the net pension liability, deferred outflows/inflows of resources and pension expense, information about the fiduciary net position of the Public Employees Retirement System (PERS) and additions to/deductions from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, plan contributions are recognized as of employer payroll paid dates and benefit payments and refunds are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value.

n) 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 short-term disability benefit payments and 100% of gross, straight-time pay. Additionally, an employee may restore work hours required for short-term disability eligibility one-time per Collective Bargaining Agreement Contract cycle (3 years). 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 $14,663 and $20,115 at December 31, 2017 and 2016, 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 for employees hired prior to April 1, 2011, and is payable upon separation of service, retirement, or death. For employees hired on or after April 1, 2011, personal leave may accumulate to a maximum of 700 hours.

The liability for unpaid leave, benefits, and related payroll taxes was $2,680,529 and $2,668,304 at December 31, 2017 and 2016, respectively. Of the liability for unpaid leave, $1,493,553 and $1,468,894 at December 31, 2017 and 2016, respectively, were classified as a current liability and the remainder as a long-term liability (see Note 4).

o) Use of Estimates: The preparation of the financial statements in conformity with GAAP 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.

p) Investments: It is the District's policy to record investments at fair value. For various risks related to the investments see Note 3.

q) 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 and other 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.

r) Bonneville Power Administration Prepay Program: In March 2013, the District participated in BPA's Prepay Program making a lump-sum up-front payment of $6.8 million. The District will receive $9.3 million in credits which started in April 2013 and continues until September 2028. (See Note 8)

Note 2 - Utility Plant

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

Activity for 2017

Electric Plant Assets	Balance Dec. 31, 2016	Increase	Decrease	Balance Dec. 31, 2017
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	**$3,474,031**	**$47,761**	**($28,151)**	**$3,493,641**
Construction Work in Progress	**5,697,524**	**10,466,791**	**(11,565,028)**	**4,599,287**
Capital Assets Being Depreciated:				
Transmission	8,085,187	1,742,468	-	9,827,655
Generation	1,912,370	-	-	1,912,370
Distribution	214,115,465	8,327,425	(576,934)	221,865,956
General	78,606,899	4,158,979	(10,440,433)	72,325,445
Subtotal	**302,719,921**	**14,228,872**	**(11,017,367)**	**305,931,426**
Less Accumulated Depreciation for:				
Transmission	(6,119,943)	(215,985)	-	(6,335,928)
Generation	(1,026,504)	(85,683)	-	(1,112,187)
Distribution	(134,983,313)	(6,440,954)	492,050	(140,932,217)
General	(46,291,568)	(3,540,517)	9,854,810	(39,977,275)
Total Accumulated Depreciation	**(188,421,328)**	**(10,283,139)**	**10,346,860**	**(188,357,607)**
Net Utility Plant	***$123,470,148***	***$14,460,285***	***($12,263,686)***	***$125,666,747***

Activity for 2016

Electric Plant Assets	Balance Dec. 31, 2015	Increase	Decrease	Balance Dec. 31, 2016
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	**$3,416,129**	**$61,911**	**($4,009)**	**$3,474,031**
Construction Work in Progress	**2,745,647**	**8,866,216**	**(5,914,339)**	**5,697,524**
Capital Assets Being Depreciated:				
Transmission	7,829,825	256,175	(813)	8,085,187
Generation	1,754,865	157,505	-	1,912,370
Distribution	209,340,236	8,863,374	(4,088,145)	214,115,465
General	76,592,786	3,372,517	(1,358,404)	78,606,899
Subtotal	**295,517,712**	**12,649,571**	**(5,447,362)**	**302,719,921**
Less Accumulated Depreciation for:				
Transmission	(5,850,947)	(270,066)	1,070	(6,119,943)
Generation	(948,571)	(77,933)	-	(1,026,504)
Distribution	(131,122,802)	(8,561,137)	4,700,626	(134,983,313)
General	(42,965,941)	(5,301,626)	1,975,999	(46,291,568)
Total Accumulated Depreciation	**(180,888,261)**	**(14,210,762)**	**6,677,695**	**(188,421,328)**
Net Utility Plant	***$120,791,227***	***$7,366,936***	***($4,688,015)***	***$123,470,148***

Note 3 - Deposits and Investments

As of December 31, 2017, the District had the following investments:

Investment Type	Maturities	Fair Value
Federal National Mortgage Assn	5/21/2018	$1,995,700
Federal Home Loan Mortgage Corp	2/28/2019	3,977,040
US Treasury	5/15/2019	1,950,480
Federal Home Loan Bank	11/15/2019	1,979,940
Federal Farm Credit Bank	12/19/2019	742,845
Federal National Mortgage Assn	3/30/2020	1,970,520
Total		**$12,616,525**

As of December 31, 2016, the District had the following investments:

Investment Type	Maturities	Fair Value
Federal National Mortgage Assn	6/1/2017	$1,994,200
Federal Home Loan Banks	9/8/2017	2,019,880
Federal National Mortgage Assn	5/21/2018	1,991,900
US Treasury	5/15/2019	1,937,920
Federal Home Loan Bank	11/15/2019	1,992,020
Federal National Mortgage Assn	3/30/2020	1,980,200
Total		**$11,916,120**

Fair Market Value – Investments have been adjusted to reflect available market values as of December 31 of 2016 and 2017 obtained from available financial industry valuation services. The District categorizes its fair value measurements within the fair value hierarchy established by GAAP. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. All of the District's fair market measurements are classified as Level 2.

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 5-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 portfolio meets the requirements set forth in GASB 79 to report the investment at amortized cost. The reported value of the pool is the same as the fair value of the pool shares. There is no formal withdrawal transaction limit; however, the LGIP requests a one day notice for transaction sizes of ten million dollars or more. The LGIP is governed by the State Finance Committee and is administered by the State Treasurer. The District's investments in the Federal National Mortgage Association, Federal Home Loan Bank, and Federal Home Loan Mortgage Corporation were rated Aaa by Moody's Investor Services and AA+ by Standard & Poor's. The District has a third-party safekeeping agreement for investments through Wells Fargo Bank, N.A.

Concentration of Credit Risk - The District's investment policy limits investments at the time of purchase to a percentage 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. The District's deposits and certificates of deposit are held by public depositaries authorized by the PDPC and are not subject to custodial credit risk. State law requires public depositaries to fully collateralize their uninsured public deposits with approved third-party safekeeping agents and provides for independent oversight of this program.

Note 4 - Other Charges and Other Credits

As of December 31, other charges consisted of the following:

Other Charges	2017	2016
Derivative Asset (Note 1)	$1,140,955	$2,077,305
White Creek Wind Project (Note 8)	5,736,268	6,314,668
Preliminary Surveys	64,007	50,006
Total	**$6,941,230**	**$8,441,979**

During the year ended December 31, 2017, the following changes occurred in other credits:

Other Credits & Other Liabilities	Balance Dec. 31, 2016	Increase	Decrease	Balance Dec. 31, 2017
Unclaimed Property	$35,542	$9,379	$7,796	$37,125
Bio Fuel Deposit	114,541	96,881	62,454	148,968
Derivative Liability (Note 1)	1,919,445	1,122,842	1,919,445	1,122,842
Deferred Revenue	462,210	1,769,913	1,758,528	473,595
Asset Retirement Obligation - Finley CT	180,113	9,006	-	189,119
Personal Leave and Benefits*	1,199,411	1,647,902	1,660,337	1,186,976
Total	**$3,911,262**	**$4,655,923**	**$5,408,560**	**$3,158,625**

** In addition to this amount, $1,493,553 is reported as a current liability for personal leave and related benefits.*

During the year ended December 31, 2016, the following changes occurred in other credits:

Other Credits & Other Liabilities	Balance Dec. 31, 2015	Increase	Decrease	Balance Dec. 31, 2016
Unclaimed Property	$33,036	$7,457	$4,951	$35,542
Bio Fuel Deposit	100,000	14,541	-	114,541
Derivative Liability (Note 1)	2,490,112	1,919,445	2,490,112	1,919,445
Deferred Revenue	580,305	813,538	931,633	462,210
Asset Retirement Obligation - Finley CT	171,536	8,577	-	180,113
Personal Leave and Benefits*	1,594,350	1,609,171	2,004,110	1,199,411
Total	**$4,969,339**	**$4,372,729**	**$5,430,806**	**$3,911,262**

** In addition to this amount, $1,468,894 is reported as a current liability for personal leave and related benefits.*

Note 5 - Long-Term Debt

During the year ended December 31, 2017, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Due Within One Year
2010 Revenue Build America Bonds, due in annual installments of $1,645,000 - $2,250,000 beginning November 1, 2022 through November 1, 2030; interest at 5.86% - 6.546%; Original issue amount: $17,345,000	$17,345,000	$ -	$ -	$17,345,000	$ -
2011 Revenue and Refunding Bonds, due in annual installments of $460,000 - $4,135,000 through November 1, 2035; interest at 2.0% - 5.0% Original issue amount: $38,545,000	20,135,000	-	3,045,000	17,090,000	3,570,000
2016 Revenue and Refunding Bonds, due in annual installments of $790,000 - $1,560,000 beginning November 1, 2023 through November 1, 2041; interest at 4.0% - 5.0%; Original issue amount: $22,470,000	22,470,000	-	-	22,470,000	-
Subtotal	59,950,000	-	3,045,000	56,905,000	3,570,000
Plus: Unamortized premium	4,845,315	-	509,004	4,336,311	
Total Long-Term Debt	**$64,795,315**	**$0**	**$3,554,004**	**$61,241,311**	**$3,570,000**

