Okanogan County Electric Cooperative

Electric Cost of Service and Rate Study
Revised Final

October 16, 2019

Prepared by:

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EES Consulting

October 16, 2019

Ms. Lynn Northcott
Okanogan County Electric Cooperative, Inc.
P.O. Box 69
Winthrop, Washington 98862

Dear Ms. Northcott:

It is with pleasure that EES Consulting, Inc. submits this Electric Cost of Service and Rate Study to Okanogan County Electric Cooperative. This version reflects final refinements to rate revenues, interest expense, and margin calculations

We appreciate all the help you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments or if OCEC would like further assistance with rate design.

Very truly yours,

Amber Nyquist

Amber Nyquist
Manager, Economic Evaluations

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COST OF SERVICE MODEL

Executive Summary

Okanogan County Electric Cooperative (OCEC) retained EES Consulting, Inc. (EES) to perform an electric cost of service and rate study as part of its ongoing efforts to maintain fiscally prudent and fair rates for its electric customers. The purpose of this report is to discuss the data inputs, assumptions and results that were part of developing the rate study. A cost of service study generally consists of two separate analyses: revenue requirement and cost of service. This study contains these analyses with a technical appendix detailing the assumptions.

Revenue Requirement

A revenue requirement analysis compares utility revenues and expenses to determine the overall rate adjustment required. For this analysis, an *accrual basis* method was used for determining OCEC's revenue requirement. Annual operating expenses from budget for calendar year (CY) 2019 were used to determine the revenue requirement as well as other information provided by OCEC.

A base case was defined to develop the cost of service analysis (COSA). This base case assumptions are provided below.

- Historic year is Calendar Year (CY) 2018 (January 2018 – December 2018).
- Test year/allocation year is CY 2019.
- Load forecast is based on PNGC's load forecast and actual customer loads from January 2018 through March 2019.
- Forecast 2019 revenues were calculated using current rates and forecast loads. Resulting revenues were 3% higher than the revenues projected in OCEC's budget. The difference is primarily due to higher loads in response to a cold spell at the start of 2019.
- Expenses were taken directly from OCEC's annual operating expenses for CY 2018 and the budget for CY 2019. Beginning in CY 2020, expenses are forecast to increase 3% annually.
- Power supply costs are based on the power cost forecast provided by PNGC and OCEC. These projections are adjusted for BPA's base rate proposal, potential implementation of the Financial Reserves Policy, and potential cost increases for PNGC services. Power costs are assumed to increase 3.55%in CY 2020 and 3.79% CY 2022.
- Margins assume a Times Interest Earned Ratio (TIER) goal of 2.4. This goal is below current TIER levels.

Total CY 2019 revenues are expected to equal $5.8 million, while expenses are projected to amount to $5.5 million. This results in a 5.8 percent surplus in revenues relative to costs. A summary of the revenue requirement is shown in Table 1 for CY 2019 and CY 2020.

Table 1 Summary of the Revenue Requirement CY: 2019 & 2020		
Revenues	**2019**	**2020**
Present Rate Revenues	$5,718,206	$5,786,720
Other Income	84,626	84,626
Total Revenues	**$5,802,832**	**$5,871,345**
Expenses		
Power Supply	$2,764,943	$2,911,576
Transmission	0	0
Distribution	686,922	707,529
Customer Accounts and Services	306,429	315,622
Administration and General	631,819	650,773
Depreciation	391,571	411,150
Taxes	216,601	223,099
Interest and Debt Service	194,237	194,210
Other Contributions (including Patronage Capital & Operating Margins)	271,932	271,894
Total Expenses	**$5,464,454**	**$5,685,853**
Surplus (Deficiency) in Funds	$338,378	$185,492
Total Required Revenue Increase (Decrease)	-5.83%	-3.16%
Present Rate Revenues	$5,718,206	$5,786,720
Rev Req (Expenses less Other Income)	$5,379,829	$5,601,228
Surplus (Deficiency) in Funds	$338,378	$185,492
Required Retail Rate Increase (Decrease)	**-5.92%**	**-3.21%**

Cost of Service Study

A cost of service study is concerned with the equitable allocation of the revenue requirement to the various customer classes. As is standard procedure for cost of service analyses, the revenue requirement for OCEC was functionalized, classified and allocated.

A COSA study can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer and are based on costs of facilities and services if incurred at the present time. This study uses an embedded COSA as this is standard methodology for electric utilities.

Cost Allocation Methodologies

Generally, there are two methodologies that can be used to classify distribution costs: 100 percent demand and minimum system. The 100 percent demand methodology assumes that the distribution system is sized and built to meet customer non-coincident peak demands regardless of the maximum demand actually placed on the system at any given point in time. In other words, 100 percent demand assumes that the distribution system needs to be sized such that it can provide service to all customers in the case that maximum demand for all occurs at the same time. Therefore, distribution costs using this method are classified as 100 percent demand related.

Alternatively, distribution costs can be split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to customers' actual demand. Therefore, these additional system costs should be treated as demand related. Because the residential class tends to have the most customers, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100 percent demand methodology. Demand-vs-customer allocations for the minimum system case were derived using data from OCEC and other Northwest public utilities.

Results

Given a number of assumptions, the results show that using present rates, OCEC would be over-collecting revenues to meet test year costs. When examining the results, it is important to note that the inter-class cost allocation is based on load data estimates and usage pattern assumptions. Therefore, deviations of less than 10 percent from the cost of service typically do not warrant interclass rate modifications.

These results are summarized in Table 2 for minimum system and in Table 3 for 100 percent demand. More detail behind the results shown in Table 2 is presented in Schedules 1.1 and 1.2 of the Technical Appendix.

Table 2

Summary of Cost of Service Analysis - Minimum System – CY 2019

	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio
General Service Rate 1	$2,181,397	$2,100,995	$80,402	103.8%
General Service Rate 2	2,390,509	2,180,893	209,616	109.6%
General Service Rate 3	485,313	439,506	45,807	110.4%
General Service Rate 4	498,907	447,477	51,430	111.5%
Irrigation Single Phase	55,803	75,222	(19,419)	74.2%
Irrigation Poly Phase	94,264	121,466	(27,202)	77.6%
2nd Meter	7,713	10,498	(2,785)	73.5%
OSIN 22 & 23	4,301	3,772	529	114.0%
TOTAL	**$5,718,206**	**$5,379,829**	**$338,378**	**106.3%**

Table 3 Summary of Cost of Service Analysis – 100% Demand – CY 2019				
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio with Average Rate Increase**
General Service Rate 1	$2,181,397	$1,925,127	$256,270	113.3%
General Service Rate 2	2,390,509	2,314,860	75,648	103.3%
General Service Rate 3	485,313	463,955	21,358	104.6%
General Service Rate 4	498,907	483,547	15,360	103.2%
Irrigation Single Phase	55,803	62,294	(6,491)	89.6%
Irrigation Poly Phase	94,264	119,126	(24,861)	79.1%
2nd Meter	7,713	6,869	844	112.3%
OSIN 22 & 23	4,301	4,051	250	106.2%
TOTAL	**$5,718,206**	**$5,379,829**	**$338,378**	**106.3%**

Unit Cost Results

Based on the cost allocation and functionalization assumptions, unit costs for customer, energy, and demand charges are developed. Table 4 shows the summary COSA Unit Cost Results by customer class. The table also includes a melded demand and energy unit cost result for classes that are not currently billed for demand. These unit cost results, compared with current rates, are the typical starting point for rate design changes.

Table 4 COSA Unit Cost Results – Minimum System								
Unit Cost or Rate	**General Service Rate 1**	**General Service Rate 2**	**General Service Rate 3**	**General Service Rate 4**	**Irrigation Single Phase**	**Irrigation Poly Phase**	**2nd Meter**	**OSIN 22 & 23**
				Current Rates				
$/Customer/Month	**$32.00**	**$50.00**	**$60.00**	**$145.00**	**$46.00**	**$56.00**	**$25.00**	**$32.00**
$/kWh	**$0.0810**	**$0.0678**	**$0.0493**	**$0.0477**	**$0.04950**	**$0.04950**	**$0.0810**	**$0.0810**
$/kWh (block 2)		**$0.0758**						
$/kW			**$3.25**	**$3.25**	**$3.25**	**$3.25**		
				Unit Cost Results				
$/Customer/Month	**$33.54**	**$33.54**	**$52.35**	**$61.75**	**$32.99**	**$44.75**	**$33.54**	**$33.54**
$/kWh	**$0.0418**	**$0.0418**	**$0.0420**	**$0.0420**	**$0.0428**	**$0.0428**	**$0.0425**	**$0.0417**
$/kW	**$2.38**	**$2.90**	**$3.95**	**$3.57**	**$6.31**	**$6.25**	**$3.59**	**$4.33**
demand + energy, $/kWh	**0.0734**	**0.0681**					**0.1197**	**0.0680**

Recommendations

Based on the projected revenue requirement and COSA analysis, the following recommendations are made:

- Using current rates, OCEC is operating with a surplus in revenues compared to CY 2019 costs. However, because the projected revenues calculated in this study may not be sufficient for future cost increases and capital requirements, it is recommended that OCEC maintain current rates and consider a slight increase in future years.

- Based on the current COSA inter-class results, it appears that an adjustment in rate design may be needed at this time. Rate design requires additional detailed analysis beyond the scope of the project requirements.

  - OCEC may want to take a closer look at net metering impacts from solar given recent developments in statewide solar policies.

  - OCEC may want to take a closer look at irrigation rates given the under collection for these rate classes.

Overview of Rate Setting Principles

EES Consulting, Inc. (EES) was retained by Okanogan County Electric Cooperative (OCEC) to perform an electric cost of service study. Cost of service analysis is necessary to assure that OCEC's rates continue to recover the cost of operations and are structured to be fair, equitable and competitive.

In conducting this study, two inter-related analyses were performed. The first analysis performed was a revenue requirement analysis. This analysis examines the various sources and applications of funds for the utility and determines the overall revenue (retail rate) adjustment required of the utility. The second analysis is the cost of service analysis. The cost of service analysis (COSA) is used to determine the fair and equitable allocation of the total revenue requirement to the various customer classes.

Overview and Organization of Report

In developing electric rates for OCEC, a major goal of the study is to develop cost-based rates that meet OCEC's revenue requirement needs. It is important to understand that revenue requirement consists of both operational expenses and capital costs. Failure to collect the full revenue requirement may lead to a system that is more expensive to operate in the long run, and more susceptible to periodic outages and failures.

This report is organized such that it follows the steps taken in analyzing and developing OCEC's cost of service. This section provides a generic discussion of the theory and financial principles behind setting rates. The next section provides the revenue requirement analysis specific to OCEC. The following section discusses the cost of service study and the results of that process. The final section provides background on recent events at BPA. BPA costs are a primary driver behind power supply costs. Because power supply costs make up a large share of the utility's operating budget, it is important to review recent events that impact those costs.

A technical appendix is attached at the end of this report that details the various analyses using the minimum system and 100% demand methodologies to classify distribution costs. The schedules contained in the technical appendix are referenced throughout the report.

Rate Setting Overview

The setting of electric utility rates that are *fair and equitable* is a complex process. This process is directed, however, by *generally accepted methodologies* that can be used as a guide in developing OCEC's electric rates. At the same time, there are often a number of financial principles or guidelines that must be taken into consideration during this process. Therefore, the setting of electric rates that are *fair and equitable* is an integration of these generally accepted methodologies and any related financial policies or specific considerations from OCEC.

The purpose of this section of the report is to provide a brief overview of the basic fundamentals of cost identification and allocation for purposes of developing electric rates. From this base-level of knowledge, more insight and understanding can be obtained from the following sections of the report that discuss the specifics of the review of OCEC's allocated costs.

Types of Utilities

As noted above, there are different methodologies for setting electric rates. The first distinction often made in developing a methodology is the type of utility that is attempting to set rates. Utilities are generally divided into two types by ownership—public and private utilities.

Public utilities are generally owned by a municipality, cooperative, county, or special district and are operated on a not-for-profit basis. Public utilities are generally capitalized by issuing debt and soliciting funds from customers through direct capital contributions or user rates. Through statute and/or the lack of profit motive, public utilities do not pay state and federal income taxes. Finally, a public utility is usually regulated by a publicly elected or appointed City Council, Board of Commissioners, or Board of Trustees. As a point of reference, OCEC is a cooperative regulated by a Board of Directors.

In contrast, private electric utilities are capitalized by issuing debt or equity (stock) to the general public. The owners of the private utility are its equity contributors, or shareholders. Private utilities are taxable entities, and finally, they are generally regulated by state public utility commissions. Pacific Power is an example of a private electric utility.

These differences in ownership, and other characteristics, often lead to two different methods for reviewing revenue requirement needs. A more detailed discussion of the different methodologies that may be used is provided below.

Overview of Revenue Requirement Methodologies

By virtue of the differences noted above for a public versus a private utility, the respective revenue requirements include different elements. Most private utilities use what is known as a *utility* or *accrual* basis of determining revenue requirement. This convention calculates a utility's annual revenue requirement by aggregating operation and maintenance (O&M) expenses, taxes, depreciation expense, and a *fair* return on investment. Operating expenses include the labor, materials, supplies, etc., that are needed to keep the utility functioning. Private utilities must also pay state and federal income taxes, along with any applicable property, franchise, sales or other forms of taxes. Next, depreciation expense is a means of recouping the cost of capital (facilities) over the useful lives of those facilities and also a means of generating internal cash. Finally, a return on the capital investments recovers the utility's interest expense on debt, provides funds for a return to the utility's equity holders in the form of dividends, and leaves a balance for retained earnings and cash flow purposes.

In contrast to the *utility* or *accrual* method of developing revenue requirements for private utilities, a different method of determining annual revenue requirement is often used for public utilities. The convention used by most public utilities is called the *cash basis* of cost accounting. As the name implies, a public utility aggregates its cash expenditures to determine its total revenue requirement for a specified period of time. This methodology conforms nicely to most public utility budget processes, and it is a very straightforward calculation. Under the *cash basis* approach, there are four cost elements: operation and maintenance expenses, taxes, debt service, and capital improvements funded from rates.

The operating portion of the revenue requirement, i.e., O&M and taxes, are similar under either cash or accrual methodologies. The major difference between the two methodologies is the way in which capital costs are viewed and handled. Capital costs under the cash basis approach are calculated by adding debt service to capital improvements financed with rate revenues. A utility's depreciation expense is often used as a measure of the reasonable level of funding required from rates for capital improvement activities. Depreciation expense represents the current investment of the utility and the portion that has become worn out or obsolete and, therefore, must be renewed or replaced. It should be noted that the two portions of the capital expense component are necessary under the cash basis approach; utilities often cannot finance all capital facilities with long-term debt.

Table 5 compares the cash and utility accounting conventions.

Table 5
Cash vs. Utility Basis Comparison

	Cash Basis		Utility (Accrual) Basis
+	O&M Expense	+	O&M Expense
+	Taxes	+	Taxes
+	Capital Improvements Financed with Operating Revenues (Depreciation Expense)	+	Depreciation Expense
+	Debt Service (Principal & Interest)	+	Return on Investment
Σ	= Revenue Requirement	Σ	= Revenue Requirement

For this study, an accrual basis was used to determine the utility's revenue requirement.

Overview of Cost Allocation Procedures

After the total revenue requirement has been determined, it is allocated to the various customer classes of service based upon a fair and equitable methodology that reflects the cost-causal relationships for the production and delivery of the services. This analytical exercise usually takes the form of a *cost-of-service* study. A cost of service study begins by *functionalizing* a utility's revenue requirement as power supply, transmission, distribution and customer. Next, the functionalized costs are *classified* to demand-, energy-, and customer-related component costs. Demand related costs are those that the utility incurs to meet a customer's maximum instantaneous usage requirement, and is usually measured in kilowatts (kW). Energy related costs are those that vary directly with longer periods of consumption and are usually measured in kilowatt-hours (kWh). Customer related costs are those that vary with the number and type of customers served. These three component costs are then *allocated* to each class of service based upon the most equitable method available for each specific cost. At that point, the revenue requirement has been allocated to each class of service and a determination of the necessary revenue adjustments between classes of service can be made.

Rate Design and Economic Theory

The final step in the rate study process is to design rates for each class of service taking into consideration the results of the revenue requirement and cost of service analysis. Rates can take many forms, but ultimately, they should reflect the component costs that the utility incurs (demand, energy and customer related costs), and collect the desired level of revenues. Industry restructuring requires a greater level of detail to be provided in rates. This creates the need to rethink traditional methods of rate design, including unbundling of rates.

The process of developing competitive rate designs in a restructured environment will require greater consideration of fundamental economic and pricing theories. For example, economic theory dictates that, in a competitive market, the price of a commodity must roughly equal its cost, if equity among customers is to be maintained. The electric industry, however, has been a monopoly since its inception over 100 years ago and the concept of a competitive market was only in the minds of regulators who attempted to establish rates that were fair and equitable.

Competitive power markets have allowed some retail customers to investigate, as well as access, alternative power suppliers in direct competition with the utility for the business of supplying power to them. Traditional rate designs using time-of-day, seasonal or marginal cost-based utility rates were originally developed primarily to provide more accurate price signals for the cost of power supply. However, new rate designs for a competitive power supply need to be more detailed than in the past. The utility, in designing power supply rates, will need to take into consideration the characteristics of the power supply it acquires, as well as the characteristics of the customer to whom the utility will sell, as the utility will need to match the quality, quantity and price of the market alternative over some period of time.

While the power supply portion of the electric industry may be open to competition for retail customers, the transmission and distribution of that electricity is not. Thus, a customer may be faced with options for power supply but will still be required to purchase wires service from the local utility. The wires cost component is fixed and does not vary with usage, although distribution system investment does vary with the number of customers. These factors must be given consideration in designing rates if the utility is to recover its costs. Consumers will also need more accurate price signals that reflect the true cost of electricity production and delivery.

Providing greater detail in rate design will not come without cost or without some degree of effort. It will require greater refinement, not only of costing and pricing techniques, but of scheduling, billing, metering and other services as well. However, the result should create more accurate price signals that reflect the true cost of electricity production and delivery, greater efficiency in the marketplace, and overall savings to customers of power services.

These basic tenets have considerable foundation in economic literature and in today's competitive electric utility environment. They also serve as primary guidelines for rate design and are used by most utility regulators and administrative agencies. This *price-equals-cost* concept will provide the basis for much of the subsequent analysis and recommendations.

Development of the Revenue Requirement

This section of the report presents the development of the electric revenue requirement for OCEC. Simply stated, a revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required.

Overview of OCEC's Revenue Requirement Methodology

In developing the revenue requirement, a number of decisions must be made regarding the basic methodology to be used. As discussed in the previous section of the report, the first decision OCEC must make is the method of accumulating costs. Like most cooperatives, OCEC uses the *accrual basis* approach for determining revenue requirement. In summary form, OCEC's components to its revenue requirement include the elements shown in Table 6.

Table 6
Elements of an Accrual Basis Revenue Requirement

+	Operation and Maintenance Expenses (O&M)	
	✓	Power Supply Expense
	✓	Transmission Expense
	✓	Distribution Expense
	✓	Customer Accounting Expenses
	✓	Customer Service & Information Expense
	✓	Administrative and General Expense
+	Interest Expense	
+	Other Contributions (including Patronage Capital & Operating Margins)	
+	Depreciation	
+	Taxes	
	=	Total Revenue Requirement
	-	Miscellaneous Revenue Sources
Σ	=	Net Revenues Required From Rates

The next step in determining the revenue requirement is to select a time period from over which to review revenues and expenses. In the case of OCEC, a calendar year test period was utilized (January through December). CY 2019 was chosen as the test period for the cost of service study. OCEC provided budgeted cost projections for CY 2019. Revenues from retail rates and purchased power costs were forecast based on forecast CY 2019 loads. Projected CY 2019 costs are provided in Schedule 3.1. OCEC's revenue requirement allocated to customer classes can be found in Schedule 3.4.

Development of the Projected Load Forecast and Forecast Revenues

The load forecast for CY 2019 through CY 2023 was calculated based on the growth rates from the load forecast provided by OCEC staff and PNGC.

The load forecast is important as it is both used to allocate costs and also the forecast defines the units of consumption for rate design purposes. A summary of the loads for historic CY 2018 can be seen on Schedule 1.7. Line losses were calculated using total system purchases and total customer sales in CY 2018. Primary line losses were assumed to be 2%, secondary line losses were assumed to be 5.3%. Load factors and coincident factors were determined using the calculated line losses and actual load data by customer class. Forecast revenues at present rates were calculated for CY 2019 using current retail rate schedules and forecasted CY 2019 loads.

Development of Power Supply Costs

OCEC purchases wholesale power as a load following customer through Pacific Northwest Generating Cooperative (PNGC) from the Bonneville Power Administration (BPA). OCEC receives all of its wholesale power requirements from PNGC. From October 2011 and forward, BPA power supply costs are based on OCEC's contract high water mark (CHWM) and BPA's tiered rate structure. OCEC has elected a share of BPA's power supply as a load following customer; therefore, OCEC pays a fixed monthly charge, load shaping charges, and demand charges. Power supply costs also include BPA transmission costs under a Network Transmission (NT) contract. Projected power supply costs were based on information provided by OCEC, PNGC, and BPA.

As with most electric utilities, the major expense associated with operating the utility is power supply. Approximately $2.8 million, or 50 percent, of the CY 2019 total revenue requirement of the utility are production costs.

The total power requirement for OCEC was projected to be approximately 62.7 million kWh in CY 2019. For the time period reviewed in this study, the peak demand was expected to occur in February. On a cost per kWh basis, power purchases would equal approximately 4.41 cents. Total power supply costs are forecast to be $2.8 million in CY 2019, $2.9 million in CY 2020 and $3 million in CY 2021.

Other Operations and Maintenance Expenses

OCEC's financial forecast was used for the development of non-purchased power related operations and maintenance (O&M) expenses. Budgeted operating costs were divided between transmission, distribution, customer service and accounting, administrative and general expenses categories through the revenue requirement development process.

Total CY 2019 O&M expenses are projected at $4.39 million. Of this amount, $2.76 million is related to power supply costs. Therefore, non-power supply operating expenses are expected to be approximately $1.63 million in CY 2019.

Taxes

For CY 2019, taxes are projected at $216,601.

Interest Expense

CY 2019 interest on long term debt and debt service is projected at $194,237.

Depreciation

CY 2019 total depreciation for OCEC is projected at $391,819.

Other Contributions (including Patronage Capital & Operating Margins)

For CY 2019, other contributions included operating margins of $271,932, based on a TIER goal of 2.4.

Miscellaneous Revenues

OCEC receives additional operating and non-operating revenues and contributions. These come in the form of interest and dividend revenues, idle service revenues, rents, and other revenue. The combined estimate of these revenue items for CY 2019 is approximately $84,626.

Summary of Revenue Requirement

Once all of the components of the accrual basis revenue requirement have been forecast, the parts can be summed to equal the total revenue requirement. Since OCEC uses an *accrual basis* approach for rate setting, the basic revenue requirement is presented in that format. A summary of OCEC's revenue requirement for the forecasted period can be seen summarized in Table 7.

Table 7 Summary of the Revenue Requirement Forecast CY 2019 & 2020		
Applications of Funds	**2019**	**2020**
Operation and Maintenance Exp.		
Power Supply	$2,764,943	$2,911,576
Distribution	686,922	707,529
Customer Service and Accounting	306,429	315,622
Administrative and General	631,819	650,773
Total O&M Expenses	**$4,390,113**	**$4,585,500**
Depreciation	391,571	411,150
Taxes	216,601	223,099
Interest and Debt Service	194,237	194,210
Other Contributions (including Patronage Capital & Operating Margins)	271,932	271,894
Total Revenue Requirement	$5,464,454	$5,685,853
Less: Other Revenues/Net	(84,626)	(84,626)
Net Revenue Requirement	$5,379,829	**$5,601,228**
Revenues at Current Rates	**$5,718,206**	$5,786,720
Needed Retail Rate Adjustment	**-5.92%**	**-3.21%**

Table 8 shows projected rate increases through CY 2023. The rate increases in column *f* are based on a snapshot in time; the rate increase needed in each year (over current rates) is calculated to meet the revenue requirement in that year only. Future rate increases are cumulative, if a rate increase occurs in a particular year, this reduces future year rate increases by that increase over current rates.

Power supply costs are shown separately in column *b*.

Table 8 Projected Rate Increases						
CY	**Present Rate Revenues** *A*	**Power Supply Costs** *b*	**Non-Power Supply Costs, Net*** *c*	**Revenue Requirement** *d = b + c*	**Surplus (Deficiency)** *e = a - d*	**Rate Increase (decrease) Over Current Rates** *f =- e/a*
2019	5,718,206	2,764,943	2,614,886	5,379,829	338,378	-5.92%
2020	**5,786,720**	**2,911,576**	**2,689,651**	**5,601,228**	**185,492**	**-3.21%**
2021	5,850,264	2,990,083	2,809,021	5,799,104	51,160	-0.87%
2022	5,914,514	3,139,195	2,937,207	6,076,401	(161,887)	2.74%
2023	5,979,479	3,180,738	3,045,237	6,225,975	(246,496)	4.12%

*Includes miscellaneous revenues.

Recommendation

OCEC's revenues are sufficient to cover its cost obligations in 2019, but future rate increases may be necessary. It is important to note that OCEC's current revenue to cost balance needs to be continually monitored. Both short- and longer-term supply and operating cost considerations will need to be evaluated and analyzed as the Board of Directors works with OCEC's management to reach its operating objectives.

Cost of Service Analysis

The objective of the COSA is to analyze costs and equitably assign those costs to customers commensurate with the cost of serving those customers. The founding principal of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to apportion the utility's cost of service and provide a summary of the results.

COSA Definition and General Principles

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based on the cost-causal relationship associated with specific expense items. This approach results in a fair and equitable designation of costs to each customer class where customers pay for the costs that they incur. Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various classes using factors appropriate to each type of expense.

A COSA study can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer, and are based on costs of facilities and services if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are generally higher than embedded costs. Therefore, the use of a marginal COSA study usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an "accounting" perspective.

This study uses an embedded COSA as its standard methodology. Therefore, OCEC's embedded cost revenue requirement, and existing rate base investment, are used in developing the COSA results.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution, and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs are related to supplying and transporting power to customers on the system. Transmission costs are related to the bulk transfer of power throughout the system, which is designed to meet the peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer. Additionally, costs can be classified based on system revenues or directly assigned to a customer or group of customers.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.

