Final Report

2013 Equity Management Plan and Electric System Rate Study

Public Utility District No. 1
of Okanogan County, Washington

August 2013

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August 22, 2013

Mr. John R. Grubich
General Manager
Okanogan County Public Utility District
1331 2nd Avenue North
Okanogan, Washington 98840

Subject: **2013 Equity Management Plan and Electric System Rate Study**

Dear Mr. Grubich:

SAIC Energy, Environment & Infrastructure, LLC and its subconsultants, NewGen Strategies & Solutions, LLC, and Cuthbert Consulting Inc. are pleased to submit this final report summarizing the results of the 2013 Equity Management Plan and Electric System Rate Study.

The preparation of this study was a collaborative effort by Okanogan PUD and the SAIC project team. We greatly appreciate Okanogan's assistance in providing information, guidance, and review during the study. Thank you for the opportunity to be of service to Okanogan PUD.

Sincerely,

Jennifer A. White
Project Manager
SAIC Energy, Environment & Infrastructure, LLC

Richard W. Cuthbert
President
Cuthbert Consulting Inc.

Gina Baxter
Senior Consultant
NewGen Strategies and Solutions, LLC

File: 001145/3153311003

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Letter of Transmittal
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Section 1
INTRODUCTION

SAIC Energy, Environment & Infrastructure, LLC (SAIC) was retained by the Public Utility District No. 1 of Okanogan County (the District) in January 2013 to assist District staff with development of the 2013 Equity Management Plan (2013 EMP) and the 2013 Electric System Cost-of-Service and Rate Design Study (2013 Rate Study). Work on these two efforts was completed between January 2013 and August 2013 by SAIC staff along with the staff of its subconsultant, NewGen Strategies & Solutions, LLC (NewGen).

Since 2008, SAIC (formerly R. W. Beck, Inc.) has provided the District assistance with its equity management plans and cost-of-service and rate design studies. SAIC developed the 2010 Equity Management Plan (2010 EMP), a long-term financial planning model. Additionally, SAIC prepared a 2010 cost-of-service and rate design study (the 2010 Rate Study) for the District based on information from the 2010 EMP to develop a series of rate increases that were implemented over the 2010 to 2012 time period. In 2012, SAIC was retained to review and modify the District's irrigation rates, which were implemented in April 2012. Following this effort, SAIC also prepared a draft update of the prior 2010 EMP for the District (the draft 2012 EMP), which indicated the likely need for rate increases by the District during calendar year 2013 and beyond.

The scope of work for the 2013 EMP is based on updating the prior EMP model, which incorporates the District's long-term planning needs and evaluates its financial outlook related to operating expenses, capital improvements, financing requirements and rate increases as well as other pertinent operating and financial information. The District faces a number of uncertainties in the coming years related to load growth, higher Bonneville Power Administration (BPA) rates, and possible capital improvement needs and resource development options. Given these uncertainties and the projected levels of rate increases, the 2013 EMP was prepared to update and refine projections of the electric system financial performance and to assist in understanding possible future rate levels, funding options and overall long-term financial options available to the District.

Additionally, the cost-of-service and rate study analyses from the 2010 Rate Study were updated to reflect the new 2013 EMP projections for use in the preparation of a new 2013 Rate Study. The results of the 2013 EMP were used as the basis for the test year (TY) 2013 revenue requirements used in this 2013 Rate Study. The cost-of service analysis provides information to the District regarding the cost of serving its customer classes and how this compares to the existing rates. As further discussed in this report, the information from this study was used to assess the need for, and magnitude of, possible rate changes to be effective September 1, 2013 and in later years.

Report Organization

This report is organized into four sections plus appendices. General information about the study is provided in Section 1. An overview of the 2013 EMP analysis is provided in Section 2 and the cost-of-service and rate design analyses for the 2013 Rate Study follow in Section 3. A discussion related to the summary and conclusions is provided in Section 4. Detailed analyses of these two studies are provided in Appendices A through I. In addition, a copy of District's Resolution No. 1567 (which authorized the District to implement new rates to be effective on or after September 1, 2013) is provided in Appendix J.

Introduction

When completed in 2010, the District's 2010 EMP indicated that the District needed a 10 percent rate increase in 2010, a 20 percent rate increase in 2012 and a 10 percent rate increase in 2014 to meet its financial objectives. The projected rate increase in the first year was attributed to the increase in purchased power costs from BPA and rate increases needed in 2012 and 2014 were driven by the need to maintain adequate cash levels. In addition, the District had been experiencing decreases in wholesale revenues.

Given the level of rate increases that were projected, a more moderate and consistent level of rate adjustments was adopted over the first three years of the projection period. The District authorized annual rate adjustments of 6.5 percent in 2010, 2011 and 2012 and 3 percent annual rate increases beginning in 2013 and every year thereafter by adoption of Resolution No. 1506. The reduction of implementing the full rate increases projected to be needed in 2010 and 2012 as identified in the 2010 EMP as well as the ongoing decrease in wholesale revenues were factors that affected the District in 2012 and were significant factors considered in the 2013 EMP review efforts.

In 2012, SAIC prepared a draft update of the prior 2010 EMP for the District, which indicated a likely need for significant rate increases during calendar year 2013 and beyond. Beginning in January 2013, the District's EMP model was updated to help the District evaluate its projected financial performance under various scenarios over a ten-year planning period from 2013 through 2022 (the study period).

As part of the development of the 2013 EMP, several factors were considered to be of significant importance in the District's financial planning efforts. These factors included the need to:

- Establish appropriate debt service coverage (DSC) and times interest earned ratio (TIER) requirements,
- Balance borrowing needs and rate-funded equity levels to fund the District's capital needs,
- Maintain a favorable equity ratio,
- Maintain appropriate cash reserve levels, and
- Evaluate future revenue requirement and future rate adjustment needs.

A principal goal defined by the District for the 2013 EMP was to examine the long-term retail rate impacts of several projected changes to the District's system, including:

- Bonneville Power Administration (BPA) rate increases,

- Declining wholesale sales revenues, and
- Development of the Enloe Dam Hydroelectric Facility.

The 2013 EMP was developed in the context of helping the District evaluate appropriate rate levels to meet the financial targets of the utility while continuing to provide reliable electric service given operational and financial changes.

Approach

The 2013 EMP process involved updating a detailed financial based spreadsheet model, which projects annual revenues and expenditures for the District over the study period. An income statement, statement of cash flows, and balance sheet projections were developed in the model as well as supporting schedules for plant investment, funding requirements and sources, existing and new debt service payments, and a general funds summary.

Updating the 2013 EMP involved discussions concerning operational and financial planning assumptions and variables among SAIC and NewGen staff, District management and staff, and the District's Board of Commissioners. Based on the results of these discussions and input received, several key assumptions were made. Some of these key assumptions made in the 2013 EMP include: (1) the District would continue with development of Enloe Dam, assumed to be operational in 2017, (2) the District's wholesale revenues would continue to decrease over time, and (3) significant BPA rate increases would continue in the future. A full discussion of the key assumptions used in the EMP is provided later in this section of the report.

Based on the above assumptions and considerations, a 2013 EMP Base Case financial projection was developed. Given that the Base Case results indicated a likely need for significant rate increases during calendar year 2013 and beyond, SAIC and NewGen staff worked with District management to identify certain alternative financial-related assumptions and options to be reviewed. The EMP model was used to analyze the impact of these alternative assumptions and options on the District's projected financial result in alterative EMP scenarios. As a result, a number of alternative scenarios were developed and evaluated, and these alternative scenarios were narrowed down to three scenarios that included consideration of the following assumptions and options:

- **Scenario 1:** Reducing the District's capital improvements expenditures by 30 percent over the 10-year study period.
- **Scenario 2:** Reducing projected operating and maintenance expenses for 2013 from the 2013 budgeted levels escalated by a 2.2 percent annual inflation rate over the study period to the 2012 actual level and escalating this amount by 3.0 percent annually over the study period. (The difference in the inflation rate assumptions was attributed to the utility's cost for one-time studies and other miscellaneous expenses that occur from time to time that are not captured in the 2012 actual base year. The 2013 budget also included $2.9 million that was reclassified as capitalized labor in this scenario.)

- **Scenario 3:** Combination of the District implementing both Scenarios 1 and 2 spending reductions.

The EMP process and draft EMP scenario results were presented to a review panel of Board-selected District customers from the community in two half-day workshops and then to the District's Board in a series of three workshops to allow for customer input and guidance during the EMP development process. In these workshops, it was the consensus that the results of both the Base Case and the three alternative scenarios all indicated the need for the District to significantly increase its revenues during first three years of the study period, and it was determined that the District should proceed use of the Base Case EMP in the 2013 Rate Study. The results of these EMP analyses are discussed in greater detail later in this section.

After receiving input on the EMP results, it was determined that three different EMP options would be developed using the Base Case EMP to review alternative timing and rate increase options for the District to consider for evaluation of rate increase options. These three alternative EMP options were as follows:

- **Base Case – Rate changes implemented only as necessary:** Annual rate adjustments were set to meet financial targets and to ensure positive net income for the District by 2014. In this EMP rate scenario, use of funds from the rate stabilization reserves were projected to be needed in order for the District to meet its 1.25 debt service coverage requirement in 2013.
- **Option 1 – Only two rate changes implemented:** Instead of significant rate increases occurring over a three-year period as in the Base Case, only two rate increases would be implemented by District to meet financial targets and to ensure positive net income by 2014. This scenario also indicated the need for the District to use funds from the rate stabilization reserves in order for the District's to meet the 1.25 debt service coverage requirement in 2013.
- **Option 2 – Moderated level of rate changes**: The rate increases in the first two years under this scenario would be at a more moderate level than the Base Case. Allocated funds from the rate stabilization reserves in 2013 and 2014 to show the District's ability to meet the 1.25 debt service coverage requirements. Funds are set aside between 2015 and 2016 to build the rate stabilization fund back up to a $3 million balance. A positive net income is not reached until 2015 under this scenario.

These results are discussed in detail later in this section. The 2013 EMP, like any financial plan, will need to be adjusted and updated periodically as conditions change and as each year's operating results become known. Given the significant uncertainty related to projected wholesale revenues, it is recommended that the District review and update the EMP annually during the next several years as part of its ongoing financial planning process.

Financial Goals

District financial goals are discussed below.

- **DSC and TIER Levels:** The District has determined that minimum DSC and TIER target levels of 1.50 are necessary to meet lender requirements and to ensure the security of debt service payments.
- **Cash Levels:** Minimum cash levels equivalent to approximately 60 days of operating expenses (i.e., operations, maintenance, and interest expenses) are necessary to maintain sufficient liquidity for cash transaction requirements and unforeseen events. In addition, District staff are considering adding a line of credit for short-term cash needs.
- **Equity Levels:** The District realizes that it is prudent to maintain a minimum long-term equity ratio of at least 50 percent. Although the District is not required to maintain a specific equity ratio, its lenders have expectations regarding equity levels consistent with strong financial performance, which the District wishes to maintain.
- **Funding of Capital Expenditures:** Significant capital expenditures, including funding for the development of Enloe Dam, are projected during the study period in order for the District to provide efficient and reliable service. It is important for the District to maintain strong financial performance levels to assure its access to low cost capital to fund these capital expenditures and to keep its rates for electric service at reasonable levels in the future.
- **Rate Stability and Competiveness:** In developing the EMP, the District worked diligently to balance the goal of stable and competitive rates for its customers with the goals of meeting its financial targets and continuing to provide reliable electric service.

Key Assumptions

Principal assumptions used in development of the 2013 EMP are as follows:

- **Cost of Power Increases**: The District will experience cost of power increases during the study period from BPA Power Supply and BPA Transmission Service.
  - **BPA Power Supply**: Estimated 9.6 percent increase in October 2013 for two years and 6 percent increases thereafter (every other year).
  - **BPA Transmission Service**: Estimated 13 percent increase in October 2013 for two years 2013 and 6 percent increases thereafter (every other year).
- **Load Forecast:** The District's projected customer sales and load requirements are based on a load forecast developed by District staff. Overall, retail sales are projected to increase 1.0 percent on an average annual basis during the study period. Wholesale sales are projected to decrease gradually (average annual growth rate of -1.0 percent from 2012-2022), with a one-year increase in wholesale sales in 2017 associated with the addition of power from Enloe Dam.

- **Wholesale Revenues:** Wholesale revenues are assumed to decrease over the study period from approximately $3.5 million in 2012 to $2.7 million in 2022. The decrease in wholesale revenues is the result of decreased wholesale sales and lower projected wholesale power prices.
- **Enloe Dam Hydroelectric Facility:** It is assumed the District will continue to pursue the development of Enloe Dam with operation projected to begin in 2017. The projected power generated and operating costs for this project were obtained from Schedule D of the Final License Application to the Federal Energy Regulatory Commission dated August 2008.
- **Capital Improvement Expenditures:** The ten-year Capital Improvement Plan (CIP) projects capital improvement expenditures to equal approximately $102.4 million (nominal dollars) during the study period. These expenditures include the following items:
  - Enloe Dam Hydroelectric Project − $35.2 million for a 9.0-MW hydroelectric facility projected to be operational in 2017.
  - Transmission – $17.3 million (including $9 million for the Pateros to Twisp 115-kV Transmission Line in 2013-2014 for the construction of a 28-mile-long, 115-kV transmission line from the existing Brewster-Pateros line to the Twisp Substation).
  - Substations – $9.8 million.
  - Normal Replacements and Additions – $24.8 million.
  - Other Projects – $15.3 million
- **Base Year Operating Results:** The District's 2010-2011 audited financial reports and unaudited 2012 reports were used to reflect actual expenditures. The 2013 final budget expenditures were the basis for the initial year of the financial projections. Operating and maintenance expenses in 2014 and beyond were escalated from the 2013 budget over the projection period.

Overview of 2013 EMP Analysis Results

The following table provides an outline of the detailed 2013 EMP analysis results as provided in the appendices to this report. The results for the EMP Base Case and Options 1 and 2 are provided in Appendices A through C.

Table 2-1
Okanogan County PUD
Outline of 2013 EMP Analysis Results

Table	Description
Table 1 – Summary of Results and Assumptions	Key results including average unit revenues, margins, equity ratio, year-end cash balances, TIER and DSC ratio levels. Basic financial assumptions, capital credit retirement assumptions, days of working cash capital, debt terms, and annual depreciation assumptions
Table 2 – Projected Revenues at Existing Rates	Projected energy sales by customer class; projected revenues from energy sales at rate levels by customer class that became effective in July 2012
Table 3 – Income Statement – Accrual Basis	Projected operating revenues and expenses; operating margins and total margins; unit revenues from energy sales
Table 4 – Pro forma Balance Sheet as of December 31	Projected year end assets, equities and liabilities; financial ratios
Table 5 – Statement of Operations – Cash Basis	Projected cash from operations; annual debt service payments; uses of cash margins; DSC
Table 6 – General Funds Summary	Projected general fund balances; sources and uses of general funds
Table 7 – Plant Investment and Depreciation Expense	Additions and replacements to utility plant; depreciation expense
Table 8 – Long-term Debt and Debt Service	Long-term debt; new debt incurred; annual debt service payment obligations; funding requirements for capital additions
Table 9 – Energy Resources and Cost of Power	Total projected District energy requirements; projected energy resources; estimated cost of purchased power and power production
Table 10 – Projected Cost of Power Adjustment Revenues	Projected retail sales, estimated change in power costs since 2012 and estimated cost of power adjustment charges

Summary of 2013 EMP – Base Case Analysis Results

A summary of key financial indicators for the Base Case EMP projections is discussed below and presented in Table 2-2. Detailed results are presented in Appendix A. The components and results of the 2013 EMP Base Case are based on the financial and operational objectives defined previously. In particular, the analysis is based on the District meeting both a target DSC ratio and a target total TIER level of 1.50 by 2015. Additionally, working capital is maintained at a level approximately equal to 60 days of operating and maintenance expenditures by 2014.

Table 2-2
Okanogan County PUD
Summary of Results
EMP Scenario – Base Case

	Historical			Projected									
SUMMARY OF RESULTS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Unit Revenue from Retail Sales (¢/kWh)	5.10	5.46	6.13	6.65	7.81	8.44	8.80	9.08	9.36	9.47	9.71	9.79	9.97
Increase over Previous Year	6.4%	7.0%	12.1%	8.6%	17.4%	8.0%	4.3%	3.2%	3.0%	1.1%	2.6%	0.9%	1.8%
Necessary Retail Rate Change (1)	0.0%	0.0%	0.0%	12.5%	12.5%	2.5%	2.5%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Equity to Total Assets	63.2%	64.0%	64.8%	64.5%	50.7%	52.3%	45.4%	46.8%	48.5%	50.2%	51.9%	53.6%	55.3%
Cash (Year End) ($000)	$7,619	$9,782	$4,416	$1,022	$22,749	$8,132	$14,297	$10,891	$9,865	$8,086	$8,675	$10,489	$13,227
Days of Working Capital on Hand	74	95	43	9	187	65	111	81	71	57	59	70	85
Debt Service Coverage Ratio (DSCR)	0.77	1.36	1.47	1.25	1.38	2.01	1.76	1.67	1.77	1.78	1.77	1.78	1.96
Operating TIER	(4.99)	(0.10)	(0.75)	(2.16)	0.34	1.23	1.03	0.99	1.09	1.08	1.03	1.02	1.02
Total TIER	(2.11)	0.46	0.96	0.29	1.00	1.93	1.54	1.52	1.65	1.67	1.67	1.71	1.77

Note: (1) Rate increases effective September 1, 2013 and July 1st for all other years.