During the year ended December 31, 2016, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Due Within One Year
2010 Revenue Build America Bonds, due in annual installments of $1,645,000 - $2,250,000 beginning November 1, 2022 through November 1, 2030; interest at 5.86% - 6.546%; Original issue amount: $17,345,000	$17,345,000	$ -	$ -	$17,345,000	$ -
2011 Revenue and Refunding Bonds, due in annual installments of $460,000 - $4,135,000 through November 1, 2035; interest at 2.0% - 5.0% Original issue amount: $38,545,000	32,390,000	-	12,255,000	20,135,000	3,045,000
2016 Revenue and Refunding Bonds, due in annual installments of $790,000 - $1,560,000 beginning November 1, 2023 through November 1, 2041; interest at 4.0% - 5.0%; Original issue amount: $22,470,000	-	22,470,000	-	22,470,000	-
Subtotal	49,735,000	22,470,000	12,255,000	59,950,000	3,045,000
Plus: Unamortized premium	3,099,629	3,991,739	2,246,053	4,845,315	
Total Long-Term Debt	**$52,834,629**	**$26,461,739**	**$14,501,053**	**$64,795,315**	**$3,045,000**

Future debt service requirements on these bonds are as follows:

Year	Principal	Interest	Total
2018	$3,570,000	$2,949,987	$6,519,987
2019	3,750,000	2,771,487	6,521,487
2020	3,940,000	2,583,987	6,523,987
2021	4,135,000	2,386,987	6,521,987
2022	3,340,000	2,180,237	5,520,237
2023-2027	13,930,000	8,555,857	22,485,857
2028-2032	12,495,000	4,273,144	16,768,144
2033-2037	5,940,000	2,247,300	8,187,300
2038-2041	5,805,000	743,500	6,548,500
Total	**$56,905,000**	**$28,692,486**	**$85,597,486**

In March 2010, the District issued $17,345,000 of taxable Electric Revenue Build America Bonds. The proceeds were used to fund capital projects. The U.S. Treasury subsidizes a portion (32.6% after sequestration) of the interest debt service payments which it pays directly to the Fiscal Paying Agent.

In October 2011, the District issued $38,545,000 of Electric Revenue and Refunding Bonds, Series 2011. The bond proceeds were used to fund $10 million of improvements and replacements in the District's electric utility system and to refund all of the 2001A bonds maturing on or after November 1, 2011, and all of the 2002 bonds maturing on or after November 1, 2012. The portion of bond proceeds for the refunding was placed in an irrevocable trust for future debt service on the refunded bonds.

In September 2016, the District issued $22,470,000 of Electric Revenue and Refunding Bonds, Series 2016. The bond proceeds were used to fund $15.1 million of improvements and replacements of the

District's electric utility system and to refund the 2011 bonds maturing on or after November 1, 2023. The portion of bond proceeds for the refunding was placed in an irrevocable trust for future debt service on the refunded bonds. At December 31, 2016, $9,335,000 of the 2011 bonds are considered defeased and are no longer reflected in the District's financial statements. The bond refunding resulted in a cash flow savings of $563,091, and a net present value savings of $462,691. As a result of the bond issue, the District increased its bond reserve fund from $1,083,997 to $1,107,865 in accordance with bond covenants to supplement the bond insurance already in place. The bond construction account had a balance of $0 at December 31, 2016.

These issuances are subject to certain bond reserve requirements satisfied by bond insurance and a bond reserve fund of $1,107,865.

In prior years, the District defeased certain electric revenue bonds by placing the proceeds of new bonds in an irrevocable trust to provide for all future certain debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the District's financial statements. At December 31, 2017, $9,335,000 of bonds outstanding are considered defeased.

Defeased Bonds	Principal	Call Date
2011	$9,335,000	11/1/2021

In March 2008, the District established a $10 million revolving line of credit, the Electric System Revenue Note, 2008, with Bank of America. In late 2014, the line of credit was extended for an additional two-year term expiring December 31, 2016, and in late 2016, the line of credit was extended for an additional two-year term expiring December 31, 2018. 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.

Note 6 - Pension Plans

The following table represents the aggregate pension amounts for all plans subject to the requirements of the GASB Statement 68, *Accounting and Financial Reporting for Pensions* for the year 2017 and 2016:

Aggregate Pension Amounts - All Plans		
	2017	2016
Pension liabilities	$9,884,887	$13,019,386
Deferred outflows of resources	$1,429,022	$2,019,756
Deferred inflows of resources	$1,866,603	$245,673
Pension expense/expenditures	$758,364	$1,032,801

State Sponsored Pension Plans

Substantially all District regular full-time and qualifying part-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 state Legislature establishes, and amends, laws pertaining to the creation and administration of all public retirement systems.

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

Or it may be downloaded from the DRS website at www.drs.wa.gov.

Public Employees' Retirement System (PERS)

PERS members include elected officials; state employees; employees of the Supreme, Appeals and Superior Courts; employees of the legislature; employees of district and municipal courts; employees of local governments; and higher education employees not participating in higher education retirement programs. PERS is comprised of three separate pension plans for membership purposes. PERS plans 1 and 2 are defined benefit plans, and PERS plan 3 is a defined benefit plan with a defined contribution component.

PERS Plan 1 provides retirement, disability and death benefits. Retirement benefits are determined as 2 percent of the member's average final compensation (AFC) times the member's years of service. The AFC is the average of the member's 24 highest consecutive service months. Members are eligible for retirement from active status at any age with at least 30 years of service, at age 55 with at least 25 years of service, or at age 60 with at least 5 years of service. Members retiring from active status prior to the age of 65 may receive actuarially reduced benefits. Retirement benefits are actuarially reduced to reflect the choice of a survivor benefit. Other benefits include duty and non-duty disability payments, an optional cost-of-living adjustment (COLA), and a one-time duty-related death benefit, if found eligible by the Department of Labor and Industries. PERS 1 members were vested after the completion of 5 years of eligible service. The plan was closed to new entrants on September 30, 1977.

Contributions - The **PERS Plan 1** member contribution rate is established by State statute at 6 percent. The employer contribution rate is developed by the Office of the State Actuary and includes an administrative expense component that is currently set at 0.18 percent. Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates.

The PERS Plan 1 required contribution rates (expressed as a percentage of covered payroll) for 2017 were as follows:

PERS Plan 1: January – June 2017

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		6.23%	6.00%
PERS Plan 1 UAAL		4.77%	
Administrative Fee		0.18%	
	Total	11.18%	6.00%

PERS Plan 1: July – December 2017

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		7.49%	6.00%
PERS Plan 1 UAAL		5.03%	
Administrative Fee		0.18%	
	Total	12.70%	6.00%

The PERS Plan 1 required contribution rates (expressed as a percentage of covered payroll) for 2016 were as follows:

PERS Plan 1

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		6.23%	6.00%
PERS Plan 1 UAAL		4.77%	
Administrative Fee		0.18%	
	Total	11.18%	6.00%

PERS Plan 2/3 provides retirement, disability and death benefits. Retirement benefits are determined as 2 percent of the member's average final compensation (AFC) times the member's years of service for Plan 2 and 1 percent of AFC for Plan 3. The AFC is the average of the member's 60 highest-paid consecutive service months. There is no cap on years of service credit. Members are eligible for retirement with a full benefit at 65 with at least 5 years of service credit. Retirement before age 65 is considered an early retirement. PERS Plan 2/3 members who have at least 20 years of service credit and are 55 years of age or older, are eligible for early retirement with a benefit that is reduced by a factor that varies according to age for each year before age 65. PERS Plan 2/3 members who have 30 or more years of service credit and are at least 55 years old can retire under one of two provisions:

- With a benefit that is reduced by 3 percent for each year before age 65; or
- With a benefit that has a smaller (or no) reduction (depending on age) that imposes stricter return-to-work rules.

PERS Plan 2/3 members hired on or after May 1, 2013 have the option to retire early by accepting a reduction of 5 percent for each year of retirement before age 65. This option is available only to those who are age 55 or older and have at least 30 years of service credit. PERS Plan 2/3 retirement benefits are also actuarially reduced to reflect the choice of a survivor benefit. Other PERS Plan 2/3 benefits include duty and non-duty disability payments, a cost-of-living allowance (based on the CPI), capped at 3 percent annually and a one-time duty related death benefit, if found eligible by the Department of Labor and Industries. PERS 2 members are vested after completing 5 years of eligible service. Plan 3 members are vested in the defined benefit portion of their plan after 10 years of service; or after 5 years of service if 12 months of that service are earned after age 44.

PERS Plan 3 defined contribution benefits are totally dependent on employee contributions and investment earnings on those contributions. PERS Plan 3 members choose their contribution rate upon joining membership and have a chance to change rates upon changing employers. As established by statute, Plan 3 required defined contribution rates are set at a minimum of 5 percent and escalate to 15 percent with a choice of six options. Employers do not contribute to the defined contribution benefits. PERS Plan 3 members are immediately vested in the defined contribution portion of their plan.

Contributions - The **PERS Plan 2/3** employer and employee contribution rates are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. The Plan 2/3 employer rates include a component to address the PERS Plan 1 UAAL and an administrative expense that is currently set at 0.18 percent. Each biennium, the state Pension Funding Council adopts Plan 2 employer and employee contribution rates and Plan 3 contribution rates.