General Ratemaking Principles

While this section does not address rate design, it is important to note that the COSA results will be one of the considerations when adjusting rates. The basic goals of rate design include:

- The utility's ability to collect the appropriate revenue requirement
- Utility revenues and customer rates are stable and predictable
- Proper price signals are sent to create efficiency of resources
- Rates are fair and equitable among customers and avoid undue discrimination
- Rates are simple, easy to understand and feasible for the utility to implement

The COSA is generally used to assist in meeting the second and fourth goals of rate design. Price signals are best if they reflect the specific costs incurred. Rates are generally considered fair and equitable if customers are deemed to pay their share of the costs incurred by the utility. Additionally, the first goal is met as long as the COSA is based on the appropriate revenue requirement, and the use of a consistent COSA methodology contributes towards the second goal. Rates are more stable through time if the COSA methodology is not significantly changed every time a rate application is made.

Functionalization of Costs

The first step in the COSA process following finalization of the revenue requirement is to functionalize the revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and customer service). Functionalization was accomplished using OCEC's system of accounts, which largely segregates costs in this manner.

In addition to the functionalized costs, certain joint costs are spread to each functional category based on the relationship of the joint cost to the business function. These joint costs include such items as administrative and general costs.

Standard Functionalization

Plant investment costs or rate base are generally functionalized into production, transmission, distribution and general cost categories. The functionalization of rate base typically is very straightforward as costs for the different functions are readily identifiable and rate base accounts are maintained by functional categories.

Expense accounts are also typically kept according to these basic functional categories, with expense items associated with certain types of plant being treated in the same manner as the corresponding plant account.

The two areas where there are differences in functionalization among utilities are in the treatment of general plant and A&G expenses. Typically, general plant is considered a separate functional category. Some utilities, when their internal accounting systems can support such an assignment process, will record general plant investment by loading the costs into the other functional categories, much like an overhead assignment or a form of activity-based accounting.

On the expense side, A&G costs can be treated in much the same way. Generally, they are treated as a separate expense category that can be spread to functions based upon all other O&M expenses. However, they can also be spread to functions on the basis of total net plant, labor ratios, or, in some cases, directly assigned as part of the activity-based accounting approach.

OCEC Functionalization Method

The specific functions used for OCEC's COSA are defined below. The functions generally follow standard cost of service approaches.

- ***Power Supply*.** The power supply function category includes all power-related services that are obtained by the utility through direct purchase. Where a utility does not produce power, the purchase activity represents a form of supply acquisition activity.
- ***Transmission*.** The transmission services that OCEC must acquire to deliver the purchased power supply to the service area are included in purchased power costs. The costs associated with the distribution system's transmission service include only those costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network.
- ***Distribution*.** Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items.

- ***Customer*.** Customer related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc.

Classification of Costs

The second step in performing a cost of service study is to classify the functionalized expenses to traditional cost causation categories. These cost causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

Functionalized power purchases, storage and transmission system costs are classified as demand-related and/or energy-related and in some instances directly assigned, while distribution costs are classified as demand or customer-related, or directly assigned to specific customer classes of service.

Standard Classification

The three most general classification categories are demand-related, energy/commodity-related and customer-related. Within these three categories there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. For example, demand and energy-related costs can be separated by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer related costs could be separated by demand and customer categories, while customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a particular category but rather in the same manner as an individual cost account or subtotal of specific cost accounts.

Generally, power production and purchased power costs are classified by a combination of demand and energy. Transmission costs are generally classified as peak demand, while distribution costs are generally split between demand and customer.

There are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak. Therefore, distribution costs are classified as 100% demand related. Specific distribution costs are sometimes split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers “demand” a higher delivery quantity. Therefore, the costs above the minimum system requirement should be treated as demand related. Because the residential class tends to have a higher number of customers, the minimum system methodology tends to allocate more costs to the residential customer class, and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and assignment philosophy. The complexity of the entire COSA process is further compounded since, in some cases, the classification category is clear, but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak for the year, a 2 CP approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks, or through some other approach such as "Average & Excess."

OCEC Classification Method

The following are the specific classifiers used in OCEC's COSA within each of the four functions:

- Power Supply

  Classifying power supply costs to demand and energy (commodity) components requires the evaluation of a number of complex, interrelated factors. Consideration must be given to what or who caused the power supply purchase to be made, and to the uses to which it will be put (i.e., meeting demand and energy requirement). Within this study, power supply costs are classified to demand, and energy based on OCEC's power cost forecast for the test period. The specific classifiers used for the power supply function include:

  - Energy
  - Demand

  Energy related costs are those that vary with the total amount of electricity consumed by a customer. Electricity usage measured in kWh is used in this portion of the analysis as well. Energy costs are the costs of consumption over a specified period of time, such as a month or year.

  Demand related costs are those that vary with the maximum demand or the maximum rates of power supply to customer classes. Customer and system demand for this analysis were measured in kW. Demand costs are generally related to the size of facilities needed to meet a customer's maximum demand at any point in time.

  Transmission

  BPA provides OCEC with transmission services to transfer power from BPA's supply to OCEC's system. The transmission bill components are separated into energy and demand costs before they are allocated to customer classes. The energy cost component is allocated to customer classes based non-coincident peak demand. The demand related component is allocated based on each customer class' share of OCEC's system peak, or coincident peak (CP). Coincident peak and, conversely, non-coincident peak are discussed more below.

- *Coincident peak demand (CP)* refers to the demand placed upon the system by each customer at the time of the system maximum peak and is generally related to meeting power supply or transmission peak requirements.
- *Non-coincident peak demand (NCP)* refers to the sum of the individual customer peak demands regardless of the time of occurrence. The sizing and corresponding expenses associated with distribution lines, which are sized to meet the specific individual customer demands for a limited geographic area within the utility's service territory, are examples of non-coincident demand costs.

  For this analysis, consumption statistics are reported as either demand (kW) or energy (kWh). Reported energy consumption reflects monthly-metered customer consumption by class. For classes that are not billed or metered on measured demand, demand information was derived based on an association between energy consumption, days within the particular month and class load factor assumptions that convert each class's consumption profile into NCP demand estimates. From those NCP determinations, customer class CP demand values were derived such that when the peak month CP values of all the various classes are summed, they match OCEC's maximum system peak metered at its interconnection with the regional transmission system. The CP and related NCP values developed within the COSA are later used to allocate demand related costs to the customer classes examined within the analysis.

- Transmission

  The transmission function includes the utility's own transmission assets associated with providing power to OCEC's distribution system. Transmission services that OCEC must incur to deliver the purchased power supply to OCEC's service area are included in purchased power costs. The costs associated with the local utility's transmission service include only those costs for operating and maintaining the transmission lines, poles, towers, substations, etc. used to deliver power to the distribution network. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system.

- Distribution

  Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's service area to the end user of the power. Classifying distribution costs requires a special analysis of the nature of the costs. Most distribution costs are split between demand and customer components. The demand component is the cost of facilities built to serve a particular load, such as distribution substations. The customer component is the cost of facilities that varies with the number of customers, such as meters. The following are the specific classifiers used for the distribution function:

- Non-coincident peak demand (NCP) on Primary System
- NCP on Secondary System
- Actual Customer
- Customers Weighted for Acct/Meter Reading
- Direct Assignment

The minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. With a relatively uniform customer base and a low percentage of industrial customers, a greater portion of costs are classified as customer related relative to demand under a minimum system approach to allocating costs. Using a *100 percent demand* classification approach assumes that distribution investment is based entirely on meeting the non-coincident peak demand.

- Customer

Customer-related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc. Customer related costs vary with the number and type of customers. They do not vary with system supply levels. These costs are sometimes referred to as *readiness to serve* or *availability* charges. Customer costs are incurred by the utility to have electricity supply readily available for a customer whether it is utilized or not.

There are two types of customer related cost classification categories—actual and weighted. Actual customer costs vary proportionally with the addition or deletion of a customer, regardless of the size or usage characteristics of the customer. An example of an actual customer related cost is postage on customer bills. The cost of postage does not vary regardless of the type or size of customer or usage levels. In contrast, a weighted customer cost reflects a disproportionate cost attributable to the addition or deletion of a customer. An example of weighted customer costs is meter-reading expenses. In some cases, it takes less time and effort to read a residential energy meter than it does to serve a large commercial customer that also has a demand meter. This type of difference is accounted for in the weighted customer allocation factors.

The specific classification of costs by account can be found in Schedule 3.3.

- Direct Assignment

Some costs can be directly assigned to certain customer classes without being classified as demand, energy, or customer related. These are generally costs associated with specific services, such as dedicated capital facilities, or with specific customer classes, such as lighting customers. Schedule 3.5 provides the background information for all direct assigned costs.

Allocation of Costs

The third step in performing a cost of service study is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

Standard Allocation

In general, the allocation of costs is straightforward once the costs have been classified to a specific category.

OCEC Allocation

The following are the specific allocation methods used in OCEC's COSA. The specific method of cost allocation by customer can be found in Technical Appendix Schedule 3.1.

- Demand Allocation Factors. For purposes of this study, five types of demand allocation factors were developed.
  - *Non-coincident peak demand allocation factor (NCP).* First, a non-coincident peak demand allocation factor was developed for each customer class. Expenses classified and allocated by the non-coincident peak demand allocation factor included those predicated on maximum demands such as distribution substations, and a portion of poles and lines, mains, meters and services. The NCP demand method allocates costs to each class of service based upon their highest individual non-coincident peak demand regardless of the time of occurrence. The NCP allocation factor is used to allocate distribution.
  - *1 Coincident peak (1 CP).* For each class of service, a contribution to a single annual system coincident peak was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the single coincident peak (1 CP) method. The 1 CP method allocates demand costs on the basis of a single demand value at the time of the system peak demand by each class. Expenses allocated on the 1 CP allocation factor include those related to OCEC's transmission system. The 1 CP allocation method is not used in this study.
  - *Sum of the two months coincident peaks (2 CP).* For each class of service, a contribution to a seasonal system coincident peak was also derived from the non-coincident peak by use of a coincidence factor. The coincident peak demand allocation method used was the sum of the summer and winter coincident peaks (2 CP) method. The 2 CP method allocates demand costs on the basis of the sum of the contributions to seasonal system peak demands by each class. The 2 CP method was not used in this study.
  - *Sum of monthly coincident peak (12 CP).* As with the 1 CP calculation, a contribution to monthly system coincident peaks was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the sum of the monthly coincident peak (12 CP) method. The 12 CP method allocates demand costs on the basis of demand value at the time of the system peak demand in each month

by each class. As discussed previously, the 12 CP method is used for power supply costs and transmission costs.

- *Average and excess method (A&E).* The average and excess method represents an alternative approach to CP related cost allocation. The A&E method compares a customer class's average demand against its maximum NCP demand in order to reflect, the classes *potential* peak demand volatility, and therefore its inherent ability to increase system peak requirement, that exists within each customer class. The A&E method was not used in this study.

- Energy Allocation Factors. Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. Energy allocation factors were used to allocate power supply costs, green-energy related costs and revenues, and surplus sales revenue.

- Customer Allocation Factors. Two basic types of customer costs were identified—actual and weighted. The allocation factor for actual customers was derived from the actual number of customers served in each class of service. Two weighted customer allocation factors were also developed. The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs.

  The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. *Since OCEC irrigation members are billed only 5 out of 12 months, the billing factors were adjusted to 0.4.* Customer allocation factors were used to allocate some distribution costs such as meters and meter installations and costs associated with customer service, accounts, and sales.

- Rate Base Allocation. The value of OCEC's assets as of December 2018 is functionalized, classified and then allocated to customer classes. The resulting functionalized, classified and allocated rate base is then used to develop rate base allocation factors. These allocation factors (i.e., general plant, net plant, distribution rate base, etc.) are then used to allocate revenue requirement expenses. For example, maintenance of station equipment can be allocated using station equipment rate base, or property taxes might be allocated using net plant.

- Other Cost Allocation. Other costs are allocated based on specific rate base items, O&M function totals, revenues, labor ratios and other allocation factors. These other allocation factors were used to allocate administrative and general expense items, some other revenues such as dividend income or non-operating rental income.

  The allocation factors shown in Schedule 3.1 are used to allocate costs by customer or by function using the percentages developed in Schedules 6.1 and 6.2.

  - Administrative and General (A&G). All costs that are related to general overhead are classified to this area. Costs are allocated to customers based on their percentage of total revenue.

- Miscellaneous Other Revenues

  - ✓ Miscellaneous other revenues are generally allocated to customers based on allocation of all other O&M expenses.

Review of Customer Classes of Service

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirement. The classes of service used within this study were as follows (rate schedule):

- General Service Rate 1
- General Service Rate 2
- General Service Rate 3
- General Service Rate 4
- Irrigation Single Phase
- Irrigation Poly Phase
- 2nd Meter
- OSIN Rate 22 and 23

Major Assumptions of the Cost of Service Study

Major assumptions used in conducting the cost of service study for OCEC are as follows:

- Forecast CY 2019 was selected as the period for the allocation of costs within the cost of service study.

- The revenue requirement as outlined in Section 2 was used for the cost of service study.

- Power supply costs are based on the power cost forecast provided by PNGC and OCEC, but adjusted for BPA's base rate proposal, potential implementation of the Financial Reserves Policy, and potential cost increases for PNGC services. Power costs are assumed to increase 3.55%t in CY 2020 and 3.79% CY 2022.

- Distribution plant was classified based on both on a *minimum system* approach and a *100% demand* approach.
- Load forecast was based on data provided by OCEC, BPA and PNGC.
- Irrigation metering services are weighted based on 5 out of 12 billing months.

Given these key assumptions, the cost of service analysis could be completed. Schedules 3.4 and 4.3 in the appendix show the functionalized and classified rate base and revenue requirement, allocated to each class of service.

Cost of Service Results

Given the above assumptions regarding the cost of service analysis, the various costs were classified and allocated to the customer classes of service. Table 9 shows the results of this analysis by function for the minimum system approach.

Table 9

Summary of Functionalized Cost of Service

Minimum System Approach – CY 2019

	Production Related	Transmission Related	Distribution Related	Customer Related	Direct Assignment	Net Revenue Requirement
General Service Rate 1	770,172	0	409,400	921,423	0	2,100,995
General Service Rate 2	1,211,494	0	527,131	442,267	0	2,180,893
General Service Rate 3	329,411	0	65,233	44,862	0	439,506
General Service Rate 4	373,460	0	65,865	8,152	0	447,477
Irrigation Single Phase	24,404	0	10,303	40,514	0	75,222
Irrigation Poly Phase	53,352	0	21,575	46,539	0	121,466
2nd Meter	687	0	957	8,853	0	10,498
OSIN 22 & 23	1,962	0	1,005	805	0	3,772
TOTAL	**2,764,943**	**0**	**1,101,470**	**1,513,416**	**0**	**5,379,829**

A summary comparison of the allocated cost of service and anticipated revenue from present rates can be found in Table 11. Unit cost estimates have been developed in Schedule 2.1.

Table 10 provides the COSA results using a 100 percent demand methodology.

Table 10 Summary of Functionalized Cost of Service 100 Percent Demand Approach – CY 2019						
	Production Related	**Transmission Related**	**Distribution Related**	**Customer Related**	**Direct Assignment**	**Net Revenue Requirement**
General Service Rate 1	770,172	0	667,838	487,117	0	1,925,127
General Service Rate 2	1,211,494	0	869,558	233,808	0	2,314,860
General Service Rate 3	329,411	0	103,228	31,316	0	463,955
General Service Rate 4	373,460	0	104,022	6,065	0	483,547
Irrigation Single Phase	24,404	0	16,786	21,103	0	62,294
Irrigation Poly Phase	53,352	0	35,673	30,100	0	119,126
2nd Meter	687	0	1,501	4,680	0	6,869
OSIN 22 & 23	1,962	0	1,663	425	0	4,051
TOTAL	**2,764,943**	**0**	**1,800,271**	**814,615**	**0**	**5,379,829**

The overall results for CY 2019 are summarized in Table 11 and Figure 1 for minimum system and in Table 12 and Figure 2 for 100 percent demand. More detail behind the results shown is presented in Schedules 1.1 and 1.2.

Table 11 Summary of Cost of Service Analysis - Minimum System – CY 2019				
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio**
General Service Rate 1	$2,181,397	$2,100,995	$80,402	103.8%
General Service Rate 2	2,390,509	2,180,893	209,616	109.6%
General Service Rate 3	485,313	439,506	45,807	110.4%
General Service Rate 4	498,907	447,477	51,430	111.5%
Irrigation Single Phase	55,803	75,222	(19,419)	74.2%
Irrigation Poly Phase	94,264	121,466	(27,202)	77.6%
2nd Meter	7,713	10,498	(2,785)	73.5%
OSIN 22 & 23	4,301	3,772	529	114.0%
TOTAL	**$5,718,206**	**$5,379,829**	**$338,378**	**106.3%**

As shown in Figure 1, the two Irrigation customer classes and the 2nd meter class are significantly outside of the 10 percent of cost of service.

Figure 1
Minimum System Results for CY 2019

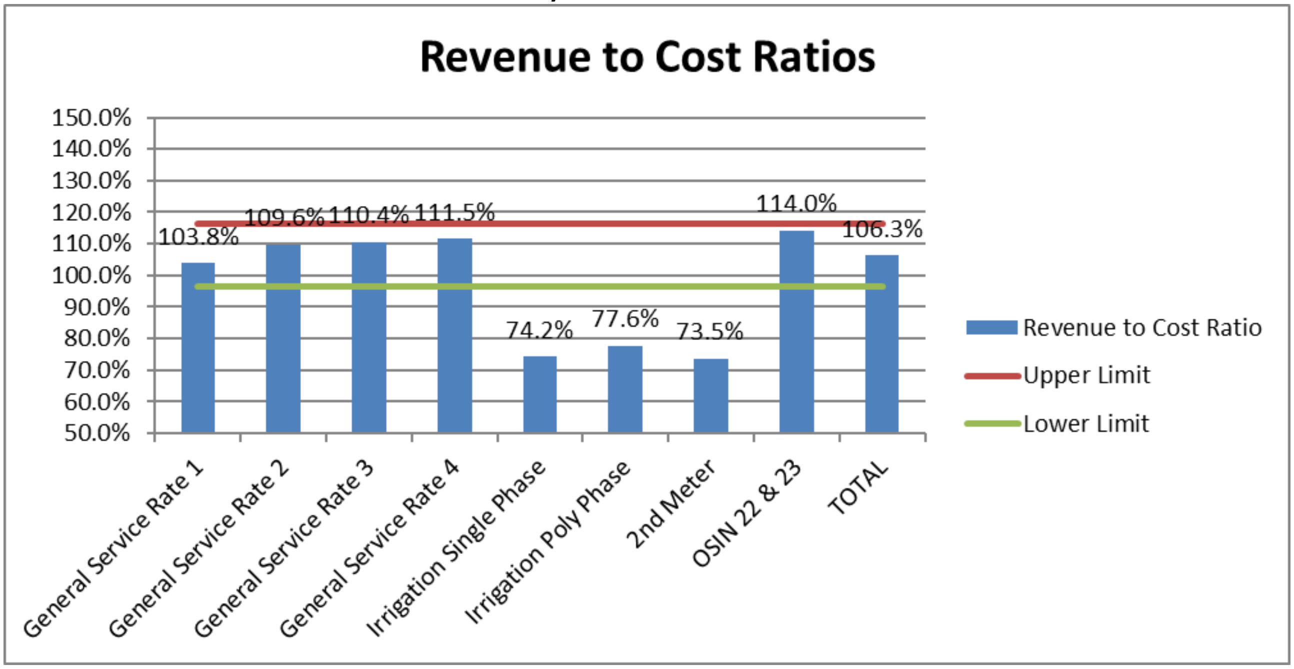
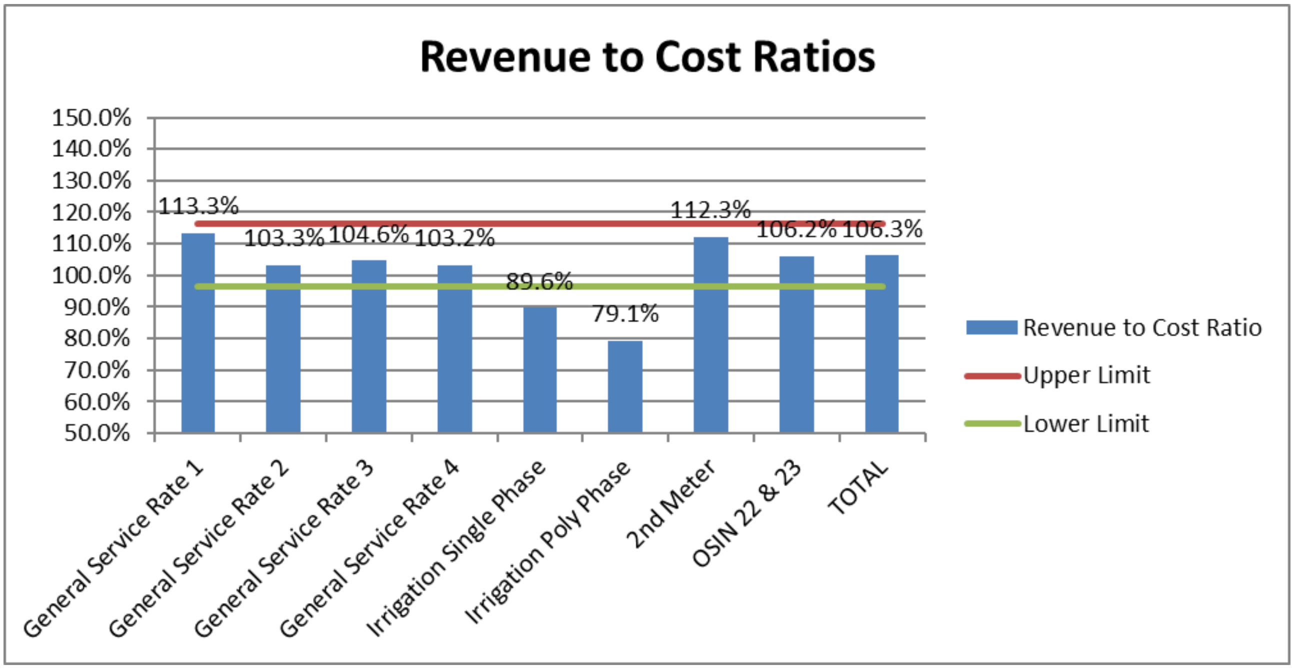


Table 12
Summary of Cost of Service Analysis – 100% Demand

	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio
General Service Rate 1	$2,181,397	$1,925,127	$256,270	113.3%
General Service Rate 2	2,390,509	2,314,860	75,648	103.3%
General Service Rate 3	485,313	463,955	21,358	104.6%
General Service Rate 4	498,907	483,547	15,360	103.2%
Irrigation Single Phase	55,803	62,294	(6,491)	89.6%
Irrigation Poly Phase	94,264	119,126	(24,861)	79.1%
2nd Meter	7,713	6,869	844	112.3%
OSIN 22 & 23	4,301	4,051	250	106.2%
TOTAL	**$5,718,206**	**$5,379,829**	**$338,378**	**106.3%**

As shown in Figure 2, the 100 percent demand methodology shows slightly less variability among customer classes with the Irrigation customer classes still significantly outside the 10 percent of cost of service range.

Figure 2
100 Percent Demand Results for CY 2019



Given a number of assumptions, the results show that using present rates, OCEC is collecting sufficient revenues to meet projected costs. When examining the results, it is important to note that the inter-class cost allocation is based on load data estimates and usage pattern assumptions. Therefore, deviations of less than 10 percent from the cost of service typically do not warrant interclass rate modifications.

Unit Cost Results

Given the above COSA assumptions, the study produces unit costs for customer, energy, and demand charges. Table 13 shows the summary COSA Unit Cost Results by customer class. The table also includes a melded demand and energy unit cost result for classes that do not have demand charges.

Table 13
COSA Unit Cost Results – Minimum System

Unit Cost or Rate	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
				Current Rates				
$/Customer/Month	$32.00	$50.00	$60.00	$145.00	$46.00	$56.00	$25.00	$32.00
$/kWh	$0.0810	$0.0678	$0.0493	$0.0477	$0.04950	$0.04950	$0.0810	$0.0810
$/kWh (block 2)	$0.0758							
$/kW			$3.25	$3.25	$3.25	$3.25		
				Unit Cost Results				
$/Customer/Month	$33.54	$33.54	$52.35	$61.75	$32.99	$44.75	$33.54	$33.54
$/kWh	$0.0418	$0.0418	$0.0420	$0.0420	$0.0428	$0.0428	$0.0425	$0.0417
$/kW	$2.38	$2.90	$3.95	$3.57	$6.31	$6.25	$3.59	$4.33
demand + energy, $/kWh	0.0734	0.0681					0.1197	0.0680

These unit cost results, when combined with existing rates, are the typical starting point for rate design changes. Added consideration of rate design changes will require further analysis and development of rate options and bill impacts by customer class.

Bonneville Power Administration

Traditionally, power supply has made up 50 percent of OCEC's annual revenue requirement. OCEC currently receives, and is expected to continue to receive, 100 percent of its wholesale power requirements from the BPA through PNGC. OCEC also purchases transmission service from BPA through PNGC. Since OCEC purchases its power and transmission requirements from BPA, an overview of recent events related to BPA and the pricing of its services is instructive.

Introduction

BPA markets electric energy from 29 federal hydroelectric projects in the Pacific Northwest, the Columbia Generating Station nuclear project, and contractual purchases and exchanges to meet approximately 50 percent of the Pacific Northwest's energy requirement. BPA also owns and operates approximately 75 percent of the Pacific Northwest's high-voltage transmission system. BPA's transmission facilities interconnect with utilities in the Canadian province of British Columbia and with utilities in California.

BPA's rate structure changed in October 2011 when it began selling wholesale power to its customer utilities at tiered rates with market-based rates serving load growth above 2010 actual loads (the high-water mark). Tier 1 allocations are roughly equal the capability of the Federal Based System (FBS) under critical water conditions. Under this approach, each BPA customer effectively receives a share of output from the FBS for a 20-year contract period. Power requirements above Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers at wholesale market-based prices. PNGC coordinates above-HWM purchases on behalf of PNGC members, including OCEC.