Under these assumptions, rate increases are projected for 2013 through 2017 with a first rate increase assumed to be effective September 1, 2013 and July 1 each year thereafter. The significant 2013 and 2014 12.5 percent rate increases are primarily driven by the need for the District to achieve adequate cash levels and to reach positive net income by 2014. These projections assume that approximately $2.6 million from the rate stabilization fund would be used to meet the 1.25 debt service coverage requirements in 2013. Projected DSC and total TIER levels are summarized in Table 2-2 and in Figure 2-1.

In addition to increased purchased power costs, the District is projecting decreased wholesale revenues from levels seen in the past few years. This is due to projected decreases in wholesale sales and lower projected wholesale power prices. An one-year increase in the power available for wholesale sales occurs in 2017 with the completion of Enloe Dam. Figure 2-2 displays the projected retail, wholesale and other revenues, and Figure 2-3 shows the historical and projected wholesale revenues.

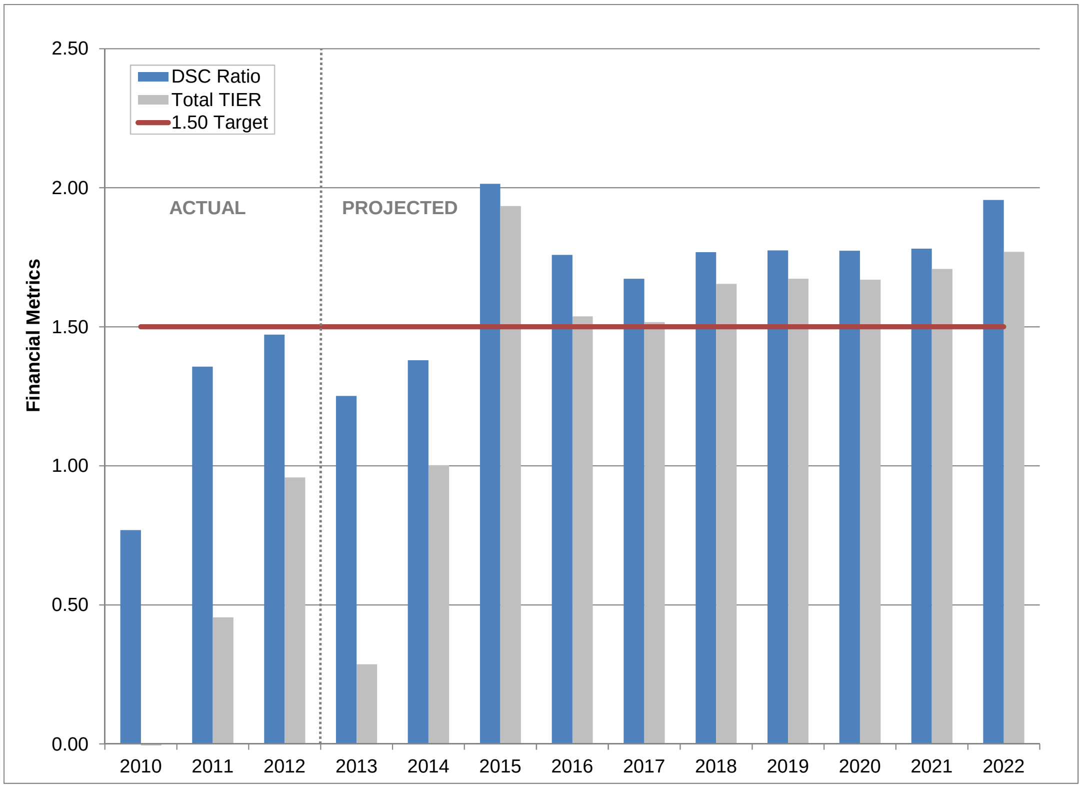

Figure 2-1: Projected DSC Ratio and Total TIER Levels

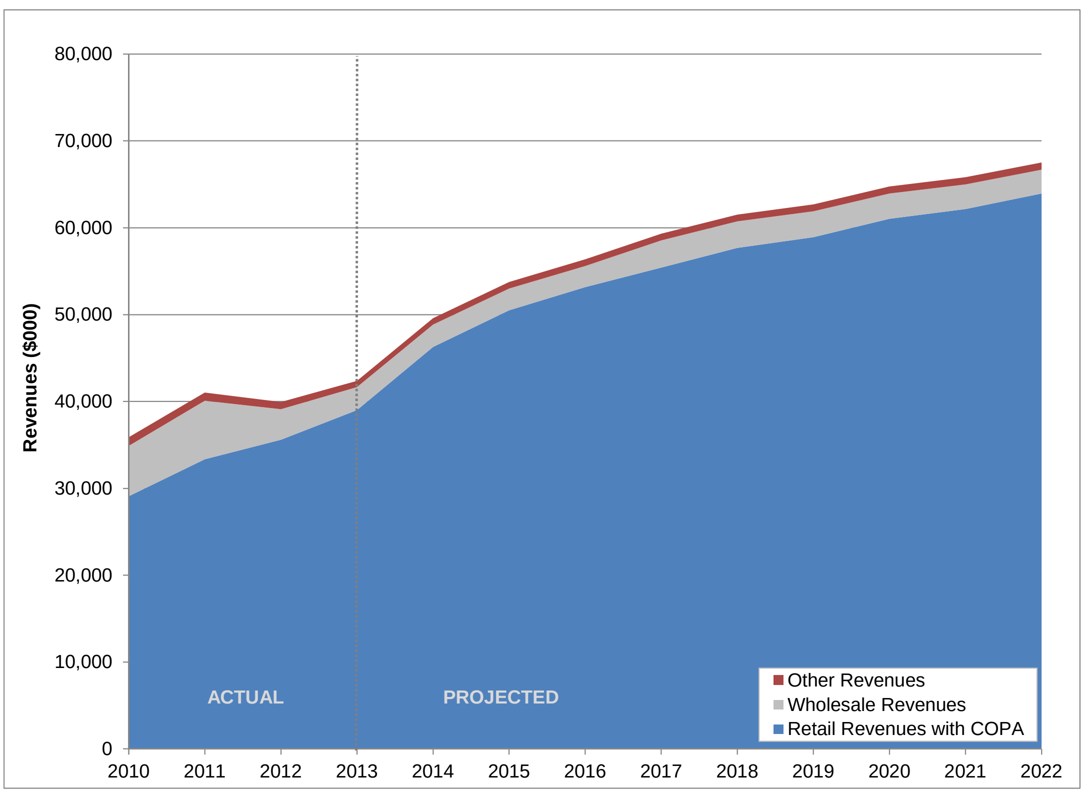

Figure 2-2: Projected Electric Revenues by Source

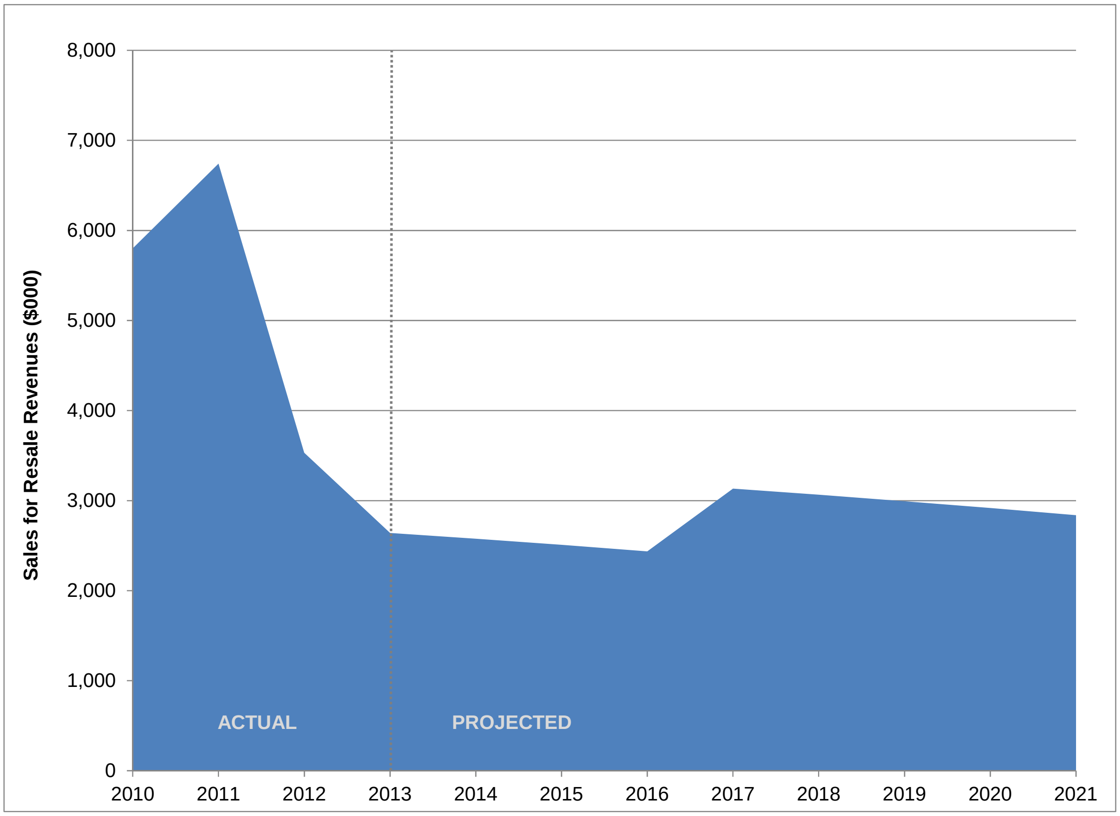

Figure 2-3: Projected Sales for Resale Revenues

Total annual capital expenditures and sources of funding are shown in Figure 2-4. It is projected that approximately $111.8 million (nominal dollars) of capital expenditures will occur during the study period. The largest amount of these expenditures occurs during the 2013 to 2016 period, when approximately $71 million of these expenditures are projected to be completed. Overall, capital expenditures will be largely funded with projected debt issuances in 2014 and 2016. Table 2-3 shows the projected debt issuances and uses of funds, and the impacts of these changes on the District's net assets (equity) and total assets are reflected in Figure 2-5.

Table 2-3
Okanogan County PUD
Projected Capital Funding

Year	Amount ($M)	Use of Funds
2013	$7.2	Use of Unspent Bond Proceeds
Projected Debt Issuance:		
2014	$35.2	Enloe Dam Construction
2016	$29.0	General Capital Improvements

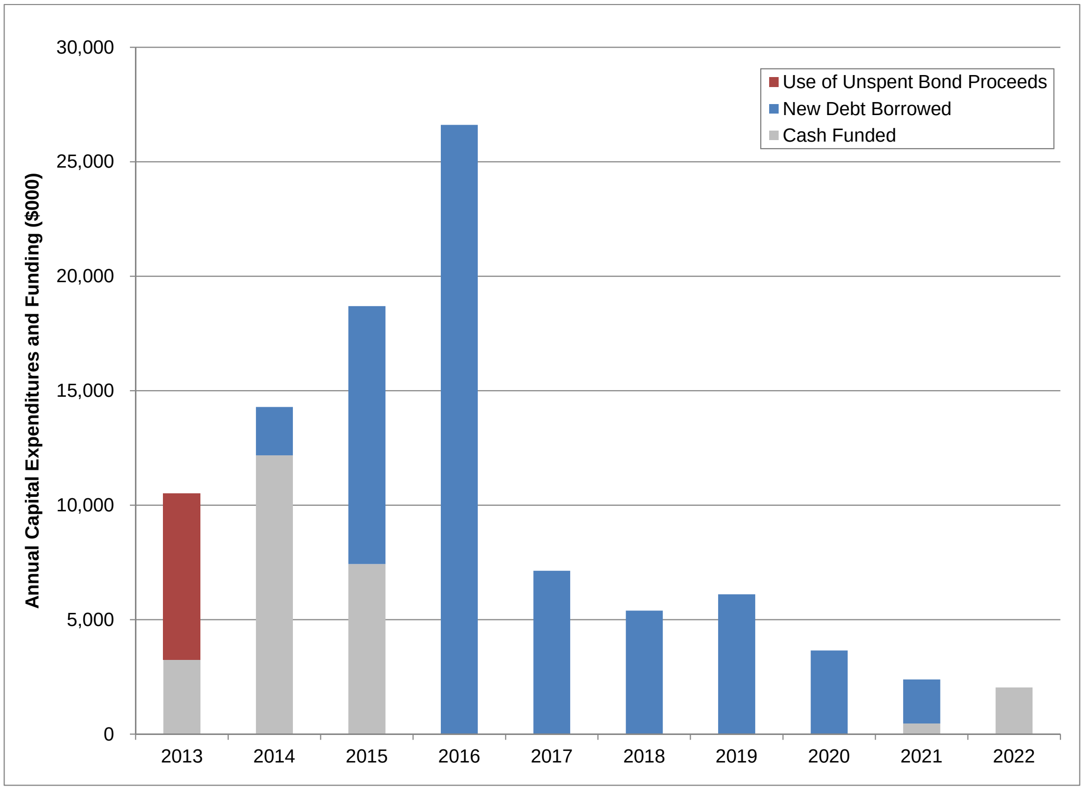

Figure 2-4: Annual Capital Expenditures and Funding ($000)

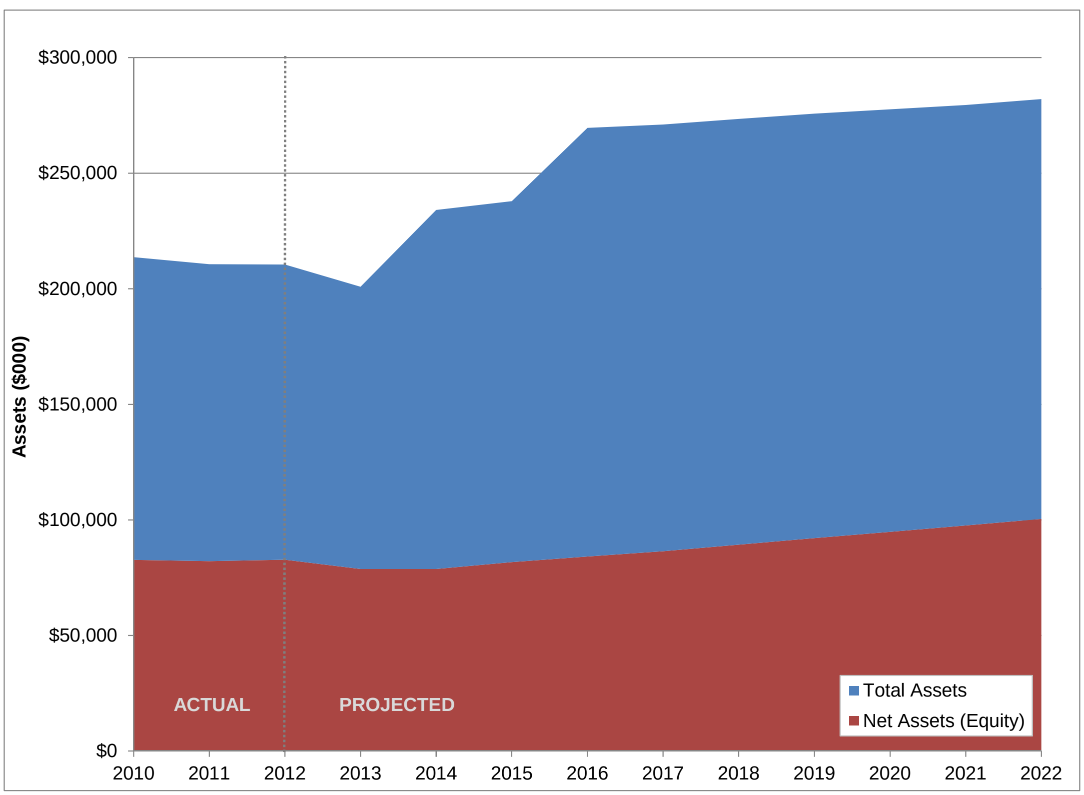

Figure 2-5: Net Assets and Total Assets

One goal of the 2013 EMP analysis was to allow the District to balance its borrowing needs sufficient to moderate rate increases while maintaining a strong equity ratio. The ratio of equity to total assets is projected to be approximately 64.5 percent by the end of 2013, decreasing to the lowest at 45.4 percent in 2016 and then increasing to 55.3 percent by 2022. The equity ratio decreases as a result of debt issuances in 2014 and 2016, as shown in Figure 2-6.