The PERS Plan 2/3 required contribution rates (expressed as a percentage of covered payroll) for 2017 were as follows:

PERS Plan 2/3: January – June 2017

Actual Contribution Rates:		Employer 2/3	Employee 2
PERS Plan 2/3		6.23%	6.12%
PERS Plan 1 UAAL		4.77%	
Administrative Fee		0.18%	
Employee PERS Plan 3			varies
	Total	11.18%	6.12%

PERS Plan 2/3: July – December 2017

Actual Contribution Rates:		Employer 2/3	Employee 2
PERS Plan 2/3		7.49%	7.38%
PERS Plan 1 UAAL		5.03%	
Administrative Fee		0.18%	
Employee PERS Plan 3			varies
	Total	12.70%	7.38%

The PERS Plan 2/3 required contribution rates (expressed as a percentage of covered payroll) for 2016 were as follows:

PERS Plan 2/3

Actual Contribution Rates:		Employer 2/3	Employee 2
PERS Plan 2/3		6.23%	6.12%
PERS Plan 1 UAAL		4.77%	
Administrative Fee		0.18%	
Employee PERS Plan 3			varies
	Total	11.18%	6.12%

Both the District and the employees made the required contributions during fiscal years 2017 and 2016. The District's required employer contributions for the years ending December 31 were as follows:

	2017	2016
PERS Plan 1	$8,343	$11,933
PERS Plan 1 UAAL	$669,660	$624,583
PERS Plan 2/3	$936,046	$815,729
Total	$1,614,049	$1,452,245

Actuarial Assumptions

The total pension liability (TPL) for each of the DRS plans was determined using the most recent actuarial valuations completed in 2017 and 2016 with a valuation date of June 30, 2016, and June 30, 2015 respectively. The actuarial assumptions used in the valuation were based on the results of the Office of the State Actuary's (OSA) *2007-2012 Experience Study and 2015 Economic Experience Study*.

Additional assumptions for subsequent events and law changes are current as of the 2016 and 2015 actuarial valuation reports. The TPL was calculated as of the valuation dates and rolled forward to the measurement dates of June 30, 2017 and June 30, 2016. Plan liabilities were rolled forward from

June 30, 2016, to June 30, 2017 and June 30, 2015 to June 30, 2016 for the respective fiscal years, reflecting each plan's normal cost (using the entry-age cost method), assumed interest and actual benefit payments.

- **Inflation:** 3% total economic inflation; 3.75% salary inflation
- **Salary increases**: In addition to the base 3.75% salary inflation assumption, salaries are also expected to grow by promotions and longevity.
- **Investment rate of return:** 7.5%

Mortality rates were based on the RP-2000 report's "Combined Healthy Table" and "Combined Disabled Table", published by the Society of Actuaries. The OSA applied offsets to the base table and recognized future improvements in mortality by projecting the mortality rates using 100 percent Scale BB. Mortality rates are applied on a generational basis; meaning members are assumed to receive additional mortality improvements in each future year throughout their lifetimes.

There were minor changes in methods and assumptions since the last valuation.

For 2017:

- How terminated and vested member benefits are valued was corrected.
- How the basic minimum COLA in PERS Plan 1 is valued for legal order payees was improved.
- For all plans, the average expected remaining service lives calculation was revised.

For 2016:

- The assumed valuation interest rate was lowered from 7.8% to 7.7%.

Discount Rate

The discount rate used to measure the total pension liability for all DRS plans was 7.5 percent. To determine that rate, an asset sufficiency test included an assumed 7.7 percent long-term discount rate to determine funding liabilities for calculating future contribution rate requirements. Consistent with the long-term expected rate of return, a 7.5 percent future investment rate of return on invested assets was assumed for the test. Contributions from plan members and employers are assumed to continue being made at contractually required rates (including PERS 2/3, whose rates include a component for the PERS 1 plan liabilities). Based on these assumptions, the pension plans' fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return of 7.5 percent was used to determine the total liability.

Long-Term Expected Rate of Return

The long-term expected rate of return on DRS pension plan investments of 7.5 percent was determined using a building-block-method. The Washington State Investment Board (WSIB) used a best estimate of expected future rates of return (expected returns, net of pension plan investment expense, including inflation) to develop each major asset class. Those expected returns make up one component of WSIB's capital market assumptions. WSIB uses the capital market assumptions and their target asset allocation to simulate future investment returns at various future times. The long-term expected rate of return of 7.5 percent approximately equals the median of the simulated investment returns over a 50-year time horizon.

Estimated Rates of Return by Asset Class

Best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of June 30, 2017, are summarized in the table below. The inflation component used to create the table is 2.2 percent and represents WSIB's most recent long-term estimate of broad economic inflation.

Asset Class	Target Allocation	% Long-Term Expected Real Rate of Return Arithmetic
Fixed Income	20%	1.70%
Tangible Assets	5%	4.90%
Real Estate	15%	5.80%
Global Equity	37%	6.30%
Private Equity	23%	9.30%
	100%	

Best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of June 30, 2016, are summarized in the table below. The inflation component used to create the table is 2.2 percent and represents WSIB's most recent long-term estimate of broad economic inflation.

Asset Class	Target Allocation	% Long-Term Expected Real Rate of Return Arithmetic
Fixed Income	20%	1.70%
Tangible Assets	5%	4.40%
Real Estate	15%	5.80%
Global Equity	37%	6.60%
Private Equity	23%	9.60%
	100%	

Sensitivity of NPL

The table below presents the District's proportionate share of the net pension liability/(asset) calculated using the discount rate of 7.5 percent, as well as what the District's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage point lower (6.5 percent) or 1-percentage point higher (8.5 percent) than the current rate.

	1% Decrease (6.5%)	Current Discount Rate (7.5%)	1% Increase (8.5%)
2017			
PERS 1	$6,268,626	$5,145,847	$4,173,281
PERS 2/3	$12,767,469	$4,739,040	($1,839,067)
2016			
PERS 1	$7,201,458	$5,971,856	$4,913,708
PERS 2/3	$12,975,770	$7,047,530	($3,668,646)

Pension Plan Fiduciary Net Position

Detailed information about the State's pension plans' fiduciary net position is available in the separately issued DRS financial report.

Pension Liabilities, Pension Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions.

At December 31, 2017, the District reported a total pension liability of $9,884,887 for its proportionate share of the net pension liabilities as follows:

	Liability
PERS 1	$5,145,847
PERS 2/3	$4,739,040

At December 31, 2016, the District reported a total pension liability of $13,019,386 for its proportionate share of the net pension liabilities as follows:

	Liability
PERS 1	$5,971,856
PERS 2/3	$7,047,530

At December 31, the District's proportionate share of the collective net pension liabilities was as follows:

	Proportionate Share 12/31/17	Proportionate Share 12/31/16	Change in Proportion
PERS 1	0.108446%	0.111198%	(0.002752%)
PERS 2/3	0.136394%	0.139973%	(0.003579%)

Employer contribution transmittals received and processed by DRS for DRS' fiscal year ended June 30 are used as the basis for determining each employer's proportionate share of the collective pension amounts reported by DRS in the Schedules of Employer and Nonemployer Allocations for all plans.

Pension Expense

For the year ended December 31, 2017 and 2016, the District recognized pension expense as follows:

2017	Pension Expense	2016	Pension Expense
PERS 1	$168,714	PERS 1	$524,740
PERS 2/3	$589,650	PERS 2/3	$508,061
Total	$758,364	Total	$1,032,801

Deferred Outflows of Resources and Deferred Inflows of Resources

At December 31, the District reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

PERS 1	Deferred Outflows of Resources		Deferred Inflows of Resources	
	2017	2016	2017	2016
Net difference between projected and actual investment earnings on pension plan investments	-	$150,362	$192,029	-
Contributions subsequent to the measurement date	349,031	323,360	-	-
TOTAL	**$349,031**	**$473,722**	**$192,029**	-

PERS 2/3	Deferred Outflows of Resources 2017	2016	Deferred Inflows of Resources 2017	2016
Effect of change in the employer's proportionate share	$32,209	($124,668)	$255,401	$ -
Differences between expected and actual experience	480,176	375,276	155,859	232,651
Net difference between projected and actual investment earnings on pension plan investments	-	862,414	1,263,314	-
Changes of assumptions	50,338	72,842	-	-
Contributions subsequent to the measurement date	517,268	414,299	-	-
TOTAL	**$1,079,991**	**$1,600,163**	**$1,674,574**	**$232,651**
Adjustments/ PY amortizations		(54,129)		13,022
TOTAL ALL PLANS	**$1,429,022**	**$2,019,756**	**$1,866,603**	**$245,673**

Deferred outflows of resources related to pensions resulting from the District's contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability in the year ended December 31, 2018.

Other amounts reported as deferred outflows and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Year ended December 31	PERS 1	PERS 2/3
2018	($129,800)	($557,480)
2019	$40,980	66,525
2020	($9,515)	(141,983)
2021	($93,694)	(529,018)
2022	-	21,786
Thereafter	-	28,319
Total	($192,029)	($1,111,851)

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 the 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, 2017 and 2016 was $0 and $44,620, respectively.

Note 7- Deferred Compensation and Health Benefit Plans

Deferred Compensation Plans

The District offers its employees deferred compensation plans created in accordance with Internal Revenue Code Sections 457(b) 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 generally not available to employees until separation from service through termination, retirement, death, or unforeseeable emergency. The 457 plan does contain an employee loan provision. Employees may apply with the Plan Administrator, terms of repayment are set by the Administrator. The plan assets are held in trust for the exclusive benefit of plan participants and beneficiaries. The plans are administered by ICMA-RC.

Health Benefit Plans

Health Reimbursement Arrangement (HRA)

The District, effective January 1, 2015, converted the employee incentive for voluntary participation in the employer provided wellness program to a monthly $150 into an HRA. This payment is intended to help employees pay for qualified health care costs and insurance premiums upon retirement. Contributions are held in trust for the exclusive benefit of participants and beneficiaries. The plan is administered by Gallagher VEBA.

Note 8 - Long-Term Purchased Power Commitments

Bonneville Power Administration (BPA)

Contracts Effective October 2011-September 2028

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 the previous agreement, the new Slice agreement has 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 1.36865%.
- The monthly Block amounts range from 80 aMW to 154 aMW.