BPA Power Services

Tier 1 power costs are based on projected FBS costs; however, the quantity of power OCEC is able to purchase at these rates is limited. BPA used weather and conservation adjusted loads from October 2009 through September 2010 (BPA fiscal year 2010) to set OCEC's HWM, or the maximum amount of energy OCEC can purchase at Tier 1 rates. Tier 1 rates are, for the most part, cost based and are determined in formal rate proceedings.

Energy requirements in excess of OCEC's HWM can be provided either by non-federal resources, wholesale market purchases or BPA Tier 2 purchases. Tier 2 rates are based on a combination of actual market purchases BPA has made to serve projected Tier 2 loads and forecast market prices. BPA's Tier 2 rates are designed to recover the full costs of the generating resources and/or market purchases that will be used to serve Tier 2 loads. Tier 2 rates apply to flat blocks of power. PNGC coordinates above-HWM purchases on behalf of PNGC members, including OCEC.

Above-HWM load is based on the amount of load growth each customer class has experienced since BPA fiscal year 2010 (October 2009 through September 2010). Due to declining prices for market purchases, above-HWM power costs are projected to stay low.

BPA's load following customers, including OCEC, are subject to BPA's load shaping rates. These rates apply when a utility's load shape is different than the utility's share of energy available from the FBS. During months in which a utility's share of the FBS is less than power requirements, load shaping charges apply. In months in which a utility's power requirements are less than the utility's share of the FBS, load shaping credits apply. Load shaping rates are based on BPA's projection of wholesale market prices at the time of the rate case.

BPA's load following customers are also subject to BPA's demand rates. The monthly billing determinants for BPA's demand product are calculated by taking OCEC's monthly system peak demand less OCEC's average on-peak energy less OCEC's above HWM purchases less OCEC's Contract Demand Quantity (CDQ). The monthly CDQs are set for the contract period (through September 2028) and are based on historic load factors. BPA's current monthly demand rates vary between a high of $13.45 per kilowatt and a low of $5.04 per kilowatt.

BPA Transmission Services

OCEC purchases transmission and ancillary services from BPA under a NT contract, through PNGC. BPA sets rates for transmission and ancillary services every other year through its rate case process. BPA's rates for each service are based on forecast sales and forecast costs associated with providing services. PNGC coordinates transmission purchases on behalf of PNGC members, including OCEC.

BPA Financial Reserve Policy and Other Surcharges

In the most recent rate case, BPA implemented its Financial Reserves Policy (FRP). Although the BPA base rate increase may be low in a particular year, if BPA runs short on cash, an FRP Surcharge is added to the power or transmission bills. The FRP amount for following years won't be known until after the fourth quarter financials are available (early November). The FRP surcharge will appear on invoices in December through September. The FRP surcharge is a fixed monthly amount for each utility. BPA's rate models include monthly FRP charge of $0.81/MWh which corresponds to $30 million cost recovery for all customers and a 1.5% rate impact to each customer. The billing determinant is monthly system shaped load (used to calculate load shaping charges) and applies to non-Slice load only (block portion of Slice/Block customers purchases).

BPA has also implemented a Spill Surcharge in the past, and, like the FRP Surcharge, this became an adder to customer bills. This Spill Surcharge could be implemented in the future; however, BPA melded these costs into the base rates for the most recent case.

Technical Appendix

EES Consulting

Okanogan County Electric Cooperative

Cost of Service Schedules

Date:	October 14, 2019
Version:	Revised Final Version
Test Period:	CY: 2019
Production Peak Allocation Method:	12 Month Peak Responsibility Method (12 CP)
Transmission Peak Allocation Method:	12 Month Peak Responsibility Method (12 CP)
Distribution System Allocation Method:	**100 Percent Demand**

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SUMMARY OF PRESENT AND PROPOSED RATE REVENUE
BY CUSTOMER CLASS
Schedule 1.1

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Revenues - Present Rate	$5,718,206	$2,181,397	$2,390,509	$485,313	$498,907	$55,803	$94,264	$7,713	$4,301
Less Allocated Revenue Requirement	$5,379,829	$1,925,127	$2,314,860	$463,955	$483,547	$62,294	$119,126	$6,869	$4,051
Difference	$338,378	$256,270	$75,648	$21,358	$15,360	-$6,491	-$24,861	$844	$250
Revenue To Cost Ratio	106.3%	113.3%	103.3%	104.6%	103.2%	89.6%	79.1%	112.3%	106.2%
% Increase Retail Rates to Equal Allocated Cost	**-5.9%**	**-11.7%**	**-3.2%**	**-4.4%**	**-3.1%**	**11.6%**	**26.4%**	**-10.9%**	**-5.8%**
Rate Base	$6,190,149	$2,378,519	$2,837,142	$366,787	$327,500	$90,359	$176,589	$7,864	$5,389
Rate Of Return, %	5.5%	10.8%	2.7%	5.8%	4.7%	-7.2%	-14.1%	10.7%	4.6%
Rate Of Return, $	$338,378	$256,270	$75,648	$21,358	$15,360	-$6,491	-$24,861	$844	$250
Modified Debt Service Coverage Ratio									
Unit Cost: Present Rates ($/kWh)	**$0.097**	**$0.136**	**$0.094**	**$0.066**	**$0.059**	**$0.107**	**$0.083**	**$0.561**	**$0.099**

Unit Cost Summary

Unit Cost: Present Rates ($/kWh)	**$0.097**	**$0.136**	**$0.094**	**$0.066**	**$0.059**	**$0.107**	**$0.083**	**$0.561**	**$0.099**
Unit Cost: COSA Rates ($/kWh)	**$0.091**	**$0.120**	**$0.091**	**$0.063**	**$0.057**	**$0.119**	**$0.104**	**$0.500**	**$0.093**
Difference from Present Rates	-5.92%	-11.75%	-3.16%	-4.40%	-3.08%	11.63%	26.37%	-10.94%	-5.81%

Okanogan County Electric Cooperative - 100 Percent Demand

Prepared By EES Consulting, Inc.

FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY
BY CUSTOMER CLASS
Schedule 1.2

	Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production										
	Demand (PD)	$286,396	$97,991	$143,590	$18,732	$19,346	$1,987	$4,503	$104	$144
	Energy (PE)	$2,478,547	$672,181	$1,067,904	$310,679	$354,114	$22,418	$48,849	$583	$1,819
	Direct Assignment (PDA)									
Transmission										
	Demand (TD)									
	Energy (TE)									
	Direct Assignment (TDA)									
Distribution										
	Demand (DD)	$1,800,271	$667,838	$869,558	$103,228	$104,022	$16,786	$35,673	$1,501	$1,663
	Energy (DE)									
	Customer (DC)	$814,615	$487,117	$233,808	$31,316	$6,065	$21,103	$30,100	$4,680	$425
	Direct Assignment (DDA)									
	Total	**$5,379,829**	**$1,925,127**	**$2,314,860**	**$463,955**	**$483,547**	**$62,294**	**$119,126**	**$6,869**	**$4,051**
Total Cost / Function										
	Production	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
	Transmission									
	Distribution	$2,614,886	$1,154,955	$1,103,366	$134,544	$110,087	$37,890	$65,774	$6,182	$2,089
	Total Cost / Function	**$5,379,829**	**$1,925,127**	**$2,314,860**	**$463,955**	**$483,547**	**$62,294**	**$119,126**	**$6,869**	**$4,051**
Total Cost / Classifier										
	Demand	$2,086,667	$765,829	$1,013,148	$121,959	$123,368	$18,773	$40,176	$1,605	$1,807
	Energy	$2,478,547	$672,181	$1,067,904	$310,679	$354,114	$22,418	$48,849	$583	$1,819
	Customer	$814,615	$487,117	$233,808	$31,316	$6,065	$21,103	$30,100	$4,680	$425
	Direct Assignment									
	Total Cost / Classifier	**$5,379,829**	**$1,925,127**	**$2,314,860**	**$463,955**	**$483,547**	**$62,294**	**$119,126**	**$6,869**	**$4,051**
	check									

FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE SUMMARY
BY CUSTOMER CLASS
Schedule 1.3

	Historic Year: 2018	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production										
	Demand (PD)	$61,408	$21,011	$30,788	$4,016	$4,148	$426	$966	$22	$31
	Energy (PE)	$206,546	$56,015	$88,992	$25,890	$29,509	$1,868	$4,071	$49	$152
	Direct Assignment (PDA)									
Transmission										
	Demand (TD)									
	Energy (TE)									
	Direct Assignment (TDA)									
Distribution										
	Demand (DD)	$5,160,443	$1,908,491	$2,528,728	$280,578	$281,778	$47,876	$104,110	$4,018	$4,863
	Energy (DE)									
	Customer (DC)	$761,752	$393,001	$188,634	$56,302	$12,064	$40,189	$67,442	$3,776	$343
	Direct Assignment (DDA)									
	Total	**$6,190,149**	**$2,378,519**	**$2,837,142**	**$366,787**	**$327,500**	**$90,359**	**$176,589**	**$7,864**	**$5,389**
Total Cost / Function										
	Production	$267,954	$77,026	$119,780	$29,906	$33,658	$2,294	$5,036	$71	$182
	Transmission									
	Distribution	$5,922,195	$2,301,492	$2,717,362	$336,881	$293,842	$88,065	$171,553	$7,794	$5,207
	Total Cost / Function	**$6,190,149**	**$2,378,519**	**$2,837,142**	**$366,787**	**$327,500**	**$90,359**	**$176,589**	**$7,864**	**$5,389**
Total Cost / Classifier										
	Demand	$5,221,851	$1,929,502	$2,559,516	$284,595	$285,926	$48,302	$105,076	$4,040	$4,894
	Energy	$206,546	$56,015	$88,992	$25,890	$29,509	$1,868	$4,071	$49	$152
	Customer	$761,752	$393,001	$188,634	$56,302	$12,064	$40,189	$67,442	$3,776	$343
	Direct Assignment									
	Total Cost / Classifier	**$6,190,149**	**$2,378,519**	**$2,837,142**	**$366,787**	**$327,500**	**$90,359**	**$176,589**	**$7,864**	**$5,389**
	check									

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION

Schedule 1.4

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Steam Power Generation									
Nuclear Power Generation									
Hydraulic Power Generation									
Gas Turbine Power Generation									
Other Power Supply									
Power Purchases	$2,314,440	$616,032	$985,626	$299,946	$343,028	$21,279	$46,269	$524	$1,736
Transmission/Ancillary Services Purchases	$450,503	$154,141	$225,868	$29,465	$30,432	$3,125	$7,083	$163	$226
BPA Transmission									
Other									
Total Production	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
Total Transmission									
Total Distribution	$686,922	$267,470	$311,963	$39,771	$33,765	$11,061	$21,355	$940	$597
Total Other									
Total Operation & Maintenance	**$3,451,865**	**$1,037,642**	**$1,523,457**	**$369,182**	**$407,225**	**$35,465**	**$74,707**	**$1,627**	**$2,560**
Total O&M w/o Purchased Power Supply & A&G	**$993,351**	**$463,791**	**$406,194**	**$45,895**	**$34,708**	**$14,717**	**$24,451**	**$2,826**	**$769**
	$2,458,514								
Total Customer Service, Accounts & Sales	$306,429	$196,322	$94,231	$6,123	$943	$3,656	$3,096	$1,886	$171
Total Administrative & General	$631,819	$294,437	$258,714	$29,267	$22,181	$9,361	$15,583	$1,787	$490
Total O&M plus A&G	**$4,390,113**	**$1,528,400**	**$1,876,403**	**$404,573**	**$430,349**	**$48,482**	**$93,386**	**$5,300**	**$3,221**
Total Depreciation	$391,571	$151,089	$180,361	$22,422	$19,632	$5,824	$11,403	$494	$346
Total Taxes	$216,601	$82,810	$92,310	$17,242	$17,364	$2,325	$4,093	$289	$168
Total Interest / Debt Service Expense	$194,237	$74,947	$89,467	$11,122	$9,738	$2,889	$5,657	$245	$171
Total Return on Investment (X.X% of Total Rate Base)									
Total Capital Projects Funded From Rates									
Total Other Contributions	$271,932	$126,964	$111,196	$12,564	$9,501	$4,029	$6,694	$774	$211
Revenue Requirement Before Other Revenues	**$5,464,454**	**$1,964,211**	**$2,349,738**	**$467,923**	**$486,584**	**$63,548**	**$121,232**	**$7,101**	**$4,117**
Revenue Req. Before Taxes and Other Revenues	**$5,247,853**	**$1,881,400**	**$2,257,428**	**$450,681**	**$469,221**	**$61,223**	**$117,139**	**$6,813**	**$3,949**
Total Other Revenues	$84,626	$39,083	$34,877	$3,968	$3,037	$1,254	$2,107	$232	$66
REVENUE REQUIREMENT for COST ALLOCATION	**$5,379,829**	**$1,925,127**	**$2,314,860**	**$463,955**	**$483,547**	**$62,294**	**$119,126**	**$6,869**	**$4,051**

SUMMARY OF RATE BASE COST ALLOCATIONS

Schedule 1.5

Historic Year: 2018	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Total Production Plant									
Total Transmission Plant									
Total Distribution Plant	$7,971,798	$3,075,945	$3,671,886	$456,483	$399,675	$118,559	$232,152	$10,060	$7,038
Total Transmission & Distribution	$7,971,798	$3,075,945	$3,671,886	$456,483	$399,675	$118,559	$232,152	$10,060	$7,038
Total General Plant	$2,197,402	$847,875	$1,012,144	$125,828	$110,169	$32,680	$63,992	$2,773	$1,940
Total Plant Before General Plant & Intangible	**$7,971,798**	**$3,075,945**	**$3,671,886**	**$456,483**	**$399,675**	**$118,559**	**$232,152**	**$10,060**	**$7,038**
Total Gross Plant in Service	**$10,170,214**	**$3,924,211**	**$4,684,497**	**$582,369**	**$509,895**	**$151,254**	**$296,174**	**$12,834**	**$8,979**
Total Accumulated Depreciation	$4,454,153	$1,718,650	$2,051,625	$255,055	$223,314	$66,243	$129,712	$5,621	$3,933
Total Net Plant	**$5,716,061**	**$2,205,561**	**$2,632,872**	**$327,314**	**$286,581**	**$85,011**	**$166,461**	**$7,213**	**$5,047**
Total Working Capital	$471,100	$171,805	$202,894	$39,302	$40,769	$5,304	$10,041	$647	$340
Total Contributions									
TOTAL RATE BASE	**$6,187,161**	**$2,377,366**	**$2,835,766**	**$366,616**	**$327,350**	**$90,315**	**$176,502**	**$7,861**	**$5,386**
Total CWIP	$2,988	$1,153	$1,376	$171	$150	$44	$87	$4	$3
TOTAL RATE BASE plus CWIP	**$6,190,149**	**$2,378,519**	**$2,837,142**	**$366,787**	**$327,500**	**$90,359**	**$176,589**	**$7,864**	**$5,389**

SUMMARY OF HISTORIC LOAD DATA

Schedule 1.6

Historic Year: 2018	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Recorded Load Data									
Energy Sales (kWh)	58,120,088	15,501,591	25,086,739	7,306,671	8,422,988	547,952	1,194,613	13,905	45,629
Total Billing Capacity (kVa)	53,622			22,256	24,967	2,036	4,362		
Avg. Monthly Billing Capacity (kVa)	4,468			1,855	2,081	170	363		
Number of Customers	3,668	2,273	1,099	71	11	102	87	23	2
Ratio of NCP to Avg. Billing Capacity				64%	60%	180%	189%		
Rate Classes NCP Demand at Meter	19,882	6,959	9,461	1,191	1,242	306	686	17	19
Estimates Based on Recorded Data									
Annual NCP Load Factor	33%	25%	30%	70%	77%	20%	20%	9%	27%
Rate Classes CP Demand at Input Voltage	20,239	7,425	10,196	1,279	1,338			1	
Annual CP Load Factor	33%	24%	28%	65%	72%			292%	
Average On-Peak kWh as a % of Total kWh		59%	59%	59%	59%	61%	61%	60%	59%
Average Off-Peak kWh as a % of Total kWh		41%	41%	41%	41%	39%	39%	40%	41%

Okanogan County Electric Cooperative - 100 Percent Demand

SUMMARY OF FORECAST LOAD DATA

Schedule 1.7

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Forecast Load Data									
Energy Sales (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Total Billing Capacity (kVa)	53,622			22,256	24,967	2,036	4,362		
Avg. Monthly Billing Capacity (kVa)	4,468			1,855	2,081	170	363		
Number of Customers	3,684	2,290	1,099	71	11	102	87	22	2
Ratio of NCP to Avg. Billing				61%	57%	172%	180%		
Rate Classes NCP Demand at Meter	23,678	9,148	11,221	1,138	1,187	292	656	17	18
Forecast Based on Recorded and Forecast Data									
Annual NCP Load Factor	29%	20%	26%	74%	81%	20%	20%	9%	27%
Rate Classes CP Demand at Input Voltage	24,355	9,760	12,092	1,223	1,279			1	
Annual CP Load Factor	28%	19%	24%	69%	75%			213%	
On-Peak kWh as a % of Total kWh	59%	59%	59%	59%	59%	61%	61%	60%	59%
Off-Peak kWh as a % of Total kWh	41%	41%	41%	41%	41%	39%	39%	40%	41%

SUMMARY OF POWER SUPPLY COSTS

Schedule 1.8

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Steam Power Generation									
Nuclear Power Generation									
Hydraulic Power Generation									
Gas Turbine Power Generation									
Other Power Supply									
Forecast Power Supply									
Power Purchases									
Load Shaping, HLH	$98,156	$26,672	$42,361	$12,275	$13,990	$869	$1,894	$23	$72
Load Shaping, LLH	$102,495	$27,851	$44,234	$12,818	$14,608	$907	$1,978	$24	$76
LDD Credit	-$164,107	-$56,150	-$82,278	-$10,733	-$11,085	-$1,138	-$2,580	-$59	-$82
IRMP									
Part B Purchase (Energy)	$63,474	$17,248	$27,393	$7,938	$9,047	$562	$1,225	$15	$47
FRP Surcharge	$3,691	$1,003	$1,593	$462	$526	$33	$71	$1	$3
Customer Refund / BPA Base Rate Red	-$52,146	-$14,170	-$22,505	-$6,521	-$7,432	-$462	-$1,006	-$12	-$38
Transmission/Ancillary Services Purchases									
Energy	$197,487	$67,571	$99,014	$12,917	$13,340	$1,370	$3,105	$72	$99
Demand									
Coincident Transmission Peak-Demand	$253,016	$86,570	$126,854	$16,548	$17,091	$1,755	$3,978	$92	$127
Wheeling Revenue									
Other									
Open									
Open									
Total Power Supply	**$502,066**	**$156,595**	**$236,666**	**$45,703**	**$50,084**	**$3,896**	**$8,666**	**$154**	**$303**

SUMMARY OF REVENUES AT PRESENT RATES

Schedule 1.9

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Revenues:									
Customer Charge Revenues	$1,664,304	$879,232	$659,400	$51,420	$19,140	$23,552	$24,192	$6,600	$768
Energy Revenues	$3,887,328	$1,302,165	$1,731,109	$364,754	$402,207	$25,926	$56,522	$1,113	$3,533
Demand Revenues	$166,575			$69,139	$77,560	$6,325	$13,550		
Surcharge									
Total Revenues	**$5,718,206**	**$2,181,397**	**$2,390,509**	**$485,313**	**$498,907**	**$55,803**	**$94,264**	**$7,713**	**$4,301**
Average Charge:									
Customer Charge $ / Per Customer / Month		$32.00	$50.00	$60.00	$145.00	$19.18	$23.26	$25.00	$32.00
Average Energy + Demand Charge $ / kWh		$0.081	$0.068	$0.059	$0.057	$0.062	$0.061	$0.081	$0.081
Average Energy Charge $ / kWh		$0.081	$0.068	$0.049	$0.048	$0.050	$0.050	$0.081	$0.081
Demand Charge $ / kVa or kW				$3.25	$3.25	$3.25	$3.25		

Okanogan County Electric Cooperative - 100 Percent Demand

SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Billing Determinants									
Total kVa	51,254			21,274	23,865	1,946	4,169		
Total Demand (kW)	495,726	212,881	231,030	21,274	23,865	1,946	4,169	296	265
Total Energy (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Average Monthly Customers	3,684	2,290	1,099	71	11	102	87	22	2

Functional Cost	Total Cost	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production									
Demand (PD)	$286,396	$97,991	$143,590	$18,732	$19,346	$1,987	$4,503	$104	$144
$/kW		$0.46	$0.62	$0.88	$0.81	$1.02	$1.08	$0.35	$0.54
or $/kVa				$0.88	$0.81	$1.02	$1.08		
Energy (PE)	$2,478,547	$672,181	$1,067,904	$310,679	$354,114	$22,418	$48,849	$583	$1,819
$/kWh		$0.042	$0.042	$0.042	$0.042	$0.043	$0.043	$0.042	$0.042
Direct Assignment (PDA)									
$/kW									
$/kVa									
$/kWh									
Transmission									
Demand (TD)									
$/kW									
or $/kVa									
Energy (TE)									
$/kWh									
Direct Assignment (TDA)									
$/kW									
$/kVa									
$/kWh									
Distribution									
Demand (DD)	$1,800,271	$667,838	$869,558	$103,228	$104,022	$16,786	$35,673	$1,501	$1,663
$/kW		$3.14	$3.76	$4.85	$4.36	$8.63	$8.56	$5.08	$6.28
or $/kVa				$4.85	$4.36	$8.63	$8.56		
Energy (DE)									

$/kWh									
Customer (DC)	$814,615	$487,117	$233,808	$31,316	$6,065	$21,103	$30,100	$4,680	$425
$/Customer/Month		$18	$18	$37	$46	$17	$29	$18	$18
Direct Assignment (DDA)									
$/kW									
$/kVa									
$/kWh									
Total	**$5,379,829**	**$1,925,127**	**$2,314,860**	**$463,955**	**$483,547**	**$62,294**	**$119,126**	**$6,869**	**$4,051**
Total									
$/kW		**$3.60**	**$4.39**	**$5.73**	**$5.17**	**$9.65**	**$9.64**	**$5.43**	**$6.82**
$/kWh		**$0.0418**	**$0.0418**	**$0.0420**	**$0.0420**	**$0.0428**	**$0.0428**	**$0.0425**	**$0.0417**
$/Customer/Month		**$17.73**	**$17.73**	**$36.54**	**$45.95**	**$17.19**	**$28.94**	**$17.73**	**$17.73**
demand + energy, $/kWh		0.0895	0.0815	0.0585	0.0566	0.0786	0.0780	0.1593	0.0831

Okanogan County Electric Cooperative - 100 Percent Demand

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Billing Determinants									
Total kVa	51,254			21,274	23,865	1,946	4,169		
Total Demand (kW)	495,726	212,881	231,030	21,274	23,865	1,946	4,169	296	265
Total Energy (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Average Monthly Customers	3,684	2,290	1,099	71	11	102	87	22	2

Functional Cost	Total Cost	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production									
Demand (PD)	$61,408	$21,011	$30,788	$4,016	$4,148	$426	$966	$22	$31
$/kW		$0.10	$0.13	$0.19	$0.17	$0.22	$0.23	$0.08	$0.12
Energy (PE)	$206,546	$56,015	$88,992	$25,890	$29,509	$1,868	$4,071	$49	$152
$/kWh	$0.003	$0.003	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004	$0.003
Direct Assignment (PDA)									
$/kW									
$/kWh									
Transmission									
Demand (TD)									

$/kW									
Energy (TE)									
$/kWh									
Direct Assignment (TDA)									
$/kW									
$/kWh									
Distribution									
Demand (DD)	$5,160,443	$1,908,491	$2,528,728	$280,578	$281,778	$47,876	$104,110	$4,018	$4,863
$/kW		$8.97	$10.95	$13.19	$11.81	$24.60	$24.97	$13.58	$18.35
Energy (DE)									
$/kWh									
Customer (DC)	$761,752	$393,001	$188,634	$56,302	$12,064	$40,189	$67,442	$3,776	$343
$/Customer/Month		$14	$14	$66	$91	$33	$65	$14	$14
Direct Assignment (DDA)									
$/kW									
$/kWh									
Total	**$6,190,149**	**$2,378,519**	**$2,837,142**	**$366,787**	**$327,500**	**$90,359**	**$176,589**	**$7,864**	**$5,389**

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Operation & Maintenance Expense				
	Other Power Supply				
555.00	Purchased Power		P	kWh	Annual Energy (kWh)
556.00	Load Dispatching		P	kWh	Annual Energy (kWh)
XXXX	Op. Supervision & Engineering		P	kWh	Annual Energy (kWh)
	Power Purchases				
XXXX	BPA Customer Charge (TRM)	$2,016,429	P	kWhP	On-Peak Annual Energy (kWh)
XXXX	Demand - BPA Contracts	$154,102	P	kWhO	Off-Peak Annual Energy (kWh)
XXXX	Load Shaping, HLH	$98,156	P	kWh	Annual Energy (kWh)
XXXX	Load Shaping, LLH	$102,495	P	kWh	Annual Energy (kWh)
XXXX	LDD Credit	-$164,107	P	CP12	12 Coincident Utility Peak
XXXX	IRMP		P	kWh	Annual Energy (kWh)
XXXX	Part B Purchase (Energy)	$63,474	P	kWh	Annual Energy (kWh)
XXXX	FRP Surcharge	$3,691	P	kWh	Annual Energy (kWh)
XXXX	Customer Refund / BPA Base Rate Red	-$52,146	P	kWh	Annual Energy (kWh)
XXXX			P	kWh	Annual Energy (kWh)
920.20	PNGC Services	$92,346	P	kWh	Annual Energy (kWh)
XXXX	Other Resources		P	kWh	Annual Energy (kWh)
XXXX	Other Resources		P	kWh	Annual Energy (kWh)
XXXX	Other Resources		P	kWh	Annual Energy (kWh)
	Transmission/Ancillary Services Purchases				
XXXX	Energy	$197,487	P	CPT	Coincident Peak - At time of Transmission Provider's Peak
XXXX	Demand		P	CPT	Coincident Peak - At time of Transmission Provider's Peak
XXXX	Coincident Transmission Peak-Demand	$253,016	P	CPT	Coincident Peak - At time of Transmission Provider's Peak
XXXX	Wheeling Revenue		P	kWh	Annual Energy (kWh)
	Other				
555.10	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	KWh	Annual Energy (kWh)
	Total Purchased Power	$2,764,943			
	Total Production	$2,764,943			
	Transmission				