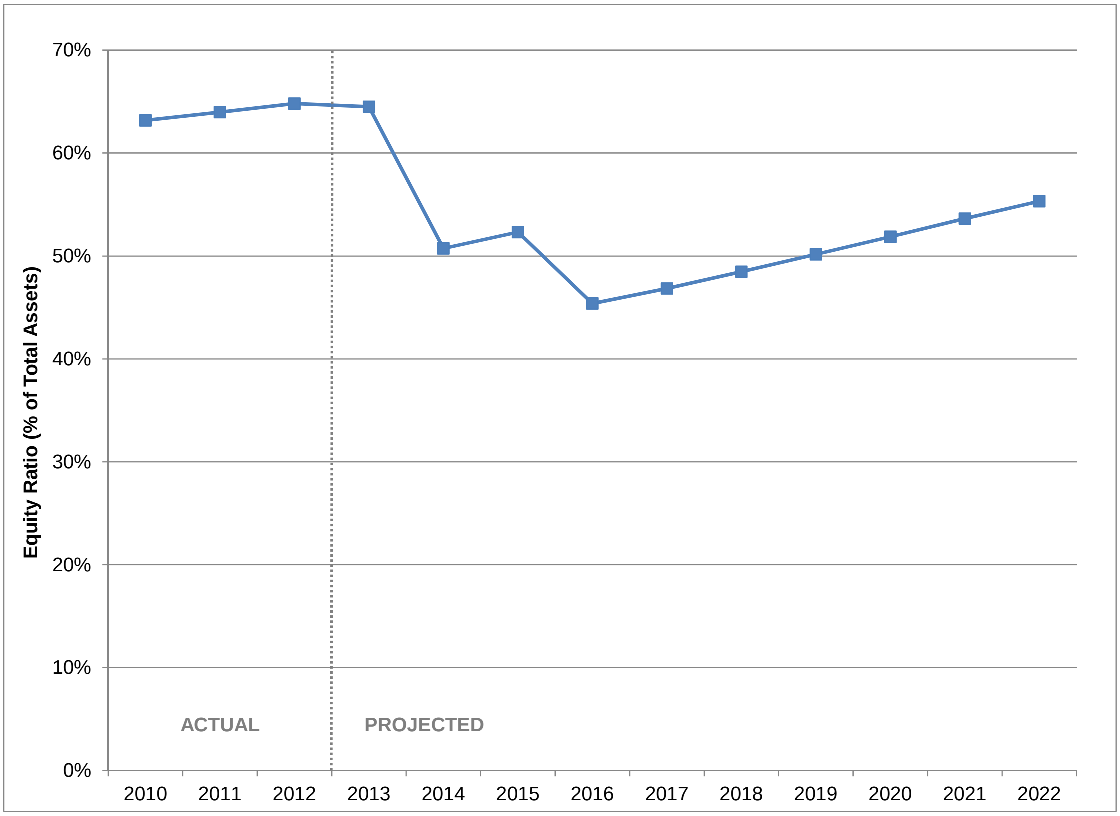

Figure 2-6: Equity Ratio (Percent of Total Assets)

The District's working capital reserves, expressed as days of operating and maintenance expenditures, are shown in Figure 2-7. Working capital reserves declined in 2012 below the 60-day target and are projected to continue to be below this level until 2014. These results indicate that given declining wholesale sales revenues, the District's existing retail rate revenues are not sufficient to sustain adequate working capital reserves. By increasing retail rates to a more sustainable level, working capital reserves are projected to increase after 2014 and are near or above the target levels through 2022.

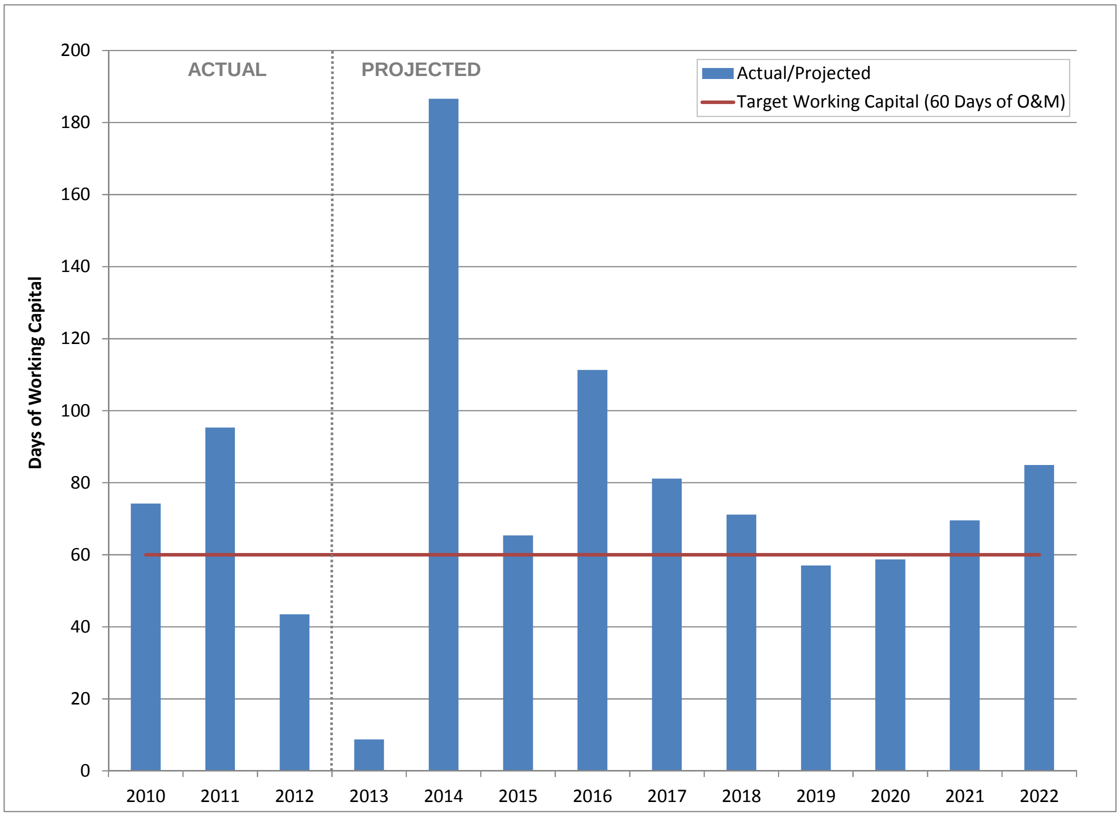

Figure 2-7: Working Capital Reserves (Days of O&M Expenditures)

The District's average retail rate revenues (presented on a nominal per kWh basis) are projected in 2022 to be approximately 9.97 cents per kWh as shown in Figure 2-8. This is an annual average rate of increase of 5.0 percent over the study period from an estimated average of 6.13 cents per kWh in 2012.

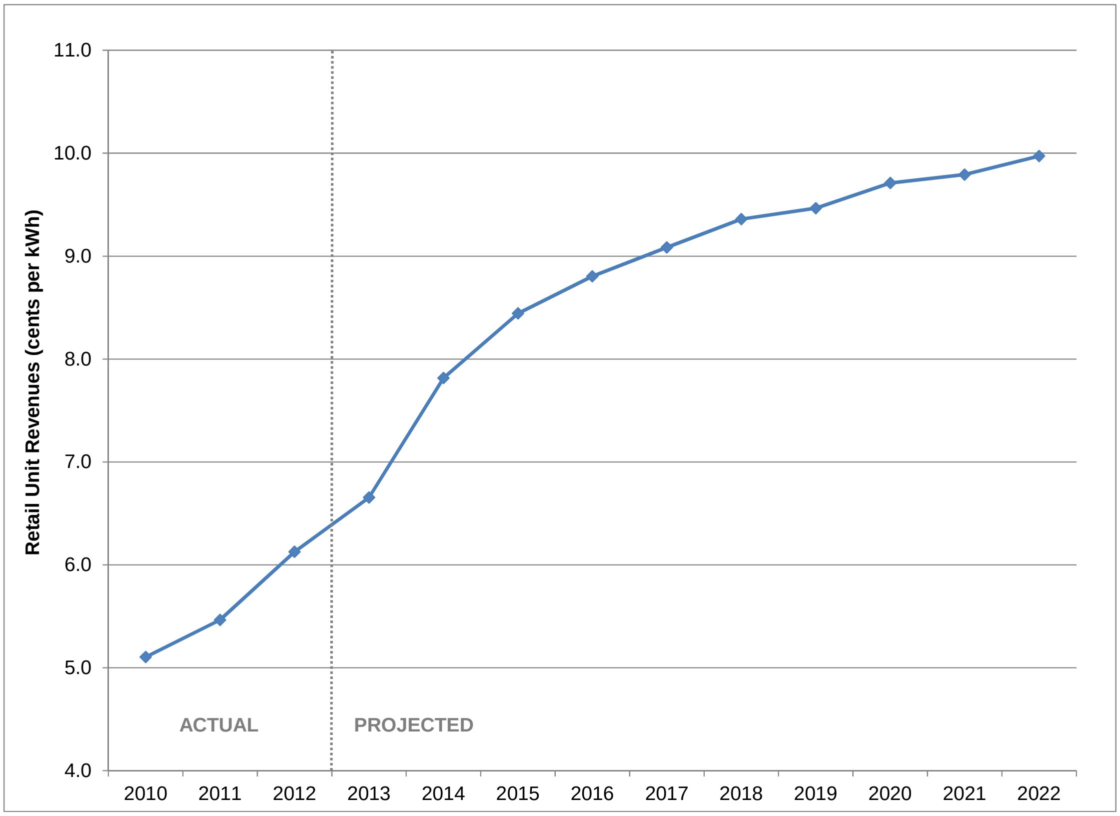

Figure 2-8: Average Unit Revenues (cents per kWh)

Alternative Cost Reduction EMP Scenarios

Given that the Base Case EMP results indicated a need for two significant rate increases during calendar years 2013 and 2014, SAIC and NewGen staff worked with District management to identify certain cost reduction options that could be reviewed with the EMP model to analyze the impact of these cost reductions on the District's projected financial results. As a result, numerous alternative scenarios were evaluated, but these were narrowed down to three alternative EMP scenarios as follows:

- **Scenario 1 – Reducing Capital Improvement Expenditures**: Under this scenario, the projected capital improvement expenditures were reduced by 30 percent from $102.4 million during the 10-year study period to $68.6 million during the study period. The projected debt issuance in 2016 would decrease from $29 million to $7 million. This reduction in capital improvement expenditures results in a lower projected interest and depreciation expenses during the study period.
- **Scenario 2 – Reduction in Operating and Maintenance Expenses and $2.9 million in Capitalized Labor:** Operating and maintenance expenses were projected in this scenario using 2012 actuals as the base year and escalating this level of expenses by 3 percent annually for inflation rather than using the 2013 budgeted expenses as the base year for projections and escalating these expenses by a 2.2 percent annual inflation rate. The difference in the inflation rate is

attributed to the utility's cost for one-time studies and other miscellaneous expenses that occur from time to time that are not captured in the 2012 actual base year. The scenario also included $2.9 million that was reclassified as capitalized labor in 2013 and every year thereafter. This reduces the operating and maintenance expenses by approximately $3.0 million per year starting in 2013, but increases the amount of debt the District would need. The debt issuance in 2016 would need to be increased from $29 million to $34 million and additional debt issuances in 2015, 2018 and 2020 totaling $25.5 million would be needed.

- **Scenario 3 – Combination of both cost reduction Scenarios 1 and 2:** The results of these three cost reduction EMP scenarios with respect to the District's projected average retail rate levels are shown in Figure 2-9. Given that the difference between these scenarios is less than 1 cent per kWh during the study period, it was determined that the District should proceed with the Base Case EMP for purposes of evaluating rate increase options.

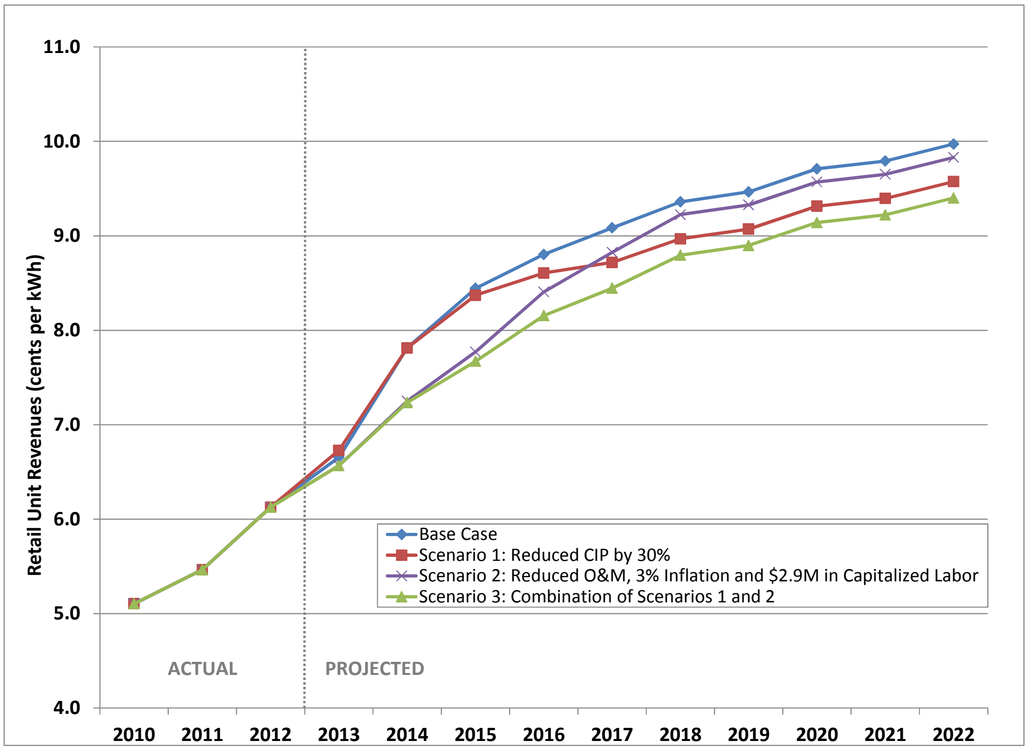

Figure 2-9: Average Unit Revenues for Base Case and Alternative Scenarios (cents per kWh)

EMP Rate Alternative Options 1 and 2

As discussed previously, two alternative rate change options were reviewed in the EMP model to help the District review alternative rate increases that achieve generally similar financial targets to those shown in the Base Case EMP results, but differ on how the rate changes would be implemented in the next three to five year period. All other financial and operational assumptions in the Base Case EMP analysis were assumed for these two rate alternative EMP scenarios.

The resultant rate changes assumed in EMP Rate Alternative Options 1 and 2 are as follows:

- **Rate Alternative Option 1 – Two 16 percent rate increases in both 2013 and 2014**: Option 1 was developed to determine the level of rate increases needed if the District only had two rate increases during the first three years of the study period rather than increases over longer period of time. Some benefits to implementing higher rate increases in a shorter period of time include a reduced amount of use of rate stabilization funds needed for the District to meet its 1.25 debt service coverage requirement in 2013 and a reduction in the debt issuance in 2016. This option would require approximately $2.2 million of the rate stabilization in 2013 rather than the $2.6 million under the Base Case EMP and a debt issuance of $29 million in 2016 would be decreased to $24 million. It was determined, however, that implementing rate increases at this level would result in a significant financial impact on customers.
- **Rate Alternative Option 2 – Three 9.5 percent rate increases in 2013 through 2015 and 2 percent rate increases in 2016 and 2017:** Option 2 was developed to meet a goal of keeping the first three annual rate increases each below 10 percent. This option relies on a much greater allocation of the rate stabilization fund in the first two years of the study period, with $2.9 million in 2013 and $1.1 million in 2014 needed for the District to meet the 1.25 debt service coverage requirements in these years. Between 2015 and 2016, the rate stabilization fund would be replenished to a $3 million level. A slight increase in the debt issuance in 2016 from $29 million to $30 million would be required, and the District would not achieve a positive net income until 2015. This scenario provides customers with more moderate and gradual level of rate changes when compared with either the Base Case or Option 1 results.

Summaries of key financial indicators for these two alternative options are presented in Table 2-4 and Table 2-5. Detailed results are presented in Appendices B and C.

Since Option 2 provides a more moderate and gradual level of rate changes, it was selected by the District's Board as the basis for determining the rate design options discussed later in this report. As shown in Table 2-5, the assumed rate adjustments needed in Option 2 maintain a DSC ratio level above target levels beginning in 2015 and throughout the remainder of the study period. The equity ratio also is maintained at a favorable 54.6 percent level by 2022. Days of working capital are mostly above the 60 day target with the exception of 2015 at 49 days, 2019 at 51 days and 2020 at 53 days.

Table 2-4
Okanogan County PUD
Summary of Results
EMP Rate Alternative Option 1

	Historical			Projected									
SUMMARY OF RESULTS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Unit Revenue from Retail Sales (¢/kWh)	5.10	5.46	6.13	6.72	8.16	8.84	9.01	9.09	9.25	9.36	9.60	9.69	9.87
Increase over Previous Year	6.4%	7.0%	12.1%	9.8%	21.3%	8.4%	1.8%	0.9%	1.8%	1.1%	2.6%	0.9%	1.9%
Necessary Retail Rate Change (1)	0.0%	0.0%	0.0%	16.0%	16.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Equity to Total Assets	63.2%	64.0%	64.8%	64.6%	51.5%	53.8%	48.4%	49.9%	51.4%	52.9%	54.5%	56.1%	57.6%
Cash (Year End) ($000)	$7,619	$9,782	$4,416	$1,031	$24,799	$12,574	$15,217	$12,223	$10,940	$8,901	$9,220	$10,758	$13,214
Days of Working Capital on Hand	74	95	43	9	203	101	118	91	79	63	62	71	85
Debt Service Coverage Ratio (DSCR)	0.77	1.36	1.47	1.25	1.77	2.47	2.02	1.77	1.78	1.78	1.78	1.79	1.97
Operating TIER	(4.99)	(0.10)	(0.75)	(1.94)	0.97	1.99	1.38	1.05	1.00	0.97	0.92	0.90	0.88
Total TIER	(2.11)	0.46	0.96	0.29	1.63	2.69	1.91	1.61	1.59	1.60	1.59	1.62	1.68

Note: (1) Rate increases effective September 1, 2013 and July 1st for all other years.

Table 2-5
Okanogan County PUD
Summary of Results
EMP Rate Alternative Option 2

	Historical			Projected									
SUMMARY OF RESULTS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Unit Revenue from Retail Sales (¢/kWh)	5.10	5.46	6.13	6.59	7.53	8.27	8.88	9.12	9.38	9.48	9.73	9.81	9.99
Increase over Previous Year	6.4%	7.0%	12.1%	7.6%	14.1%	9.9%	7.4%	2.7%	2.8%	1.1%	2.6%	0.9%	1.8%
Necessary Retail Rate Change (1)	0.0%	0.0%	0.0%	9.5%	9.5%	9.5%	2.0%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Equity to Total Assets	63.2%	64.0%	64.8%	64.4%	50.1%	51.4%	44.4%	45.9%	47.6%	49.3%	51.0%	52.9%	54.6%
Cash (Year End) ($000)	$7,619	$9,782	$4,416	$1,021	$22,081	$6,089	$13,187	$9,944	$8,951	$7,209	$7,834	$9,686	$12,463
Days of Working Capital on Hand	74	95	43	9	181	49	103	74	65	51	53	64	80
Debt Service Coverage Ratio (DSCR)	0.77	1.36	1.47	1.25	1.25	1.75	1.74	1.69	1.77	1.77	1.77	1.78	1.95
Operating TIER	(4.99)	(0.10)	(0.75)	(2.35)	(0.19)	0.91	1.13	1.03	1.11	1.09	1.05	1.04	1.04
Total TIER	(2.11)	0.46	0.96	0.29	0.80	1.50	1.52	1.55	1.66	1.68	1.68	1.72	1.78

Note: (1) Rate increases effective September 1, 2013 and July 1st for all other years.