In conjunction with the new Slice/Block agreement, BPA implemented a Tiered Rates Methodology (TRM). Under the TRM and new agreements, BPA has implemented a cap on the amount of power that the District can purchase at the lowest cost based rates (Tier 1). The cap is referred to in the contract as a Contract High Water Mark (CHWM). The District's CHWM is 204.3 aMW. The maximum amount of power the District can purchase in any federal fiscal year (FFY) is referred to as the Rate Period High

Water Mark (RHWM), which adjusts the CHWM for changes in Federal System Capability. For FFY 2016 the RHWM was 199.6 aMW, for FFY 2017 it was 199.6, and FFY 2018 it is 198.0. BPA has a fiscal year of October through September. The amount of power the District can purchase in a FFY is the lesser of its Net Requirement (Forecast load less its share of Packwood) or RHWM and is the Tier 1 amount. This amount for FFY 2016 was 199.6, for FFY 2017 was 199.6, and FFY 2018 is 198.0.

The TRM provides for the determination of Tier One Cost Allocators (TOCA) to determine monthly charges. The TOCA is determined by dividing the Tier 1 amount by the sum of all BPA customers' RHWM. For FFY 2016, this value for the District was 2.859%; for FFY 2017, this value was 2.859%, and FFY 2018 is 2.852. The TOCA is multiplied by BPA’s monthly Composite Charge to determine that portion of the District’s monthly BPA power bill that represents BPA’s costs. The nonslice TOCA is the TOCA minus the slice percentage resulting in a FFY 2016 value of 1.489%, FFY 2017 value of 1.489% and FFY 2018 value of 1.483%. The nonslice TOCA is multiplied by BPA’s nonslice charge to determine that portion of the District’s monthly BPA power bill that represent several BPA revenues, primarily their wholesale sales.

BPA has put in place a Power Cost Recovery Adjustment Clause (Power CRAC) that applies to the District’s Block purchases. The Power CRAC will trigger if BPA’s forecasted Accumulated Calibrated Net Revenues (ACNR) were lower than a calculated amount. For FFY 2017 and 2018, ACNR represents the power net revenues, modified by certain items, as accumulated since FFY 2016. The amount of the Power CRAC would have been determined by the amount ACNR is forecasted to be less than certain values and is capped at $300 million per year. For FFY 2017, the trigger is based on BPA Power function cash reserves for risk levels. If these levels drop below zero, the CRAC could trigger. It is still 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 would then be increased if BPA triggered a National Marine Fisheries Service FCRPS BiOp (NFB) adjustment. The NFB adjustment would have been triggered if a court ordered additional expenditures for Fish and Wildlife mitigation, an Endangered Species Act (ESA) litigation settlement occurred which resulted in higher costs, a new, more expensive, Biological Opinion (BiOp) was implemented, or BPA committed to implement a recovery plan under the ESA. The NFB adjustment would have started at the beginning of a fiscal year, or during the fiscal year if an emergency was declared. The CRAC did not trigger for FFY 2016, 2017, or 2018.

The rates also contained a Power Reserves Distribution Clause (RDC), which would operate similar to the CRAC but would have lowered the Block rates charged to the District. The RDC would have been triggered when Power ACNR exceeds the Power RDC threshold, measured in Power ACNR, and BPA ACNR exceeds the BPA RDC threshold, measured in BPA ACNR. In FFY 2017 and 2018, the cap is $500 million. The RDC did not trigger for FFY’s 2016, 2017, or 2018.

The rates also contained a spill surcharge created to recover the costs associated with increased spill at the dams that is anticipated as a result of a ruling issued Spring 2017 by the U.S. District Court for the District of Oregon. The court indicated that it will order increased spill at eight Federal Columbia River Power System dams on the lower Columbia and Snake rivers for the 2018 spring fish passage season. The surcharge would be in addition to the new power rates and would be implemented once sufficient information becomes available regarding planned annual spill levels.

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.

The District, along with over 80% of BPA's Consumer Owned Utility (COU) customers and the region's IOUs entered into an agreement to settle the amount of the residential exchange benefits paid by BPA to the IOUs. The settlement included a provision for BPA to continue to provide COU's a discount on BPA power bills. For the FFY 2016 period, the discount for the District was $182,597/month, and for FFY 2017, the discount was $182,097/month. For FFY 2018, the discount is $183,818/month.

BPA Prepay Program

BPA developed a Prepay Program to help fund hydro system infrastructure and as a means to allow customers to prepay for the future delivery of power consistent with the existing power supply agreements, except that payment provisions would be revised to reflect the prepayment. The District submitted an offer for one block in the amount of $6.8 million that was accepted and, in return, would receive a total of $9.3 million in credits resulting in net present value savings of $1.1 million. The District made a lump-sum up-front payment in March 2013, and began receiving a $50,000 credit each month on its power bill beginning April 2013 and continues until September 2028.

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% 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 5-year terms) and provided the District with 6 MW (2 aMW) from the Phase III expansion (see Note 12).

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 statement of net position. No distributions were made in 2017 or 2016.

Frederickson Plant
In March 2001, the District entered into a 20-year agreement with Frederickson Power LP for the purchase of 50 MW of contract capacity beginning September 2002 from the 249 MW Frederickson 1 Generating Station combined-cycle natural gas fired combustion turbine plant near Tacoma, Washington. The agreement includes firm gas transportation from the Canadian border to the plant. 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 receives fuel management services for the Frederickson Plant from The Energy Authority (TEA).

Lakeview Light and Power (LL&P) Wind Energy, Inc.
In April 2007, the District entered into a 20-year Energy and Environmental Attributes Purchase Agreement with LL&P to purchase 3 MW of capacity (1 aMW) at the White Creek Wind Project. This project is a wind generation facility with capacity of 204.7 MW. It is located in Klickitat County and was declared to be in commercial operation in November 2007. The purchase is part of the District's strategy for meeting renewable resource requirements of the Energy Independence Act (EIA) (see Note 12). The District pays for only the energy and associated environmental attributes generated by the project.

White Creek Wind 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 EIA (see Note 12). The purchase cost is being amortized on a straight-line basis over a 19-year term. In 2016 and 2017, power supply expense includes $578,400 each year in amortization of the purchase cost. This 3% share of the 204.7 MW project represents 6.14 MW (2 aMW).

BioFuels Washington, LLC Project/Emerald City Renewables LLC
In February 2013, the District entered into a contract with BioFuels Washington, LLC of Encinitas, CA, to purchase 33,000 Renewable Energy Credits (REC) annually, with a contract term of March 1, 2013, through March 31, 2026, with delivery beginning January 1, 2016. This REC purchase counts toward the District's compliance with the EIA target of 9% renewable energy that began in 2016.

Subsequently, on September 18, 2013, the State of Washington Department of Commerce issued an advisory opinion stating that electricity generated by the BioFuels Washington facility qualifies as distributed generation under RCW 19.285.040(2)(b). For purposes of the compliance with EIA, the Renewable Energy Credits purchased from BioFuels will count double. Therefore, for compliance purposes, this contract provides 66,000 RECs annually toward the District's 9% renewable energy target.

In October 2015, the District consented to the assignment of contracts of the facility to Emerald City Renewables LLC. There were no changes to the District's rights or obligations.

Idaho Wind Partners
In December 2014, the District entered into contracts with Payne's Ferry Wind Park, LLC and Yahoo Creek Wind Park, LLC, which are owned by Idaho Wind Partners, to purchase Renewable Energy Credits (REC) with a contract term starting in 2015 through 2024. This REC purchase counts toward the District's compliance with the EIA target of 9% renewable energy that began in 2016.

Other Power Supply Contracts and Purchases
The District entered into a Resource Management Agreement (RMA) with TEA on July 1, 2006, to provide scheduling, dispatching, fuel management, and other power management services. The agreement was restated and extended in 2009 and continues until terminated by either party. The District and TEA have the right to terminate the agreement upon 1 years written notice. The agreement also provides for annual consulting task orders to provide for a variety of power management services. Under the agreement, TEA is authorized to trade real time, day-ahead transactions, and forward transactions as principal on behalf of the District. TEA is currently not trading forward transactions as principal. 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(i).

As discussed in Note 1(i), the District entered into other power supply contracts and purchases as follows:

- At December 31, 2017, the District had entered into various short-term financial forward sales and purchase contracts committing the District through December 2019. Financial forward contracts for electricity and gas had a net positive fair value of $18,113 at December 31, 2017, and are reflected in the financial statements as deferred inflows of resources and deferred outflows of resources.

- At December 31, 2016, the District had entered into various short-term financial forward sales and purchase contracts committing the District through February 2019. Financial forward contracts for electricity and gas had a net positive fair value of $171,796 at December 31, 2016, and are reflected in the financial statements as deferred inflows of resources and deferred outflows of resources. In addition, the District had entered into put options expiring the first quarter of 2017. These options had a negative fair value of $13,935 at December 31, 2016, and are reflected in the financial statements as deferred inflows of resources and deferred outflows of resources.

Note 9 - Self-Insurance

In the normal course of business, the District is exposed to various risks of loss related to liability claims, property damage, and employee health and welfare programs. The District participates in the following self-insurance programs to protect against such losses.

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 17 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 consists 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. 1019718 and 1019719 for fiscal year 2016 and 1017390 and 1017391 for fiscal year 2015).

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 3 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 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 level of $500,000. The fund also maintains $10 million in cyber security liability coverage with a retention level of $500,000. The deductible is $250.

The liability pool reserve balance is $3.35 million. 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. The minimum reserve balance may be increased above $3.35 million through member assessments to meet legal funding requirements based on annual actuarial reviews.