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
560.00	Op. Supervision & Engineering		T	RBT	On the Basis of Transmission Rate Base
	System Control and Loading Dispatch		P	RBT	On the Basis of Transmission Rate Base
561.00	Load Dispatching		T	RBT	On the Basis of Transmission Rate Base
562.00	Station Expenses		T	RBT	On the Basis of Transmission Rate Base
563.00	Overhead Lines		T	RBT	On the Basis of Transmission Rate Base
564.00	Underground Lines		T	RBT	On the Basis of Transmission Rate Base
565.00	Transmission of Electricity		T	RBT	On the Basis of Transmission Rate Base
566.00	Miscellaneous Transmission		T	RBT	On the Basis of Transmission Rate Base
567.00	Rents		T	RBT	On the Basis of Transmission Rate Base
567.10	Op. Supplies		T	RBT	On the Basis of Transmission Rate Base
568.00	Maint. Supervision & Engineering		T	RBT	On the Basis of Transmission Rate Base
569.00	Maint. of Structures		T	RBT	On the Basis of Transmission Rate Base
570.00	Maint. of Station Equipment		T	RBT	On the Basis of Transmission Rate Base
571.00	Maint. of Overhead Lines		T	RBT	On the Basis of Transmission Rate Base
572.00	Maint. Of Underground Lines		T	RBT	On the Basis of Transmission Rate Base
573.00	Maint. of Misc. Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
574.00	Maint. Of Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
	Total Transmission				
	Distribution				
580.00	Op. Supervision & Engineering		D	OMDS&E	On the Basis of Distribution O&M for Supervision & Engineering
581.00	Load Dispatching		D	RBD	On the Basis of Distribution Rate Base
582.00	Line and Station Expenses	$1,259	D	RBD	On the Basis of Distribution Rate Base
583.00	Overhead Lines	$3,748	D	RBOH	On the Basis of all Overhead Rate Base
584.00	Underground Lines	$12	D	RBUG	On the Basis of all Underground Rate Base
585.00	Street Lighting & Signal System		D	RBD	On the Basis of Distribution Rate Base
586.00	Meters	$22,430	D	CUSTM	Customers Weighted for Meters and Services
587.00	Customer Installations		D	CUSTM	Customers Weighted for Meters and Services
588.00	Misc. Distribution	$32,543	D	RBD	On the Basis of Distribution Rate Base
588.10	Standby Time	$35,197	D	RBD	On the Basis of Distribution Rate Base
589.00	Rents		D	RBD	On the Basis of Distribution Rate Base
590.00	Maint. Supervision & Engineering	$92,599	D	OMDS&E	On the Basis of Distribution O&M for Supervision & Engineering
591.00	Maint. of Structures	$41,255	D	RBD	On the Basis of Distribution Rate Base
592.00	Maint. of Station Equipment	$16,097	D	RBD	On the Basis of Distribution Rate Base
592.10	Maint. of Structures and Equipment		D	RBD	On the Basis of Distribution Rate Base
593.00	Maint. of Overhead Lines	$265,955	D	RBOH	On the Basis of all Overhead Rate Base
594.00	Maint. Of Underground Lines	$29,816	D	RBUG	On the Basis of all Underground Rate Base
594.10	Locates	$93,472	D	RBUG	On the Basis of all Underground Rate Base

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
595.00	Maint. of Line Transformers	$1,187	D	RBOH	On the Basis of all Overhead Rate Base
595.00	Maint. of Line Transformers - Underground		D	OMDLUGT	On the Basis of Distribution O&M less UG Transformers
596.00	Maint. of Street Lighting & Signal System		D	RBD	On the Basis of Distribution Rate Base
597.00	Maint. of Meters	$51,352	D	CUSTM	Customers Weighted for Meters and Services
598.00	Maint. of Misc. Distribution Plant		D	CUST	Actual Customers
XXXX	Other		D	RBD	On the Basis of Distribution Rate Base
XXXX	Other		D	RBD	On the Basis of Distribution Rate Base
XXXX	Other		D	RBD	On the Basis of Distribution Rate Base
	Total Distribution	$686,922			
	Total Operation & Maintenance	$3,451,865			
	Customer Service, Accounts, & Sales				
901/907/911	Supervision		D	CUSTW	Customers Weighted for Accounting/Metering
902.00	Meter Reading	$9,434	D	CUSTMR	Customers Weighted for Meter Reading
903.00	Customer Records Collection	$296,307	D	CUSTW	Customers Weighted for Accounting/Metering
904.00	Uncollectable Accounts		D	CUSTW	Customers Weighted for Accounting/Metering
905.00	Misc. Customer Accounts		D	CUSTW	Customers Weighted for Accounting/Metering
906.00	Customer Service & Information		D	CUSTW	Customers Weighted for Accounting/Metering
907.00	Customer Communication & Education		D	CUSTW	Customers Weighted for Accounting/Metering
908.00	Customer Assistance	$3,687	D	CUSTW	Customers Weighted for Accounting/Metering
910.00	Conservation		D	CUSTW	Customers Weighted for Accounting/Metering
912.00	Demonstrating & Selling		D	CUSTW	Customers Weighted for Accounting/Metering
913.00	Advertising		D	CUSTW	Customers Weighted for Accounting/Metering
915.00	Expenses and costs from Merchandise	-$2,998	D	CUSTW	Customers Weighted for Accounting/Metering
917.00	Sales Expenses		D	OM	On the Basis of All O&M
902.10	Irrigation Annual Meter Maintenance		D	DA2	Direct Assignment for Irrigation
909.00	Informational and Instructional Advertising Expenses		D	CUSTW	Customers Weighted for Accounting/Metering
	Total Customer Service, Accounts & Sales	$306,429			
	Total O&M w/o Purchased Power Supply & A&	$993,351			
	Administrative & General				
920.00	Administrative & General Salaries	$303,818	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
921.00	Office Supplies	$149,895	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
922.00	Civic Services	$1,360	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
923.00	Special Services	$14,563	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
924.00	Property Insurance	$6,872	SS	NETPLT	On the Basis of Net Plant
925.00	Injuries and Damages	$23,179	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
926.00	Employee Pension & Benefits		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
927.00	Franchise Requirements		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
928.00	Regulatory Expense		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
929.00	Duplicate Charge - Credit		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.10	Director Fees & Mileage	$12,001	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.00	Misc. General Expense	$53,368	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.40	Misc. General Expense Board	$5,602	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
931.00	Misc. Expenses & Employee Training	$61,162	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
932.00	Maint. of General Plant & Communication Equipment		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
933.00	Transportation		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
935.00	Salaries - Interfund		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Total Administrative & General	$631,819			
	Total O&M plus A&G	$4,390,113			
	Depreciation				
403.30	Generation Plant		P	RBG	On the Basis of Generation Rate Base
403.50	Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
403.60	Distribution Plant	$348,201	D	RBD	On the Basis of Distribution Rate Base
403.70	General Plant	$43,370	SS	RBGP	On the Basis of General Plant Rate Base
403.80	Amortization of Plant		D	RBD	On the Basis of Distribution Rate Base
	Total Depreciation	$391,571			
	Taxes				
408.00	Property Tax	$41,346	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
408.70	Taxes - Excise	$175,255	SS	REV	On The Basis of Revenue
	Total Taxes	$216,601			
	Interest and Debt Service Expense				
427.00	Interest on Long-Term Debt	$194,237	SS	NETPLT	On the Basis of Net Plant
428.00	Amortization of Debt Discount		SS	NETPLT	On the Basis of Net Plant
431.00	Other Interest Expense		SS	NETPLT	On the Basis of Net Plant
	Total Interest / Debt Service Expense	$194,237			
	Other Contributions				
	Operating Reserve		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Rate Stabilization Account		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Additional Revenue needed for TIER Requirement		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Operating Margins	$271,932	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
426.00	Donations		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Misc. Income Deductions		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Patronage Capital & Operating Margins		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Total Other Contributions	$271,932			
	Revenue Requirement Before Other Revenues	$5,464,454			

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Revenue Req. Before Taxes and Other Revenue	$5,247,853			
	Other Revenues				
450.00	Forfeited Deposits	$4,712	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
451.00	Misc. Service Revenues		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
454.00	Rent - Electric Property Pole Contacts	$9,677	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
455.00	Rent - Facility	$18,000	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
456.20	Misc. Revenue (Other)	$31,595	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
457.00	Transfer Credits		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
419&424	Dividends from Affiliates, Interest		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
449.00	Other Revenues (Idle Services)	$15,361	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Street Lights	$5,280	D	RBD	On the Basis of Distribution Rate Base
	Total Other Revenues	$84,626			
	REVENUE REQUIREMENT for COST ALLOCATIOI	$5,379,829			

Okanogan County Electric Cooperative - 100 Percent Demand

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

			Production			Transmission			Distribution			
		Allocation Date 2019 **Total Expenses**	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
FERC Account	**Operation & Maintenance Expense**											
	Other Power Supply											
555.00	Purchased Power											
556.00	Load Dispatching											
XXXX	Op. Supervision & Engineering											
	Power Purchases											
XXXX	BPA Customer Charge (TRM)	$2,016,429		$2,016,429								
XXXX	Demand - BPA Contracts	$154,102		$154,102								
XXXX	Load Shaping, HLH	$98,156		$98,156								
XXXX	Load Shaping, LLH	$102,495		$102,495								
XXXX	LDD Credit	-$164,107	-$164,107									
XXXX	IRMP											
XXXX	Part B Purchase (Energy)	$63,474		$63,474								
XXXX	FRP Surcharge	$3,691		$3,691								
XXXX	Customer Refund / BPA Base Rate Red	-$52,146		-$52,146								
XXXX												
920.20	PNGC Services	$92,346		$92,346								
XXXX	Other Resources											
XXXX	Other Resources											
XXXX	Other Resources											
	Transmission/Ancillary Services Purchases											
XXXX	Energy	$197,487	$197,487									
XXXX	Demand											
XXXX	Coincident Transmission Peak-Demand	$253,016	$253,016									
XXXX	Wheeling Revenue											
	Other											
555.10	Open											
XXXX	Open											
XXXX	Open											
XXXX	Open											
XXXX	Open											
XXXX	Open											
	Total Purchased Power	$2,764,943	$286,396	$2,478,547								
	Total Production	$2,764,943	$286,396	$2,478,547								
	Transmission											
560.00	Op. Supervision & Engineering											
	System Control and Loading Dispatch											
561.00	Load Dispatching											
562.00	Station Expenses											
563.00	Overhead Lines											

		Allocation Date	Production			Transmission			Distribution			
		2019 **Total** **Expenses**	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
564.00	Underground Lines											
565.00	Transmission of Electricity											
566.00	Miscellaneous Transmission											
567.00	Rents											
567.10	Op. Supplies											
568.00	Maint. Supervision & Engineering											
569.00	Maint. of Structures											
570.00	Maint. of Station Equipment											
571.00	Maint. of Overhead Lines											
572.00	Maint. Of Underground Lines											
573.00	Maint. of Misc. Transmission Plant											
574.00	Maint. Of Transmission Plant											
	Total Transmission											
	Distribution											
580.00	Op. Supervision & Engineering											
581.00	Load Dispatching											
582.00	Line and Station Expenses	$1,259							$1,259			
583.00	Overhead Lines	$3,748							$3,748			
584.00	Underground Lines	$12							$12			
585.00	Street Lighting & Signal System											
586.00	Meters	$22,430									$22,430	
587.00	Customer Installations											
588.00	Misc. Distribution	$32,543							$28,679		$3,864	
588.10	Standby Time	$35,197							$31,018		$4,179	
589.00	Rents											
590.00	Maint. Supervision & Engineering	$92,599							$81,757		$10,842	
591.00	Maint. of Structures	$41,255							$36,357		$4,898	
592.00	Maint. of Station Equipment	$16,097							$14,186		$1,911	
592.10	Maint. of Structures and Equipment											
593.00	Maint. of Overhead Lines	$265,955							$265,955			
594.00	Maint. Of Underground Lines	$29,816							$29,816			
594.10	Locates	$93,472							$93,472			
595.00	Maint. of Line Transformers	$1,187							$1,187			
595.00	Maint. of Line Transformers - Underground											
596.00	Maint. of Street Lighting & Signal System											
597.00	Maint. of Meters	$51,352									$51,352	
598.00	Maint. of Misc. Distribution Plant											
XXXX	Other											
XXXX	Other											
XXXX	Other											
	Total Distribution	$686,922							$587,446		$99,476	
	Total Operation & Maintenance	$3,451,865	$286,396	$2,478,547					$587,446		$99,476	
	Customer Service, Accounts, & Sales											
901/907/911	Supervision											
902.00	Meter Reading	$9,434									$9,434	

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

			Production			Transmission			Distribution			
		Allocation Date 2019 **Total Expenses**	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
903.00	Customer Records Collection	$296,307									$296,307	
904.00	Uncollectable Accounts											
905.00	Misc. Customer Accounts											
906.00	Customer Service & Information											
907.00	Customer Communication & Education											
908.00	Customer Assistance	$3,687									$3,687	
910.00	Conservation											
912.00	Demonstrating & Selling											
913.00	Advertising											
915.00	Expenses and costs from Merchandise	-$2,998									-$2,998	
917.00	Sales Expenses											
902.10	Irrigation Annual Meter Maintenance											
909.00	Informational and Instructional Advertising Expenses											
	Total Customer Service, Accounts & Sales	$306,429									$306,429	
	Total O&M w/o Purchased Power Supply & A&G	$993,351							$587,446		$405,905	
	Administrative & General											
920.00	Administrative & General Salaries	$303,818							$179,671		$124,147	
921.00	Office Supplies	$149,895							$88,645		$61,251	
922.00	Civic Services	$1,360							$805		$556	
923.00	Special Services	$14,563							$8,612		$5,951	
924.00	Property Insurance	$6,872							$6,056		$816	
925.00	Injuries and Damages	$23,179							$13,707		$9,471	
926.00	Employee Pension & Benefits											
927.00	Franchise Requirements											
928.00	Regulatory Expense											
929.00	Duplicate Charge - Credit											
930.10	Director Fees & Mileage	$12,001							$7,097		$4,904	
930.00	Misc. General Expense	$53,368							$31,560		$21,807	
930.40	Misc. General Expense Board	$5,602							$3,313		$2,289	
931.00	Misc. Expenses & Employee Training	$61,162							$36,170		$24,992	
932.00	Maint. of General Plant & Communication Equipment											
933.00	Transportation											
935.00	Salaries - Interfund											
	Total Administrative & General	$631,819							$375,636		$256,183	
	Total O&M plus A&G	$4,390,113	$286,396	$2,478,547					$963,082		$662,088	
	Depreciation											
403.30	Generation Plant											
403.50	Transmission Plant											
403.60	Distribution Plant	$348,201							$306,861		$41,340	
403.70	General Plant	$43,370							$38,221		$5,149	
403.80	Amortization of Plant											
	Total Depreciation	$391,571							$345,082		$46,489	
	Taxes											
408.00	Property Tax	$41,346							$36,437		$4,909	
408.70	Taxes - Excise	$175,255							$175,255			
	Total Taxes	$216,601							$211,692		$4,909	

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

			Production			Transmission			Distribution			
		Allocation Date 2019 **Total** **Expenses**	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
	Interest and Debt Service Expense											
427.00	Interest on Long-Term Debt	$194,237							$171,176		$23,061	
428.00	Amortization of Debt Discount											
431.00	Other Interest Expense											
	Total Interest / Debt Service Expense	$194,237							$171,176		$23,061	
	Other Contributions											
	Operating Reserve											
	Rate Stabilization Account											
	Additional Revenue needed for TIER Requirement											
	Operating Margins	$271,932							$160,814		$111,117	
426.00	Donations											
	Misc. Income Deductions											
	Patronage Capital & Operating Margins											
	Total Other Contributions	$271,932							$160,814		$111,117	
	Revenue Requirement Before Other Revenues	$5,464,454	$286,396	$2,478,547					$1,851,847		$847,664	
	Revenue Req. Before Taxes and Other Revenues	$5,247,853	$286,396	$2,478,547					$1,640,155		$842,755	
	Other Revenues											
450.00	Forfeited Deposits	$4,712							$2,787		$1,926	
451.00	Misc. Service Revenues											
454.00	Rent - Electric Property Pole Contacts	$9,677							$5,723		$3,954	
455.00	Rent - Facility	$18,000							$10,645		$7,355	
456.20	Misc. Revenue (Other)	$31,595							$18,685		$12,910	
457.00	Transfer Credits											
419&424	Dividends from Affiliates, Interest											
449.00	Other Revenues (Idle Services)	$15,361							$9,084		$6,277	
	Street Lights	$5,280							$4,653		$627	
	Total Other Revenues	$84,626							$51,576		$33,049	
	REVENUE REQUIREMENT for COST ALLOCATION	$5,379,829	$286,396	$2,478,547					$1,800,271		$814,615	

Okanogan County Electric Cooperative - 100 Percent Demand

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

FERC Account	Operation & Maintenance Expense	Allocation Date 2019 Total Expenses	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Other Power Supply									
555.00	Purchased Power									
556.00	Load Dispatching									
XXXX	Op. Supervision & Engineering									
	Power Purchases									
XXXX	BPA Customer Charge (TRM)	$2,016,429	$546,446	$868,249	$252,978	$288,359	$18,386	$40,056	$477	$1,477
XXXX	Demand - BPA Contracts	$154,102	$42,038	$66,725	$19,182	$21,855	$1,305	$2,848	$35	$115
XXXX	Load Shaping, HLH	$98,156	$26,672	$42,361	$12,275	$13,990	$869	$1,894	$23	$72
XXXX	Load Shaping, LLH	$102,495	$27,851	$44,234	$12,818	$14,608	$907	$1,978	$24	$76
XXXX	LDD Credit	-$164,107	-$56,150	-$82,278	-$10,733	-$11,085	-$1,138	-$2,580	-$59	-$82
XXXX	IRMP									
XXXX	Part B Purchase (Energy)	$63,474	$17,248	$27,393	$7,938	$9,047	$562	$1,225	$15	$47
XXXX	FRP Surcharge	$3,691	$1,003	$1,593	$462	$526	$33	$71	$1	$3
XXXX	Customer Refund / BPA Base Rate Red	-$52,146	-$14,170	-$22,505	-$6,521	-$7,432	-$462	-$1,006	-$12	-$38
XXXX										
920.20	PNGC Services	$92,346	$25,093	$39,854	$11,549	$13,161	$818	$1,782	$21	$68
XXXX	Other Resources									
XXXX	Other Resources									
XXXX	Other Resources									
	Transmission/Ancillary Services Purchases									
XXXX	Energy	$197,487	$67,571	$99,014	$12,917	$13,340	$1,370	$3,105	$72	$99
XXXX	Demand									
XXXX	Coincident Transmission Peak-Demand	$253,016	$86,570	$126,854	$16,548	$17,091	$1,755	$3,978	$92	$127
XXXX	Wheeling Revenue									
	Other									
555.10	Open									
XXXX	Open									
XXXX	Open									
XXXX	Open									
XXXX	Open									
XXXX	Open									
	Total Purchased Power	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
	Total Production	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
	Transmission									
560.00	Op. Supervision & Engineering									
	System Control and Loading Dispatch									
561.00	Load Dispatching									
562.00	Station Expenses									

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

		Allocation Date 2019 Total Expenses								
563.00	Overhead Lines									
564.00	Underground Lines									
565.00	Transmission of Electricity									
566.00	Miscellaneous Transmission									
567.00	Rents									
567.10	Op. Supplies									
568.00	Maint. Supervision & Engineering									
569.00	Maint. of Structures									
570.00	Maint. of Station Equipment									
571.00	Maint. of Overhead Lines									
572.00	Maint. Of Underground Lines									
573.00	Maint. of Misc. Transmission Plant									
574.00	Maint. Of Transmission Plant									
	Total Transmission									
	Distribution									
580.00	Op. Supervision & Engineering									
581.00	Load Dispatching									
582.00	Line and Station Expenses	$1,259	$465	$617	$68	$69	$12	$25	$1	$1
583.00	Overhead Lines	$3,748	$1,386	$1,837	$204	$205	$35	$76	$3	$4
584.00	Underground Lines	$12	$5	$6	$1	$1	$0	$0	$0	$0
585.00	Street Lighting & Signal System									
586.00	Meters	$22,430	$11,323	$5,435	$1,766	$381	$1,265	$2,143	$109	$10
587.00	Customer Installations									
588.00	Misc. Distribution	$32,543	$12,557	$14,990	$1,863	$1,632	$484	$948	$41	$29
588.10	Standby Time	$35,197	$13,581	$16,212	$2,015	$1,765	$523	$1,025	$44	$31
589.00	Rents									
590.00	Maint. Supervision & Engineering	$92,599	$35,709	$42,689	$5,299	$4,648	$1,370	$2,685	$116	$82
591.00	Maint. of Structures	$41,255	$15,918	$19,002	$2,362	$2,068	$614	$1,201	$52	$36
592.00	Maint. of Station Equipment	$16,097	$6,211	$7,415	$922	$807	$239	$469	$20	$14
592.10	Maint. of Structures and Equipment									
593.00	Maint. of Overhead Lines	$265,955	$98,358	$130,324	$14,460	$14,522	$2,467	$5,366	$207	$251
594.00	Maint. Of Underground Lines	$29,816	$11,027	$14,611	$1,621	$1,628	$277	$602	$23	$28
594.10	Locates	$93,472	$34,569	$45,803	$5,082	$5,104	$867	$1,886	$73	$88
595.00	Maint. of Line Transformers	$1,187	$439	$581	$65	$65	$11	$24	$1	$1
595.00	Maint. of Line Transformers - Underground									
596.00	Maint. of Street Lighting & Signal System									
597.00	Maint. of Meters	$51,352	$25,922	$12,442	$4,043	$872	$2,896	$4,906	$249	$23
598.00	Maint. of Misc. Distribution Plant									
XXXX	Other									
XXXX	Other									
XXXX	Other									
	Total Distribution	$686,922	$267,470	$311,963	$39,771	$33,765	$11,061	$21,355	$940	$597
	Total Operation & Maintenance	$3,451,865	$1,037,642	$1,523,457	$369,182	$407,225	$35,465	$74,707	$1,627	$2,560
	Customer Service, Accounts, & Sales									

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

		Allocation Date 2019 Total Expenses								
901/907/911	Supervision									
902.00	Meter Reading	$9,434	$6,044	$2,901	$189	$29	$113	$95	$58	$5
903.00	Customer Records Collection	$296,307	$189,836	$91,118	$5,921	$912	$3,535	$2,994	$1,824	$166
904.00	Uncollectable Accounts									
905.00	Misc. Customer Accounts									
906.00	Customer Service & Information									
907.00	Customer Communication & Education									
908.00	Customer Assistance	$3,687	$2,362	$1,134	$74	$11	$44	$37	$23	$2
910.00	Conservation									
912.00	Demonstrating & Selling									
913.00	Advertising									
915.00	Expenses and costs from Merchandise	-$2,998	-$1,921	-$922	-$60	-$9	-$36	-$30	-$18	-$2
917.00	Sales Expenses									
902.10	Irrigation Annual Meter Maintenance									
909.00	Informational and Instructional Advertising Expenses									
	Total Customer Service, Accounts & Sales	$306,429	$196,322	$94,231	$6,123	$943	$3,656	$3,096	$1,886	$171
	Total O&M w/o Purchased Power Supply & A&G	$993,351	$463,791	$406,194	$45,895	$34,708	$14,717	$24,451	$2,826	$769
	Administrative & General									
920.00	Administrative & General Salaries	$303,818	$141,851	$124,235	$14,037	$10,616	$4,501	$7,478	$864	$235
921.00	Office Supplies	$149,895	$69,985	$61,294	$6,925	$5,237	$2,221	$3,690	$426	$116
922.00	Civic Services	$1,360	$635	$556	$63	$48	$20	$33	$4	$1
923.00	Special Services	$14,563	$6,799	$5,955	$673	$509	$216	$358	$41	$11
924.00	Property Insurance	$6,872	$2,652	$3,165	$394	$345	$102	$200	$9	$6
925.00	Injuries and Damages	$23,179	$10,822	$9,478	$1,071	$810	$343	$571	$66	$18
926.00	Employee Pension & Benefits									
927.00	Franchise Requirements									
928.00	Regulatory Expense									
929.00	Duplicate Charge - Credit									
930.10	Director Fees & Mileage	$12,001	$5,603	$4,907	$554	$419	$178	$295	$34	$9
930.00	Misc. General Expense	$53,368	$24,917	$21,823	$2,466	$1,865	$791	$1,314	$152	$41
930.40	Misc. General Expense Board	$5,602	$2,615	$2,291	$259	$196	$83	$138	$16	$4
931.00	Misc. Expenses & Employee Training	$61,162	$28,556	$25,010	$2,826	$2,137	$906	$1,505	$174	$47
932.00	Maint. of General Plant & Communication Equipment									
933.00	Transportation									
935.00	Salaries - Interfund									
	Total Administrative & General	$631,819	$294,437	$258,714	$29,267	$22,181	$9,361	$15,583	$1,787	$490
	Total O&M plus A&G	$4,390,113	$1,528,400	$1,876,403	$404,573	$430,349	$48,482	$93,386	$5,300	$3,221
	Depreciation									
403.30	Generation Plant									
403.50	Transmission Plant									
403.60	Distribution Plant	$348,201	$134,355	$160,385	$19,939	$17,457	$5,179	$10,140	$439	$307
403.70	General Plant	$43,370	$16,735	$19,977	$2,483	$2,174	$645	$1,263	$55	$38
403.80	Amortization of Plant									
	Total Depreciation	$391,571	$151,089	$180,361	$22,422	$19,632	$5,824	$11,403	$494	$346
	Taxes									