At a meeting held on July 30, 2013, the District's Board adopted Resolution No. 1567 authorizing a rate adjustment of a 9.5 percent revenue increase effective September 1, 2013 based on EMP Rate Alternative Option 2 in Table 2-5. A decision on future rate increases for 2014 and beyond was deferred until after the Board's next budget review process is completed.

Section 3
ELECTRIC SYSTEM RATE STUDY ANALYSIS

The District currently has seven major customer classes,[1] each with separate rates. The customer and rate classes are defined as follows:

- **Residential**: Service applicable to each individual customer/family residing in a single-family dwelling or multiple family building, and to a farm which processes only its own products.
- **Small General Service**: Electrical service to commercial, governmental, industrial, or other services not eligible under other rate schedules where measured demand is less than 50 kW at least ten months in the previous twelve-month period.
- **Large General Service**: Service to any individual customer for which another specific rate schedule is not available with a connected load of 50 kW or greater. The schedule is based on continuous use and minimums will be billed for twelve consecutive months.
- **Primary Industrial**: Service applicable to any load with measured monthly demand of at least 1,000 kW and not more than a 10,000 kW average annual increase.
- **Irrigation**: Applicable to service for irrigation or drainage and incidental farm use. The schedule is based on continuous service for the irrigation season of April 1 through October 31.
- **Frost Control**: Applicable to service to wind machines or pumps used only for frost protection.
- **Street Lighting**: Applicable to any publicly owned organization constituted by State law for lighting of streets, alleys and thoroughfares.

All of these customer classes have a monthly basic charge and one or more energy charges with either uniform or inclining block rate structures. The Small and Large General Service and Industrial classes also have demand charges applicable to certain customers in these customer classes. The District's current rates are summarized in Table 3-1.

[1] In addition to the seven customer classes listed, the District has additional rate schedules for New Single Large Loads (Service Schedule Number 5) and Area Lighting (Service Schedule Number 10).

Table 3-1
Okanogan County PUD
Existing Rates

	Rates	Units
Residential Service Rates		
Basic Charge	10.00	dollars per month
Energy Charge (1)		
First 2,000 kWh	5.750	cents per kWh
Over 2,000 kWh	6.316	cents per kWh
Minimum Energy Charge (2)	25.00	dollars per month, includes the first 500 kWh
Cost of Power Adjustment Charge (3)	0.240	cents per kWh
Small General Service Rates		
Basic Charge	12.00	dollars per month
Energy Charge (1)	5.855	cents per kWh
Minimum Energy Charge	25.00	dollars per month, includes the first 500 kWh
Demand Charge	5.00	dollars per all kW, when kW is equal to or exceeds 50
Cost of Power Adjustment Charge (3)	0.240	cents per kWh
Large General Service Rates		
Basic Charge	12.00	dollars per month
Energy Charge	4.150	cents per kWh
Demand Charge	5.00	dollars per all kW above 50 kW
Minimum Demand Charge	250.00	dollars per month, includes first 50 kW
Cost of Power Adjustment Charge (3)	0.240	cents per kWh
Industrial Service Rates		
Basic Charge	75.00	dollars
Energy Charge	3.631	cents per kWh
Demand Charge	5.50	dollars per all kW above 1,000 kW per month
Minimum Demand Charge	5,500.00	dollars per month, includes the first 1,000 kW
Cost of Power Adjustment Charge (3)	0.240	cents per kWh
Irrigation Service Rates		
Basic Charge	12.00	dollars
Seasonal Energy Charge	3.720	cents per kWh
Inter-Seasonal Energy Charge	5.855	cents per kWh
Demand Charge	3.00	dollars per kW
Cost of Power Adjustment Charge (3)	0.240	cents per kWh
Frost Control Service Rates		
Facilities Charge	4.50	dollars per HP per year
Energy Charge	2.874	cents per kWh
Cost of Power Adjustment Charge (3)	0.240	cents per kWh
Street Lighting Service Rates		
175W MVP or 100W HPS	6.40	dollars per month
400W MVP or 200W HPS	9.80	dollars per month

(1) Charged on all energy in excess of the kWh in the minimum energy charge.
(2) No minimum energy charge will be assessed on a meter if the sole purpose of that meter is to measure the energy consumption of a well pump providing domestic water to a single family residence (WAC 173-505-090).
(3) Effective December 1, 2011.

Objectives

The District identified the following objectives for the 2013 Rate Study:

- Provide the District's staff and Board of Commissioners with updated electric system cost-of-service information for a TY 2013 study period.
- Use the TY 2013 cost-of-service information and final 2013 EMP results to identify one or more sets of rate changes the District could implement for its existing customer classes for the District's review and consideration.
- Develop final rate design for the TY 2013 through 2015 for the District's review and consideration.

The Rate Review Process

The results of the 2013 EMP analysis (discussed in Section 2) show that the District will need additional revenue and rate increases during the 2013 to 2015 time period, and possibly beyond. The projected TY 2013 revenue requirements and cost-of-service analysis presented later in this report reflects the 12.5 percent retail rate increase projected for 2013 in the Base Case EMP.

Using the TY 2013 cost-of-service analysis, a number of alternative rate design options were developed and presented to the District for review and consideration. It was decided that the first year of proposed rates would become effective on September 1, 2013 to give the District and the District's Board sufficient time to evaluate and decide on a course of action given the level of rate increases projected. For all other projected years, proposed rates would become effective July 1st of each year.[2] The alterative rate design options were presented in a series of public meetings conducted at several location in the District during July 2013.

Based on input received at the meetings, the District's Board adopted Resolution No. 1567 authorizing the September 1, 2013 rates developed in this study at a meeting held on July 30, 2013. In addition, the Board approved as part of Resolution No. 1567 the implementation of automatic cost of power adjustments to reflect any significant increase or decrease in the cost of power from contracted power sources within 30 days of the District incurring such increase or decrease, unless suspended by a Resolution of the Board of Commissioners. A copy of this resolution is provided in Appendix J of this report.

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[2] Irrigation customer class rates will be effective on April 1st for each year to correspond with the growing season. The Frost Control customer class rates will be effective on June 1st for each year to correspond with the annual billing cycle.

Revenue Requirements Analysis

Overview

The District's revenue requirements for this rate study were based on information from the District's 2013 Base Case EMP as discussed in Section 2. Revenue requirements consist of the sum of the electric system's operating costs plus an amount associated with meeting the electric system's debt and capital funding needs for a test year period.

The projected test year (TY) 2013 revenue requirements results used in this study were developed starting with the 2013 budget adopted by the District's Board on December 21, 2012. Detailed tables showing the TY 2013 revenue requirements analysis used in this study are provided in Appendix D.

Revenue Requirements

Table 3-2 provides a summary of the District's projected operating results for 2013, the pro forma adjustments, and the adjusted TY 2013 revenue requirements. The DSC and TIER levels shown are consistent with the financial targets established by District staff as part of the 2013 EMP study. The adjusted TY 2013 revenue requirements show the need for an increase in the District's total revenues of 12.5 percent on an annual basis, which equates to a 10.4 percent increase in retail rate revenues over a 10-month period from September 1, 2013 to June 30, 2014. The adjusted TY 2013 revenue requirements were used as the basis for the cost-of-service analysis presented later in this section.

Table 3-2
Okanogan County PUD
Summary of Test Year 2013 Revenue Requirements

Description	Projected Test Year 2013	Pro forma Adjustments (1)	Adjusted Test Year 2013 (2)
Total Revenues From Sales of Electricity	$40,190,912	$3,749,759	$43,940,671
Other Electric Revenues	727,000	-	727,000
Total Revenues	$40,917,912	$3,749,759	$44,667,671
Operating Expenses	$46,427,249	$0	$46,427,249
Other Expenses	1,959,636	-	1,959,636
Total Operating Cost of Service	$48,386,885	$0	$48,386,885
Margins or Increase in Net Assets	(2,798,973)	3,749,759	950,786
Operating Revenue Requirements	$45,587,912	$3,749,759	$49,337,671
Total Non-Operating Revenues	$4,670,000	$0	$4,670,000
Total Revenue Requirements	$45,587,912	$3,749,759	$49,337,671
Less Interest Income	(991,000)	-	(991,000)
Less Contributions in Aid of Construction	(1,104,000)	-	(1,104,000)
Less Use of Rate Stabilization Funds	(2,575,000)	-	(2,575,000)
Less Other Revenues	(727,000)	-	(727,000)
Less Wholesale Revenues	(2,640,925)	-	(2,640,925)
Revenue Requirements from Rates	$37,549,988	$3,749,759	$41,299,746
Revenue Increase (Decrease)	-		$3,749,759
Percent Change	-		10.4%
Debt Service Coverage Ratio (DSC)	0.83		1.91
TIER (Operating)	(2.94)		(0.94)
TIER (Total)	(0.49)		1.51

(1) Assumes retail revenue increase equal to 12.5% effective for a 10-month period.
(2) The rate stabilization funds are used to meet the minimum 1.25 debt service coverage requirement. Financial metrics in the adjusted TY 2013 column reflect a rate increase for a 10-month period.

Cost-of-Service Analysis

Overview

A cost-of-service analysis for the District's TY 2013 revenue requirements was prepared based on the general framework developed in the January 1992 "NARUC Electric Utility Cost Allocation Manual" (NARUC Manual). The results of the cost-of-service analysis are summarized in this section.

Methodology

The process of developing a cost-of-service analysis for the District included the functionalization, classification and allocation of the District's TY 2013 revenue requirements in collaboration with District staff. For functionalization, the revenue requirements were organized by function including production, transmission and distribution cost categories. Administrative and general costs were primarily functionalized based on labor ratios and plant ratios. Each of the functionalized revenue requirement items was classified into demand, energy or customer components. The classified revenue requirements were then allocated to each customer class based on appropriate allocation factors developed for each class. Estimated revenues at existing rates for each rate class were compared to the cost-of-service results to determine both the need for rate changes and the reasonableness of proposed rate options. Unit demand, energy and customer costs were also developed and utilized in the evaluation of alternative rate design options.

Functionalization and Classification

Table 3-3 provides a summary of the functionalization and classification of the test year revenue requirements. Classifications of costs were generally performed using the methodologies set forth in the NARUC Manual. The detailed results of these analyses are provided in Appendices E and F.

Table 3-3
Okanogan County PUD
Summary of Functionalization and Classification of Revenue Requirements
(Adjusted Test Year 2013)

Description	Demand	Energy	Customer	Total
Production	$8,283,939	$17,017,158	$0	$25,301,097
Transmission	430,323	0	0	430,323
Distribution	9,647,332	0	8,561,918	18,209,251
Total Cost of Service	$18,361,594	$17,017,158	$8,561,918	$43,940,671

Allocation

After functionalized costs were classified into detailed cost components, an allocation was made of these costs to the District's customer classes. Three basic methods of allocating demand costs to classes of service discussed in the NARUC Manual are: (a) the peak responsibility (coincident peak) method, (b) the non-coincident peak method, and (c) the average and excess demand method. Under the peak responsibility method, system demand costs are allocated among classes in proportion to each class's load at the time of the system peak. Under the non-coincident peak method, system demand costs are allocated to classes in proportion to class maximum loads, regardless of time of occurrence. The average and excess demand method allocates costs to rate classes using a factor that combines the classes' average demands and non-coincident peak demands. Variations of these methods are also commonly used. In this study, both the peak responsibility and the average and excess methods were evaluated.

The main allocation factors developed for this analysis are described below:

Allocation Factor	Description
4 CP	The 4 coincident peak allocator represents each class's contribution to the system peak during the 4 peak months of the year, based on 2013 load research analysis results.
12 NCP	The 12 non-coincident peak allocator relates the peak demand for each customer class, not necessarily coincident with the system peak, to the sum of peak demands for all classes during the each month of the year, based on 2013 load research analysis results.
Average and Excess	The average and excess allocator combines the class's average demands and non-coincident peak demands, based on 2013 load research analysis results.
Energy	The energy allocator represents each class's share of annual energy sold, excluding sales for resale.
Customer Allocator	The customer allocator relates the number of customers within each class to the total number of District customers served.
Weighted Customer Allocators	The weighted customer allocators adjust the customer allocator by the relative service level required for each customer class. The three weighted customer allocators are for the cost of meters, meter reading and customer service.
Other Allocators	Other allocators were developed based on intermediate results of the cost-of-service analysis.

In the peak responsibility method, demand-related generation and transmission costs were allocated using the 4 CP allocator. In the average and excess method, these costs were allocated using the average and excess allocator, which combines the class's average demands and non-coincident peak demands. In both analyses, energy-related production costs were allocated on a per-kilowatt hour basis, demand-related distribution costs were allocated based on 12 NCP allocators, and customer-related costs were assigned to classes of service based on either the customer allocator or one of several weighted customer allocation factors. Line transformer and service drop costs were not allocated to the industrial class because they are served at a primary voltage service level.

The demand, energy and customer allocation factors used in this study are presented in Appendix G. The estimated cost of service for each of the District's main customer classes using both the peak responsibility method and the average and excess method is summarized in Table 3-4.

Table 3-4
Okanogan County PUD
Allocated Cost of Service by Customer Class
(Adjusted Test Year 2013)

	Demand	Energy	Customer	Total
Average and Excess Method				
Residential	$9,877,118	$8,565,721	$6,869,366	$25,312,205
Small General Service	1,643,670	1,581,490	989,738	4,214,898
Large General Service	4,218,554	4,405,518	164,618	8,788,689
Industrial	326,459	534,377	1,788	862,624
Irrigation	2,152,451	1,880,188	410,126	4,442,765
Frost Control	111,409	10,397	6,935	128,742
Street Lights	31,933	39,468	119,347	190,748
Total	$18,361,594	$17,017,158	$8,561,918	$43,940,671
Peak Responsibility Method				
Residential	$10,888,515	$8,565,721	$6,869,366	$26,323,602
Small General Service	1,661,170	1,581,490	989,738	4,232,398
Large General Service	4,513,710	4,405,518	164,618	9,083,846
Industrial	331,696	534,377	1,788	867,861
Irrigation	904,717	1,880,188	410,126	3,195,031
Frost Control	28,682	10,397	6,935	46,015
Street Lights	33,104	39,468	119,347	191,919
Total	$18,361,594	$17,017,158	$8,561,918	$43,940,671

Cost-of-Service Analysis Results

In Table 3-5, the cost-of-service results are compared to revenues from existing rates by customer class. The revenues under existing rates are shown in the first column, and the second column provides the allocated costs of service for each customer class. The third column summarizes the amount that revenues from existing rates over or under recover the allocated cost of service. The last column shows the percentage that revenues from current rates would need to be reduced or increased if rates were to be adjusted to reflect cost-of-service levels for each class.

Table 3-5
Okanogan County PUD
Summary of Cost-of-Service Results
(Adjusted Test Year 2013)

Average and Excess Method

Customer Class	Adjusted Revenue Under Existing Base Rates	Allocated Cost of Service (1)	Over (Under) Cost of Service	Percent Change in Revenue
Residential	$19,311,279	$23,007,708	($3,696,429)	19.1%
Small General Service	3,605,173	3,816,975	(211,803)	5.9%
Large General Service	8,755,922	7,857,665	898,257	-10.3%
Industrial	1,036,906	761,919	274,986	-26.5%
Irrigation	3,087,505	4,003,837	(916,332)	29.7%
Frost Control	65,507	120,054	(54,547)	83.3%
Street Lights	135,393	179,283	(43,891)	32.4%
Total	$35,997,683	$39,747,442	($3,749,759)	10.4%

Peak Responsibility Method

Customer Class	Adjusted Revenue Under Existing Base Rates	Allocated Cost of Service (1)	Over (Under) Cost of Service	Percent Change in Revenue
Residential	$19,311,279	$23,958,318	($4,647,039)	24.1%
Small General Service	3,605,173	3,833,423	(228,250)	6.3%
Large General Service	8,755,922	8,135,083	620,839	-7.1%
Industrial	1,036,906	766,842	270,064	-26.0%
Irrigation	3,087,505	2,831,094	256,411	-8.3%
Frost Control	65,507	42,298	23,209	-35.4%
Street Lights	135,393	180,384	(44,991)	33.2%
Total	$35,997,683	$39,747,442	($3,749,759)	10.4%

(1) Allocated cost of service includes allocation of wholesale revenues of $2.6 million and cost of power adjustment revenues of $1.6 million, which are allocated to each customer class. Reflects retail revenue increase equal to 12.5% effective for a 10-month period as shown in the Base Case EMP.

Rate Design

Overview

The purpose of the rate design analysis was to identify an equitable rate structure for the District that will adequately recover the test year revenue requirements of the electric system while meeting the policy objectives of the utility. Additionally, the District elected to establish implementation dates for the proposed rates developed in this study to be effective on September 1, 2013 and July 1 of 2014 and 2015.[3] Although the rate design modifications were in part based on the results of the cost-of-service analysis, other District policy factors were also considered in designing rates.

[3] Irrigation customer class rates will be effective on April 1st for each year to correspond with the growing season. The Frost Control customer class will be effective on June 1st for each year to correspond with the annual billing cycle.