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 $200 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. The minimum reserve balance may be increased above $750,000 through member assessments to meet legal funding requirements based on annual actuarial reviews.

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 consisting 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 reports for the Trust are available from the Washington State Auditor's Office (Report Nos. 1019357 and 1019358 for fiscal year 2016 and 1017101 for fiscal year 2015).

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 disability claims.

Note 10 - Participation in Northwest Open Access Network, Inc. (NoaNet)

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

As a member of NoaNet and as allowed by RCW 54.16, the District has guaranteed certain portions of NoaNet debt based on its proportionate membership share (see Note 12). The District's membership interest in NoaNet was 20.72% in 2017 and 2016. NoaNet continues to meet its debt obligations through profitable operations. NoaNet reserves the right to assess members to cover deficits from operations. There have been no member assessments since 2011.

NoaNet recorded a decrease in net position (excluding grant proceeds) of $6,791,730 (unaudited) for 2017 and a decrease of $7,206,634 (audited) for 2016. In accordance with GAAP a proportionate share of these gains/losses has not been recorded by the District. In accordance with GASB Statement No. 70, *Accounting and Financial Reporting for Nonexchange Financial Guarantees,* the District has included all required disclosures for its guarantees of NoaNet debt (see Note 12).

Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, Chief Financial Officer, 7195 Wagner Way, Suite 104, Gig Harbor, WA 98335.

Note 11 - 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. The District regularly reviews its product offerings and makes adjustments as needed. In 2017, the District began offering an Access Internet service option.

Broadband operations and capital activity for the years ended December 31, 2017 and 2016 follows:

Broadband	2017	2016
Operating Revenues		
Ethernet	$1,391,655	$1,301,597
TDM	56,463	69,372
Internet Transport Service	50,181	76,765
Fixed Wireless	64,924	75,282
Access Internet	76,323	-
Other Revenue	524,954	522,741
Total Operating Revenues	***$2,164,500***	***$2,046,069***
Operating Expenses		
General Expenses	$769,268	$811,789
Other Maintenance	71,666	120,000
NoaNet Maintenance Expense	3,754	-
Subtotal before depreciation	844,688	931,789
Depreciation	777,331	990,049
Total Operating Expenses	***$1,622,019***	***$1,921,838***
Nonoperating Expenses	$9,675	$3,864
Capital Investment (Annual)	$1,040,811	$877,652
Capital Investment (Cumulative)	$21,760,283	$20,719,472

The above amounts are included in summarized line items on the Statement of Net Position and Statement of Revenues, Expenditures, and Changes in Net Position

NOTE 12 - Other Commitments and Contingent Liabilities

Repayment Agreement Relating to NoaNet Revenue Bonds (see Note 10)

In July 2001, NoaNet issued $27 million in Telecommunications Network Revenue Bonds (2001 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%. In June 2011, NoaNet issued $13,165,000 in Telecommunications Network Revenue Refunding Bonds (2011 Refunding Bonds) to refinance certain 2001 Bonds. The final principal payment on the nonrefunded 2001 Bonds was made in December 2011. The 2011 Refunding Bonds became due in December 2012 through December 2016 with interest due semi-annually at rates ranging from 0.75% to 3.0%.

Current and former Members of NoaNet entered into Repayment Agreements to guarantee the debt of NoaNet. Under the Repayment Agreement, each guarantor acknowledged and agreed that it is a guarantor of the payment of the principal of and interest on the Bonds and was 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 was 14.06% of the outstanding Bonds.

In the event of a failure by any guarantor to pay such amounts when due, NoaNet may bill as necessary, and each guarantor was 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 was 17.57%. The Bonds were entirely paid off in 2016; therefore, the District has no continuing guaranty.

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%

Energy Independence Act (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 renewable energy in gradually increasing percentages and to establish and meet a minimum biennial energy conservation target. As of December 31, 2012, the District had renewable energy contracts in place that satisfy the Initiative's initial renewable target of 3% by 2012. The renewable requirement increases to 9% of retail load in 2016, and finally to 15% of retail load in the year 2020. Total incremental expenses for qualifying renewable resources plus the cost of renewable energy credits are limited to 4% of the annual retail revenue requirement.

In 2015, the Commission established the minimum Biennial Conservation Target for 2016–2017 of 1.97 aMW. The District exceeded the goal with 2.60 aMW.

Operating Leases

The District leases electrical testing equipment on an annual basis. The annual rental cost was $27,910 for 2017 and $25,749 for 2016.

The District has entered into an agreement 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 20 years with the consent of both parties. The agreement is classified as a non-cancellable operating lease of more than 1 year. The annual rental cost for the land was $58,008 and $56,838 for 2017 and 2016, respectively.

The future minimum rental payments are:

Year	Minimum Rental Payment
2018	$58,724
2019	58,724
2020	58,724
2021	29,362
Total	$205,534

Required Supplementary Information

Public Utility District No. 1 of Benton County

Schedule of Proportionate Share of the Net Pension Liability

PERS Plan 1
As of June 30, 2017
Last 10 Fiscal Years

	2017	2016	2015	2014
Employer's proportion of the net pension liability (asset)	0.108446%	0.111198%	0.114841%	0.115142%
Employer's proportionate share of the net pension liability	$5,145,847	$5,971,856	$6,007,252	$5,800,332
Employer's covered employee payroll	$131,788	$106,938	$100,338	$188,586
Employer's proportionate share of the net pension liability as a percentage of covered employee payroll	3905%	5584%	5987%	3076%
Plan fiduciary net position as a percentage of the total pension liability	61%	57%	59%	61%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Public Utility District No. 1 of Benton County

Schedule of Proportionate Share of the Net Pension Liability

PERS Plan 2/3
As of June 30, 2017
Last 10 Fiscal Years

	2017	2016	2015	2014
Employer's proportion of the net pension liability (asset)	0.136394%	0.139973%	0.145674%	0.143243%
Employer's proportionate share of the net pension liability	$4,739,040	$7,047,530	$5,205,015	$2,895,458
Employer's covered employee payroll	$13,371,937	$12,986,531	$12,446,584	$12,271,821
Employer's proportionate share of the net pension liability as a percentage of covered employee payroll	35%	54%	42%	24%
Plan fiduciary net position as a percentage of the total pension liability	91%	86%	89%	93%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Public Utility District No. 1 of Benton County

Schedule of Employer Contributions

PERS Plan 1
As of December 31, 2017
Last 10 Fiscal Years

	2017	2016	2015	2014
Statutorily or contractually required contributions	$678,004	$636,516	$571,651	$514,217
Contributions in relation to the statutorily or contractually required contributions	(678,004)	(636,516)	(571,651)	(514,217)
Contribution deficiency (excess)	-	-	-	-
Covered employer payroll	$75,850	$108,487	$105,271	$139,599
Contributions as a percentage of covered employee payroll	894%	587%	543%	368%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Public Utility District No. 1 of Benton County

Schedule of Employer Contributions

PERS Plan 2/3
As of December 31, 2017
Last 10 Fiscal Years

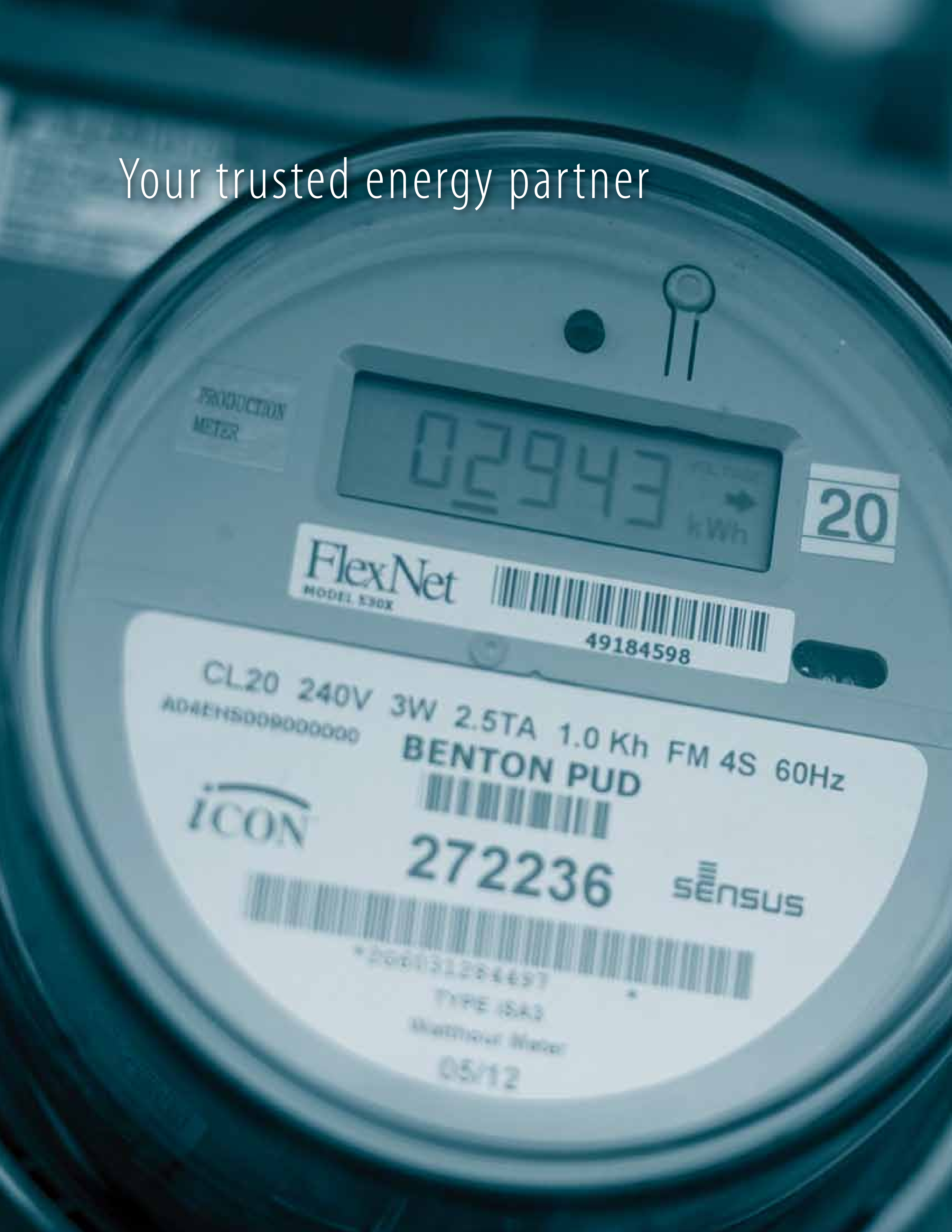
	2017	2016	2015	2014
Statutorily or contractually required contributions	$936,046	$815,729	$720,845	$612,316
Contributions in relation to the statutorily or contractually required contributions	(936,046)	(815,729)	(720,845)	(612,316)
Contribution deficiency (excess)	-	-	-	-
Covered employer payroll	$13,675,514	$13,096,369	$12,790,442	$12,335,880
Contributions as a percentage of covered employee payroll	7%	6%	6%	5%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