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

		Allocation Date 2019 Total Expenses								
408.00	Property Tax	$41,346	$15,953	$19,044	$2,368	$2,073	$615	$1,204	$52	$37
408.70	Taxes - Excise	$175,255	$66,857	$73,266	$14,874	$15,291	$1,710	$2,889	$236	$132
	Total Taxes	$216,601	$82,810	$92,310	$17,242	$17,364	$2,325	$4,093	$289	$168
	Interest and Debt Service Expense									
427.00	Interest on Long-Term Debt	$194,237	$74,947	$89,467	$11,122	$9,738	$2,889	$5,657	$245	$171
428.00	Amortization of Debt Discount									
431.00	Other Interest Expense									
	Total Interest / Debt Service Expense	$194,237	$74,947	$89,467	$11,122	$9,738	$2,889	$5,657	$245	$171
	Other Contributions									
	Operating Reserve									
	Rate Stabilization Account									
	Additional Revenue needed for TIER Requirement									
	Operating Margins	$271,932	$126,964	$111,196	$12,564	$9,501	$4,029	$6,694	$774	$211
426.00	Donations									
	Misc. Income Deductions									
	Patronage Capital & Operating Margins									
	Total Other Contributions	$271,932	$126,964	$111,196	$12,564	$9,501	$4,029	$6,694	$774	$211
	Revenue Requirement Before Other Revenues	$5,464,454	$1,964,211	$2,349,738	$467,923	$486,584	$63,548	$121,232	$7,101	$4,117
	Revenue Req. Before Taxes and Other Revenues	$5,247,853	$1,881,400	$2,257,428	$450,681	$469,221	$61,223	$117,139	$6,813	$3,949
	Other Revenues									
450.00	Forfeited Deposits	$4,712	$2,200	$1,927	$218	$165	$70	$116	$13	$4
451.00	Misc. Service Revenues									
454.00	Rent - Electric Property Pole Contacts	$9,677	$4,518	$3,957	$447	$338	$143	$238	$28	$7
455.00	Rent - Facility	$18,000	$8,404	$7,360	$832	$629	$267	$443	$51	$14
456.20	Misc. Revenue (Other)	$31,595	$14,752	$12,920	$1,460	$1,104	$468	$778	$90	$24
457.00	Transfer Credits									
419&424	Dividends from Affiliates, Interest									
449.00	Other Revenues (Idle Services)	$15,361	$7,172	$6,281	$710	$537	$228	$378	$44	$12
	Street Lights	$5,280	$2,037	$2,432	$302	$265	$79	$154	$7	$5
	Total Other Revenues	$84,626	$39,083	$34,877	$3,968	$3,037	$1,254	$2,107	$232	$66
	REVENUE REQUIREMENT for COST ALLOCATION	$5,379,829	$1,925,127	$2,314,860	$463,955	$483,547	$62,294	$119,126	$6,869	$4,051

INPUT RATE BASE

Schedule 4.1

FERC Account		Year 2018 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Intangible Plant				
301.00	Organization	$15	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
302.00	Franchise and Consents		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
303.00	Miscellaneous Intangible Plant	$999	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Intangible Plant	$1,014			
	Distribution Plant				
360.00	Land & Rights		D	NCPP	Non-Coincident Peak - Primary
361.00	Structures & Improvements		D	NCPP	Non-Coincident Peak - Primary
362.00	Station Equipment - Distribution	$72,394	D	NCPP	Non-Coincident Peak - Primary
363.00	Storage & Battery Equipment		D	NCPP	Non-Coincident Peak - Primary
364.00	Poles, Towers, & Fixtures	$1,131,547	D	100%DP	Demand Only - Poles, Towers & Fixtures (100% Demand)
365.00	Overhead Conductors & Devices	$1,181,083	D	100%DC	Demand Only - Overhead and Underground Conduit (100% Demand)
366.00	Underground Conduit		D	100%DC	Demand Only - Overhead and Underground Conduit (100% Demand)
367.00	Underground Conductors & Devices	$1,747,908	D	100%DC	Demand Only - Overhead and Underground Conduit (100% Demand)
368.00	Line Transformers	$2,889,668	D	100%DT	Demand Only- Transformers (100% Demand)
369.00	Services	$286,578	D	CUSTM	Customers Weighted for Meters and Services
370.00	Meters	$622,375	D	CUSTM	Customers Weighted for Meters and Services
371.00	Installation on Customer Premises	$37,123	D	CUSTM	Customers Weighted for Meters and Services
372.00	Leased Property on Cust. Premises		D	CUSTM	Customers Weighted for Meters and Services
373.00	Street Lights and Signal Systems	$3,122	D	RBDnoLights	On the Basis of Distribution Rate Base excluding Lights
	Total Distribution Plant	$7,971,798			
	Total Transmission & Distribution	$7,971,798			
	General Plant				
389.00	Land & Land Rights	$271,389	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
390.00	Structures & Improvements	$773,674	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
391.00	Office Furniture & Equipment	$237,354	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
392.00	Transportation Equipment	$629,831	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
393.00	Stores Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
394.00	Tools, Shop, & Garage Equipment	$75,081	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
395.00	Laboratory Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
396.00	Power Operated Equipment	$201,732	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
397.00	Communication Equipment	$8,341	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
398.00	Misc. Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
399.00	Other Tangible Property		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total General Plant	$2,197,402			
	Total Plant Before General Plant & Intangible	$7,971,798			

INPUT RATE BASE
Schedule 4.1

FERC Account

	Year 2018 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
Total Gross Plant in Service	$10,170,214			
Less: Accumulated Depreciation				
Intangible Plant		P	RBIG	On the Basis of Intangible Plant Rate Base
Steam Production Plant		P	RBSG	On the Basis of Steam Generation Rate Base
Nuclear Production Plant		P	RBG	On the Basis of Generation Rate Base
Hydraulic Production Plant		P	RBHG	On the Basis of Hydraulic Generation Rate Base
Biogas Production Plant		P	RBGG	On the Basis of Gas Turbine Generation Rate Base
Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
Distribution Plant	$2,604,817	D	RBD	On the Basis of Distribution Rate Base
General Plant	$1,849,336	SS	RBGP	On the Basis of General Plant Rate Base
Unclassified Plant		SS	RBGP	On the Basis of General Plant Rate Base
Misc. Plant		SS	RBGP	On the Basis of General Plant Rate Base
Total Accumulated Depreciation	$4,454,153			
Total Net Plant	$5,716,061			
Working Capital				
1/8 O&M	$203,146	SS	OMWOP	On the Basis of O&M (w/o Purch. Power Supply)
1/12 Purchased Power Supply Cost	$230,412	P	OMP	On the Basis of Purchased Power O&M
1/12 Purchased Transmission Charges	$37,542	P	OMPT	On the Basis of Purchased Transmission O&M
Total Working Capital	$471,100			
Less: Net Customer Contributions				
Production Plant		P	RBG	On the Basis of Generation Rate Base
Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
Distribution Plant		D	RBD	On the Basis of Distribution Rate Base
Street Lights		D	DA1	Direct Assignment for Streetlights
General Plant		SS	RBGP	On the Basis of General Plant Rate Base
Total Contributions				
TOTAL RATE BASE	$6,187,161			
CWIP				
Production Plant		P	RBG	On the Basis of Generation Rate Base
Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
Distribution Plant	$2,988	D	RBD	On the Basis of Distribution Rate Base
Services		D	RBD	On the Basis of Distribution Rate Base
General Plant		SS	RBGP	On the Basis of General Plant Rate Base
Other		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
Total CWIP	$2,988			
TOTAL RATE BASE plus CWIP	$6,190,149			

Okanogan County Electric Cooperative - 100 Percent Demand

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

			Production			Transmission			Distribution			
FERC Account	Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
	Intangible Plant											
301.00	Organization	$15							$13		$2	
302.00	Franchise and Consents											
303.00	Miscellaneous Intangible Plant	$999							$881		$119	
	Total Intangible Plant	$1,014							$894		$120	
	Distribution Plant											
360.00	Land & Rights											
361.00	Structures & Improvements											
362.00	Station Equipment - Distribution	$72,394							$72,394			
363.00	Storage & Battery Equipment											
364.00	Poles, Towers, & Fixtures	$1,131,547							$1,131,547			
365.00	Overhead Conductors & Devices	$1,181,083							$1,181,083			
366.00	Underground Conduit											
367.00	Underground Conductors & Devices	$1,747,908							$1,747,908			
368.00	Line Transformers	$2,889,668							$2,889,668			
369.00	Services	$286,578									$286,578	
370.00	Meters	$622,375									$622,375	
371.00	Installation on Customer Premises	$37,123									$37,123	
372.00	Leased Property on Cust. Premises											
373.00	Street Lights and Signal Systems	$3,122							$2,751		$371	
	Total Distribution Plant	$7,971,798							$7,025,351		$946,447	
	Total Transmission & Distribution	$7,971,798							$7,025,351		$946,447	
	General Plant											
389.00	Land & Land Rights	$271,389							$239,168		$32,220	
390.00	Structures & Improvements	$773,674							$681,820		$91,854	
391.00	Office Furniture & Equipment	$237,354							$209,175		$28,180	
392.00	Transportation Equipment	$629,831							$555,054		$74,776	
393.00	Stores Equipment											
394.00	Tools, Shop, & Garage Equipment	$75,081							$66,167		$8,914	
395.00	Laboratory Equipment											
396.00	Power Operated Equipment	$201,732							$177,781		$23,950	
397.00	Communication Equipment	$8,341							$7,351		$990	
398.00	Misc. Equipment											
399.00	Other Tangible Property											
	Total General Plant	$2,197,402							$1,936,517		$260,885	
	Total Plant Before General Plant & Intangible	$7,971,798							$7,025,351		$946,447	
	Total Gross Plant in Service	$10,170,214							$8,962,761		$1,207,453	
	Less: Accumulated Depreciation											
	Intangible Plant											
	Steam Production Plant											
	Nuclear Production Plant											

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

		Production			Transmission			Distribution			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
FERC Account											
Hydraulic Production Plant											
Biogas Production Plant											
Transmission Plant											
Distribution Plant	$2,604,817							$2,295,562		$309,255	
General Plant	$1,849,336							$1,629,775		$219,561	
Unclassified Plant											
Misc. Plant											
Total Accumulated Depreciation	$4,454,153							$3,925,336		$528,817	
Total Net Plant	$5,716,061							$5,037,425		$678,636	
Working Capital											
1/8 O&M	$203,146							$120,385		$82,761	
1/12 Purchased Power Supply Cost	$230,412	$23,866	$206,546								
1/12 Purchased Transmission Charges	$37,542	$37,542									
Total Working Capital	$471,100	$61,408	$206,546					$120,385		$82,761	
Less: Net Customer Contributions											
Production Plant											
Transmission Plant											
Distribution Plant											
Street Lights											
General Plant											
Total Contributions											
TOTAL RATE BASE	$6,187,161	$61,408	$206,546					$5,157,810		$761,397	
CWIP											
Production Plant											
Transmission Plant											
Distribution Plant	$2,988							$2,633		$355	
Services											
General Plant											
Other											
Total CWIP	$2,988							$2,633		$355	
TOTAL RATE BASE plus CWIP	$6,190,149	$61,408	$206,546					$5,160,443		$761,752	

Okanogan County Electric Cooperative - 100 Percent Demand

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RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

FERC Account	Account Description	Total Rate Base	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Intangible Plant									
301.00	Organization	$15	$6	$7	$1	$1	$0	$0	$0	$0
302.00	Franchise and Consents									
303.00	Miscellaneous Intangible Plant	$999	$386	$460	$57	$50	$15	$29	$1	$1
	Total Intangible Plant	$1,014	$391	$467	$58	$51	$15	$30	$1	$1
	Distribution Plant									
360.00	Land & Rights									
361.00	Structures & Improvements									
362.00	Station Equipment - Distribution	$72,394	$26,774	$35,475	$3,936	$3,953	$672	$1,461	$56	$68
363.00	Storage & Battery Equipment									
364.00	Poles, Towers, & Fixtures	$1,131,547	$418,481	$554,482	$61,523	$61,786	$10,498	$22,829	$881	$1,066
365.00	Overhead Conductors & Devices	$1,181,083	$436,801	$578,756	$64,217	$64,491	$10,957	$23,828	$919	$1,113
366.00	Underground Conduit									
367.00	Underground Conductors & Devices	$1,747,908	$646,430	$856,512	$95,036	$95,442	$16,216	$35,264	$1,361	$1,647
368.00	Line Transformers	$2,889,668	$1,068,688	$1,415,999	$157,114	$157,786	$26,809	$58,298	$2,250	$2,723
369.00	Services	$286,578	$144,661	$69,435	$22,560	$4,865	$16,163	$27,378	$1,390	$126
370.00	Meters	$622,375	$314,166	$150,794	$48,996	$10,565	$35,103	$59,458	$3,019	$274
371.00	Installation on Customer Premises	$37,123	$18,739	$8,994	$2,922	$630	$2,094	$3,547	$180	$16
372.00	Leased Property on Cust. Premises									
373.00	Street Lights and Signal Systems	$3,122	$1,205	$1,438	$179	$157	$46	$91	$4	$3
	Total Distribution Plant	$7,971,798	$3,075,945	$3,671,886	$456,483	$399,675	$118,559	$232,152	$10,060	$7,038
	Total Transmission & Distribution	$7,971,798	$3,075,945	$3,671,886	$456,483	$399,675	$118,559	$232,152	$10,060	$7,038
	General Plant									
389.00	Land & Land Rights	$271,389	$104,716	$125,004	$15,540	$13,606	$4,036	$7,903	$342	$240
390.00	Structures & Improvements	$773,674	$298,525	$356,362	$44,302	$38,789	$11,506	$22,531	$976	$683
391.00	Office Furniture & Equipment	$237,354	$91,584	$109,328	$13,591	$11,900	$3,530	$6,912	$300	$210
392.00	Transportation Equipment	$629,831	$243,022	$290,106	$36,066	$31,577	$9,367	$18,342	$795	$556
393.00	Stores Equipment									
394.00	Tools, Shop, & Garage Equipment	$75,081	$28,970	$34,583	$4,299	$3,764	$1,117	$2,186	$95	$66
395.00	Laboratory Equipment									
396.00	Power Operated Equipment	$201,732	$77,839	$92,919	$11,552	$10,114	$3,000	$5,875	$255	$178
397.00	Communication Equipment	$8,341	$3,218	$3,842	$478	$418	$124	$243	$11	$7
398.00	Misc. Equipment									

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

FERC Account	Account Description	Total Rate Base	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
399.00	Other Tangible Property									
	Total General Plant	$2,197,402	$847,875	$1,012,144	$125,828	$110,169	$32,680	$63,992	$2,773	$1,940
	Total Plant Before General Plant & Intangible	$7,971,798	$3,075,945	$3,671,886	$456,483	$399,675	$118,559	$232,152	$10,060	$7,038
	Total Gross Plant in Service	$10,170,214	$3,924,211	$4,684,497	$582,369	$509,895	$151,254	$296,174	$12,834	$8,979
	Less: Accumulated Depreciation									
	Intangible Plant									
	Steam Production Plant									
	Nuclear Production Plant									
	Hydraulic Production Plant									
	Biogas Production Plant									
	Transmission Plant									
	Distribution Plant	$2,604,817	$1,005,077	$1,199,804	$149,158	$130,595	$38,740	$75,857	$3,287	$2,300
	General Plant	$1,849,336	$713,572	$851,822	$105,897	$92,719	$27,504	$53,856	$2,334	$1,633
	Unclassified Plant									
	Misc. Plant									
	Total Accumulated Depreciation	$4,454,153	$1,718,650	$2,051,625	$255,055	$223,314	$66,243	$129,712	$5,621	$3,933
	Total Net Plant	$5,716,061	$2,205,561	$2,632,872	$327,314	$286,581	$85,011	$166,461	$7,213	$5,047
	Working Capital									
	1/8 O&M	$203,146	$94,779	$83,114	$9,395	$7,111	$3,010	$5,004	$577	$157
	1/12 Purchased Power Supply Cost	$230,412	$64,181	$100,958	$27,451	$31,122	$2,034	$4,446	$57	$164
	1/12 Purchased Transmission Charges	$37,542	$12,845	$18,822	$2,455	$2,536	$260	$590	$14	$19
	Total Working Capital	$471,100	$171,805	$202,894	$39,302	$40,769	$5,304	$10,041	$647	$340
	Less: Net Customer Contributions									
	Production Plant									
	Transmission Plant									
	Distribution Plant									
	Street Lights									
	General Plant									
	Total Contributions									
	TOTAL RATE BASE	$6,187,161	$2,377,366	$2,835,766	$366,616	$327,350	$90,315	$176,502	$7,861	$5,386
	CWIP									
	Production Plant									
	Transmission Plant									
	Distribution Plant	$2,988	$1,153	$1,376	$171	$150	$44	$87	$4	$3
	Services									

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

FERC Account	Account Description	Total Rate Base	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	General Plant									
	Other									
	Total CWIP	$2,988	$1,153	$1,376	$171	$150	$44	$87	$4	$3
	TOTAL RATE BASE plus CWIP	$6,190,149	$2,378,519	$2,837,142	$366,787	$327,500	$90,359	$176,589	$7,864	$5,389

EES Consulting

Okanogan County Electric Cooperative

Cost of Service Schedules

Date:	October 14, 2019
Version:	Revised Final Version
Test Period:	CY: 2019
Production Peak Allocation Method:	12 Month Peak Responsibility Method (12 CP)
Transmission Peak Allocation Method:	12 Month Peak Responsibility Method (12 CP)
Distribution System Allocation Method:	Minimum System Analysis

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A registered professional engineering corporation with offices in the Seattle and Portland areas.

SUMMARY OF PRESENT AND PROPOSED RATE REVENUE
BY CUSTOMER CLASS
Schedule 1.1

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Revenues - Present Rate	$5,718,206	$2,181,397	$2,390,509	$485,313	$498,907	$55,803	$94,264	$7,713	$4,301
Less Allocated Revenue Requirement	$5,379,829	$2,100,995	$2,180,893	$439,506	$447,477	$75,222	$121,466	$10,498	$3,772
Difference	$338,378	$80,402	$209,616	$45,807	$51,430	-$19,419	-$27,202	-$2,785	$529
Revenue To Cost Ratio	106.3%	103.8%	109.6%	110.4%	111.5%	74.2%	77.6%	73.5%	114.0%
% Increase Retail Rates to Equal Allocated Cost	**-5.9%**	**-3.7%**	**-8.8%**	**-9.4%**	**-10.3%**	**34.8%**	**28.9%**	**36.1%**	**-12.3%**
Rate Base	$6,190,149	$2,945,779	$2,405,031	$287,930	$211,155	$132,057	$184,139	$19,570	$4,488
Rate Of Return, %	5.5%	2.7%	8.7%	15.9%	24.4%	-14.7%	-14.8%	-14.2%	11.8%
Rate Of Return, $	$338,378	$80,402	$209,616	$45,807	$51,430	-$19,419	-$27,202	-$2,785	$529
Modified Debt Service Coverage Ratio									
Unit Cost: Present Rates ($/kWh)	**$0.097**	**$0.136**	**$0.094**	**$0.066**	**$0.059**	**$0.107**	**$0.083**	**$0.561**	**$0.099**

Unit Cost Summary

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Unit Cost: Present Rates ($/kWh)	**$0.097**	**$0.136**	**$0.094**	**$0.066**	**$0.059**	**$0.107**	**$0.083**	**$0.561**	**$0.099**
Unit Cost: COSA Rates ($/kWh)	**$0.091**	**$0.131**	**$0.085**	**$0.059**	**$0.053**	**$0.144**	**$0.106**	**$0.764**	**$0.086**
Difference from Present Rates	-5.92%	-3.69%	-8.77%	-9.44%	-10.31%	34.80%	28.86%	36.11%	-12.30%

FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY
BY CUSTOMER CLASS

Schedule 1.2

	Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production										
	Demand (PD)	$286,396	$97,991	$143,590	$18,732	$19,346	$1,987	$4,503	$104	$144
	Energy (PE)	$2,478,547	$672,181	$1,067,904	$310,679	$354,114	$22,418	$48,849	$583	$1,819
	Direct Assignment (PDA)									
Transmission										
	Demand (TD)									
	Energy (TE)									
	Direct Assignment (TDA)									
Distribution										
	Demand (DD)	$1,101,470	$409,400	$527,131	$65,233	$65,865	$10,303	$21,575	$957	$1,005
	Energy (DE)									
	Customer (DC)	$1,513,416	$921,423	$442,267	$44,862	$8,152	$40,514	$46,539	$8,853	$805
	Direct Assignment (DDA)									
	Total	**$5,379,829**	**$2,100,995**	**$2,180,893**	**$439,506**	**$447,477**	**$75,222**	**$121,466**	**$10,498**	**$3,772**
Total Cost / Function										
	Production	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
	Transmission									
	Distribution	$2,614,886	$1,330,823	$969,398	$110,096	$74,017	$50,817	$68,115	$9,811	$1,810
	Total Cost / Function	**$5,379,829**	**$2,100,995**	**$2,180,893**	**$439,506**	**$447,477**	**$75,222**	**$121,466**	**$10,498**	**$3,772**
Total Cost / Classifier										
	Demand	$1,387,866	$507,391	$670,721	$83,965	$85,211	$12,290	$26,078	$1,061	$1,148
	Energy	$2,478,547	$672,181	$1,067,904	$310,679	$354,114	$22,418	$48,849	$583	$1,819
	Customer	$1,513,416	$921,423	$442,267	$44,862	$8,152	$40,514	$46,539	$8,853	$805
	Direct Assignment									
	Total Cost / Classifier	**$5,379,829**	**$2,100,995**	**$2,180,893**	**$439,506**	**$447,477**	**$75,222**	**$121,466**	**$10,498**	**$3,772**
	check									

FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE SUMMARY
BY CUSTOMER CLASS
Schedule 1.3

	Historic Year: 2018	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production										
	Demand (PD)	$61,408	$21,011	$30,788	$4,016	$4,148	$426	$966	$22	$31
	Energy (PE)	$206,546	$56,015	$88,992	$25,890	$29,509	$1,868	$4,071	$49	$152
	Direct Assignment (PDA)									
Transmission										
	Demand (TD)									
	Energy (TE)									
	Direct Assignment (TDA)									
Distribution										
	Demand (DD)	$2,906,473	$1,074,903	$1,424,234	$158,028	$158,703	$26,965	$58,637	$2,263	$2,739
	Energy (DE)									
	Customer (DC)	$3,015,722	$1,793,849	$861,016	$99,996	$18,794	$102,798	$120,466	$17,236	$1,567
	Direct Assignment (DDA)									
	Total	**$6,190,149**	**$2,945,779**	**$2,405,031**	**$287,930**	**$211,155**	**$132,057**	**$184,139**	**$19,570**	**$4,488**
Total Cost / Function										
	Production	$267,954	$77,026	$119,780	$29,906	$33,658	$2,294	$5,036	$71	$182
	Transmission									
	Distribution	$5,922,195	$2,868,753	$2,285,250	$258,024	$177,497	$129,763	$179,103	$19,499	$4,306
	Total Cost / Function	**$6,190,149**	**$2,945,779**	**$2,405,031**	**$287,930**	**$211,155**	**$132,057**	**$184,139**	**$19,570**	**$4,488**
Total Cost / Classifier										
	Demand	$2,967,881	$1,095,914	$1,455,022	$162,044	$162,852	$27,391	$59,603	$2,285	$2,770
	Energy	$206,546	$56,015	$88,992	$25,890	$29,509	$1,868	$4,071	$49	$152
	Customer	$3,015,722	$1,793,849	$861,016	$99,996	$18,794	$102,798	$120,466	$17,236	$1,567
	Direct Assignment									
	Total Cost / Classifier	**$6,190,149**	**$2,945,779**	**$2,405,031**	**$287,930**	**$211,155**	**$132,057**	**$184,139**	**$19,570**	**$4,488**
	check									

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION

Schedule 1.4

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Steam Power Generation									
Nuclear Power Generation									
Hydraulic Power Generation									
Gas Turbine Power Generation									
Other Power Supply									
Power Purchases	$2,314,440	$616,032	$985,626	$299,946	$343,028	$21,279	$46,269	$524	$1,736
Transmission/Ancillary Services Purchases	$450,503	$154,141	$225,868	$29,465	$30,432	$3,125	$7,083	$163	$226
BPA Transmission									
Other									
Total Production	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
Total Transmission									
Total Distribution	$686,922	$330,511	$263,941	$31,008	$20,836	$15,695	$22,194	$2,241	$497
Total Other									
Total Operation & Maintenance	**$3,451,865**	**$1,100,684**	**$1,475,436**	**$360,418**	**$394,295**	**$40,099**	**$75,546**	**$2,928**	**$2,460**
Total O&M w/o Purchased Power Supply & A&G	**$993,351**	**$526,833**	**$358,172**	**$37,131**	**$21,779**	**$19,351**	**$25,290**	**$4,127**	**$669**
	$2,458,514								
Total Customer Service, Accounts & Sales	$306,429	$196,322	$94,231	$6,123	$943	$3,656	$3,096	$1,886	$171
Total Administrative & General	$631,819	$334,764	$227,995	$23,661	$13,910	$12,325	$16,120	$2,619	$426
Total O&M plus A&G	**$4,390,113**	**$1,631,769**	**$1,797,661**	**$390,203**	**$409,148**	**$56,080**	**$94,762**	**$7,433**	**$3,057**
Total Depreciation	$391,571	$189,044	$151,450	$17,146	$11,847	$8,613	$11,908	$1,277	$285
Total Taxes	$216,601	$86,818	$89,257	$16,685	$16,542	$2,620	$4,146	$371	$162
Total Interest / Debt Service Expense	$194,237	$93,774	$75,126	$8,505	$5,877	$4,273	$5,907	$634	$142
Total Return on Investment (X.X% of Total Rate Base)									
Total Capital Projects Funded From Rates									
Total Other Contributions	$271,932	$144,221	$98,050	$10,165	$5,962	$5,297	$6,923	$1,130	$183
Revenue Requirement Before Other Revenues	**$5,464,454**	**$2,145,626**	**$2,211,544**	**$442,704**	**$449,376**	**$76,883**	**$123,647**	**$10,845**	**$3,829**
Revenue Req. Before Taxes and Other Revenues	**$5,247,853**	**$2,058,808**	**$2,122,287**	**$426,019**	**$432,834**	**$74,264**	**$119,501**	**$10,473**	**$3,667**
Total Other Revenues	$84,626	$44,631	$30,652	$3,197	$1,899	$1,662	$2,181	$347	$57
REVENUE REQUIREMENT for COST ALLOCATION	**$5,379,829**	**$2,100,995**	**$2,180,893**	**$439,506**	**$447,477**	**$75,222**	**$121,466**	**$10,498**	**$3,772**