Policy and Rate Design Guidelines

As described previously, the District's Board and management met several times to discuss various policy issues related to the study. The following paragraphs provide a summary of the basic policy and rate design guidelines that were developed in consultation with the District's Board and management and were used to develop the proposed rate adjustments.

Financial Integrity: Rates must preserve the District's financial integrity to allow for future capital investments and to meet the financial targets of the utility.

Cost-of Service Based: Rate should generally reflect and be consistent with the cost of providing electric service to each customer class.

Rate Stability: Rate adjustments should, to the extent possible, promote stable rates for customers and avoid large changes in rates.

Simplification: The rate structure should be simple and easily understood by customers.

Equity: The rates should be equitable and, to the extent practicable, reflect the cost to provide service.

Reliability of Service: The District's rates should provide adequate funding to support the District to continue to provide reliable service to its customers.

Efficiency/Conservation: The rate structure should help encourage conservation and the efficient use of electricity.

Rate Development

In the development of the rate design options considered by the District, the existing rates and rate structures for the District's various customer classes were reviewed and modified to better meet the District's policies, with higher priority paid to rate design options that provide more stable revenue recovery, more closely reflects fixed cost recovery, and simpler and easier to understand rates for the District's customers. Specific changes in the District's rate design included in the rate options were the following:

- **Greater Fixed Cost Recovery:** For all customer classes, the fixed basic charges and/or the demand charges were proposed to be increased to help the District better its recover fixed costs.
- **Minimum Energy Charge:** For the Residential and Small General Service customer classes, the minimum energy charge was proposed to be combined with the basic charge each month to help the District move towards more fixed cost recovery. The 500 kilowatt-hour minimum energy charge allowance for both customer classes was proposed to be phased out or eliminated.

- **Frost Control Customer Class:** The existing rates for the Frost Control customer class with a facilities charge based on a per-horsepower estimate was proposed to be replaced with a demand charge.

Proposed Rate Options

Multiple rate options were developed for review and input from the Board and the customer review panel based on the EMP Option 2 with 9.5 percent rate increases annually each year from 2013 through 2015. The rate design was narrowed down to two rate proposal options as follows:

- Rate Design Option 1: The minimum energy charge allowance for Residential and Small General Service customer classes would be eliminated in 2013. Rates for all customer classes would be adjusted to include a 9.5 percent rate increase in 2013, 2014 and 2015.
- Rate Design Option 2: Two-year phase out of the minimum energy charge allowance for Residential and Small General Service. Other adjustments in this option included no change in energy charges for Residential customers for 2013 through 2015, no change in the energy charge for Small General Service for 2013 through 2014, and rates for all other customer classes adjusted to collect a 9.5 percent rate revenue increase in 2013 through 2015

Table 3-6 summarizes the existing and proposed rates for each customer class under Rate Design Option 1, and the detailed rate design analysis for this option is provided in Appendix H.

Table 3-6
Okanogan County PUD
Rate Design Option 1 - Existing and Proposed Rates

Schedule No. 2 - Residential	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (2) September 2013	July 2014	July 2015
Base Rates					
Basic Charge ($/month)	$10.00	$28.07	$35.00	$40.00	$45.00
Energy Charge ($/kWh)					
< 2,000 kWh	$0.05750	$0.05993	$0.04350	$0.04657	$0.05023
> 2,000 kWh	$0.06316	$0.05993	$0.06316	$0.06762	$0.07293
Minimum Charge ($/month)	n/a	$79.80	n/a	n/a	n/a
Minimum Energy Charge ($/month)	$25.00	n/a	n/a	n/a	n/a
kWh in Basic Charge	500		n/a	n/a	n/a
Percent Change in Base Rate Revenue		17.4%	9.5%	9.5%	9.5%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) Set the basic charge to $35 per month in 2013 and increased this to $45 per month by 2015.
The energy charge is applied to all kilowatt-hours in 2013 and beyond. No change in the energy charge for usage above 2,000 kilowatt-hours in 2013. Decreased the energy charge applied to the first 2,000 kilowatt-hours in 2013 to offset the bill impacts from eliminating the minimum energy allowance (first 500 kilowatt-hours). Adjusted the energy charge as necessary to collect sufficient revenues for all other years. The energy charge for usage above 2,000 kilowatt-hours in 2014 and on is adjusted to maintain the same rate ratio between the lower and higher usage blocks.

Schedule No. 3 - Small General Service	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (2) September 2013	July 2014	July 2015
Base Rates					
Basic Charge ($/month)	$12.00	$32.73	$40.00	$45.00	$50.00
Energy Charge ($/kWh)	$0.05855	$0.05684	$0.05308	$0.05757	$0.06272
Demand Charge ($/kW/month equals or exceed 50 kW)	$5.00	n/a	$5.50	$6.00	$6.50
Minimum Charge ($/month)	n/a	$102.10	n/a	n/a	n/a
Minimum Energy Charge ($/month)	$25.00	n/a	n/a	n/a	n/a
kWh in Minimum Energy Charge	500	n/a	n/a	n/a	n/a
Percent Change in Base Rate Revenue		5.0%	9.5%	9.5%	9.5%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) Set the basic charge to $40 per in 2013 and increased this to $50 per month by 2015.
Energy charge applied to all kilowatt-hours in 2013 and beyond. Adjusted the energy charge as necessary to collect sufficient revenues. Demand charge increases $0.50 per kilowatt each year until 2015.

Table 3-6 (Continued)

Schedule No. 3 - Large General Service	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (3) September 2013	July 2014	July 2015
Base Rates					
Basic Charge ($/month)	$12.00	$41.62	$20.00	$30.00	$40.00
Energy Charge ($/kWh)	$0.04150	$0.02542	$0.04521	$0.04940	$0.05416
Demand Charge ($/kW/month above 50 kW)	$5.00	n/a	$5.50	$6.00	$6.50
Demand Charge ($/all kW/month)	n/a	$9.83	n/a	n/a	n/a
Minimum Charge ($/month)	n/a	$1,407	n/a	n/a	n/a
Minimum Demand Charge ($/month)	$250.00	n/a	$275.00	$300.00	$325.00
kW in Minimum Demand Charge	50	n/a	50	50	50
Power Factor Charge (2)	97.0%		97.0%	97.0%	97.0%
Percent Change in Base Rate Revenue		-6.8%	9.5%	9.5%	9.5%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) For every percentage a customer's power factor is below 97 percent, the demand charge will increase 1.0 percent.
(3) Set the basic charge to $20 per month in 2013 and increased to $40 per month by 2015.
Adjusted the energy charge as necessary to collect sufficient revenues.
Demand charge increases $0.50 per kilowatt each year until 2015.

Schedule No. 4 - Primary Industrial Service	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (3) September 2013	July 2014	July 2015
Base Rates					
Basic Charge ($/month)	$75.00	$41.86	$80.00	$90.00	$100.00
Energy Charge ($/kWh)	$0.03631	$0.02612	$0.03631	$0.03846	$0.04124
Demand Charge ($/billed kW/month)	$5.50	$5.84	$7.00	$8.00	$9.00
Minimum Charge ($/month)	n/a	$9,911	n/a	n/a	n/a
Minimum Demand Charge ($/month)	$5,500	n/a	$7,000	$8,000	$9,000
kW in Minimum Demand Charge	1,000	n/a	1,000	1,000	1,000
Power Factor Charge (2)	97.0%		97.0%	97.0%	97.0%
Percent Change in Base Rate Revenue		-23.9%	9.6%	9.4%	9.5%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) For every percentage a customer's power factor is below 97 percent, the demand charge will increase 1.0 percent.
(3) Set the basic charge to $80 per month in 2013 and increased to $100 per month by 2015.
Adjusted the energy charge as necessary to collect sufficient revenues.
Demand charge increases $1.50 per kilowatt in 2013 and $1.00 per kilowatt each year until 2015.

Table 3-6 (Continued)

Schedule No. 6 - Irrigation	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (3) April 2013	April 2014	April 2015
Base Rates (2)					
Basic Charge ($/month)	$12.00	$41.34	$12.00	$15.00	$20.00
Demand Charge ($/billed kW/month)	$3.00	$11.76	$3.00	$4.00	$5.00
Seasonal Energy Charge	$0.03720	$0.02485	$0.03720	$0.04338	$0.04529
Inter-Seasonal Energy Charge	$0.05855	$0.02485	$0.05855	$0.06828	$0.07128
Minimum Charge ($/month)	n/a	$312	n/a	n/a	n/a
Percent Change in Base Rate Revenue		31.5%	0.0%	19.9%	9.5%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) Rate schedule is based on continuous service for the irrigation season of April 1 through October 31.
(3) Set the basic charge to $15 per month in 2014 and increased to $20 per month by 2015.
Adjusted the energy charge as necessary to collect sufficient revenues.
The inter-seasonal energy charge is adjusted to maintain the same rate ratio between the seasonal and inter-seasonal energy charges for 2014 and on. Demand charge increases $1.00 per kilowatt each year through 2015.

Schedule No. 7 - Frost Control	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (3) June 2013	June 2014	June 2015
Base Rates (2)					
Basic Charge ($/year)	n/a	$42.00	n/a	$120.00	$135.00
Demand Charge ($/billed kW)	n/a	$11.31	n/a	$4.50	$5.00
Annual Facilities Charge ($/horsepower)	$4.50	$9.82	$4.50	n/a	n/a
Energy Charge ($/kWh)	$0.02874	$0.00707	$0.02874	$0.02874	$0.03160
Minimum Charge ($/month)	n/a	$860	n/a	n/a	n/a
Percent Change in Base Rate Revenue		86.3%	0.0%	11.0%	11.3%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) Customers served under this customer class are billed annually in June.
(3) Set the basic charge to $120 per month in 2014 and increased to $150 per month by 2015.
Adjusted the energy charge as necessary to collect sufficient revenues.
Demand charge increases $0.50 per kilowatt each year in 2015.

Schedule No. 8 - Street Lighting	Existing Rates	TY 2013 Cost of Service	Proposed Rates September 2013	July 2014	July 2015
Base Rates					
Fixture Charge ($/Fixture)					
8,000 Lumen (175 MVP or 100W HPS)	$6.40	$9.05	$7.00	$7.70	$8.40
22,000 Lumen (400W MVP or 200W HPS)	$9.80	$9.05	$10.70	$11.80	$12.90
Percent Change in Base Rate Revenue		23.3%	9.3%	10.2%	9.2%

Table 3-7 summarizes the existing and proposed rates under Rate Design Option 2, and the detailed rate design analysis is provided in Appendix I. Only the rates for the Residential and Small General Service customer classes differ from those in Rate Design Option 1. The rates shown in Rate Design Option 1 for all other customer classes remain the same under Rate Design Option 2.

Table 3-7
Okanogan County PUD
Rate Design Option 2 - Existing and Proposed Rates

Schedule No. 2 - Residential	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (2) September 2013	July 2014	July 2015
Base Rates					
Basic Charge ($/month)	$10.00	$28.07	$35.00	$35.00	$40.00
Energy Charge ($/kWh)					
< 2,000 kWh	$0.05750	$0.05993	$0.05750	$0.05750	$0.05750
> 2,000 kWh	$0.06316	$0.05993	$0.06316	$0.06316	$0.06316
Minimum Charge ($/month)	n/a	$79.80	n/a	n/a	n/a
Minimum Energy Charge ($/month)	$25.00	n/a	n/a	n/a	n/a
kWh in Basic Charge	500		250	0	n/a
Percent Change in Base Rate Revenue		17.4%	12.7%	12.5%	4.2%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) Set the basic charge to $35 per month in 2013 and is increased to $40 per month by 2015.
Energy charge applied after the first 250 kilowatt-hours in 2013 and to all kilowatt-hours in 2014 and beyond.
No changes in the energy charge.

Schedule No. 3 - Small General Service	Existing Rates	TY 2013 Cost of Service (1)	Proposed Rates (2) September 2013	July 2014	July 2015
Base Rates					
Basic Charge ($/month)	$12.00	$32.73	$40.00	$45.00	$50.00
Energy Charge ($/kWh)	$0.05855	$0.05684	$0.05855	$0.05855	$0.06272
Demand Charge ($/kW/month equals or exceed 50 kW)	$5.00	n/a	$5.50	$6.00	$6.50
Minimum Charge ($/month)	n/a	$102.10	n/a	n/a	n/a
Minimum Energy Charge ($/month)	$25.00	n/a	n/a	n/a	n/a
kWh in Minimum Energy Charge	500	n/a	250	0	n/a
Percent Change in Base Rate Revenue		5.0%	9.3%	11.0%	8.2%
Cost of Power Adjustment	$0.00240	n/a	$0.00265	$0.00501	$0.00579

Notes
(1) Cost of service rates include allocation of wholesale revenues.
(2) Set the basic charge to $40 per month in 2013 and increases to $50 per month by 2015.
Energy charge applied after the first 250 kilowatt-hours in 2013 and to all kilowatt-hours in 2014 and beyond.
Adjusted the energy charge as necessary to collect sufficient revenues. Demand charge increases $0.50 per kilowatt each year until 2015.

The proposed rate options reflect the policies and rate design direction provided by the District's staff and Board.

At a Board meeting held on July 30, 2013, Resolution No. 1567 was adopted by the Board authorizing the rates effective September 1, 2013 under Rate Design Option 1 to become effective. A decision on any future rate changes was deferred at this meeting. Overall under Rate Design Option 1, the District's proposed base rates are expected to result in an overall annualized 9.5 percent revenue increase during 2013 from the revenues provided with current rates in 2012.

Table 3-8 summarizes the estimated revenues for TY 2013 under existing and the adopted rates for each customer class compared to the allocated cost of service for each class. In addition, the estimated change in TY 2013 revenues as compared to revenues under existing rates is summarized.

Table 3-8
Okanogan County PUD
Summary of Estimated Test Year 2013 Revenues
Based on Rate Design Option 1 - Adopted Rates

Customer Class	Adjusted Revenue Under Existing Rates	Allocated Cost of Service (1)	Percent Over (Under) Revenue at Existing Rates	Annual Revenue Under TY 2013 Adopted Rates (2)	Percent Over (Under) Revenue at Existing Rates
Residential	$19,311,279	$22,664,193	17.4%	$21,147,004	9.5%
Small General Service	3,605,173	3,785,226	5.0%	3,947,659	9.5%
Large General Service	8,755,922	8,161,728	-6.8%	9,587,489	9.5%
Industrial	1,036,906	788,741	-23.9%	1,136,838	9.6%
Irrigation	3,087,505	4,058,656	31.5%	3,087,505	0.0%
Frost Control	65,507	122,023	86.3%	65,507	0.0%
Street Lights	135,393	166,874	23.3%	147,934	9.3%
Total	$35,997,683	$39,747,442	10.4%	$39,119,934	8.7%

(1) Allocated cost of service includes allocation of wholesale revenues of $2.6 million and cost of power adjustment revenues of $1.6 million, which are allocated to each customer class. Reflects retail revenue increase equal to 12.5% effective for a 10-month period as shown in the Base Case EMP.

(2) Irrigation customer class rates will be effective on April 1, 2014 and the Frost Control customer class rates will be effective on March 1, 2014.

Section 4
SUMMARY AND CONCLUSIONS

Summary

As discussed previously, the 2013 EMP Option 2 was selected as representing the District's preferred financial course of action in achieving its financial goals. Key 2013 EMP conclusions are as follows:

- The District's equity level is strong and provides a good base upon which additional debt financing is possible.
- Existing retail rates are not sufficient to meet the District's current and projected operating costs, and this is reflected in net losses since 2010.
- The District's DSC and TIER levels will need to reach target levels during the first few years of the study period. In the EMP Option 2, the rate stabilization fund is used to show that the District can meet the 1.25 debt service coverage requirements in both 2013 and 2014.
- Unless the District's costs are reduced from those projected in the 2013 EMP analysis, the District faces a need for rate increases until 2015 as a result of:
  - Deferral of full rate increases recommended in the 2010 EMP.
  - Lower retail sales growth than projected in the 2010 EMP.
  - Decreasing wholesale revenues projected.
  - A need to achieve higher revenues to maintain adequate cash reserve levels.

The 2013 Rate Study included development of the detailed revenue requirements, cost-of-service and rate design analyses. Rate Design Option 1 for the September 1, 2013 rate change was selected by the Board as representing the District's preferred option for balancing customer impacts and collecting increased revenue necessary to maintain efficient and reliable service.

Conclusions

Key conclusions of the 2013 Rate Study are as follows:

- Proposed rates were developed that would be effective in September 2013 and in July 2014 and 2015.
- Proposed rate changes generally reflected across-the-board rate increases with the exception of the Residential and Small General Service customer classes where the minimum energy charge allowance is eliminated or phased out.
- Rates were designed to increase the District's fixed cost recovery.

- The District's Residential and Small General Service rates were simplified to make it easier for the District's customers to understand.
- For the Frost Control customer class, the facilities charge based on horsepower ratings was changed to a demand and basic charge.

On July 30, 2013, the Board approved as part of Resolution No. 1567 the following measures:

- Authorized a 9.5 percent base rate revenue increase effective September 1, 2013 as presented in the Option 2 EMP.
- Approved rate design adjustments representing an across-the-board 9.5 percent revenue increase effective September 1, 2013 as presented in Rate Design Option 1.
- A decision on future rate increases after September 1, 2013 was deferred for consideration until a later date.
- Implementation of automatic cost of power adjustments (COPA) to reflect significant increase or decrease in the cost of power from contracted power sources within 30 days of the District incurring such increase or decrease, unless suspended by a Resolution of the Board of Commissioners.

A copy of the Board Resolution is provided in Appendix J of this report.