STATISTICAL SECTION

Your trusted energy partner

Your trusted energy partner



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 POSITION

For the years ended December 31 (unaudited)

	2017	2016	2015	2014 restated(3)
OPERATING REVENUES				
Sales of Electric Energy - Retail	$130,811,427	$120,438,526	$116,820,422	$117,641,940
Secondary Market Sales	14,542,756	14,808,281	17,678,932	23,325,872
Transmission of Power for Others	1,284,536	915,169	690,639	632,528
Broadband Revenue	2,164,500	2,046,068	2,024,661	2,191,287
Other Revenue	1,338,933	1,653,580	1,670,466	1,472,425
Total Operating Revenues	150,142,152	139,861,624	138,885,120	145,264,052
OPERATING EXPENSES				
Purchased Power	83,025,012	80,889,012	82,340,739	84,714,618
Purchased Transmission & Ancillary Services	13,205,172	12,997,169	12,816,306	12,925,752
Conservation Program	544,381	307,113	417,113	89,940
Transmission Operations & Maintenance	199,419	260,519	81,305	81,220
Distribution Operations & Maintenance	9,799,347	9,029,751	9,051,462	8,540,568
Broadband Expense	844,688	931,789	1,022,025	982,869
Customer Accounting, Collection & Information	3,735,098	3,411,338	3,794,832	3,788,799
Administrative & General	7,181,596	6,331,749	7,229,048	6,909,615
Taxes	14,018,894	12,630,500	12,263,706	12,394,110
Depreciation	10,177,574	12,630,490	13,207,539	12,894,915
Total Operating Expenses	142,731,181	139,419,430	142,224,075	143,322,406
OPERATING INCOME/(LOSS)	**7,410,971**	**442,194**	**(3,338,955)**	**1,941,646**
NONOPERATING REVENUES & EXPENSES				
Interest & Other Nonoperating Income	1,167,737	647,361	748,220	525,553
Interest Expense & Other Nonoperating Expense	(2,910,007)	(2,664,442)	(2,756,755)	(2,844,753)
Debt Premium Amortization & Loss on Defeased Debt (1)	492,959	143,522	419,819	445,518
Unrealized Gain/(Loss) on Investments	(33,130)	(4,170)	24,568	173,722
Assessments to Joint Venture	-	-	-	-
Total Nonoperating Revenues & Expenses	(1,282,441)	(1,877,729)	(1,564,148)	(1,699,960)
INCOME/(LOSS) BEFORE CONTRIBUTIONS AND EXTRAORDINARY ITEM	**6,128,530**	**(1,435,535)**	**(4,903,103)**	**241,686**
CAPITAL CONTRIBUTIONS	1,990,641	1,164,819	2,471,250	3,834,420
EXTRAORDINARY ITEM	-	-	-	-
CHANGE IN NET POSITION	**8,119,171**	**($270,716)**	**($2,431,853)**	**4,076,106**

NET POSITION

For the years ended December 31 (unaudited)

	2017	2016	2015	2014(3)
Net Investment in Capital Assets	$64,407,047	$58,672,489	$68,039,579	$65,363,895
Restricted for Debt Service	1,107,865	1,107,865	1,083,997	140,017
Restricted Settlement Proceeds	-	-	-	-
Unrestricted(2)	58,640,111	56,255,498	47,182,992	53,234,509
Total Net Position	**$124,155,023**	**$116,035,852**	**$116,306,568**	**$118,738,421**

(1) Governmental Accounting Standards Board Statement No. 65 was implemented effective 2012 classifying debt issuance costs as expense when incurred. 2011 was restated for comparative purposes in the financial statements.

(2) Governmental Accounting Standards Board Statement No. 65 was implemented effective 2012 classifying debt issuance costs as expense when incurred. 2010 was restated for comparative purposes and the cumulative effect of $(703,941) for prior years has been applied to the Unrestricted balance.

(3) Governmental Accounting Standards Board Statement No. 68 was implemented effective 2015 recognizing liabilities, deferred outflows of resources, deferred inflows of resources, and expenses relating to pension liabilities. The cumulative effect on net pension for 2014 was $12, 217,716.

2013	2012	2011 restated	2010 restated	2009	2008
$115,079,778	$110,799,843	$105,228,051	$94,137,792	$91,942,100	$86,236,604
18,232,140	14,048,971	25,773,429	30,122,467	38,885,352	53,188,137
776,957	797,837	397,063	230,978	229,429	225,908
1,980,605	1,620,054	1,617,919	1,181,892	927,041	858,566
1,249,791	1,879,829	1,424,566	1,403,220	1,348,716	1,449,381
137,319,271	129,146,534	134,441,028	127,076,349	133,332,638	141,958,596
77,877,737	68,652,534	75,475,402	78,768,878	75,055,153	91,764,877
11,677,803	11,260,088	10,276,334	9,315,582	10,074,812	10,295,990
1,315,642	405,589	808,494	1,795,846	679,406	130,064
82,066	12,684	17,575	26,909	30,026	20,449
8,092,079	8,191,232	7,499,422	7,163,781	7,092,143	6,998,119
890,521	696,415	674,581	712,433	577,958	662,267
4,026,839	3,954,421	3,388,582	3,773,740	4,011,243	3,850,215
6,444,642	6,276,795	5,384,210	5,396,629	5,557,985	5,420,309
12,144,846	11,814,545	10,890,913	9,513,213	9,956,874	9,197,531
12,671,992	11,642,052	10,769,424	9,751,161	9,367,272	9,369,594
135,224,167	122,906,355	125,184,937	126,218,172	122,402,872	137,709,415
2,095,104	**6,240,179**	**9,256,091**	**858,177**	**10,929,766**	**4,249,181**
612,901	668,774	602,075	488,924	358,811	1,198,244
(2,913,078)	(3,001,895)	(2,958,273)	(2,703,991)	(2,278,184)	(2,443,373)
459,652	459,198	(237,799)	(674,641)	(34,128)	(40,312)
(241,104)	19,862	-	-	-	-
-	-	(70,300)	(129,550)	(236,393)	(402,707)
(2,081,629)	(1,854,061)	(2,664,297)	(3,019,258)	(2,189,894)	(1,688,148)
13,475	**4,386,118**	**6,591,794**	**(2,161,081)**	**8,739,872**	**2,561,033**
2,706,411	2,368,597	1,394,438	1,271,831	3,072,025	1,885,387
-	-	-	-	-	-
2,719,886	**6,754,715**	**7,986,232**	**($889,250)**	**11,811,897**	**4,446,420**

2013	**2012**	**2011**	**2010**	**2009**	**2008**
$62,492,766	$58,085,620	$59,836,918	$61,389,146	$64,930,735	$56,656,963
140,017	140,017	140,017	706,157	-	-
-	-	-	-	86,955	-
64,247,248	65,934,508	57,428,495	47,323,895	45,848,815	42,397,645
$126,880,031	**$124,160,145**	**$117,405,430**	**$109,419,198**	**$110,866,505**	**$99,054,608**

REVENUES AND CONSUMPTION BY CUSTOMER CLASS

For the years ended December 31 (unaudited)

	2017	2016	2015	2014
AVERAGE NUMBER OF CUSTOMERS				
Residential	43,870	43,157	42,375	41,758
General Service	5,919	5,840	5,737	5,643
Industrial	5	5	3	3
Irrigation	987	790	794	788
Miscellaneous	2,330	1,850	1,853	1,861
Total	53,111	51,642	50,762	50,053
RETAIL ELECTRIC SALES (IN THOUSANDS) (1)				
Residential	$62,861	$53,643	$51,402	$52,862
General Service	36,690	34,223	33,706	33,829
Industrial	3,440	3,214	3,051	3,250
Irrigation	21,825	22,348	22,283	22,794
Miscellaneous	673	656	616	616
Total	$125,489	$114,084	$111,058	$113,351
RETAIL ELECTRIC SALES IN MWh				
Residential	759,634	661,742	665,505	696,804
General Service	545,884	525,603	530,283	533,008
Industrial	67,084	64,612	66,942	71,869
Irrigation	405,805	435,186	468,202	472,643
Miscellaneous	6,691	6,935	7,090	6,998
Total	1,785,098	1,694,078	1,738,022	1,781,322
AVERAGE REVENUE PER kWh (CENTS) (1)				
Residential	8.28	8.11	7.72	7.59
General Service	6.72	6.51	6.36	6.35
Industrial	5.13	4.97	4.56	4.52
Irrigation	5.38	5.14	4.76	4.82
Miscellaneous	10.05	9.46	8.69	8.81
Average - All Classes	7.03	6.73	6.39	6.36