SUMMARY OF RATE BASE COST ALLOCATIONS

Schedule 1.5

Historic Year: 2018	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Total Production Plant									
Total Transmission Plant									
Total Distribution Plant	$7,971,798	$3,848,640	$3,083,284	$349,068	$241,196	$175,357	$242,437	$26,004	$5,812
Total Transmission & Distribution	$7,971,798	$3,848,640	$3,083,284	$349,068	$241,196	$175,357	$242,437	$26,004	$5,812
Total General Plant	$2,197,402	$1,060,866	$849,898	$96,219	$66,485	$48,337	$66,827	$7,168	$1,602
Total Plant Before General Plant & Intangible	**$7,971,798**	**$3,848,640**	**$3,083,284**	**$349,068**	**$241,196**	**$175,357**	**$242,437**	**$26,004**	**$5,812**
Total Gross Plant in Service	**$10,170,214**	**$4,909,995**	**$3,933,575**	**$445,332**	**$307,711**	**$223,716**	**$309,295**	**$33,175**	**$7,414**
Total Accumulated Depreciation	$4,454,153	$2,150,384	$1,722,751	$195,038	$134,765	$97,979	$135,459	$14,529	$3,247
Total Net Plant	**$5,716,061**	**$2,759,611**	**$2,210,824**	**$250,294**	**$172,946**	**$125,737**	**$173,836**	**$18,646**	**$4,167**
Total Working Capital	$471,100	$184,726	$193,051	$37,505	$38,119	$6,254	$10,213	$914	$319
Total Contributions									
TOTAL RATE BASE	**$6,187,161**	**$2,944,336**	**$2,403,875**	**$287,799**	**$211,065**	**$131,991**	**$184,049**	**$19,560**	**$4,486**
Total CWIP	$2,988	$1,442	$1,156	$131	$90	$66	$91	$10	$2
TOTAL RATE BASE plus CWIP	**$6,190,149**	**$2,945,779**	**$2,405,031**	**$287,930**	**$211,155**	**$132,057**	**$184,139**	**$19,570**	**$4,488**

SUMMARY OF HISTORIC LOAD DATA

Schedule 1.6

Historic Year: 2018	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Recorded Load Data									
Energy Sales (kWh)	58,120,088	15,501,591	25,086,739	7,306,671	8,422,988	547,952	1,194,613	13,905	45,629
Total Billing Capacity (kVa)	53,622			22,256	24,967	2,036	4,362		
Avg. Monthly Billing Capacity (kVa)	4,468			1,855	2,081	170	363		
Number of Customers	3,668	2,273	1,099	71	11	102	87	23	2
Ratio of NCP to Avg. Billing Capacity				64%	60%	180%	189%		
Rate Classes NCP Demand at Meter	19,882	6,959	9,461	1,191	1,242	306	686	17	19
Estimates Based on Recorded Data									
Annual NCP Load Factor	33%	25%	30%	70%	77%	20%	20%	9%	27%
Rate Classes CP Demand at Input Voltage	20,239	7,425	10,196	1,279	1,338			1	
Annual CP Load Factor	33%	24%	28%	65%	72%			292%	
Average On-Peak kWh as a % of Total kWh		59%	59%	59%	59%	61%	61%	60%	59%
Average Off-Peak kWh as a % of Total kWh		41%	41%	41%	41%	39%	39%	40%	41%

Okanogan County Electric Cooperative - Minimum System Analysis

SUMMARY OF FORECAST LOAD DATA

Schedule 1.7

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Forecast Load Data									
Energy Sales (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Total Billing Capacity (kVa)	53,622			22,256	24,967	2,036	4,362		
Avg. Monthly Billing Capacity (kVa)	4,468			1,855	2,081	170	363		
Number of Customers	3,684	2,290	1,099	71	11	102	87	22	2
Ratio of NCP to Avg. Billing				61%	57%	172%	180%		
Rate Classes NCP Demand at Meter	23,678	9,148	11,221	1,138	1,187	292	656	17	18
Forecast Based on Recorded and Forecast Data									
Annual NCP Load Factor	29%	20%	26%	74%	81%	20%	20%	9%	27%
Rate Classes CP Demand at Input Voltage	24,355	9,760	12,092	1,223	1,279			1	
Annual CP Load Factor	28%	19%	24%	69%	75%			213%	
On-Peak kWh as a % of Total kWh	59%	59%	59%	59%	59%	61%	61%	60%	59%
Off-Peak kWh as a % of Total kWh	41%	41%	41%	41%	41%	39%	39%	40%	41%

SUMMARY OF POWER SUPPLY COSTS

Schedule 1.8

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Steam Power Generation									
Nuclear Power Generation									
Hydraulic Power Generation									
Gas Turbine Power Generation									
Other Power Supply									
Forecast Power Supply									
Power Purchases									
Load Shaping, HLH	$98,156	$26,672	$42,361	$12,275	$13,990	$869	$1,894	$23	$72
Load Shaping, LLH	$102,495	$27,851	$44,234	$12,818	$14,608	$907	$1,978	$24	$76
LDD Credit	-$164,107	-$56,150	-$82,278	-$10,733	-$11,085	-$1,138	-$2,580	-$59	-$82
IRMP									
Part B Purchase (Energy)	$63,474	$17,248	$27,393	$7,938	$9,047	$562	$1,225	$15	$47
FRP Surcharge	$3,691	$1,003	$1,593	$462	$526	$33	$71	$1	$3
Customer Refund / BPA Base Rate Red	-$52,146	-$14,170	-$22,505	-$6,521	-$7,432	-$462	-$1,006	-$12	-$38
Transmission/Ancillary Services Purchases									
Energy	$197,487	$67,571	$99,014	$12,917	$13,340	$1,370	$3,105	$72	$99
Demand									
Coincident Transmission Peak-Demand	$253,016	$86,570	$126,854	$16,548	$17,091	$1,755	$3,978	$92	$127
Wheeling Revenue									
Other									
Open									
Open									
Total Power Supply	**$502,066**	**$156,595**	**$236,666**	**$45,703**	**$50,084**	**$3,896**	**$8,666**	**$154**	**$303**

SUMMARY OF REVENUES AT PRESENT RATES

Schedule 1.9

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Revenues:									
Customer Charge Revenues	$1,664,304	$879,232	$659,400	$51,420	$19,140	$23,552	$24,192	$6,600	$768
Energy Revenues	$3,887,328	$1,302,165	$1,731,109	$364,754	$402,207	$25,926	$56,522	$1,113	$3,533
Demand Revenues	$166,575			$69,139	$77,560	$6,325	$13,550		
Surcharge									
Total Revenues	**$5,718,206**	**$2,181,397**	**$2,390,509**	**$485,313**	**$498,907**	**$55,803**	**$94,264**	**$7,713**	**$4,301**
Average Charge:									
Customer Charge $ / Per Customer / Month		$32.00	$50.00	$60.00	$145.00	$19.18	$23.26	$25.00	$32.00
Average Energy + Demand Charge $ / kWh		$0.081	$0.068	$0.059	$0.057	$0.062	$0.061	$0.081	$0.081
Average Energy Charge $ / kWh		$0.081	$0.068	$0.049	$0.048	$0.050	$0.050	$0.081	$0.081
Demand Charge $ / kVa or kW				$3.25	$3.25	$3.25	$3.25		

Okanogan County Electric Cooperative - Minimum System Analysis

SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Billing Determinants									
Total kVa	51,254			21,274	23,865	1,946	4,169		
Total Demand (kW)	495,726	212,881	231,030	21,274	23,865	1,946	4,169	296	265
Total Energy (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Average Monthly Customers	3,684	2,290	1,099	71	11	102	87	22	2

Functional Cost	Total Cost	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production									
Demand (PD)	$286,396	$97,991	$143,590	$18,732	$19,346	$1,987	$4,503	$104	$144
$/kW		$0.46	$0.62	$0.88	$0.81	$1.02	$1.08	$0.35	$0.54
or $/kVa				$0.88	$0.81	$1.02	$1.08		
Energy (PE)	$2,478,547	$672,181	$1,067,904	$310,679	$354,114	$22,418	$48,849	$583	$1,819
$/kWh		$0.042	$0.042	$0.042	$0.042	$0.043	$0.043	$0.042	$0.042
Direct Assignment (PDA)									
$/kW									
$/kVa									
$/kWh									
Transmission									
Demand (TD)									
$/kW									
or $/kVa									
Energy (TE)									
$/kWh									
Direct Assignment (TDA)									
$/kW									
$/kVa									
$/kWh									
Distribution									
Demand (DD)	$1,101,470	$409,400	$527,131	$65,233	$65,865	$10,303	$21,575	$957	$1,005
$/kW		$1.92	$2.28	$3.07	$2.76	$5.29	$5.17	$3.24	$3.79
or $/kVa				$3.07	$2.76	$5.29	$5.17		
Energy (DE)									

$/kWh									
Customer (DC)	$1,513,416	$921,423	$442,267	$44,862	$8,152	$40,514	$46,539	$8,853	$805
$/Customer/Month		$34	$34	$52	$62	$33	$45	$34	$34
Direct Assignment (DDA)									
$/kW									
$/kVa									
$/kWh									
Total	**$5,379,829**	**$2,100,995**	**$2,180,893**	**$439,506**	**$447,477**	**$75,222**	**$121,466**	**$10,498**	**$3,772**
Total									
$/kW		**$2.38**	**$2.90**	**$3.95**	**$3.57**	**$6.31**	**$6.25**	**$3.59**	**$4.33**
$/kWh		**$0.0418**	**$0.0418**	**$0.0420**	**$0.0420**	**$0.0428**	**$0.0428**	**$0.0425**	**$0.0417**
$/Customer/Month		**$33.54**	**$33.54**	**$52.35**	**$61.75**	**$32.99**	**$44.75**	**$33.54**	**$33.54**
demand + energy, $/kWh		0.0734	0.0681	0.0533	0.0521	0.0663	0.0656	0.1197	0.0680

Okanogan County Electric Cooperative - Minimum System Analysis

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2019	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Billing Determinants									
Total kVa	51,254			21,274	23,865	1,946	4,169		
Total Demand (kW)	495,726	212,881	231,030	21,274	23,865	1,946	4,169	296	265
Total Energy (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Average Monthly Customers	3,684	2,290	1,099	71	11	102	87	22	2

Functional Cost	Total Cost	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Production									
Demand (PD)	$61,408	$21,011	$30,788	$4,016	$4,148	$426	$966	$22	$31
$/kW		$0.10	$0.13	$0.19	$0.17	$0.22	$0.23	$0.08	$0.12
Energy (PE)	$206,546	$56,015	$88,992	$25,890	$29,509	$1,868	$4,071	$49	$152
$/kWh	$0.003	$0.003	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004	$0.003
Direct Assignment (PDA)									
$/kW									
$/kWh									
Transmission									
Demand (TD)									

$/kW									
Energy (TE)									
$/kWh									
Direct Assignment (TDA)									
$/kW									
$/kWh									
Distribution									
Demand (DD)	$2,906,473	$1,074,903	$1,424,234	$158,028	$158,703	$26,965	$58,637	$2,263	$2,739
$/kW		$5.05	$6.16	$7.43	$6.65	$13.85	$14.06	$7.65	$10.34
Energy (DE)									
$/kWh									
Customer (DC)	$3,015,722	$1,793,849	$861,016	$99,996	$18,794	$102,798	$120,466	$17,236	$1,567
$/Customer/Month		$65	$65	$117	$142	$84	$116	$65	$65
Direct Assignment (DDA)									
$/kW									
$/kWh									
Total	**$6,190,149**	**$2,945,779**	**$2,405,031**	**$287,930**	**$211,155**	**$132,057**	**$184,139**	**$19,570**	**$4,488**

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
FERC Account	**Operation & Maintenance Expense**				
	Other Power Supply				
555.00	Purchased Power		P	kWh	Annual Energy (kWh)
556.00	Load Dispatching		P	kWh	Annual Energy (kWh)
XXXX	Op. Supervision & Engineering		P	kWh	Annual Energy (kWh)
	Power Purchases				
XXXX	BPA Customer Charge (TRM)	$2,016,429	P	kWhP	On-Peak Annual Energy (kWh)
XXXX	Demand - BPA Contracts	$154,102	P	kWhO	Off-Peak Annual Energy (kWh)
XXXX	Load Shaping, HLH	$98,156	P	kWh	Annual Energy (kWh)
XXXX	Load Shaping, LLH	$102,495	P	kWh	Annual Energy (kWh)
XXXX	LDD Credit	-$164,107	P	CP12	12 Coincident Utility Peak
XXXX	IRMP		P	kWh	Annual Energy (kWh)
XXXX	Part B Purchase (Energy)	$63,474	P	kWh	Annual Energy (kWh)
XXXX	FRP Surcharge	$3,691	P	kWh	Annual Energy (kWh)
XXXX	Customer Refund / BPA Base Rate Red	-$52,146	P	kWh	Annual Energy (kWh)
XXXX			P	kWh	Annual Energy (kWh)
920.20	PNGC Services	$92,346	P	kWh	Annual Energy (kWh)
XXXX	Other Resources		P	kWh	Annual Energy (kWh)
XXXX	Other Resources		P	kWh	Annual Energy (kWh)
XXXX	Other Resources		P	kWh	Annual Energy (kWh)
	Transmission/Ancillary Services Purchases				
XXXX	Energy	$197,487	P	CPT	Coincident Peak - At time of Transmission Provider's Peak
XXXX	Demand		P	CPT	Coincident Peak - At time of Transmission Provider's Peak
XXXX	Coincident Transmission Peak-Demand	$253,016	P	CPT	Coincident Peak - At time of Transmission Provider's Peak
XXXX	Wheeling Revenue		P	kWh	Annual Energy (kWh)
	Other				
555.10	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	kWh	Annual Energy (kWh)
XXXX	Open		P	KWh	Annual Energy (kWh)
	Total Purchased Power	$2,764,943			
	Total Production	$2,764,943			
	Transmission				

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
560.00	Op. Supervision & Engineering		T	RBT	On the Basis of Transmission Rate Base
	System Control and Loading Dispatch		P	RBT	On the Basis of Transmission Rate Base
561.00	Load Dispatching		T	RBT	On the Basis of Transmission Rate Base
562.00	Station Expenses		T	RBT	On the Basis of Transmission Rate Base
563.00	Overhead Lines		T	RBT	On the Basis of Transmission Rate Base
564.00	Underground Lines		T	RBT	On the Basis of Transmission Rate Base
565.00	Transmission of Electricity		T	RBT	On the Basis of Transmission Rate Base
566.00	Miscellaneous Transmission		T	RBT	On the Basis of Transmission Rate Base
567.00	Rents		T	RBT	On the Basis of Transmission Rate Base
567.10	Op. Supplies		T	RBT	On the Basis of Transmission Rate Base
568.00	Maint. Supervision & Engineering		T	RBT	On the Basis of Transmission Rate Base
569.00	Maint. of Structures		T	RBT	On the Basis of Transmission Rate Base
570.00	Maint. of Station Equipment		T	RBT	On the Basis of Transmission Rate Base
571.00	Maint. of Overhead Lines		T	RBT	On the Basis of Transmission Rate Base
572.00	Maint. Of Underground Lines		T	RBT	On the Basis of Transmission Rate Base
573.00	Maint. of Misc. Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
574.00	Maint. Of Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
	Total Transmission				
	Distribution				
580.00	Op. Supervision & Engineering		D	OMDS&E	On the Basis of Distribution O&M for Supervision & Engineering
581.00	Load Dispatching		D	RBD	On the Basis of Distribution Rate Base
582.00	Line and Station Expenses	$1,259	D	RBD	On the Basis of Distribution Rate Base
583.00	Overhead Lines	$3,748	D	RBOH	On the Basis of all Overhead Rate Base
584.00	Underground Lines	$12	D	RBUG	On the Basis of all Underground Rate Base
585.00	Street Lighting & Signal System		D	RBD	On the Basis of Distribution Rate Base
586.00	Meters	$22,430	D	CUSTM	Customers Weighted for Meters and Services
587.00	Customer Installations		D	CUSTM	Customers Weighted for Meters and Services
588.00	Misc. Distribution	$32,543	D	RBD	On the Basis of Distribution Rate Base
588.10	Standby Time	$35,197	D	RBD	On the Basis of Distribution Rate Base
589.00	Rents		D	RBD	On the Basis of Distribution Rate Base
590.00	Maint. Supervision & Engineering	$92,599	D	OMDS&E	On the Basis of Distribution O&M for Supervision & Engineering
591.00	Maint. of Structures	$41,255	D	RBD	On the Basis of Distribution Rate Base
592.00	Maint. of Station Equipment	$16,097	D	RBD	On the Basis of Distribution Rate Base
592.10	Maint. of Structures and Equipment		D	RBD	On the Basis of Distribution Rate Base
593.00	Maint. of Overhead Lines	$265,955	D	RBOH	On the Basis of all Overhead Rate Base
594.00	Maint. Of Underground Lines	$29,816	D	RBUG	On the Basis of all Underground Rate Base
594.10	Locates	$93,472	D	RBUG	On the Basis of all Underground Rate Base

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
595.00	Maint. of Line Transformers	$1,187	D	RBOH	On the Basis of all Overhead Rate Base
595.00	Maint. of Line Transformers - Underground		D	OMDLUGT	On the Basis of Distribution O&M less UG Transformers
596.00	Maint. of Street Lighting & Signal System		D	RBD	On the Basis of Distribution Rate Base
597.00	Maint. of Meters	$51,352	D	CUSTM	Customers Weighted for Meters and Services
598.00	Maint. of Misc. Distribution Plant		D	CUST	Actual Customers
XXXX	Other		D	RBD	On the Basis of Distribution Rate Base
XXXX	Other		D	RBD	On the Basis of Distribution Rate Base
XXXX	Other		D	RBD	On the Basis of Distribution Rate Base
	Total Distribution	$686,922			
	Total Operation & Maintenance	$3,451,865			
	Customer Service, Accounts, & Sales				
901/907/911	Supervision		D	CUSTW	Customers Weighted for Accounting/Metering
902.00	Meter Reading	$9,434	D	CUSTMR	Customers Weighted for Meter Reading
903.00	Customer Records Collection	$296,307	D	CUSTW	Customers Weighted for Accounting/Metering
904.00	Uncollectable Accounts		D	CUSTW	Customers Weighted for Accounting/Metering
905.00	Misc. Customer Accounts		D	CUSTW	Customers Weighted for Accounting/Metering
906.00	Customer Service & Information		D	CUSTW	Customers Weighted for Accounting/Metering
907.00	Customer Communication & Education		D	CUSTW	Customers Weighted for Accounting/Metering
908.00	Customer Assistance	$3,687	D	CUSTW	Customers Weighted for Accounting/Metering
910.00	Conservation		D	CUSTW	Customers Weighted for Accounting/Metering
912.00	Demonstrating & Selling		D	CUSTW	Customers Weighted for Accounting/Metering
913.00	Advertising		D	CUSTW	Customers Weighted for Accounting/Metering
915.00	Expenses and costs from Merchandise	-$2,998	D	CUSTW	Customers Weighted for Accounting/Metering
917.00	Sales Expenses		D	OM	On the Basis of All O&M
902.10	Irrigation Annual Meter Maintenance		D	DA2	Direct Assignment for Irrigation
909.00	Informational and Instructional Advertising Expenses		D	CUSTW	Customers Weighted for Accounting/Metering
	Total Customer Service, Accounts & Sales	$306,429			
	Total O&M w/o Purchased Power Supply & A&	$993,351			
	Administrative & General				
920.00	Administrative & General Salaries	$303,818	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
921.00	Office Supplies	$149,895	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
922.00	Civic Services	$1,360	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
923.00	Special Services	$14,563	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
924.00	Property Insurance	$6,872	SS	NETPLT	On the Basis of Net Plant
925.00	Injuries and Damages	$23,179	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
926.00	Employee Pension & Benefits		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
927.00	Franchise Requirements		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
928.00	Regulatory Expense		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
929.00	Duplicate Charge - Credit		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.10	Director Fees & Mileage	$12,001	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.00	Misc. General Expense	$53,368	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.40	Misc. General Expense Board	$5,602	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
931.00	Misc. Expenses & Employee Training	$61,162	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
932.00	Maint. of General Plant & Communication Equipment		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
933.00	Transportation		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
935.00	Salaries - Interfund		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Total Administrative & General	$631,819			
	Total O&M plus A&G	$4,390,113			
	Depreciation				
403.30	Generation Plant		P	RBG	On the Basis of Generation Rate Base
403.50	Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
403.60	Distribution Plant	$348,201	D	RBD	On the Basis of Distribution Rate Base
403.70	General Plant	$43,370	SS	RBGP	On the Basis of General Plant Rate Base
403.80	Amortization of Plant		D	RBD	On the Basis of Distribution Rate Base
	Total Depreciation	$391,571			
	Taxes				
408.00	Property Tax	$41,346	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
408.70	Taxes - Excise	$175,255	SS	REV	On The Basis of Revenue
	Total Taxes	$216,601			
	Interest and Debt Service Expense				
427.00	Interest on Long-Term Debt	$194,237	SS	NETPLT	On the Basis of Net Plant
428.00	Amortization of Debt Discount		SS	NETPLT	On the Basis of Net Plant
431.00	Other Interest Expense		SS	NETPLT	On the Basis of Net Plant
	Total Interest / Debt Service Expense	$194,237			
	Other Contributions				
	Operating Reserve		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Rate Stabilization Account		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Additional Revenue needed for TIER Requirement		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Operating Margins	$271,932	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
426.00	Donations		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Misc. Income Deductions		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Patronage Capital & Operating Margins		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Total Other Contributions	$271,932			
	Revenue Requirement Before Other Revenues	$5,464,454			

Okanogan County Electric Cooperative

INPUT REVENUE REQUIREMENT

Schedule 3.1

		Year 2019 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Revenue Req. Before Taxes and Other Revenue	$5,247,853			
	Other Revenues				
450.00	Forfeited Deposits	$4,712	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
451.00	Misc. Service Revenues		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
454.00	Rent - Electric Property Pole Contacts	$9,677	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
455.00	Rent - Facility	$18,000	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
456.20	Misc. Revenue (Other)	$31,595	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
457.00	Transfer Credits		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
419&424	Dividends from Affiliates, Interest		SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
449.00	Other Revenues (Idle Services)	$15,361	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Street Lights	$5,280	D	RBD	On the Basis of Distribution Rate Base
	Total Other Revenues	$84,626			
	REVENUE REQUIREMENT for COST ALLOCATIOI	$5,379,829			

Okanogan County Electric Cooperative

PROJECTED REVENUE REQUIREMENTS

Schedule 3.2

FERC Account	Operation & Maintenance Expense	Total 2018 Expenses	2019	2020	2021	2022	2023
	Other Power Supply						
555.00	Purchased Power	$2,707,600					
556.00	Load Dispatching						
XXXX	Op. Supervision & Engineering						
	Power Purchases						
XXXX	BPA Customer Charge (TRM)		**$2,016,429**	**$1,999,455**	**$2,011,910**	**$2,049,440**	**$2,062,205**
XXXX	Demand - BPA Contracts		**$154,102**	**$165,742**	**$173,713**	**$196,638**	**$191,628**
XXXX	Load Shaping, HLH		**$98,156**	**$87,171**	**$61,664**	**$25,197**	**$31,983**
XXXX	Load Shaping, LLH		**$102,495**	**$97,929**	**$81,014**	**$60,032**	**$63,286**
XXXX	LDD Credit		**-$164,107**	**-$176,336**	**-$174,690**	**-$174,925**	**-$176,261**
XXXX	IRMP						
XXXX	Part B Purchase (Energy)		**$63,474**	**$76,506**	**$165,306**	**$295,374**	**$311,413**
XXXX	FRP Surcharge		**$3,691**	**$36,911**	**$37,004**	**$37,834**	**$37,929**
XXXX	Customer Refund / BPA Base Rate Red		**-$52,146**				
XXXX							
920.20	PNGC Services		**$92,346**	**$94,131**	**$95,949**	**$97,804**	**$99,693**
XXXX	Other Resources						
XXXX	Other Resources						
XXXX	Other Resources						
	Transmission/Ancillary Services Purchases						
XXXX	Energy		**$197,487**	**$271,269**	**$273,195**	**$278,938**	**$280,934**
XXXX	Demand						
XXXX	Coincident Transmission Peak-Demand		**$253,016**	**$258,798**	**$265,019**	**$272,863**	**$277,928**
XXXX	Wheeling Revenue						
	Other						
555.10	Open						
XXXX	Open						
XXXX	Open						

Okanogan County Electric Cooperative

PROJECTED REVENUE REQUIREMENTS

Schedule 3.2

		Total **2018** Expenses	2019	2020	2021	2022	2023
XXXX	Open						
XXXX	Open						
XXXX	Open						
	Total Purchased Power	$2,707,600	$2,764,943	$2,911,576	$2,990,083	$3,139,195	$3,180,738
	Total Production	$2,707,600	$2,764,943	$2,911,576	$2,990,083	$3,139,195	$3,180,738
	Transmission						
560.00	Op. Supervision & Engineering						
	System Control and Loading Dispatch						
561.00	Load Dispatching						
562.00	Station Expenses						
563.00	Overhead Lines						
564.00	Underground Lines						
565.00	Transmission of Electricity						
566.00	Miscellaneous Transmission						
567.00	Rents						
567.10	Op. Supplies						
568.00	Maint. Supervision & Engineering						
569.00	Maint. of Structures						
570.00	Maint. of Station Equipment						
571.00	Maint. of Overhead Lines						
572.00	Maint. Of Underground Lines						
573.00	Maint. of Misc. Transmission Plant						
574.00	Maint. Of Transmission Plant						
	Total Transmission						
	Distribution						
580.00	Op. Supervision & Engineering						
581.00	Load Dispatching						
582.00	Line and Station Expenses	$1,172	$1,259	$1,296	$1,335	$1,375	$1,416
583.00	Overhead Lines	$3,491	$3,748	$3,861	$3,977	$4,096	$4,219
584.00	Underground Lines	$12	$12	$13	$13	$14	$14
585.00	Street Lighting & Signal System						