Recent Update

On July 24, 2013, BPA announced its final rate changes to be effective beginning October 1, 2013. For the District, this means that the BPA power supply rates will increase by 9 percent and the BPA transmission rates will increase 11 percent for the District effective October 1, 2013. These increases will be recovered through the COPA charge and are generally consistent with the assumptions made in the 2013 EMP and 2013 Rate Study analyses, but no final adjustments were made to this study's results to reflect this more recent information.

Appendix A
EQUITY MANAGEMENT PLAN - BASE CASE

Okanogan County PUD

Preliminary Draft

2013 Equity Management Plan Update - Base Case

Okanogan County PUD
2013 Equity Management Plan
Summary of Results

Line		Historical			Projected										Avg. Annual Rate Change
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2012 - 2022
	Scenario: Base Case														
1	Unit Revenue from Retail Sales (¢/kWh)	5.10	5.46	6.13	6.65	7.81	8.44	8.80	9.08	9.36	9.47	9.71	9.79	9.97	
2	Increase over Previous Year	6.4%	7.0%	12.1%	8.6%	17.4%	8.0%	4.3%	3.2%	3.0%	1.1%	2.6%	0.9%	1.8%	5.0%
3	Base Retail Rate Change (Effective July 1) (1)	0.0%	0.0%	0.0%	12.5%	12.5%	2.5%	2.5%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	
4	Equity to Total Assets	63.2%	64.0%	64.8%	64.5%	50.7%	52.3%	45.4%	46.8%	48.5%	50.2%	51.9%	53.6%	55.3%	
5	Cash (Year End) ($000)	$7,619	$9,782	$4,416	$1,022	$22,749	$8,132	$14,297	$10,891	$9,865	$8,086	$8,675	$10,489	$13,227	
6	Days of Working Capital on Hand	74	95	43	9	187	65	111	81	71	57	59	70	85	
7	Debt Service Coverage	0.77	1.36	1.47	1.25	1.38	2.01	1.76	1.67	1.77	1.78	1.77	1.78	1.96	
8	Operating TIER	(4.99)	(0.10)	(0.75)	(2.16)	0.34	1.23	1.03	0.99	1.09	1.08	1.03	1.02	1.02	
9	Total TIER	(2.11)	0.46	0.96	0.29	1.00	1.93	1.54	1.52	1.65	1.67	1.67	1.71	1.77	

Okanogan County PUD
2013 Equity Management Plan
Table 1 - Summary of Results and Assumptions

Scenario: Base Case

		Historical			Projected										Avg. Annual Rate Change
Line	SUMMARY OF RESULTS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2012 - 2022
1	Unit Revenue from Retail Sales (¢/kWh)	5.10	5.46	6.13	6.65	7.81	8.44	8.80	9.08	9.36	9.47	9.71	9.79	9.97	
2	Increase over Previous Year	6.4%	7.0%	12.1%	8.6%	17.4%	8.0%	4.3%	3.2%	3.0%	1.1%	2.6%	0.9%	1.8%	5.0%
3	Necessary Retail Rate Change (Effective July 1)	0.0%	0.0%	0.0%	12.5%	12.5%	2.5%	2.5%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	
4	Equity to Total Assets	63.2%	64.0%	64.8%	64.5%	50.7%	52.3%	45.4%	46.8%	48.5%	50.2%	51.9%	53.6%	55.3%	
5	Cash (Year End) ($000)	$7,619	$9,782	$4,416	$1,022	$22,749	$8,132	$14,297	$10,891	$9,865	$8,086	$8,675	$10,489	$13,227	
6	Days of Working Capital on Hand	74	95	43	9	187	65	111	81	71	57	59	70	85	
7	Debt Service Coverage Ratio (DSCR)	0.77	1.36	1.47	1.25	1.38	2.01	1.76	1.67	1.77	1.78	1.77	1.78	1.96	
8	Operating TIER	(4.99)	(0.10)	(0.75)	(2.16)	0.34	1.23	1.03	0.99	1.09	1.08	1.03	1.02	1.02	
9	Total TIER	(2.11)	0.46	0.96	0.29	1.00	1.93	1.54	1.52	1.65	1.67	1.67	1.71	1.77	

Line	ASSUMPTIONS	
10	General Inflation (1)	2.20%
11	Inflation for Other Operating Revenues (2)	1.50%
12	Customer Service Inflation (2)	2.20%
13	Power Supply and Costs - Scenario Selection	Base Case
14	Borrowing Assumptions - Enloe Dam	
15	Interest Rate - Co Bank	4.0%
16	Term (Years)	40
17	Borrowing Assumptions - Non-Enloe Dam	
18	Interest Rate	5.0%
19	Term (Years)	20
20	2013 Effective Energy/Demand Rates ($/kWh)	
21	Residential	0.05849
22	General Service	0.05826
23	Industrial	0.05618
24	Irrigation	0.04611
25	Frost Control	0.02874
26	Street Lighting	0.09958

Scenario: Base Case

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
27	Capital Improvements ($000) - 2012$ (3)											
28	Funded with Bonds											
29	Enloe Dam License/Construction	3,049	1,600	10,550	20,000	0	0	0	0	0	0	35,199
30	Funded with Revenue and/or Reserves											
31	Normal Replacements & Additions	2,916	2,065	2,175	1,925	1,995	2,040	2,790	2,850	3,000	3,000	24,756
32	PT Transmission Line	2,500	6,500	0	0	0	0	0	0	0	0	9,000
33	Gold Creek Substation Construction	500	0	0	0	0	0	0	0	0	0	500
34	Aeneas to Tonasket 115kV Transmission Line Construction	0	0	0	0	0	300	2,400	0	0	0	2,700
35	Aeneas Valley Substation	0	0	0	0	0	0	0	1,200	0	0	1,200
36	Tonasket Substation Addition	0	2,200	1,400	0	0	0	0	0	0	0	3,600
37	Okanogan to Brewster 115kV Transmission Line Replacement	0	0	0	0	3,300	0	0	0	0	0	3,300
38	Sandflat Substation Addition	0	0	0	750	0	0	0	0	0	0	750
39	Ophir to Monse 115kV Transmission Line	0	300	2,000	0	0	0	0	0	0	0	2,300
40	Monse Substation Construction	0	0	0	1,500	0	0	0	0	0	0	1,500
41	Loup Loup Substation Addition / MOS and Power Transformer	0	0	0	0	0	750	0	0	0	0	750
42	Facilities	2,020	550	410	0	660	1,500	60	0	200	0	5,400
43	Mobile Substation and Power Transformer Replacements	0	0	750	0	0	0	750	0	0	0	1,500
44	SCADA	0	60	60	60	60	60	60	60	60	60	540
45	Vehicle Replacements and New	634	680	580	350	685	465	360	230	165	75	4,224
46	Distribution Projects (No projects planned after 2020 at this time)	0	935	825	1,075	1,005	960	210	150	0	0	5,160
47	Other Capital Additions											0
48	Total	$11,619	$14,890	$18,750	$25,660	$7,705	$6,075	$6,630	$4,490	$3,425	$3,135	$102,379
49	Check				-	-	-	-	-	-	-	
50	Target DSCR	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	
51	Target Operating TIER	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
52	Target Total TIER	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	
53	Target Working Capital (Days of O&M)	60	60	60	60	60	60	60	60	60	60	

Notes:

(1) Sources: Projected long term growth rate of GDP Price Index per October 2012 Blue Chip Economic Indicator report.
(2) Per OKPUD staff, email on 7/17/12
(3) The 2013 CIP budget is in 2013 dollars. 2013 Budget Source: Capital Outlay 2012 and 2013 Rev.xlsx, 2014-2022 Source: EMP Estimate.xlsx.

Table 2 - Projected Revenues at Existing Rates

Scenario: Base Case

Line		Historical (1)			Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	SALES (MWh)													
1	Residential	289,163	324,538	289,640	295,092	298,892	302,730	306,606	310,521	314,476	318,469	322,503	326,577	330,692
2	General Service	197,733	202,557	204,212	206,255	208,317	210,400	212,504	214,629	216,776	218,943	221,133	223,344	225,578
3	Industrial	21,602	21,141	20,584	18,409	18,409	18,409	18,409	18,409	18,409	18,409	18,409	18,409	18,409
4	Irrigation	59,820	60,318	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773
5	Frost Control	438	517	358	358	358	358	358	358	358	358	358	358	358
6	Street Lighting	1,340	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360
7	Total Retail Sales	570,097	610,431	580,927	586,247	592,110	598,031	604,011	610,051	616,152	622,313	628,536	634,822	641,170
8	Sales for Resale	213,866	357,255	267,366	163,437	157,097	150,694	144,227	182,659	176,062	169,398	162,669	155,872	149,008
9	Adjustment	0	0	0	-	-	-	-	-	-	-	-	-	-
10	Total Energy Sales	783,963	967,686	848,293	749,684	749,207	748,725	748,238	792,710	792,213	791,712	791,205	790,694	790,178
					-	-	-	-	-	-	-	-	-	-
	CUSTOMER ACCOUNTS													
11	Residential	16,857	16,840	16,937	17,106	17,277	17,450	17,625	17,801	17,979	18,159	18,340	18,524	18,709
12	General Service	2,378	2,367	2,377	2,401	2,425	2,449	2,474	2,498	2,523	2,548	2,574	2,600	2,626
13	Industrial	4	4	4	3	3	3	3	3	3	3	3	3	3
14	Irrigation	1,207	1,198	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
15	Frost Control	134	136	140	140	140	140	140	140	140	140	140	140	140
16	Street Lighting	21	21	21	21	21	21	21	21	21	21	21	21	21
17	Total Customer Accounts	20,601	20,566	20,679	20,871	21,066	21,263	21,462	21,663	21,866	22,071	22,278	22,487	22,699
	CUSTOMER HP RATING (IRR./FROST CONTROL)													
18	Irrigation													
19	0 - 74.9 HP	17,177	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	75+ HP	27,190	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	Total HP	44,367	45,761	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	Frost Control	10,433	12,096	12,208	12,269	12,331	12,392	12,454	12,517	12,579	12,642	12,705	12,769	12,833
	MONTHLY USAGE PER CUSTOMER ACCOUNT (kWh)													
23	Residential	1,429	1,606	1,425	1,438	1,442	1,446	1,450	1,454	1,458	1,462	1,465	1,469	1,473
24	General Service	6,929	7,131	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159
25	Industrial	450,046	440,438	428,827	511,374	511,374	511,374	511,374	511,374	511,374	511,374	511,374	511,374	511,374
26	Irrigation	4,130	4,196	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498
27	Frost Control	272	317	213	213	213	213	213	213	213	213	213	213	213
28	Street Lighting	5,318	5,397	5,396	5,396	5,396	5,396	5,396	5,396	5,396	5,396	5,396	5,396	5,396
	EXISTING RATES - CUSTOMER CHARGE ($/customer/month)													
29	Residential	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
30	General Service	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
31	Industrial	417.50	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
32	Irrigation	0.00	0.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
33	Frost Control	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	Street Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
				-	-	-	-	-	-	-	-	-	-	-

Okanogan County PUD
2013 Equity Management Plan
Table 2 - Projected Revenues at Existing Rates

Scenario: Base Case

Line			Historical (1)					Projected					
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	EXISTING RATES - AVERAGE ENERGY AND DEMAND RATE ($/kWh)													
35	Residential	$0.04475	$0.04925	$0.05571	$0.05849	$0.05849	$0.05849	$0.05849	$0.05849	$0.05849	$0.05849	$0.05849	$0.05849	$0.05849
36	General Service	0.05325	0.05592	0.05677	0.05826	0.05826	0.05826	0.05826	0.05826	0.05826	0.05826	0.05826	0.05826	0.05826
37	Industrial	0.04456	0.04944	0.05258	0.05618	0.05618	0.05618	0.05618	0.05618	0.05618	0.05618	0.05618	0.05618	0.05618
38	Irrigation	0.02870	0.02749	0.04065	0.04611	0.04611	0.04611	0.04611	0.04611	0.04611	0.04611	0.04611	0.04611	0.04611
39	Frost Control	0.05960	0.04295	0.03870	0.02874	0.02874	0.02874	0.02874	0.02874	0.02874	0.02874	0.02874	0.02874	0.02874
40	Street Lighting	0.09459	0.09154	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958
	EXISTING RATES - COPA ($/kWh)													
41	Residential	n/a	$0.00240	$0.00240	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593
42	General Service	n/a	$0.00240	$0.00240	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593
43	Industrial	n/a	$0.00240	$0.00240	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593
44	Irrigation	n/a	$0.00240	$0.00240	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593
45	Frost Control	n/a	$0.00240	$0.00240	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593
46	Street Lighting	n/a	$0.00240	$0.00240	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593
	EXISTING RATES - FACILITIES CHARGE ($/HP) -- IRR. AND FROST CONTROL													
47	Irrigation													
48	0 - 74.9 HP	$10.85	$14.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
49	75+ HP	7.00	14.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
50	Frost Control	3.73	4.13	4.38	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
	RETAIL REVENUES AT EXISTING RATES - EXCLUDES COPA													
51	Residential	$14,961,740	$18,003,321	$18,167,523	$19,311,279	$19,554,046	$19,799,241	$20,046,887	$20,297,010	$20,549,634	$20,804,785	$21,062,487	$21,322,766	$21,585,648
52	General Service	10,872,507	11,667,321	11,935,462	12,361,095	12,484,706	12,609,553	12,735,648	12,863,005	12,991,635	13,121,551	13,252,767	13,385,294	13,519,147
53	Industrial	982,598	1,048,770	1,085,905	1,036,906	1,036,906	1,036,906	1,036,906	1,036,906	1,036,906	1,036,906	1,036,906	1,036,906	1,036,906
54	Irrigation	2,093,757	2,299,074	2,805,886	3,087,505	3,087,505	3,087,505	3,087,505	3,087,505	3,087,505	3,087,505	3,087,505	3,087,505	3,087,505
55	Frost Control	64,968	72,102	67,274	65,507	65,783	66,060	66,339	66,619	66,901	67,184	67,469	67,754	68,042
56	Street Lighting	126,761	124,492	135,393	135,393	135,393	135,393	135,393	135,393	135,393	135,393	135,393	135,393	135,393
57	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	1
58	Total Revenue from Retail Sales	$29,102,332	$33,215,081	$34,197,442	$35,997,683	$36,364,337	$36,734,656	$37,108,677	$37,486,437	$37,867,973	$38,253,323	$38,642,525	$39,035,618	$39,432,641
	COPA REVENUES													
59	Residential	$0	$86,380	$695,136	$783,181	$1,497,552	$1,753,079	$2,271,638	$2,545,805	$3,100,244	$3,472,237	$4,299,819	$4,620,166	$5,268,072
60	General Service	0	50,465	490,110	547,404	1,043,740	1,218,407	1,574,439	1,759,635	2,137,073	2,387,116	2,948,285	3,159,704	3,593,553
61	Industrial	0	3,907	49,401	48,859	92,238	106,607	136,395	150,930	181,489	200,716	245,447	260,443	293,271
62	Irrigation	0	0	155,456	171,909	324,536	375,095	479,903	531,042	638,563	706,215	863,597	916,362	1,031,866
63	Frost Control	0	0	860	951	1,795	2,074	2,654	2,937	3,531	3,905	4,776	5,068	5,706
64	Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
65	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
66	Total COPA Revenues	$0	$140,751	$1,390,961	$1,552,304	$2,959,861	$3,455,262	$4,465,029	$4,990,348	$6,060,900	$6,770,190	$8,361,923	$8,961,743	$10,192,469
67	Total Revenue for Retail Sales + COPA	$29,102,332	$33,355,832	$35,588,403	$37,549,987	$39,324,198	$40,189,918	$41,573,706	$42,476,785	$43,928,873	$45,023,513	$47,004,448	$47,997,361	$49,625,110
68	Percent Change	-4.8%	14.6%	6.7%	5.5%	4.7%	2.2%	3.4%	2.2%	3.4%	2.5%	4.4%	2.1%	3.4%
69	Unit Revenue at Existing Rates (cents/kWh)													
70	Retail Rates	5.10	5.46	6.13	6.41	6.64	6.72	6.88	6.96	7.13	7.23	7.48	7.56	7.74

Note:
(1) Source: Revenue Stats 2005 - 12312012 (Operating Data 6c) Feb 2013.xls

Okanogan County PUD
2013 Equity Management Plan
Table 3 - Income Statement - Accrual Basis
($000)