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

2013	2012	2011	2010	2009	2008
41,322	40,645	40,201	39,687	39,220	38,855
5,572	5,499	5,421	5,356	5,289	5,192
3	3	3	3	3	3
772	721	722	736	746	736
1,852	1,842	1,850	1,834	1,816	1,814
49,521	48,710	48,197	47,616	47,074	46,600
$52,924	$50,678	$49,258	$43,707	$43,704	$41,116
32,959	32,416	29,864	27,575	25,605	24,750
3,176	3,223	2,780	2,167	1,483	1,662
19,630	18,817	17,602	15,642	16,290	13,936
622	821	790	762	733	690
$109,311	$105,955	$100,294	$89,853	$87,815	$82,154
697,887	668,018	687,953	654,775	721,720	666,418
519,493	512,797	503,471	503,037	530,255	510,144
69,803	70,575	65,411	55,365	38,909	47,760
402,619	385,738	381,999	371,321	427,269	407,432
6,972	8,148	9,528	8,304	8,188	8,102
1,696,774	1,645,276	1,648,362	1,592,802	1,726,341	1,639,856
7.58	7.59	7.16	6.68	6.06	6.17
6.34	6.32	5.93	5.48	4.83	4.85
4.55	4.57	4.25	3.91	3.81	3.48
4.88	4.88	4.61	4.21	3.81	3.42
8.92	10.08	8.29	9.17	8.95	8.51
6.44	6.44	6.08	5.64	5.09	5.01

RETAIL RATES (1)

For the years ended December 31 (unaudited)

	2017	2016	2015	2014
Residential				
Daily System Charge (2)	$0.62	$0.55	$0.52	-
Monthly Base Charge (single phase)	-	-	-	$11.05
Energy Charge (cents/kWh)	7.18	7.18	6.84	6.84
Small General Service				
Daily System Charge (2) (Single-Phase)	$0.54	$0.46	$0.44	-
Daily System Charge (2) (Multi-Phase)	$0.80	$0.68	$0.65	-
Monthly Base Charge (single phase)	-	-	-	$11.95
Energy Charge Effective 2010 (cents/kwh)	6.44	6.44	6.14	6.14
Prior to 2010				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Medium General Service				
Daily System Charge (2) (Single-Phase)	$1.08	$0.92	$0.88	-
Daily System Charge (2) (Multi-Phase)	$1.61	$1.38	$1.32	-
Monthly Base Charge (single phase)	-	-	-	$17.55
Energy Charge (cents/kwh)				
Summer (Effective 2011)	5.09	5.09	4.85	4.85
Winter (Effective 2011)	5.97	5.97	5.69	5.69
Summer (Prior to 2011)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter (Prior to 2011)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Demand Charge	$9.55	$8.77	$8.36	$8.36
Large General Service				
Daily System Charge (2) (Multi-Phase)	$1.96	$1.38	$1.32	-
Monthly Base Charge (multi phase)	-	-	-	$26.10
Energy Charge - Non Time of Use (cents/kwh)				
Summer (Effective 2010)	4.11	4.11	3.92	3.89
Winter (Effective 2010)	4.92	4.92	4.69	4.65
Summer (Prior to 2010)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter (Prior to 2010)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Demand Charge	$7.93	$7.45	$7.10	$7.00

(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.

(2) The Daily System Charge was effective 9/1/2015 and replaced the Monthly Base Charge.
The rate is per day and applied to the number of days in the billing period.

2013	2012	2011	2010	2009	2008
-	-	-	-	-	-
$11.05	$11.05	$10.50	$9.20	$8.80	$8.80
6.84	6.84	6.49	6.05	5.78	5.78
-	-	-	-	-	-
-	-	-	-	-	-
$11.95	$11.95	$11.45	$11.45	$10.70	$10.70
6.14	6.14	5.88	5.47	-	-
-	-	-	-	5.13	5.13
-	-	-	-	3.35	3.35
-	-	-	-	-	-
-	-	-	-	-	-
$17.55	$17.55	$16.30	$14.25	$13.20	$13.20
4.85	4.85	4.51	-	-	-
5.69	5.69	5.29	-	-	-
-	-	-	4.45	4.46	4.46
-	-	-	3.55	2.74	2.74
-	-	-	5.29	5.24	5.24
-	-	-	4.19	3.33	3.33
$8.36	$8.36	$7.77	$7.13	$6.60	$6.60
-	-	-	-	-	-
$26.10	$26.10	$24.15	$18.60	$17.40	$17.40
3.89	3.89	3.59	3.31	-	-
4.65	4.65	4.30	3.97	-	-
-	-	-	-	4.33	4.33
-	-	-	-	2.89	2.89
-	-	-	-	4.72	4.72
-	-	-	-	3.56	3.56
$7.00	$7.00	$6.48	$5.99	$5.60	$5.60

PRINCIPAL RATEPAYERS

For the years ended December 31 (unaudited)

2017

Ratepayer's Rate Class (1)	Rank	Retail Sales(2)	Percentage of Total Retail Electric Sales	kWh	aMW	Percentage of Total kWh
Large Irrigation Customer 1	1	$9,732,252	7.8%	180,482,756	20.6	10.1%
Large Irrigation Customer 2	2	3,731,647	3.0%	70,717,123	8.1	4.0%
Large Industrial Customer 1	3	3,444,412	2.7%	67,201,139	7.7	3.8%
Large Irrigation Customer 3	4	2,846,845	2.3%	52,824,219	6.0	3.0%
Large General Customer 1	5	1,954,000	1.6%	26,415,051	3.0	1.5%
Large Irrigation Customer 4	6	1,807,119	1.4%	34,130,517	3.9	1.9%
Large Irrigation Customer 5	7	1,677,641	1.3%	29,769,740	3.4	1.7%
Large General Customer 2	8	1,675,623	1.3%	23,269,949	2.7	1.3%
Large Irrigation Customer 6	9	1,239,792	1.0%	24,659,112	2.8	1.4%
Large General Customer 3	10	1,206,301	1.0%	18,353,632	2.1	1.0%
Large General Customer 4	-	-	-	-	-	-
		$29,315,632	23.4%	527,823,238	60.3	29.7%
Total All Ratepayers		**$125,488,602**		**1,785,098,170**		

(1) To preserve confidentiality, individual ratepayer names are not disclosed.
(2) Retail sales are before taxes, bad debt expense, and unbilled revenue.

2008

Rank	Retail Sales[(2)]	Percentage of Total Retail Electric Sales	kWh	aMW	Percentage of Total kWh
1	$3,997,083	4.6%	174,331,941	19.9	10.6%
2	2,438,223	2.8%	68,537,940	7.8	4.2%
3	1,662,045	1.9%	47,760,295	5.5	2.9%
4	1,261,923	1.5%	37,571,772	4.3	2.3%
9	1,154,866	1.3%	22,078,701	2.5	1.3%
6	1,128,540	1.3%	33,177,167	3.8	2.0%
5	1,159,535	1.3%	35,770,119	4.1	2.2%
10	1,324,158	1.5%	21,398,769	2.4	1.3%
8	815,106	0.9%	23,772,000	2.7	1.4%
-		-		-	-
7	1,057,009	1.2%	24,403,431	2.8	1.5%
	$15,998,488	18.3%	488,802,135	55.8	29.7%
	$86,236,604		**1,639,856,302**		

RATIOS OF OUTSTANDING DEBT

For the years ended December 31 (unaudited)

	2017	2016	2015	2014 restated
Revenue Bonds	$56,905,000	$59,950,000	$49,735,000	$53,600,000
Unamortized Premium & Discount	4,336,311	4,845,315	3,099,629	3,572,728
Total Outstanding Revenue Debt	$61,241,311	$64,795,315	$52,834,629	$57,172,728
Total Revenue Debt to Operating Revenues	41%	46%	38%	39%
Total Revenue Debt to Total Assets	28%	30%	26%	27%
Total Revenue Debt per Ratepayer	$1,153	$1,255	$1,041	$1,142

DEBT MARGIN INFORMATION (1)

For the year ended December 31, 2017 (unaudited)

Net Revenues November 2017 - October 2017(2)	$22,378,187
Maximum Future Annual Debt Service (2020)	$6,523,987
Maximum Allowable Annual Debt Service per Bond Covenants (2)	$17,902,550
Allowable Additional Annual Debt Service	$11,378,563

(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%.

(3) With implementation of GASB 65 in 2012, bond issuance costs are expensed in the year incurred. The District restated 2011 for comparative purposes to match the financial statements. In addition, prior to 2011, the unamortized loss on defeasance is included in Total Outstanding Revenue Debt.