Scenario: Base Case

Line		Historical (1) 2010	2011	2012	Budget 2013	Projected 2014	2015	2016	2017	2018	2019	2020	2021	2022
1	Operating Revenue													
2	Retail Rate Revenues at Existing Rates	$29,102	$33,215	$34,197	$35,998	$36,364	$36,735	$37,109	$37,486	$37,868	$38,253	$38,643	$39,036	$39,433
	Future Base Rate Increases													
3	% of Base / Months													
4	Year / Sales Revenue / Effective													
5	2013 / 12.5% / 4				1,461	4,546	4,592	4,639	4,686	4,734	4,782	4,830	4,880	4,929
6	2014 / 12.5% / 6					2,404	5,166	5,218	5,271	5,325	5,379	5,434	5,489	5,545
7	2015 / 2.5% / 6						546	1,174	1,186	1,198	1,210	1,223	1,235	1,248
8	2016 / 2.5% / 6							566	1,216	1,228	1,241	1,253	1,266	1,279
9	2017 / 2.5% / 6								586	1,259	1,272	1,285	1,298	1,311
10	2018 / 0.0% / 6									0	0	0	0	0
11	2019 / 0.0% / 6										0	0	0	0
12	2020 / 0.0% / 6											0	0	0
13	2021 / 0.0% / 6												0	0
14	2022 / 0.0% / 6													0
15	Sales for Resale Revenue	$5,802	$6,742	$3,532	$2,641	$2,577	$2,509	$2,437	$3,133	$3,065	$2,993	$2,917	$2,837	$2,753
16	COPA Revenues	0	141	1,391	1,552	2,960	3,455	4,465	4,990	6,061	6,770	8,362	8,962	10,192
17	Other Revenues	992	924	830	727	738	749	760	771	783	795	807	819	831
18	Total Operating Revenues	$35,896	$41,021	$39,950	$42,379	$49,588	$53,752	$56,368	$59,325	$61,520	$62,695	$64,754	$65,822	$67,521
19	Operating Expenses													
20	Production	$85	$113	$83	$108	$111	$113	$115	$118	$121	$124	$127	$130	$133
21	Purchased Power	23,896	24,061	22,284	23,837	25,244	25,740	26,749	28,417	29,509	30,240	31,854	32,476	33,730
22	Other Power Supply	521	687	832	1,086	1,110	1,134	1,159	1,184	1,210	1,237	1,264	1,292	1,320
23	Transmission	82	34	40	52	53	54	55	56	57	58	59	60	61
24	Distribution	5,381	4,721	5,427	7,088	7,244	7,403	7,566	7,732	7,902	8,076	8,254	8,436	8,622
25	Consumer Accounting	1,285	1,344	1,348	1,761	1,800	1,840	1,880	1,921	1,963	2,006	2,050	2,095	2,141
26	Customer Service & Information	677	509	747	976	997	1,019	1,041	1,064	1,087	1,111	1,135	1,160	1,186
27	Admin. & General	3,728	3,864	4,094	5,348	5,465	5,585	5,708	5,834	5,962	6,093	6,227	6,364	6,504
28	Tax Expense	1,829	2,127	2,210	2,360	2,474	2,528	2,615	2,672	2,763	2,832	2,957	3,019	3,122
29	Depreciation/Amortization	3,067	3,756	3,866	3,812	4,002	4,436	4,793	5,925	6,207	6,406	6,652	6,805	6,916
30	Total Cost of Electric Service	$40,552	$41,215	$40,931	$46,427	$48,500	$49,852	$51,682	$54,923	$56,782	$58,183	$60,579	$61,838	$63,735
31	Net Operating Revenues	($4,656)	($194)	($981)	($4,048)	$1,088	$3,900	$4,686	$4,401	$4,739	$4,511	$4,175	$3,984	$3,786
32	Other Income	401	564	1,323	991	979	975	975	975	975	975	975	975	975
33	Interest Expense	(932)	(1,970)	(1,302)	(1,875)	(3,235)	(3,161)	(4,530)	(4,451)	(4,328)	(4,190)	(4,045)	(3,894)	(3,723)
34	Debt Issuance Expense and Discount	(60)	(95)	(85)	(85)	(85)	(85)	(85)	(85)	(85)	(85)	(85)	(80)	(35)
35	Other Deductions	(50)	(351)	0	0	0	0	0	0	0	0	0	0	0
36	Contributions in Aid of Construction (2)	996	975	992	1,104	1,260	1,323	1,389	1,459	1,532	1,608	1,689	1,773	1,862
37	Use of Rate Stabilization Funds	1,400	0	0	2,575	0	0	0	0	0	0	0	0	0
38	Net Income (Loss)	($2,901)	($1,071)	($53)	($1,338)	$8	$2,953	$2,436	$2,300	$2,833	$2,820	$2,710	$2,758	$2,866
39	Total Retail Energy Sales (MWh)	570,097	610,431	580,927	586,247	592,110	598,031	604,011	610,051	616,152	622,313	628,536	634,822	641,170
40	Unit Revenue from Retail Sales (¢/kWh)	5.10	5.46	6.13	6.65	7.81	8.44	8.80	9.08	9.36	9.47	9.71	9.79	9.97
41	Increase over Previous Year	6.4%	7.0%	12.1%	8.6%	17.4%	8.0%	4.3%	3.2%	3.0%	1.1%	2.6%	0.9%	1.8%
42	Necessary Retail Rate Change			0.0%	12.5%	12.5%	2.5%	2.5%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%
43	DSC Ratio	0.77	1.36	1.47	1.25	1.38	2.01	1.76	1.67	1.77	1.78	1.77	1.78	1.96
44	Operating TIER	(4.99)	(0.10)	(0.75)	(2.16)	0.34	1.23	1.03	0.99	1.09	1.08	1.03	1.02	1.02
45	Total TIER	(2.11)	0.46	0.96	0.29	1.00	1.93	1.54	1.52	1.65	1.67	1.67	1.71	1.77
46	Working Capital (Days of O&M)	74	95	43	9	187	65	111	81	71	57	59	70	85

Note:
(1) Sources: 2010 - 2011 Financial and Statistcal Reports, Draft 2012 Financial and Statistcal Report
(2) Sources: EMP 2011 CIAC.xlsx

Okanogan County PUD
2013 Equity Management Plan
Table 4 - Pro-Forma Balance Sheet as of December 31
($000)

Scenario: Base Case

		Historical (1)			Projected									
Line		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	ASSETS AND OTHER DEBITS													
1	Total Utility Plant	$137,519	$141,269	$146,711	$157,340	$171,903	$190,927	$217,931	$225,532	$231,464	$238,195	$242,549	$245,725	$248,632
2	Accum. Prov. for Deprec.	(52,369)	(53,648)	(56,805)	(59,627)	(62,639)	(66,085)	(69,888)	(74,823)	(80,040)	(85,456)	(91,118)	(96,933)	(102,859)
3	Net Utility Plant	$85,150	$87,621	$89,906	$97,713	$109,264	$124,842	$148,043	$150,709	$151,424	$152,739	$151,431	$148,792	$145,773
4	Other Property & Investments													
5	Investments in Associated Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Electric Investment in Communications	2,150	1,979	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799
7	Total Other Property & Investments	$2,150	$1,979	$1,799	$1,799	$1,799	$1,799	$1,799	$1,799	$1,799	$1,799	$1,799	$1,799	$1,799
8	Current Assets													
9	Revenue Fund	$2,832	$3,763	$1,818	$1,818	$1,818	$1,818	$1,818	$1,818	$1,818	$1,818	$1,818	$1,818	$1,818
10	Working Funds	15	15	15	15	15	15	15	15	15	15	15	15	15
11	Temporary Cash Investments	4,773	6,004	2,582	(812)	20,915	6,299	12,463	9,058	8,031	6,253	6,841	8,656	11,394
12	Accrued Utility Revenues	2,321	1,996	2,189	2,189	2,189	2,189	2,189	2,189	2,189	2,189	2,189	2,189	2,189
13	Other Current Assets	6,302	5,990	6,835	6,835	6,835	6,835	6,835	6,835	6,835	6,835	6,835	6,835	6,835
14	Total Unrestricted Current Assets	$16,243	$17,768	$13,440	$10,046	$31,773	$17,156	$23,321	$19,915	$18,889	$17,111	$17,699	$19,513	$22,251
15	Restricted Current Assets													
16	Bond Sinking Funds	$567	$290	$290	$290	$290	$290	$290	$290	$290	$290	$290	$290	$290
17	Customer Deposits	450	600	600	600	600	600	600	600	600	600	600	600	600
18	Compensated Absences	1,100	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
19	Debt Service Reserve Funds	0	0	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945
20	Bond Construction Funds	14,898	9,263	7,266	0	0	0	0	0	0	0	0	0	0
21	Other Special Funds (Rate Stab. Fund)	6,135	6,135	6,135	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460
22	Total Restricted Current Assets	$23,150	$17,687	$17,635	$7,694	$7,694	$7,694	$7,694	$7,694	$7,694	$7,694	$7,694	$7,694	$7,694
23	Deferred Debits													
24	Unamortized Debt Expense	$415	$389	$370	$351	$333	$314	$295	$276	$257	$238	$220	$201	$182
25	Unamortized Loss on Reacquired Debt	845	770	695	620	545	470	395	321	246	171	96	25	0
26	Other Deferred Debits	2,987	2,222	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882
27	Total Assets & Other Debits	$130,940	$128,436	$127,728	$122,106	$155,290	$156,159	$185,430	$184,597	$184,192	$183,635	$182,821	$181,906	$181,582
	EQUITIES AND LIABILITIES													
28	Net Assets													
29	Restricted for Capital Construction	$14,898	$9,263	$7,266	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Restricted for Debt Service	0	0	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078
31	Restricted for Contingencies	6,135	6,135	6,250	3,575	3,575	3,575	3,575	3,575	3,575	3,575	3,575	3,575	3,575
32	Appropriated Net Assets	4,000	4,000	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036
33	Unappropriated Net Assets	46,144	51,208	52,584	58,512	58,520	61,473	63,909	66,209	69,042	71,862	74,572	77,330	80,195
34	Contributions in Aid of Construction	11,558	11,558	11,558	11,558	11,558	11,558	11,558	11,558	11,558	11,558	11,558	11,558	11,558
35	Total Net Assets	$82,735	$82,164	$82,772	$78,759	$78,767	$81,720	$84,156	$86,456	$89,289	$92,109	$94,819	$97,576	$100,442
36	Non-Current Liabilities													
37	Long-Term Debt	$39,595	$38,040	$36,440	$34,425	$67,550	$65,394	$91,270	$88,041	$84,673	$81,159	$77,496	$74,315	$74,315
38	Other Long Term Liabilities	363	357	347	338	329	320	311	302	293	283	274	265	256
39	Total Long-Term Liabilities	$39,958	$38,397	$36,787	$34,763	$67,879	$65,714	$91,581	$88,343	$84,966	$81,442	$77,770	$74,580	$74,571
40	Current and Accrued Liabilities													
41	Warrants Outstanding	$625	$247	$188	$188	$188	$188	$188	$188	$188	$188	$188	$188	$188
42	Accounts Payable	3,344	3,126	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283
43	Taxes Accrued	822	944	969	969	969	969	969	969	969	969	969	969	969
44	Miscellaneous	78	85	86	86	86	86	86	86	86	86	86	86	86
45	Other Regulatory Liabilities	0	0	0	0	0	0	0	0	0	0	0	0	0
46	Total Current and Accrued Liabilities	$4,869	$4,402	$4,527	$4,527	$4,527	$4,527	$4,527	$4,527	$4,527	$4,527	$4,527	$4,527	$4,527
47	Current Liab. Payable from Restricted Assets													
48	Current Portion of Long Term Debt	$1,190	$1,555	$1,600	$2,015	$2,075	$2,156	$3,124	$3,229	$3,368	$3,514	$3,663	$3,181	$0
49	Interest on Long Term Debt	431	160	156	156	156	156	156	156	156	156	156	156	156
50	Compensated Absences	1,199	1,191	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
51	Customer Deposits	558	568	535	535	535	535	535	535	535	535	535	535	535
52	Total Current Liab. Payable from Restricted Assets	$3,378	$3,474	$3,642	$4,057	$4,117	$4,198	$5,166	$5,271	$5,410	$5,556	$5,705	$5,223	$2,042
53	Deferred Credits	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Total Equities and Liabilities	$130,939	$128,436	$127,728	$122,106	$155,290	$156,159	$185,430	$184,596	$184,191	$183,634	$182,821	$181,906	$181,582
	FINANCIAL RATIOS													
55	Equity to Total Assets	63.2%	64.0%	64.8%	64.5%	50.7%	52.3%	45.4%	46.8%	48.5%	50.2%	51.9%	53.6%	55.3%
56	Working Capital (Days of O&M)	74	95	43	9	187	65	111	81	71	57	59	70	85

Note:
(1) Sources: 2010 - 2011 Financial and Statistical Reports, Draft 2012 Financial and Statistical Report

Okanogan County PUD
2013 Equity Management Plan
Table 5 - Statement of Operations - Cash Basis
($000)

Scenario: Base Case

Line		Projected 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	Total Net Operating Revenues	($4,048)	$1,088	$3,900	$4,686	$4,401	$4,739	$4,511	$4,175	$3,984	$3,786
2	Add: Depreciation	3,812	4,002	4,436	4,793	5,925	6,207	6,406	6,652	6,805	6,916
3	Add: Other Income	991	979	975	975	975	975	975	975	975	975
4	Add: Use of Rate Stabilization Fund	2,575	0	0	0	0	0	0	0	0	0
5	Cash from Operations	$3,330	$6,069	$9,312	$10,455	$11,302	$11,921	$11,893	$11,803	$11,764	$11,678
6	Debt Service - Long Term										
7	Existing - Interest	$1,875	$1,827	$1,768	$1,702	$1,639	$1,577	$1,502	$1,424	$1,342	$1,244
8	Existing - Principal	1,600	1,645	1,690	1,755	1,830	1,875	1,950	2,030	2,110	1,555
9	New - Interest	0	1,408	1,393	2,828	2,812	2,751	2,688	2,621	2,552	2,479
10	New - Principal	0	370	385	401	1,294	1,354	1,418	1,484	1,553	1,626
11	Total Debt Service	$3,475	$5,250	$5,236	$6,686	$7,575	$7,557	$7,558	$7,559	$7,557	$6,904
12	Cash Margins After Debt Service	($145)	$819	$4,076	$3,769	$3,727	$4,364	$4,335	$4,244	$4,207	$4,774
13	Cash from Investing Activities										
14	Total Additions and Replacements	(10,515)	(14,292)	(18,692)	(26,605)	(7,132)	(5,391)	(6,113)	(3,655)	(2,393)	(2,036)
15	Cash from Financing Activities										
16	Proceeds from Long Term Debt	0	35,200	0	29,000	0	0	0	0	0	0
17	Proceeds from Bond Construction Funds	7,266	0	0	0	0	0	0	0	0	0
18	Cash from Investing and Financing Activities	(3,249)	20,908	(18,692)	2,395	(7,132)	(5,391)	(6,113)	(3,655)	(2,393)	(2,036)
19	Net Cash	(3,394)	21,727	(14,616)	6,164	(3,405)	(1,027)	(1,778)	588	1,814	2,738
	FINANCIAL RATIOS										
20	Debt Service Coverage	1.25	1.38	2.01	1.76	1.67	1.77	1.78	1.77	1.78	1.96

Okanogan County PUD
2013 Equity Management Plan
Table 6 - General Funds Summary
($000)

Scenario: Base Case

Line		Projected 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	SOURCES OF GENERAL FUNDS										
1	Net General Funds - Beg. of Year (1)	$19,904	$6,569	$28,296	$13,680	$19,844	$16,438	$15,412	$13,634	$14,222	$16,036
2	Cash Margins after Debt Service	(145)	819	4,076	3,769	3,727	4,364	4,335	4,244	4,207	4,774
3	Loan Proceeds	0	35,200	0	29,000	0	0	0	0	0	0
4	Adjustments made to Balance Sheet	(2,675)	0	0	0	0	0	0	0	0	0
5	Total General Funds Available	$17,084	$42,588	$32,372	$46,448	$23,571	$20,803	$19,747	$17,877	$18,429	$20,810
	USES OF GENERAL FUNDS										
6	Debt Funded Plant Investment	7,266	35,200	0	29,000	0	0	0	0	0	0
7	General Funded Plant Investment	3,249	(20,908)	18,692	(2,395)	7,132	5,391	6,113	3,655	2,393	2,036
8	Repayment of Short Term Debt	0	0	0	0	0	0	0	0	0	0
9	Total Uses of General Funds	$10,515	$14,292	$18,692	$26,605	$7,132	$5,391	$6,113	$3,655	$2,393	$2,036
10	Net General Funds - End of Year	$6,569	$28,296	$13,680	$19,844	$16,438	$15,412	$13,634	$14,222	$16,036	$18,774

Notes

		2012
(1)	Components of general funds as of December 31 were:	
	Sinking Funds	$290
	Rate Stabilization Fund	6,135
	Employee Compensated Absences Fund	1,400
	Customer Deposit Fund	600
	Revenue Fund Less Warrants Outstanding	1,631
	Temporary Cash Investments	2,582
	Bond Construction Funds	7,266
	Total	$19,904

Okanogan County PUD
2013 Equity Management Plan
Table 7 - Plant Investment and Depreciation Expense
($000)

Scenario: Base Case

Line		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
		Projected									
	UTILITY PLANT										
1	Total Utility Plant (Beg Yr)	$146,711	$157,340	$171,903	$190,927	$217,931	$225,532	$231,464	$238,195	$242,549	$245,725
2	Additions and Replacements - CIP Inflation Adjusted										
3	Funded with Bonds										
4	Enloe Dam License/Construction	3,049	1,671	11,262	21,819	0	0	0	0	0	0
5	Funded with Revenue and/or Reserves										
6	Normal Replacements & Additions	2,916	2,157	2,322	2,100	2,224	2,325	3,249	3,392	3,649	3,729
7	PT Transmission Line	2,500	6,789	0	0	0	0	0	0	0	0
8	Gold Creek Substation Construction	500	0	0	0	0	0	0	0	0	0
9	Aeneas to Tonasket 115kV Transmission Line Construction	0	0	0	0	0	342	2,795	0	0	0
10	Aeneas Valley Substation	0	0	0	0	0	0	0	1,428	0	0
11	Tonasket Substation Addition	0	2,298	1,494	0	0	0	0	0	0	0
12	Okanogan to Brewster 115kV Transmission Line Replacement	0	0	0	0	3,679	0	0	0	0	0
13	Sandflat Substation Addition	0	0	0	818	0	0	0	0	0	0
14	Ophir to Monse 115kV Transmission Line	0	313	2,135	0	0	0	0	0	0	0
15	Monse Substation Construction	0	0	0	1,636	0	0	0	0	0	0
16	Loup Loup Substation Addition / MOS and Power Transformer	0	0	0	0	0	855	0	0	0	0
17	Facilities	2,020	574	438	0	736	1,709	70	0	243	0
18	Mobile Substation and Power Transformer Replacements	0	0	801	0	0	0	873	0	0	0
19	SCADA	0	63	64	65	67	68	70	71	73	75
20	Vehicle Replacements and New	634	710	619	382	764	530	419	274	201	93
21	Distribution Projects (District) (No projects planned after 2020 at this time)	0	977	881	1,173	1,121	1,094	245	179	0	0
22	Other Capital Additions	0	0	0	0	0	0	0	0	0	0
23	Total	$11,619	$15,552	$20,015	$27,994	$8,591	$6,922	$7,721	$5,344	$4,166	$3,897
24	Less Retirements	990	990	990	990	990	990	990	990	990	990
25	Total Utility Plant (End Yr)	$157,340	$171,903	$190,927	$217,931	$225,532	$231,464	$238,195	$242,549	$245,725	$248,632
26	Net Additions and Replacements										
27	Distribution	$6,070	$6,779	$6,618	$6,175	$4,911	$6,580	$4,926	$5,344	$4,166	$3,897
28	Other Generation & Transmission	5,549	8,774	13,397	21,819	3,679	342	2,795	-	-	-
29	Total Net Additions and Replacements	$11,619	$15,552	$20,015	$27,994	$8,591	$6,922	$7,721	$5,344	$4,166	$3,897

Okanogan County PUD
2013 Equity Management Plan
Table 7 - Plant Investment and Depreciation Expense
($000)

Scenario: Base Case

Line			Projected 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	DEPRECIATION EXPENSE											
30	Funded with Bonds											
31	Enloe Dam License/Construction	2.50%	0	0	0	0	945	945	945	945	945	945
32	Funded with Revenue and/or Reserves											
33	Normal Replacements & Additions	3.00%	0	87	152	222	285	352	421	519	621	730
34	PT Transmission Line	3.00%	0	0	279	279	279	279	279	279	279	279
35	Gold Creek Substation Construction	3.00%	0	15	15	15	15	15	15	15	15	15
36	Aeneas to Tonasket 115kV Transmission Line Construction	3.00%	0	0	0	0	0	0	0	94	94	94
37	Aeneas Valley Substation	3.00%	0	0	0	0	0	0	0	0	43	43
38	Tonasket Substation Addition	3.00%	0	0	0	114	114	114	114	114	114	114
39	Okanogan to Brewster 115kV Transmission Line Replacement	3.00%	0	0	0	0	0	110	110	110	110	110
40	Sandflat Substation Addition	3.00%	0	0	0	0	25	25	25	25	25	25
41	Ophir to Monse 115kV Transmission Line	3.00%	0	0	0	73	73	73	73	73	73	73
42	Monse Substation Construction	3.00%	0	0	0	0	49	49	49	49	49	49
43	Loup Loup Substation Addition / MOS and Power Transformer	3.00%	0	0	0	0	0	0	26	26	26	26
44	Facilities	2.50%	0	51	65	76	76	94	137	139	139	145
45	Mobile Substation and Power Transformer Replacements	3.00%	0	0	0	24	24	24	24	50	50	50
46	SCADA	3.00%	0	0	2	4	6	8	10	12	14	16
47	Vehicle Replacements and New	10.00%	0	63	134	196	235	311	364	406	433	453
48	Distribution Projects (District) (No projects planned after 2020 at this time)	3.00%	0	0	29	56	91	125	157	165	170	170
49	Existing Plant	2.62%	3,812	3,786	3,760	3,734	3,708	3,683	3,657	3,631	3,605	3,579
50	Total Depreciation Expense		$3,812	$4,002	$4,436	$4,793	$5,925	$6,207	$6,406	$6,652	$6,805	$6,916
51	Less Depreciation in Other Accounts		0	0	0	0	0	0	0	0	0	0
52	Net Depreciation Expense		$3,812	$4,002	$4,436	$4,793	$5,925	$6,207	$6,406	$6,652	$6,805	$6,916
53	2012 ESTIMATED DEPRECIATION RATE ON EXISTING PLANT											
54	Total Utility Plant in Service (EOY)	146,711										
55	Depreciation Expense	3,838										
56	Estimated Average Depreciation Rate	2.62%										
57	ESTIMATED PLANT IN SERVICE - EXISTING PLANT											
58	Total Existing Plant in Service (BOY)		146,711	145,721	144,731	143,741	142,751	141,761	140,771	139,781	138,791	137,801
59	Retirements		990	990	990	990	990	990	990	990	990	990
60	Total Existing Plant in Service (EOY)		145,721	144,731	143,741	142,751	141,761	140,771	139,781	138,791	137,801	136,811
61	Estimated Depreciation Expense on Existing Plant		3,812	3,786	3,760	3,734	3,708	3,683	3,657	3,631	3,605	3,579

Okanogan County PUD
2013 Equity Management Plan
Table 8 - Long-Term Debt and Debt Service
($000)

Scenario: Base Case

		Projected									
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	EXISTING LONG TERM DEBT										
1	Balance (Beg Yr)	$38,040	$36,440	$34,795	$33,105	$31,350	$29,520	$27,645	$25,695	$23,665	$21,555
2	Principal Repayments	1,600	1,645	1,690	1,755	1,830	1,875	1,950	2,030	2,110	1,555
3	Balance (End Yr)	$36,440	$34,795	$33,105	$31,350	$29,520	$27,645	$25,695	$23,665	$21,555	$20,000
	EXISTING DEBT INTEREST AND PRINCIPAL PAYMENTS										
4	Interest										
5	2003 Bonds	$321	$293	$261	$228	$192	$158	$130	$101	$70	$36
6	2010 Bonds	1,554	1,534	1,507	1,475	1,447	1,419	1,372	1,323	1,272	1,208
7	Total Interest	$1,875	$1,827	$1,768	$1,702	$1,639	$1,577	$1,502	$1,424	$1,342	$1,244
8	Principal										
9	2003 Bonds	$555	$580	$615	$650	$685	$700	$730	$760	$790	$825
10	2010 Bonds	1,045	1,065	1,075	1,105	1,145	1,175	1,220	1,270	1,320	730
11	Total Principal	$1,600	$1,645	$1,690	$1,755	$1,830	$1,875	$1,950	$2,030	$2,110	$1,555
	FUNDING REQUIREMENTS										
12	Capital Funding Requirements (1)	$10,515	$14,292	$18,692	$26,605	$7,132	$5,391	$6,113	$3,655	$2,393	$2,036
13	Refinancing Requirements	0	0	0	0	0	0	0	0	0	0
14	Total Funding Requirements	$10,515	$14,292	$18,692	$26,605	$7,132	$5,391	$6,113	$3,655	$2,393	$2,036
15	Loan Funds Advanced	0	35,200	0	29,000	0	0	0	0	0	0
16	Use of Unspent Bond Proceeds	7,266	0	0	0	0	0	0	0	0	0
17	General Funds Invested	$3,249	($20,908)	$18,692	($2,395)	$7,132	$5,391	$6,113	$3,655	$2,393	$2,036
	NEW LONG TERM DEBT										
18	New Long Term Debt										
19	BOY Balance	$0	$0	$34,830	$34,445	$63,044	$61,750	$60,396	$58,978	$57,494	$55,941
20	Loan Funds Advanced	0	35,200	0	29,000	0	0	0	0	0	0
21	Interest Expense	0	1,408	1,393	2,828	2,812	2,751	2,688	2,621	2,552	2,479
22	Principal Payments	0	370	385	401	1,294	1,354	1,418	1,484	1,553	1,626
23	Total Debt Service	$0	$1,778	$1,778	$3,229	$4,106	$4,105	$4,106	$4,105	$4,105	$4,105
24	EOY Balance	$0	$34,830	$34,445	$63,044	$61,750	$60,396	$58,978	$57,494	$55,941	$54,315
	TOTAL LONG TERM DEBT SERVICE										
25	Interest										
26	Existing Debt	$1,875	$1,827	$1,768	$1,702	$1,639	$1,577	$1,502	$1,424	$1,342	$1,244
27	New Long Term Debt	0	1,408	1,393	2,828	2,812	2,751	2,688	2,621	2,552	2,479
28	Total Interest	$1,875	$3,235	$3,161	$4,530	$4,451	$4,328	$4,190	$4,045	$3,894	$3,723
29	Principal										
30	Existing Debt	$1,600	$1,645	$1,690	$1,755	$1,830	$1,875	$1,950	$2,030	$2,110	$1,555
31	New Long Term Debt	0	370	385	401	1,294	1,354	1,418	1,484	1,553	1,626
32	Total Principal	$1,600	$2,015	$2,075	$2,156	$3,124	$3,229	$3,368	$3,514	$3,663	$3,181
33	Total Debt Service	$3,475	$5,250	$5,236	$6,686	$7,575	$7,557	$7,558	$7,559	$7,557	$6,904
34	Less Portion Allocated to Telecom	0	0	0	0	0	0	0	0	0	0
35	Total Electric System Debt Service	$3,475	$5,250	$5,236	$6,686	$7,575	$7,557	$7,558	$7,559	$7,557	$6,904
	TOTAL LONG TERM DEBT										
34	Balance (Beg Yr)	$38,040	$36,440	$69,625	$67,550	$94,394	$91,270	$88,041	$84,673	$81,159	$77,496
35	Loan Funds Advanced	-	35,200	-	29,000	-	-	-	-	-	-
36	Less Principal Repayments	1,600	2,015	2,075	2,156	3,124	3,229	3,368	3,514	3,663	3,181
37	Balance (End Yr)	$36,440	$69,625	$67,550	$94,394	$91,270	$88,041	$84,673	$81,159	$77,496	$74,315
35	Current Portion of Long Term Debt - EOY										
36	Existing Debt	$1,645	$1,690	$1,755	$1,830	$1,875	$1,950	$2,030	$2,110	$1,555	$0
37	New Long Term Debt	370	385	401	1,294	1,354	1,418	1,484	1,553	1,626	0
38	Total Current Portion	$2,015	$2,075	$2,156	$3,124	$3,229	$3,368	$3,514	$3,663	$3,181	$0

Notes
(1) Includes CIAC

Table 9 - Energy Resources and Cost of Power

Scenario: Base Case

		Projected										Avg. Annual Increase
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013 - 2022
	POWER SUPPLY (MWh)											
1	Purchased Power											
2	BPA Block	209,496	209,496	209,496	209,496	209,496	209,496	209,496	209,496	209,496	209,496	0.0%
3	BPA Slice	286,179	286,179	286,179	286,179	286,179	286,179	286,179	286,179	286,179	286,179	0.0%
4	Douglas NCW Trans.	629	629	629	629	629	629	629	629	629	629	0.0%
5	Wells	258,942	258,942	258,942	258,942	258,942	258,942	258,942	258,942	258,942	258,942	0.0%
6	Nine Canyon Wind	42,156	42,156	42,156	42,156	42,156	42,156	42,156	42,156	42,156	42,156	0.0%
7	Douglas-Nine Canyon Wind	0	0	0	0	0	0	0	0	0	0	n/a
8	Other	0	0	0	0	0	0	0	0	0	0	n/a
9	Subtotal - Purchased Power	797,402	797,402	797,402	797,402	797,402	797,402	797,402	797,402	797,402	797,402	0.0%
10	New Resources											
11	Enloe Dam	0	0	0	0	44,963	44,963	44,963	44,963	44,963	44,964	n/a
12	Subtotal - New Resources	0	0	0	0	44,963	44,963	44,963	44,963	44,963	44,964	n/a
13	Generation Losses	0	0	0	0	0	0	0	0	0	0	n/a
14	Total Power Supply	797,402	797,402	797,402	797,402	842,365	842,365	842,365	842,365	842,365	842,366	0.6%
		-	-	-	-	-	-	-	-	-	-	
	POWER REQUIREMENTS (MWh)											
15	Retail Energy Sales	586,247	592,110	598,031	604,011	610,051	616,152	622,313	628,536	634,822	641,170	1.0%
16	Sales for Resale	163,437	157,097	150,694	144,227	182,659	176,062	169,398	162,669	155,872	149,008	-1.0%
17	Station Use	0	0	0	0	0	0	0	0	0	0	n/a
18	Distribution Line Losses	47,718	48,195	48,677	49,164	49,655	50,152	50,653	51,160	51,672	52,188	1.0%
19	Total	797,402	797,402	797,402	797,402	842,365	842,365	842,365	842,365	842,365	842,366	0.6%
		-	-	-	-	-	-	-	-	-	-	
	LOSSES (MWh)											
20	As a Percent of Requirements	6.0%	6.0%	6.1%	6.2%	5.9%	6.0%	6.0%	6.1%	6.1%	6.2%	
	POWER COSTS ($000)											
21	Purchased Power											
22	BPA Block	$6,363	$6,789	$6,904	$7,197	$7,319	$7,629	$7,758	$8,086	$8,223	$8,572	3.4%
23	BPA Slice	8,365	8,935	9,065	9,455	9,593	10,006	10,305	11,200	11,364	11,856	4.0%
24	Douglas NCW Trans.	2,139	2,341	2,376	2,481	2,518	2,630	2,669	2,788	2,830	2,955	3.7%
25	Wells	4,143	4,267	4,395	4,527	4,663	4,803	4,947	5,095	5,248	5,405	3.0%
26	Nine Canyon Wind	2,827	2,912	3,000	3,090	3,182	3,278	3,376	3,477	3,582	3,689	3.0%
27	Douglas-Nine Canyon Wind	0	0	0	0	0	0	0	0	0	0	n/a
28	Other	0	0	0	0	0	0	0	0	0	0	n/a
29	Subtotal - Purchased Power	$23,837	$25,244	$25,740	$26,749	$27,275	$28,345	$29,054	$30,646	$31,246	$32,477	3.5%
30	New Resources											
31	Enloe Dam	$0	$0	$0	$0	$1,143	$1,164	$1,186	$1,208	$1,231	$1,254	
32	Subtotal - New Resources	$0	$0	$0	$0	$1,143	$1,164	$1,186	$1,208	$1,231	$1,254	
33	Total Power Costs	$23,837	$25,244	$25,740	$26,749	$28,417	$29,509	$30,240	$31,854	$32,476	$33,730	
34	UNIT POWER COSTS (cents/kWh)											
35	BPA Block	3.04	3.24	3.30	3.44	3.49	3.64	3.70	3.86	3.93	4.09	3.4%
36	BPA Slice	2.92	3.12	3.17	3.30	3.35	3.50	3.60	3.91	3.97	4.14	4.0%
37	Douglas NCW Trans.	340.02	372.12	377.71	394.45	400.37	418.12	424.39	443.21	449.85	469.80	3.7%
38	Wells	1.60	1.65	1.70	1.75	1.80	1.85	1.91	1.97	2.03	2.09	3.0%
39	Nine Canyon Wind	6.71	6.91	7.12	7.33	7.55	7.78	8.01	8.25	8.50	8.75	3.0%
40	Douglas-Nine Canyon Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
41	Other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
42	Enloe Dam	n/a	n/a	n/a	n/a	2.54	2.59	2.64	2.69	2.74	2.79	n/a
43	Total	2.99	3.17	3.23	3.35	3.37	3.50	3.59	3.78	3.86	4.00	3.3%

Okanogan County PUD
2013 Equity Management Plan
Table 10 - Projected COPA Revenues

Scenario: Base Case

		Actual		Projected									
Line		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	SALES (MWh)												
1	Residential	324,538	289,640	295,092	298,892	302,730	306,606	310,521	314,476	318,469	322,503	326,577	330,692
2	General Service	202,557	204,212	206,255	208,317	210,400	212,504	214,629	216,776	218,943	221,133	223,344	225,578
3	Industrial	21,141	20,584	18,409	18,409	18,409	18,409	18,409	18,409	18,409	18,409	18,409	18,409
4	Irrigation	60,318	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773	64,773
5	Frost Control	517	358	358	358	358	358	358	358	358	358	358	358
6	Street Lighting	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Retail Sales	609,071	579,567	584,888	590,750	596,671	602,651	608,692	614,792	620,954	627,177	633,462	639,810
8													
9	POWER SUPPLY COSTS ($000)												
10	Total Power Costs	$24,061	$22,284	$23,837	$25,244	$25,740	$26,749	$28,417	$29,509	$30,240	$31,854	$32,476	$33,730
11	Less Enloe Dam	-	-	-	-	-	-	1,143	1,164	1,186	1,208	1,231	1,254
12	Net Power Costs	$24,061	$22,284	$23,837	$25,244	$25,740	$26,749	$27,275	$28,345	$29,054	$30,646	$31,246	$32,477
13													
14	Additional COPA Revenue ($000)		n/a	$1,552	$2,960	$3,455	$4,465	$4,990	$6,061	$6,770	$8,362	$8,962	$10,192
15													
16	COPA Charge ($/kWh)	n/a	n/a	$0.00265	$0.00501	$0.00579	$0.00741	$0.00820	$0.00986	$0.01090	$0.01333	$0.01415	$0.01593

Appendix B
EQUITY MANAGEMENT PLAN – RATE ALTERNATIVE OPTION 1

Appendix C
EQUITY MANAGEMENT PLAN - RATE ALTERNATIVE OPTION 2

Appendix D
2013 ELECTRIC SYSTEM RATE STUDY
DISTRICT'S TEST YEAR 2013 REVENUE REQUIREMENTS

Appendix E
2013 ELECTRIC SYSTEM RATE STUDY
FUNCTIONALIZATION OF REVENUE REQUIREMENTS

Appendix F
2013 ELECTRIC SYSTEM RATE STUDY
CLASSIFICATION OF REVENUE REQUIREMENTS

Appendix G
2013 ELECTRIC SYSTEM RATE STUDY
ALLOCATION OF REVENUE REQUIREMENTS

Appendix H
2013 ELECTRIC SYSTEM RATE STUDY
RATE DESIGN OPTION 1

Appendix I
2013 ELECTRIC SYSTEM RATE STUDY
RATE DESIGN OPTION 2

Appendix J
PUBLIC UTILITY DISTRICT NO. 1 OF OKANOGAN COUNTY RESOLUTION