2013	2012	2011[3]	2010	2009	2008
$56,635,000	$59,575,000	$62,330,000	$59,165,000	$50,865,000	$53,395,000
4,072,098	4,597,935	5,134,338	452,684	597,829	663,277
$60,707,098	$64,172,935	$67,464,338	$59,617,684	$51,462,829	$54,058,277
44%	50%	50%	47%	39%	38%
29%	31%	34%	32%	29%	29%
$1,226	$1,317	$1,400	$1,252	$1,093	$1,160

DEBT SERVICE COVERAGE

For the years ended December 31 (unaudited)

	2017	2016	2015	2014 restated
DEBT SERVICE CALCULATION				
Change in Net Position	$8,119,171	($270,716)	($2,431,853)	$4,076,106
Adjustments to (from) Change in Net Position				
Depreciation	10,177,574	12,630,490	13,207,539	12,894,915
Prepaid Power (1)	1,017,144	1,017,144	1,017,144	1,017,144
Interest Expense	2,910,007	2,664,442	2,756,755	2,844,753
Debt Discount/Premium Amortization & Bond Issue Costs	(492,959)	(143,522)	(419,819)	(445,518)
GASB 68 Pension noncash entry	(593,733)	(308,366)	(157,447)	(245,062)
Transfer (to) from Rate Stabilization	-	-	-	-
REVENUE AVAILABLE FOR DEBT SERVICE	**$21,137,204**	**$15,589,472**	**$13,972,319**	**$20,142,338**
DEBT SERVICE (2)	**$6,226,648**	**$5,351,412**	**$4,767,944**	**$5,966,784**
DEBT SERVICE COVERAGE RATIO	**3.39**	**2.91**	**2.93**	**3.38**

(1) White Creek Wind Project amortization and Bonneville Power Administration prepaid power.
(2) Reduced by capitalized interest.

2013	2012	2011	2010	2009	2008
$2,719,886	$6,754,715	$7,986,232	($889,251)	$11,811,897	$4,446,420
12,671,992	11,642,052	10,769,424	9,751,161	9,367,272	9,369,594
907,457	578,400	578,400	578,400	578,400	144,600
2,913,078	3,001,895	2,958,273	2,683,991	2,259,809	2,442,913
(459,652)	(459,198)	237,799	674,641	34,128	40,312
-	-	(2,369,920)	-	-	-
$18,752,761	**$21,517,864**	**$20,160,208**	**$12,798,942**	**$24,051,506**	**$16,443,839**
$5,965,509	**$5,969,064**	**$5,002,221**	**$5,445,961**	**$5,131,680**	**$5,130,080**
3.14	**3.60**	**4.03**	**2.35**	**4.69**	**3.21**

PRINCIPAL EMPLOYERS - TRI-CITIES METROPOLITAN STATISTICAL AREA

For the years ended December 31 (unaudited)

		2017		
Employer	**Product/Service**	**Employees**	**Rank**	**Percentage of Total MSA Nonfarm Employment**
Battelle/Pacific NW National Laboratory	Research/National Laboratory	4,500	1	3.9%
Kadlec Medical Center	Health Care	3,532	2	3.1%
ConAgra/Lamb Weston Inc.	Food Processing	3,000	3	2.6%
Bechtel National, Inc.	Engineering & Construction	2,943	4	2.6%
Kennewick School District	Education	2,336	5	2.0%
Washington River Protection Solutions	Environmental Remediation	2,129	6	1.9%
Pasco School District	Education	2,015	7	1.8%
Mission Support Alliance, LLC	Support Services Hanford	1,902	8	1.7%
CH2MHill Hanford Group Inc./CHG	Environmental Engineering	1,682	9	1.5%
Richland School District	Education	1,500	10	1.3%
Wyckoff Farms	Agriculture	-	-	-
Fluor Hanford Inc./URS	Environmental Engineering	-	-	-
Tyson Fresh Meats/Iowa Beef	Meat Packing	-	-	-
Total		25,539		22.4%

Source: Tri-City Development Council

2008		
Employees	Rank	Percentage of Total MSA Nonfarm Employment
4,220	1	4.5%
1,422	10	1.5%
2,128	4	2.3%
2,800	2	3.0%
1,800	8	1.9%
-	-	-
2,002	5	2.1%
-	-	-
1,950	6	2.1%
-	-	-
2,500	3	2.7%
1,561	9	1.7%
1,800	7	1.9%
22,183		23.7%

DEMOGRAPHIC STATISTICS

For the years ended December 31 (unaudited)

	2017	2016	2015	2014
Population (1)				
Tri-Cities Metropolitan Statistical Area	283,830	279,170	275,740	273,100
Benton County	193,500	190,500	188,590	186,500
City of Kennewick	80,280	79,120	78,290	77,700
Prosser	5,965	5,940	5,845	5,815
Benton City	3,360	3,325	3,285	3,255
Total Personal Income - Benton County (2)	N/A	$8,779,652	$8,324,360	$7,683,703
Per Capita Income - Benton County (2)	N/A	$45,329	$43,735	$41,186
Unemployment Rate - Benton County (3)	6.1%	7.0%	7.1%	7.7%
Building Permits Issued (4)				
Kennewick	2,064	2,211	2,005	2,054
Benton County (Unincorporated)	997	919	784	713
Taxable Retail Sales - All of Benton County (5)	N/A	$3,789,869,697	$3,612,773,217	$3,284,581,847

(1) Source: Washington State Office of Financial Management. 2010 was restated with census numbers.
(2) Source: U.S. Bureau of Economic Analysis. 2008-2015 revised estimates from BEA in 2017.
(3) Source: December 2016 Unemployment Rates, Washington Employment Security Department
(4) Source: City of Kennewick and Benton County Building Departments
(5) Source: Washington State Department of Revenue

2013	2012	2011	2010	2009	2008
268,200	262,500	258,400	253,340	242,000	235,700
183,400	180,000	177,900	175,177	169,300	165,500
76,410	75,160	74,665	73,917	67,180	65,860
5,810	5,785	5,780	5,714	5,110	5,075
3,240	3,295	3,145	3,038	2,955	2,855
$7,430,711	$7,529,470	$7,577,726	$7,166,114	$6,590,197	$6,290,231
$40,270	$41,261	$41,978	$40,598	$38,512	$37,763
7.9%	9.0%	9.2%	7.1%	7.4%	6.5%
1,989	1,918	2,123	2,161	1,868	1,649
728	588	711	753	674	562
$3,189,855,069	$2,937,655,298	$2,959,959,724	$2,731,890,939	$2,623,845,560	$2,601,911,391

OPERATING INDICATORS

For the years ended December 31 (unaudited)

	2017	2016	2015	2014 restated
Operating Expenses / Revenues	95.1%	99.7%	102.4%	98.7%
Total Electric Sales in MWh				
Retail Sales	1,785,098	1,694,078	1,738,022	1,781,322
Secondary Market Sales	609,721	576,289	662,886	717,847
Total MWh Sales	2,394,819	2,270,367	2,400,908	2,499,169
Average Annual kWh per Customer				
Residential	17,316	15,333	15,692	16,687
General Service	92,226	90,004	92,432	94,455
Industrial	13,416,822	12,922,400	22,313,962	23,956,495
Irrigation	411,150	550,578	589,675	599,801
Miscellaneous	2,872	3,749	3,826	3,760
Average Annual kWh per Customer - All Classes	33,611	32,804	34,239	35,589
Average Revenue per Customer				
Residential	$1,433	$1,243	$1,213	$1,266
General Service	6,199	5,860	5,875	5,995
Industrial	687,927	642,800	1,016,944	1,083,292
Irrigation	22,112	28,274	28,065	28,926
Miscellaneous	289	355	332	331
Average Revenue per Customer - All Classes	$2,363	$2,209	$2,188	$2,265
Additions to Electric Plant, excluding work-in-progress	$14,248,483	$12,707,389	$10,795,807	$14,325,929
Net Electric Utility Plant	$125,666,747	$123,470,148	$120,791,227	$122,400,363
Capitalized Payroll	$2,435,631	$3,213,042	$2,201,618	$2,289,991
Total Payroll Expense	$13,864,893	$13,630,457	$12,967,615	$12,674,072
Full Time Equivalent Employees (1)	152	153	152	152
Cooling Degree Days (2)	1,347	1,099	1,534	1,426
Heating Degree Days (2)	5,618	4,392	4,228	4,611
Annual Precipitation (inches) (2)	8.60	7.66	6.48	6.53
Peak Load (MW's) (3)	426	425	429	431

(1) Includes regular and temporary employees. In 2017, all years employee counts were reduced to account for shared employees billed to other governments.

(2) 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.

(3) Source: The Energy Authority, Inc.

2013	2012	2011	2010	2009	2008
98.5%	95.2%	93.1%	99.3%	91.8%	97.0%
1,696,774	1,645,277	1,648,362	1,592,802	1,726,341	1,639,856
580,417	687,098	929,688	693,299	667,758	818,485
2,277,191	2,332,375	2,578,050	2,286,101	2,394,099	2,458,341
16,889	16,435	17,113	16,498	18,402	17,151
93,233	93,253	92,874	93,920	100,256	98,256
23,267,593	23,525,055	21,803,603	18,454,887	12,969,692	15,920,098
521,528	535,005	529,085	504,513	572,747	553,576
3,764	4,423	5,150	4,528	4,509	4,466
34,264	33,777	34,201	33,451	36,673	35,190
$1,281	$1,247	$1,225	$1,101	$1,114	$1,058
5,915	5,895	5,509	5,148	4,841	4,767
1,058,609	1,074,442	926,683	722,372	494,424	554,015
25,428	26,098	24,380	21,253	21,836	18,934
336	446	427	415	403	380
$2,207	$2,175	$2,081	$1,887	$1,865	$1,763
$14,261,262	$11,658,180	$16,575,853	$17,203,386	$10,736,615	$10,358,753
$123,009,752	$122,002,258	$121,789,048	$120,302,889	$115,807,257	$110,029,356
$2,344,440	$2,550,126	$2,858,449	$2,677,911	$2,363,236	$2,008,050
$12,573,298	$12,401,390	$11,637,285	$11,672,710	$11,585,291	$11,041,774
153	150	152	154	158	155
1,318	1,057	884	870	1,235	991
5,320	4,940	5,466	4,896	5,679	5,581
5.38	8.18	4.45	10.19	5.47	5.49
415	394	380	392	402	397

BENTON P·U·D

RP3 RELIABLE PUBLIC POWER PROVIDER
American Public Power Association

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BentonPUD.org