Okanogan County Electric Cooperative

PROJECTED REVENUE REQUIREMENTS

Schedule 3.2

		Total **2018** Expenses	2019	2020	2021	2022	2023
586.00	Meters	$20,888	$22,430	$23,103	$23,796	$24,510	$25,246
587.00	Customer Installations						
588.00	Misc. Distribution	$30,306	$32,543	$33,519	$34,525	$35,560	$36,627
588.10	Standby Time	$32,777	$35,197	$36,253	$37,341	$38,461	$39,615
589.00	Rents						
590.00	Maint. Supervision & Engineering	$86,233	$92,599	$95,376	$98,238	$101,185	$104,221
591.00	Maint. of Structures	$38,419	$41,255	$42,492	$43,767	$45,080	$46,432
592.00	Maint. of Station Equipment	$14,991	$16,097	$16,580	$17,078	$17,590	$18,118
592.10	Maint. of Structures and Equipment						
593.00	Maint. of Overhead Lines	$247,672	$265,955	$273,933	$282,151	$290,616	$299,335
594.00	Maint. Of Underground Lines	$27,766	$29,816	$30,711	$31,632	$32,581	$33,558
594.10	Locates	$87,046	$93,472	$96,276	$99,164	$102,139	$105,203
595.00	Maint. of Line Transformers	$1,105	$1,187	$1,222	$1,259	$1,297	$1,336
595.00	Maint. of Line Transformers - Underground						
596.00	Maint. of Street Lighting & Signal System						
597.00	Maint. of Meters	$47,822	$51,352	$52,893	$54,480	$56,114	$57,798
598.00	Maint. of Misc. Distribution Plant						
XXXX	Other						
XXXX	Other						
XXXX	Other						
	Total Distribution	$639,701	$686,922	$707,529	$728,756	$750,618	$773,138
	Total Operation & Maintenance	$3,347,301	$3,451,865	$3,619,105	$3,718,839	$3,889,813	$3,953,876
	Customer Service, Accounts, & Sales						
901/907/911	Supervision						
902.00	Meter Reading	$8,984	$9,434	$9,717	$10,008	$10,308	$10,618
903.00	Customer Records Collection	$282,197	$296,307	$305,196	$314,352	$323,782	$333,495
904.00	Uncollectable Accounts						
905.00	Misc. Customer Accounts						
906.00	Customer Service & Information						
907.00	Customer Communication & Education						
908.00	Customer Assistance	$2,355	$3,687	$3,798	$3,912	$4,029	$4,150

Okanogan County Electric Cooperative

PROJECTED REVENUE REQUIREMENTS

Schedule 3.2

		Total **2018** Expenses	2019	2020	2021	2022	2023
910.00	Conservation						
912.00	Demonstrating & Selling						
913.00	Advertising						
915.00	Expenses and costs from Merchandise	$7,162	-$2,998	-$3,088	-$3,181	-$3,276	-$3,374
917.00	Sales Expenses						
902.10	Irrigation Annual Meter Maintenance						
909.00	Informational and Instructional Advertising Expenses	$3,431					
	Total Customer Service, Accounts & Sales	$304,129	$306,429	$315,622	$325,091	$334,843	$344,888
	Total O&M w/o Purchased Power Supply & A&G	$943,830	$993,351	$1,023,151	$1,053,847	$1,085,462	$1,118,026
	Administrative & General						
920.00	Administrative & General Salaries	$268,351	$303,818	$312,932	$322,320	$331,990	$341,949
921.00	Office Supplies	$132,397	$149,895	$154,392	$159,024	$163,795	$168,708
922.00	Civic Services	$1,202	$1,360	$1,401	$1,443	$1,487	$1,531
923.00	Special Services	$12,863	$14,563	$14,999	$15,449	$15,913	$16,390
924.00	Property Insurance	$6,070	$6,872	$7,078	$7,290	$7,509	$7,734
925.00	Injuries and Damages	$20,473	$23,179	$23,874	$24,590	$25,328	$26,088
926.00	Employee Pension & Benefits						
927.00	Franchise Requirements						
928.00	Regulatory Expense						
929.00	Duplicate Charge - Credit	-$3,979					
930.10	Director Fees & Mileage	$10,600	$12,001	$12,361	$12,732	$13,114	$13,507
930.00	Misc. General Expense	$47,138	$53,368	$54,969	$56,618	$58,316	$60,066
930.40	Misc. General Expense Board	$4,948	$5,602	$5,770	$5,943	$6,121	$6,305
931.00	Misc. Expenses & Employee Training	$54,022	$61,162	$62,997	$64,887	$66,833	$68,838
932.00	Maint. of General Plant & Communication Equipment						
933.00	Transportation						
935.00	Maintenance of General Plant						
	Total Administrative & General	$554,083	$631,819	$650,773	$670,297	$690,405	$711,117
	Total O&M plus A&G	$4,205,514	$4,390,113	$4,585,500	$4,714,227	$4,915,062	$5,009,881
	Depreciation						
403.30	Generation Plant						
403.50	Transmission Plant						

Okanogan County Electric Cooperative

PROJECTED REVENUE REQUIREMENTS

Schedule 3.2

		Total **2018** Expenses	2019	2020	2021	2022	2023
403.60	Distribution Plant	$332,645	$348,201	$365,611	$383,892	$403,086	$423,241
403.70	General Plant	$41,433	$43,370	$45,539	$47,816	$50,206	$52,717
403.80	Amortization of Plant						
	Total Depreciation	$374,077	$391,571	$411,150	$431,707	$453,293	$475,957
	Taxes						
408.00	Property Tax	$45,055	$41,346	$42,586	$43,864	$45,180	$46,535
408.70	Taxes - Excise	$173,425	$175,255	$180,513	$185,928	$191,506	$197,251
	Total Taxes	$218,481	$216,601	$223,099	$229,792	$236,686	$243,786
	Interest and Debt Service Expense						
427.00	Interest on Long-Term Debt	$201,713	$194,237	$194,210	$211,668	$231,661	$242,073
428.00	Amortization of Debt Discount						
431.00	Other Interest Expense						
	Total Interest / Debt Service Expense	$201,713	$194,237	$194,210	$211,668	$231,661	$242,073
	Other Contributions						
	Operating Reserve						
	Rate Stabilization Account						
	Additional Revenue needed for TIER Requirement						
	Operating Margins	$845,610	$271,932	$271,894	$296,335	$324,325	$338,902
426.00	Donations						
	Misc. Income Deductions						
	Patronage Capital & Operating Margins						
	Total Other Contributions	$845,610	$271,932	$271,894	$296,335	$324,325	$338,902
	Revenue Requirement Before Other Revenues	$5,845,395	$5,464,454	$5,685,853	$5,883,730	$6,161,027	$6,310,600
	Revenue Req. Before Taxes and Other Revenues	$5,626,914	$5,247,853	$5,462,754	$5,653,938	$5,924,341	$6,066,814
	Other Revenues						
450.00	Forfeited Deposits	$4,712	$4,712	$4,712	$4,712	$4,712	$4,712
451.00	Misc. Service Revenues						
454.00	Rent - Electric Property Pole Contacts	$9,677	$9,677	$9,677	$9,677	$9,677	$9,677
455.00	Rent - Facility	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000
456.20	Misc. Revenue (Other)	$31,595	$31,595	$31,595	$31,595	$31,595	$31,595

Okanogan County Electric Cooperative

PROJECTED REVENUE REQUIREMENTS

Schedule 3.2

		Total 2018 Expenses	2019	2020	2021	2022	2023
457.00	Transfer Credits						
419&424	Dividends from Affiliates, Interest						
449.00	Other Revenues (Idle Services)	$15,361	$15,361	$15,361	$15,361	$15,361	$15,361
	Street Lights	$5,280	$5,280	$5,280	$5,280	$5,280	$5,280
	Total Other Revenues	$84,626	$84,626	$84,626	$84,626	$84,626	$84,626
	REVENUE REQUIREMENT for COST ALLOCATION	$5,760,769	$5,379,829	$5,601,228	$5,799,104	$6,076,401	$6,225,975

Okanogan County Electric Cooperative - Minimum System Analysis

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

			Production			Transmission			Distribution			
		Allocation Date 2019 **Total** **Expenses**	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
FERC Account	**Operation & Maintenance Expense**											
	Other Power Supply											
555.00	Purchased Power											
556.00	Load Dispatching											
XXXX	Op. Supervision & Engineering											
	Power Purchases											
XXXX	BPA Customer Charge (TRM)	$2,016,429		$2,016,429								
XXXX	Demand - BPA Contracts	$154,102		$154,102								
XXXX	Load Shaping, HLH	$98,156		$98,156								
XXXX	Load Shaping, LLH	$102,495		$102,495								
XXXX	LDD Credit	-$164,107	-$164,107									
XXXX	IRMP											
XXXX	Part B Purchase (Energy)	$63,474		$63,474								
XXXX	FRP Surcharge	$3,691		$3,691								
XXXX	Customer Refund / BPA Base Rate Red	-$52,146		-$52,146								
XXXX												
920.20	PNGC Services	$92,346		$92,346								
XXXX	Other Resources											
XXXX	Other Resources											
XXXX	Other Resources											
	Transmission/Ancillary Services Purchases											
XXXX	Energy	$197,487	$197,487									
XXXX	Demand											
XXXX	Coincident Transmission Peak-Demand	$253,016	$253,016									
XXXX	Wheeling Revenue											
	Other											
555.10	Open											
XXXX	Open											
XXXX	Open											
XXXX	Open											
XXXX	Open											
XXXX	Open											
	Total Purchased Power	$2,764,943	$286,396	$2,478,547								
	Total Production	$2,764,943	$286,396	$2,478,547								
	Transmission											
560.00	Op. Supervision & Engineering											
	System Control and Loading Dispatch											
561.00	Load Dispatching											
562.00	Station Expenses											
563.00	Overhead Lines											

Prepared By EES Consulting, Inc.

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

		Allocation Date 2019 Total Expenses	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
564.00	Underground Lines											
565.00	Transmission of Electricity											
566.00	Miscellaneous Transmission											
567.00	Rents											
567.10	Op. Supplies											
568.00	Maint. Supervision & Engineering											
569.00	Maint. of Structures											
570.00	Maint. of Station Equipment											
571.00	Maint. of Overhead Lines											
572.00	Maint. Of Underground Lines											
573.00	Maint. of Misc. Transmission Plant											
574.00	Maint. Of Transmission Plant											
	Total Transmission											
	Distribution											
580.00	Op. Supervision & Engineering											
581.00	Load Dispatching											
582.00	Line and Station Expenses	$1,259							$1,259			
583.00	Overhead Lines	$3,748							$2,249		$1,499	
584.00	Underground Lines	$12							$7		$5	
585.00	Street Lighting & Signal System											
586.00	Meters	$22,430									$22,430	
587.00	Customer Installations											
588.00	Misc. Distribution	$32,543							$16,146		$16,397	
588.10	Standby Time	$35,197							$17,463		$17,734	
589.00	Rents											
590.00	Maint. Supervision & Engineering	$92,599							$46,586		$46,013	
591.00	Maint. of Structures	$41,255							$20,468		$20,787	
592.00	Maint. of Station Equipment	$16,097							$7,987		$8,111	
592.10	Maint. of Structures and Equipment											
593.00	Maint. of Overhead Lines	$265,955							$159,573		$106,382	
594.00	Maint. Of Underground Lines	$29,816							$17,890		$11,926	
594.10	Locates	$93,472							$46,736		$46,736	
595.00	Maint. of Line Transformers	$1,187							$593		$593	
595.00	Maint. of Line Transformers - Underground											
596.00	Maint. of Street Lighting & Signal System											
597.00	Maint. of Meters	$51,352									$51,352	
598.00	Maint. of Misc. Distribution Plant											
XXXX	Other											
XXXX	Other											
XXXX	Other											
	Total Distribution	$686,922							$336,955		$349,967	
	Total Operation & Maintenance	$3,451,865	$286,396	$2,478,547					$336,955		$349,967	
	Customer Service, Accounts, & Sales											
901/907/911	Supervision											
902.00	Meter Reading	$9,434									$9,434	

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

		Allocation Date 2019 Total Expenses	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
903.00	Customer Records Collection	$296,307									$296,307	
904.00	Uncollectable Accounts											
905.00	Misc. Customer Accounts											
906.00	Customer Service & Information											
907.00	Customer Communication & Education											
908.00	Customer Assistance	$3,687									$3,687	
910.00	Conservation											
912.00	Demonstrating & Selling											
913.00	Advertising											
915.00	Expenses and costs from Merchandise	-$2,998									-$2,998	
917.00	Sales Expenses											
902.10	Irrigation Annual Meter Maintenance											
909.00	Informational and Instructional Advertising Expenses											
	Total Customer Service, Accounts & Sales	$306,429									$306,429	
	Total O&M w/o Purchased Power Supply & A&G	$993,351							$336,955		$656,396	
	Administrative & General											
920.00	Administrative & General Salaries	$303,818							$103,058		$200,759	
921.00	Office Supplies	$149,895							$50,846		$99,049	
922.00	Civic Services	$1,360							$461		$899	
923.00	Special Services	$14,563							$4,940		$9,623	
924.00	Property Insurance	$6,872							$3,409		$3,463	
925.00	Injuries and Damages	$23,179							$7,863		$15,316	
926.00	Employee Pension & Benefits											
927.00	Franchise Requirements											
928.00	Regulatory Expense											
929.00	Duplicate Charge - Credit											
930.10	Director Fees & Mileage	$12,001							$4,071		$7,930	
930.00	Misc. General Expense	$53,368							$18,103		$35,265	
930.40	Misc. General Expense Board	$5,602							$1,900		$3,702	
931.00	Misc. Expenses & Employee Training	$61,162							$20,747		$40,415	
932.00	Maint. of General Plant & Communication Equipment											
933.00	Transportation											
935.00	Salaries - Interfund											
	Total Administrative & General	$631,819							$215,398		$416,421	
	Total O&M plus A&G	$4,390,113	$286,396	$2,478,547					$552,353		$1,072,817	
	Depreciation											
403.30	Generation Plant											
403.50	Transmission Plant											
403.60	Distribution Plant	$348,201							$172,755		$175,446	
403.70	General Plant	$43,370							$21,518		$21,853	
403.80	Amortization of Plant											
	Total Depreciation	$391,571							$194,273		$197,299	
	Taxes											
408.00	Property Tax	$41,346							$20,513		$20,833	
408.70	Taxes - Excise	$175,255							$175,255			
	Total Taxes	$216,601							$195,768		$20,833	

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

		Allocation Date 2019 Total Expenses	Production			Transmission			Distribution			
			Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
	Interest and Debt Service Expense											
427.00	Interest on Long-Term Debt	$194,237							$96,368		$97,869	
428.00	Amortization of Debt Discount											
431.00	Other Interest Expense											
	Total Interest / Debt Service Expense	$194,237							$96,368		$97,869	
	Other Contributions											
	Operating Reserve											
	Rate Stabilization Account											
	Additional Revenue needed for TIER Requirement											
	Operating Margins	$271,932							$92,242		$179,690	
426.00	Donations											
	Misc. Income Deductions											
	Patronage Capital & Operating Margins											
	Total Other Contributions	$271,932							$92,242		$179,690	
	Revenue Requirement Before Other Revenues	$5,464,454	$286,396	$2,478,547					$1,131,005		$1,568,507	
	Revenue Req. Before Taxes and Other Revenues	$5,247,853	$286,396	$2,478,547					$935,236		$1,547,674	
	Other Revenues											
450.00	Forfeited Deposits	$4,712							$1,598		$3,114	
451.00	Misc. Service Revenues											
454.00	Rent - Electric Property Pole Contacts	$9,677							$3,283		$6,395	
455.00	Rent - Facility	$18,000							$6,106		$11,894	
456.20	Misc. Revenue (Other)	$31,595							$10,717		$20,878	
457.00	Transfer Credits											
419&424	Dividends from Affiliates, Interest											
449.00	Other Revenues (Idle Services)	$15,361							$5,211		$10,150	
	Street Lights	$5,280							$2,620		$2,660	
	Total Other Revenues	$84,626							$29,534		$55,091	
	REVENUE REQUIREMENT for COST ALLOCATION	$5,379,829	$286,396	$2,478,547					$1,101,470		$1,513,416	

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

FERC Account	Operation & Maintenance Expense	Allocation Date 2019 Total Expenses	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Other Power Supply									
555.00	Purchased Power									
556.00	Load Dispatching									
XXXX	Op. Supervision & Engineering									
	Power Purchases									
XXXX	BPA Customer Charge (TRM)	$2,016,429	$546,446	$868,249	$252,978	$288,359	$18,386	$40,056	$477	$1,477
XXXX	Demand - BPA Contracts	$154,102	$42,038	$66,725	$19,182	$21,855	$1,305	$2,848	$35	$115
XXXX	Load Shaping, HLH	$98,156	$26,672	$42,361	$12,275	$13,990	$869	$1,894	$23	$72
XXXX	Load Shaping, LLH	$102,495	$27,851	$44,234	$12,818	$14,608	$907	$1,978	$24	$76
XXXX	LDD Credit	-$164,107	-$56,150	-$82,278	-$10,733	-$11,085	-$1,138	-$2,580	-$59	-$82
XXXX	IRMP									
XXXX	Part B Purchase (Energy)	$63,474	$17,248	$27,393	$7,938	$9,047	$562	$1,225	$15	$47
XXXX	FRP Surcharge	$3,691	$1,003	$1,593	$462	$526	$33	$71	$1	$3
XXXX	Customer Refund / BPA Base Rate Red	-$52,146	-$14,170	-$22,505	-$6,521	-$7,432	-$462	-$1,006	-$12	-$38
XXXX										
920.20	PNGC Services	$92,346	$25,093	$39,854	$11,549	$13,161	$818	$1,782	$21	$68
XXXX	Other Resources									
XXXX	Other Resources									
XXXX	Other Resources									
	Transmission/Ancillary Services Purchases									
XXXX	Energy	$197,487	$67,571	$99,014	$12,917	$13,340	$1,370	$3,105	$72	$99
XXXX	Demand									
XXXX	Coincident Transmission Peak-Demand	$253,016	$86,570	$126,854	$16,548	$17,091	$1,755	$3,978	$92	$127
XXXX	Wheeling Revenue									
	Other									
555.10	Open									
XXXX	Open									
XXXX	Open									
XXXX	Open									
XXXX	Open									
XXXX	Open									
	Total Purchased Power	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
	Total Production	$2,764,943	$770,172	$1,211,494	$329,411	$373,460	$24,404	$53,352	$687	$1,962
	Transmission									
560.00	Op. Supervision & Engineering									
	System Control and Loading Dispatch									
561.00	Load Dispatching									
562.00	Station Expenses									
563.00	Overhead Lines									
564.00	Underground Lines									
565.00	Transmission of Electricity									

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

		Allocation Date 2019 Total Expenses								
566.00	Miscellaneous Transmission									
567.00	Rents									
567.10	Op. Supplies									
568.00	Maint. Supervision & Engineering									
569.00	Maint. of Structures									
570.00	Maint. of Station Equipment									
571.00	Maint. of Overhead Lines									
572.00	Maint. Of Underground Lines									
573.00	Maint. of Misc. Transmission Plant									
574.00	Maint. Of Transmission Plant									
	Total Transmission									
	Distribution									
580.00	Op. Supervision & Engineering									
581.00	Load Dispatching									
582.00	Line and Station Expenses	$1,259	$465	$617	$68	$69	$12	$25	$1	$1
583.00	Overhead Lines	$3,748	$1,764	$1,549	$151	$127	$63	$81	$11	$3
584.00	Underground Lines	$12	$6	$5	$1	$0	$0	$0	$0	$0
585.00	Street Lighting & Signal System									
586.00	Meters	$22,430	$11,323	$5,435	$1,766	$381	$1,265	$2,143	$109	$10
587.00	Customer Installations									
588.00	Misc. Distribution	$32,543	$15,711	$12,587	$1,425	$985	$716	$990	$106	$24
588.10	Standby Time	$35,197	$16,992	$13,613	$1,541	$1,065	$774	$1,070	$115	$26
589.00	Rents									
590.00	Maint. Supervision & Engineering	$92,599	$44,561	$35,947	$4,068	$2,833	$2,021	$2,803	$299	$68
591.00	Maint. of Structures	$41,255	$19,917	$15,956	$1,806	$1,248	$907	$1,255	$135	$30
592.00	Maint. of Station Equipment	$16,097	$7,772	$6,226	$705	$487	$354	$490	$53	$12
592.10	Maint. of Structures and Equipment									
593.00	Maint. of Overhead Lines	$265,955	$125,132	$109,929	$10,738	$9,031	$4,435	$5,722	$760	$208
594.00	Maint. Of Underground Lines	$29,816	$14,028	$12,324	$1,204	$1,012	$497	$641	$85	$23
594.10	Locates	$93,472	$46,331	$36,843	$3,447	$2,691	$1,732	$2,042	$315	$69
595.00	Maint. of Line Transformers	$1,187	$588	$468	$44	$34	$22	$26	$4	$1
595.00	Maint. of Line Transformers - Underground									
596.00	Maint. of Street Lighting & Signal System									
597.00	Maint. of Meters	$51,352	$25,922	$12,442	$4,043	$872	$2,896	$4,906	$249	$23
598.00	Maint. of Misc. Distribution Plant									
XXXX	Other									
XXXX	Other									
XXXX	Other									
	Total Distribution	$686,922	$330,511	$263,941	$31,008	$20,836	$15,695	$22,194	$2,241	$497
	Total Operation & Maintenance	$3,451,865	$1,100,684	$1,475,436	$360,418	$394,295	$40,099	$75,546	$2,928	$2,460
	Customer Service, Accounts, & Sales									
901/907/911	Supervision									
902.00	Meter Reading	$9,434	$6,044	$2,901	$189	$29	$113	$95	$58	$5
903.00	Customer Records Collection	$296,307	$189,836	$91,118	$5,921	$912	$3,535	$2,994	$1,824	$166

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

		Allocation Date 2019 Total Expenses								
904.00	Uncollectable Accounts									
905.00	Misc. Customer Accounts									
906.00	Customer Service & Information									
907.00	Customer Communication & Education									
908.00	Customer Assistance	$3,687	$2,362	$1,134	$74	$11	$44	$37	$23	$2
910.00	Conservation									
912.00	Demonstrating & Selling									
913.00	Advertising									
915.00	Expenses and costs from Merchandise	-$2,998	-$1,921	-$922	-$60	-$9	-$36	-$30	-$18	-$2
917.00	Sales Expenses									
902.10	Irrigation Annual Meter Maintenance									
909.00	Informational and Instructional Advertising Expenses									
	Total Customer Service, Accounts & Sales	$306,429	$196,322	$94,231	$6,123	$943	$3,656	$3,096	$1,886	$171
	Total O&M w/o Purchased Power Supply & A&G	$993,351	$526,833	$358,172	$37,131	$21,779	$19,351	$25,290	$4,127	$669
	Administrative & General									
920.00	Administrative & General Salaries	$303,818	$161,132	$109,547	$11,357	$6,661	$5,918	$7,735	$1,262	$205
921.00	Office Supplies	$149,895	$79,498	$54,048	$5,603	$3,286	$2,920	$3,816	$623	$101
922.00	Civic Services	$1,360	$722	$491	$51	$30	$27	$35	$6	$1
923.00	Special Services	$14,563	$7,723	$5,251	$544	$319	$284	$371	$61	$10
924.00	Property Insurance	$6,872	$3,318	$2,658	$301	$208	$151	$209	$22	$5
925.00	Injuries and Damages	$23,179	$12,293	$8,358	$866	$508	$452	$590	$96	$16
926.00	Employee Pension & Benefits									
927.00	Franchise Requirements									
928.00	Regulatory Expense									
929.00	Duplicate Charge - Credit									
930.10	Director Fees & Mileage	$12,001	$6,365	$4,327	$449	$263	$234	$306	$50	$8
930.00	Misc. General Expense	$53,368	$28,304	$19,243	$1,995	$1,170	$1,040	$1,359	$222	$36
930.40	Misc. General Expense Board	$5,602	$2,971	$2,020	$209	$123	$109	$143	$23	$4
931.00	Misc. Expenses & Employee Training	$61,162	$32,438	$22,053	$2,286	$1,341	$1,191	$1,557	$254	$41
932.00	Maint. of General Plant & Communication Equipment									
933.00	Transportation									
935.00	Salaries - Interfund									
	Total Administrative & General	$631,819	$334,764	$227,995	$23,661	$13,910	$12,325	$16,120	$2,619	$426
	Total O&M plus A&G	$4,390,113	$1,631,769	$1,797,661	$390,203	$409,148	$56,080	$94,762	$7,433	$3,057
	Depreciation									
403.30	Generation Plant									
403.50	Transmission Plant									
403.60	Distribution Plant	$348,201	$168,105	$134,675	$15,247	$10,535	$7,659	$10,589	$1,136	$254
403.70	General Plant	$43,370	$20,938	$16,774	$1,899	$1,312	$954	$1,319	$141	$32
403.80	Amortization of Plant									
	Total Depreciation	$391,571	$189,044	$151,450	$17,146	$11,847	$8,613	$11,908	$1,277	$285
	Taxes									
408.00	Property Tax	$41,346	$19,961	$15,992	$1,810	$1,251	$909	$1,257	$135	$30
408.70	Taxes - Excise	$175,255	$66,857	$73,266	$14,874	$15,291	$1,710	$2,889	$236	$132
	Total Taxes	$216,601	$86,818	$89,257	$16,685	$16,542	$2,620	$4,146	$371	$162

REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

		Allocation Date 2019 Total Expenses								
	Interest and Debt Service Expense									
427.00	Interest on Long-Term Debt	$194,237	$93,774	$75,126	$8,505	$5,877	$4,273	$5,907	$634	$142
428.00	Amortization of Debt Discount									
431.00	Other Interest Expense									
	Total Interest / Debt Service Expense	$194,237	$93,774	$75,126	$8,505	$5,877	$4,273	$5,907	$634	$142
	Other Contributions									
	Operating Reserve									
	Rate Stabilization Account									
	Additional Revenue needed for TIER Requirement									
	Operating Margins	$271,932	$144,221	$98,050	$10,165	$5,962	$5,297	$6,923	$1,130	$183
426.00	Donations									
	Misc. Income Deductions									
	Patronage Capital & Operating Margins									
	Total Other Contributions	$271,932	$144,221	$98,050	$10,165	$5,962	$5,297	$6,923	$1,130	$183
	Revenue Requirement Before Other Revenues	$5,464,454	$2,145,626	$2,211,544	$442,704	$449,376	$76,883	$123,647	$10,845	$3,829
	Revenue Req. Before Taxes and Other Revenues	$5,247,853	$2,058,808	$2,122,287	$426,019	$432,834	$74,264	$119,501	$10,473	$3,667
	Other Revenues									
450.00	Forfeited Deposits	$4,712	$2,499	$1,699	$176	$103	$92	$120	$20	$3
451.00	Misc. Service Revenues									
454.00	Rent - Electric Property Pole Contacts	$9,677	$5,132	$3,489	$362	$212	$189	$246	$40	$7
455.00	Rent - Facility	$18,000	$9,546	$6,490	$673	$395	$351	$458	$75	$12
456.20	Misc. Revenue (Other)	$31,595	$16,757	$11,392	$1,181	$693	$615	$804	$131	$21
457.00	Transfer Credits									
419&424	Dividends from Affiliates, Interest									
449.00	Other Revenues (Idle Services)	$15,361	$8,147	$5,539	$574	$337	$299	$391	$64	$10
	Street Lights	$5,280	$2,549	$2,042	$231	$160	$116	$161	$17	$4
	Total Other Revenues	$84,626	$44,631	$30,652	$3,197	$1,899	$1,662	$2,181	$347	$57
	REVENUE REQUIREMENT for COST ALLOCATION	$5,379,829	$2,100,995	$2,180,893	$439,506	$447,477	$75,222	$121,466	$10,498	$3,772

INPUT RATE BASE
Schedule 4.1

FERC Account		Year 2018 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Intangible Plant				
301.00	Organization	$15	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
302.00	Franchise and Consents		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
303.00	Miscellaneous Intangible Plant	$999	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Intangible Plant	$1,014			
	Distribution Plant				
360.00	Land & Rights		D	NCPP	Non-Coincident Peak - Primary
361.00	Structures & Improvements		D	NCPP	Non-Coincident Peak - Primary
362.00	Station Equipment - Distribution	$72,394	D	NCPP	Non-Coincident Peak - Primary
363.00	Storage & Battery Equipment		D	NCPP	Non-Coincident Peak - Primary
364.00	Poles, Towers, & Fixtures	$1,131,547	D	MINSYSP	Minimum System - Poles, Towers & Fixtures (40% Customer, 60% Demand)
365.00	Overhead Conductors & Devices	$1,181,083	D	MINSYSC	Minimum System - Overhead and Underground Conduit (40% Customer, 60% Demand)
366.00	Underground Conduit		D	MINSYSC	Minimum System - Overhead and Underground Conduit (40% Customer, 60% Demand)
367.00	Underground Conductors & Devices	$1,747,908	D	MINSYSC	Minimum System - Overhead and Underground Conduit (40% Customer, 60% Demand)
368.00	Line Transformers	$2,889,668	D	MINSYST	Minimum System - Transformers (50% Customer, 50% Demand)
369.00	Services	$286,578	D	CUSTM	Customers Weighted for Meters and Services
370.00	Meters	$622,375	D	CUSTM	Customers Weighted for Meters and Services
371.00	Installation on Customer Premises	$37,123	D	CUSTM	Customers Weighted for Meters and Services
372.00	Leased Property on Cust. Premises		D	CUSTM	Customers Weighted for Meters and Services
373.00	Street Lights and Signal Systems	$3,122	D	RBDnoLights	On the Basis of Distribution Rate Base excluding Lights
	Total Distribution Plant	$7,971,798			
	Total Transmission & Distribution	$7,971,798			
	General Plant				
389.00	Land & Land Rights	$271,389	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
390.00	Structures & Improvements	$773,674	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
391.00	Office Furniture & Equipment	$237,354	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
392.00	Transportation Equipment	$629,831	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
393.00	Stores Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
394.00	Tools, Shop, & Garage Equipment	$75,081	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
395.00	Laboratory Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
396.00	Power Operated Equipment	$201,732	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
397.00	Communication Equipment	$8,341	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
398.00	Misc. Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
399.00	Other Tangible Property		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total General Plant	$2,197,402			
	Total Plant Before General Plant & Intangible	$7,971,798			

INPUT RATE BASE
Schedule 4.1

FERC Account

	Year 2018 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
Total Gross Plant in Service	$10,170,214			
Less: Accumulated Depreciation				
Intangible Plant		P	RBIG	On the Basis of Intangible Plant Rate Base
Steam Production Plant		P	RBSG	On the Basis of Steam Generation Rate Base
Nuclear Production Plant		P	RBG	On the Basis of Generation Rate Base
Hydraulic Production Plant		P	RBHG	On the Basis of Hydraulic Generation Rate Base
Biogas Production Plant		P	RBGG	On the Basis of Gas Turbine Generation Rate Base
Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
Distribution Plant	$2,604,817	D	RBD	On the Basis of Distribution Rate Base
General Plant	$1,849,336	SS	RBGP	On the Basis of General Plant Rate Base
Unclassified Plant		SS	RBGP	On the Basis of General Plant Rate Base
Misc. Plant		SS	RBGP	On the Basis of General Plant Rate Base
Total Accumulated Depreciation	$4,454,153			
Total Net Plant	$5,716,061			
Working Capital				
1/8 O&M	$203,146	SS	OMWOP	On the Basis of O&M (w/o Purch. Power Supply)
1/12 Purchased Power Supply Cost	$230,412	P	OMP	On the Basis of Purchased Power O&M
1/12 Purchased Transmission Charges	$37,542	P	OMPT	On the Basis of Purchased Transmission O&M
Total Working Capital	$471,100			
Less: Net Customer Contributions				
Production Plant		P	RBG	On the Basis of Generation Rate Base
Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
Distribution Plant		D	RBD	On the Basis of Distribution Rate Base
Street Lights		D	DA1	Direct Assignment for Streetlights
General Plant		SS	RBGP	On the Basis of General Plant Rate Base
Total Contributions				
TOTAL RATE BASE	$6,187,161			
CWIP				
Production Plant		P	RBG	On the Basis of Generation Rate Base
Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
Distribution Plant	$2,988	D	RBD	On the Basis of Distribution Rate Base
Services		D	RBD	On the Basis of Distribution Rate Base
General Plant		SS	RBGP	On the Basis of General Plant Rate Base
Other		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
Total CWIP	$2,988			
TOTAL RATE BASE plus CWIP	$6,190,149			

Prepared By EES Consulting, Inc.

Okanogan County Electric Cooperative - Minimum System Analysis

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

FERC Account	Account Description	Total Rate Base	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
	Intangible Plant											
301.00	Organization	$15							$7		$8	
302.00	Franchise and Consents											
303.00	Miscellaneous Intangible Plant	$999							$496		$504	
	Total Intangible Plant	$1,014							$503		$511	
	Distribution Plant											
360.00	Land & Rights											
361.00	Structures & Improvements											
362.00	Station Equipment - Distribution	$72,394							$72,394			
363.00	Storage & Battery Equipment											
364.00	Poles, Towers, & Fixtures	$1,131,547							$678,928		$452,619	
365.00	Overhead Conductors & Devices	$1,181,083							$708,650		$472,433	
366.00	Underground Conduit											
367.00	Underground Conductors & Devices	$1,747,908							$1,048,745		$699,163	
368.00	Line Transformers	$2,889,668							$1,444,834		$1,444,834	
369.00	Services	$286,578									$286,578	
370.00	Meters	$622,375									$622,375	
371.00	Installation on Customer Premises	$37,123									$37,123	
372.00	Leased Property on Cust. Premises											
373.00	Street Lights and Signal Systems	$3,122							$1,549		$1,573	
	Total Distribution Plant	$7,971,798							$3,955,099		$4,016,698	
	Total Transmission & Distribution	$7,971,798							$3,955,099		$4,016,698	
	General Plant											
389.00	Land & Land Rights	$271,389							$134,646		$136,743	
390.00	Structures & Improvements	$773,674							$383,848		$389,826	
391.00	Office Furniture & Equipment	$237,354							$117,760		$119,594	
392.00	Transportation Equipment	$629,831							$312,482		$317,349	
393.00	Stores Equipment											
394.00	Tools, Shop, & Garage Equipment	$75,081							$37,251		$37,831	
395.00	Laboratory Equipment											
396.00	Power Operated Equipment	$201,732							$100,086		$101,645	
397.00	Communication Equipment	$8,341							$4,138		$4,203	
398.00	Misc. Equipment											
399.00	Other Tangible Property											
	Total General Plant	$2,197,402							$1,090,211		$1,107,191	
	Total Plant Before General Plant & Intangible	$7,971,798							$3,955,099		$4,016,698	
	Total Gross Plant in Service	$10,170,214							$5,045,814		$5,124,400	
	Less: Accumulated Depreciation											
	Intangible Plant											
	Steam Production Plant											
	Nuclear Production Plant											

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

Prepared By EES Consulting, Inc.

		Production			Transmission			Distribution			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
FERC Account											
Hydraulic Production Plant											
Biogas Production Plant											
Transmission Plant											
Distribution Plant	$2,604,817							$1,292,345		$1,312,472	
General Plant	$1,849,336							$917,523		$931,813	
Unclassified Plant											
Misc. Plant											
Total Accumulated Depreciation	$4,454,153							$2,209,868		$2,244,285	
Total Net Plant	$5,716,061							$2,835,946		$2,880,115	
Working Capital											
1/8 O&M	$203,146							$69,044		$134,102	
1/12 Purchased Power Supply Cost	$230,412	$23,866	$206,546								
1/12 Purchased Transmission Charges	$37,542	$37,542									
Total Working Capital	$471,100	$61,408	$206,546					$69,044		$134,102	
Less: Net Customer Contributions											
Production Plant											
Transmission Plant											
Distribution Plant											
Street Lights											
General Plant											
Total Contributions											
TOTAL RATE BASE	$6,187,161	$61,408	$206,546					$2,904,990		$3,014,217	
CWIP											
Production Plant											
Transmission Plant											
Distribution Plant	$2,988							$1,482		$1,505	
Services											
General Plant											
Other											
Total CWIP	$2,988							$1,482		$1,505	
TOTAL RATE BASE plus CWIP	$6,190,149	$61,408	$206,546					$2,906,473		$3,015,722	

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

FERC Account	Account Description	Total Rate Base	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Intangible Plant									
301.00	Organization	$15	$7	$6	$1	$0	$0	$0	$0	$0
302.00	Franchise and Consents									
303.00	Miscellaneous Intangible Plant	$999	$482	$386	$44	$30	$22	$30	$3	$1
	Total Intangible Plant	$1,014	$490	$392	$44	$31	$22	$31	$3	$1
	Distribution Plant									
360.00	Land & Rights									
361.00	Structures & Improvements									
362.00	Station Equipment - Distribution	$72,394	$26,774	$35,475	$3,936	$3,953	$672	$1,461	$56	$68
363.00	Storage & Battery Equipment									
364.00	Poles, Towers, & Fixtures	$1,131,547	$532,392	$467,710	$45,688	$38,423	$18,871	$24,345	$3,231	$886
365.00	Overhead Conductors & Devices	$1,181,083	$555,699	$488,185	$47,688	$40,105	$19,697	$25,411	$3,373	$924
366.00	Underground Conduit									
367.00	Underground Conductors & Devices	$1,747,908	$822,390	$722,475	$70,575	$59,353	$29,150	$37,606	$4,992	$1,368
368.00	Line Transformers	$2,889,668	$1,432,312	$1,139,009	$106,565	$83,207	$53,538	$63,138	$9,753	$2,146
369.00	Services	$286,578	$144,661	$69,435	$22,560	$4,865	$16,163	$27,378	$1,390	$126
370.00	Meters	$622,375	$314,166	$150,794	$48,996	$10,565	$35,103	$59,458	$3,019	$274
371.00	Installation on Customer Premises	$37,123	$18,739	$8,994	$2,922	$630	$2,094	$3,547	$180	$16
372.00	Leased Property on Cust. Premises									
373.00	Street Lights and Signal Systems	$3,122	$1,507	$1,208	$137	$94	$69	$95	$10	$2
	Total Distribution Plant	$7,971,798	$3,848,640	$3,083,284	$349,068	$241,196	$175,357	$242,437	$26,004	$5,812
	Total Transmission & Distribution	$7,971,798	$3,848,640	$3,083,284	$349,068	$241,196	$175,357	$242,437	$26,004	$5,812
	General Plant									
389.00	Land & Land Rights	$271,389	$131,022	$104,966	$11,884	$8,211	$5,970	$8,253	$885	$198
390.00	Structures & Improvements	$773,674	$373,516	$299,237	$33,878	$23,408	$17,019	$23,529	$2,524	$564
391.00	Office Furniture & Equipment	$237,354	$114,590	$91,803	$10,393	$7,181	$5,221	$7,218	$774	$173
392.00	Transportation Equipment	$629,831	$304,071	$243,602	$27,579	$19,056	$13,855	$19,154	$2,055	$459
393.00	Stores Equipment									
394.00	Tools, Shop, & Garage Equipment	$75,081	$36,248	$29,040	$3,288	$2,272	$1,652	$2,283	$245	$55
395.00	Laboratory Equipment									
396.00	Power Operated Equipment	$201,732	$97,392	$78,025	$8,833	$6,104	$4,438	$6,135	$658	$147
397.00	Communication Equipment	$8,341	$4,027	$3,226	$365	$252	$183	$254	$27	$6
398.00	Misc. Equipment									

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

FERC Account	Account Description	Total Rate Base	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
399.00	Other Tangible Property									
	Total General Plant	$2,197,402	$1,060,866	$849,898	$96,219	$66,485	$48,337	$66,827	$7,168	$1,602
	Total Plant Before General Plant & Intangible	$7,971,798	$3,848,640	$3,083,284	$349,068	$241,196	$175,357	$242,437	$26,004	$5,812
	Total Gross Plant in Service	$10,170,214	$4,909,995	$3,933,575	$445,332	$307,711	$223,716	$309,295	$33,175	$7,414
	Less: Accumulated Depreciation									
	Intangible Plant									
	Steam Production Plant									
	Nuclear Production Plant									
	Hydraulic Production Plant									
	Biogas Production Plant									
	Transmission Plant									
	Distribution Plant	$2,604,817	$1,257,559	$1,007,476	$114,059	$78,812	$57,299	$79,217	$8,497	$1,899
	General Plant	$1,849,336	$892,826	$715,275	$80,978	$55,954	$40,680	$56,242	$6,033	$1,348
	Unclassified Plant									
	Misc. Plant									
	Total Accumulated Depreciation	$4,454,153	$2,150,384	$1,722,751	$195,038	$134,765	$97,979	$135,459	$14,529	$3,247
	Total Net Plant	$5,716,061	$2,759,611	$2,210,824	$250,294	$172,946	$125,737	$173,836	$18,646	$4,167
	Working Capital									
	1/8 O&M	$203,146	$107,700	$73,271	$7,599	$4,461	$3,959	$5,176	$843	$137
	1/12 Purchased Power Supply Cost	$230,412	$64,181	$100,958	$27,451	$31,122	$2,034	$4,446	$57	$164
	1/12 Purchased Transmission Charges	$37,542	$12,845	$18,822	$2,455	$2,536	$260	$590	$14	$19
	Total Working Capital	$471,100	$184,726	$193,051	$37,505	$38,119	$6,254	$10,213	$914	$319
	Less: Net Customer Contributions									
	Production Plant									
	Transmission Plant									
	Distribution Plant									
	Street Lights									
	General Plant									
	Total Contributions									
	TOTAL RATE BASE	$6,187,161	$2,944,336	$2,403,875	$287,799	$211,065	$131,991	$184,049	$19,560	$4,486
	CWIP									
	Production Plant									
	Transmission Plant									
	Distribution Plant	$2,988	$1,442	$1,156	$131	$90	$66	$91	$10	$2
	Services									

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

FERC Account	Account Description	Total Rate Base	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	General Plant									
	Other									
	Total CWIP	$2,988	$1,442	$1,156	$131	$90	$66	$91	$10	$2
	TOTAL RATE BASE plus CWIP	$6,190,149	$2,945,779	$2,405,031	$287,930	$211,155	$132,057	$184,139	$19,570	$4,488

FORECAST OF REVENUES FROM CURRENT RATES

Schedule 7.1

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Number of Customers									
Jan-19	3,702	2,296	1,111	71	11	102	87	22	2
Feb-19	3,696	2,289	1,111	72	11	102	87	22	2
Mar-19	3,704	2,295	1,112	73	11	102	87	22	2
Apr-19	3,636	2,233	1,108	71	11	102	87	22	2
May-19	3,649	2,249	1,104	71	11	103	87	22	2
Jun-19	3,664	2,271	1,099	71	11	102	86	22	2
Jul-19	3,683	2,294	1,095	71	11	102	86	22	2
Aug-19	3,682	2,291	1,095	71	11	103	87	22	2
Sep-19	3,687	2,302	1,091	71	11	102	86	22	2
Oct-19	3,704	2,317	1,090	72	11	102	88	22	2
Nov-19	3,702	2,318	1,089	71	11	102	87	22	2
Dec-19	3,700	2,321	1,083	72	11	102	87	22	2
Total / Average	3,684	2,290	1,099	71	11	102	87	22	2
Customer Charge Revenues	**Rate: $/Month**	$32.00	$50.00	$60.00	$145.00	$46.00	$56.00	$25.00	$32.00
Jan-19	$135,491	$73,472	$55,550	$4,260	$1,595			$550	$64
Feb-19	$135,327	$73,248	$55,550	$4,320	$1,595			$550	$64
Mar-19	$135,629	$73,440	$55,600	$4,380	$1,595			$550	$64
Apr-19	$133,325	$71,456	$55,400	$4,260	$1,595			$550	$64
May-19	$143,247	$71,968	$55,200	$4,260	$1,595	$4,738	$4,872	$550	$64
Jun-19	$143,599	$72,672	$54,950	$4,260	$1,595	$4,692	$4,816	$550	$64
Jul-19	$144,135	$73,408	$54,750	$4,260	$1,595	$4,692	$4,816	$550	$64
Aug-19	$144,141	$73,312	$54,750	$4,260	$1,595	$4,738	$4,872	$550	$64
Sep-19	$144,191	$73,664	$54,550	$4,260	$1,595	$4,692	$4,816	$550	$64
Oct-19	$135,173	$74,144	$54,500	$4,320	$1,595			$550	$64
Nov-19	$135,095	$74,176	$54,450	$4,260	$1,595			$550	$64
Dec-19	$134,951	$74,272	$54,150	$4,320	$1,595			$550	$64
Total	$1,664,304	$879,232	$659,400	$51,420	$19,140	$23,552	$24,192	$6,600	$768
	$1,570,044	$834,268	$613,790	$41,159	$22,550	$24,751	$23,745	$8,848	$933
Forecast kWh									
Jan-19	7,929,659	2,310,929	3,764,217	876,339	970,604	-	-	849	6,721
Feb-19	8,344,644	2,586,788	3,884,667	875,619	990,884	-	-	792	5,894
Mar-19	6,155,003	1,696,626	2,905,569	736,126	810,824	-	-	582	5,276
Apr-19	3,611,474	987,877	1,689,013	425,920	504,380	-	-	412	3,871
May-19	3,001,592	691,153	1,116,725	453,322	507,802	72,402	157,192	1,498	1,498
Jun-19	3,019,683	666,112	1,078,485	469,649	521,566	97,494	182,662	2,497	1,219
Jul-19	3,822,255	828,608	1,314,157	573,390	608,987	143,954	349,652	2,636	871
Aug-19	3,508,875	750,176	1,193,098	544,739	592,470	134,523	291,072	1,918	879
Sep-19	3,059,801	697,157	1,085,658	465,036	581,383	71,945	156,088	1,009	1,525
Oct-19	3,839,537	1,014,560	1,604,593	531,061	676,852	3,436	5,189	412	3,434
Nov-19	5,368,205	1,543,125	2,419,315	644,564	755,307	-	-	463	5,431
Dec-19	7,501,593	2,303,000	3,477,079	802,896	910,955	-	-	668	6,995

Prepared By EES Consulting, Inc.

FORECAST OF REVENUES FROM CURRENT RATES

Schedule 7.1

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Total / Average		59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Budget Sales 2018		58,120,088								
Energy Rates										
Flat Rate:		Flat Rate $/kWh	$0.0810	$0.0678	$0.0493	$0.0477	$0.04950	$0.04950	$0.0810	$0.0810
Seasonal Rate:	Jan $/kWh									
	Feb $/kWh									
	Mar $/kWh									
	Ap $/kWh									
	May $/kWh									
	Jun $/kWh									
	Jul $/kWh									
	Aug $/kWh									
	Sep $/kWh									
	Oct $/kWh									
	Nov $/kWh									
	Dec $/kWh									
Distribution Charge for $/kWh:										
Block Rate:	1st Block kWh									
	2nd Block kWh									
	3rd Block kWh									
	4th Block kWh									
	1st Block $/kWh									
	2nd Block $/kWh									
	3rd Block $/kWh									
	4th Block $/kWh									
Energy Revenues										
Jan-19		$532,514	$187,185	$255,214	$43,204	$46,298			$69	$544
Feb-19		$563,885	$209,530	$263,380	$43,168	$47,265			$64	$477
Mar-19		$409,866	$137,427	$196,998	$36,291	$38,676			$47	$427
Apr-19		$239,937	$80,018	$114,515	$20,998	$24,059			$33	$314
May-19		$189,876	$55,983	$75,714	$22,349	$24,222	$3,584	$7,781	$121	$121
Jun-19		$189,277	$53,955	$73,121	$23,154	$24,879	$4,826	$9,042	$202	$99
Jul-19		$238,251	$67,117	$89,100	$28,268	$29,049	$7,126	$17,308	$214	$71
Aug-19		$218,066	$60,764	$80,892	$26,856	$28,261	$6,659	$14,408	$155	$71
Sep-19		$192,228	$56,470	$73,608	$22,926	$27,732	$3,561	$7,726	$82	$123
Oct-19		$250,176	$82,179	$108,791	$26,181	$32,286	$170	$257	$33	$278
Nov-19		$357,305	$124,993	$164,030	$31,777	$36,028			$37	$440
Dec-19		$505,945	$186,543	$235,746	$39,583	$43,453			$54	$567
Subtotal		$3,887,328	$1,302,165	$1,731,109	$364,754	$402,207	$25,926	$56,522	$1,113	$3,533

FORECAST OF REVENUES FROM CURRENT RATES

Schedule 7.1

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Surcharge									
	Total	$3,887,328	$1,302,165	$1,731,109	$364,754	$402,207	$25,926	$56,522	$1,113	$3,533
		$3,374,069	$1,013,192	$1,641,820	$265,754	$361,341	$28,297	$58,586	$1,900	$3,178
Demand kVa or kW										
	Jan-19	47,920	21,008	22,222	2,214	2,458	-	-	17	-
	Feb-19	58,030	26,907	26,095	2,372	2,638	-	-	18	-
	Mar-19	45,530	17,542	24,107	1,918	1,945	-	-	19	-
	Apr-19	41,227	18,294	19,549	1,629	1,738	-	-	17	-
	May-19	33,875	14,292	15,010	1,724	1,480	419	918	32	-
	Jun-19	36,044	16,821	14,979	1,370	1,539	433	852	50	-
	Jul-19	31,959	11,137	16,058	1,649	1,697	489	880	49	-
	Aug-19	33,081	13,444	16,036	1,280	1,285	279	731	26	-
	Sep-19	36,439	16,890	15,544	1,385	1,536	296	765	24	-
	Oct-19	45,049	20,054	21,491	1,556	1,880	30	24	16	-
	Nov-19	39,486	17,146	17,685	1,974	2,670	-	-	11	-
	Dec-19	46,819	19,346	22,255	2,203	2,998	-	-	17	-
Total / Average										
	Total	495,461	212,881	231,030	21,274	23,865	1,946	4,169	296	-
Demand Revenues		**Rate: $/kVa**								
		Rate: $/kW			$3.25	$3.25	$3.25	$3.25		
	Jan-19									
	Feb-19									
	Mar-19									
	Apr-19									
	May-19									
	Jun-19									
	Jul-19									
	Aug-19									
	Sep-19									
	Oct-19									
	Nov-19									
	Dec-19									
	Jan-19	$15,187			$7,197	$7,990				
	Feb-19	$16,281			$7,707	$8,574				
	Mar-19	$12,553			$6,232	$6,321				
	Apr-19	$10,944			$5,294	$5,650				
	May-19	$14,761			$5,604	$4,811	$1,361	$2,984		
	Jun-19	$13,631			$4,451	$5,001	$1,408	$2,770		
	Jul-19	$15,324			$5,360	$5,515	$1,591	$2,859		
	Aug-19	$11,619			$4,161	$4,176	$908	$2,374		
	Sep-19	$12,939			$4,500	$4,991	$961	$2,486		
	Oct-19	$11,337			$5,056	$6,108	$96	$76		

FORECAST OF REVENUES FROM CURRENT RATES

Schedule 7.1

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Nov-19	$15,095			$6,417	$8,679				
Dec-19	$16,903			$7,160	$9,744				
Total	$166,575			$69,139	$77,560	$6,325	$13,550		
	$160,865			$66,769	$74,902	$6,108	$13,086		

Total Revenues

		General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	$683,192	$260,657	$310,764	$54,661	$55,883			$619	$608
Feb-19	$715,493	$282,778	$318,930	$55,195	$57,434			$614	$541
Mar-19	$558,048	$210,867	$252,598	$46,903	$46,592			$597	$491
Apr-19	$384,206	$151,474	$169,915	$30,552	$31,304			$583	$378
May-19	$347,884	$127,951	$130,914	$32,213	$30,628	$9,683	$15,637	$671	$185
Jun-19	$346,507	$126,627	$128,071	$31,865	$31,475	$10,926	$16,628	$752	$163
Jul-19	$397,710	$140,525	$143,850	$37,888	$36,158	$13,408	$24,983	$764	$135
Aug-19	$373,826	$134,076	$135,642	$35,276	$34,032	$12,305	$21,654	$705	$135
Sep-19	$349,358	$130,134	$128,158	$31,686	$34,318	$9,214	$15,029	$632	$187
Oct-19	$396,686	$156,323	$163,291	$35,557	$39,989	$266	$333	$583	$342
Nov-19	$507,496	$199,169	$218,480	$42,454	$46,302			$587	$504
Dec-19	$657,799	$260,815	$289,896	$51,062	$54,791			$604	$631
Subtotal	**$5,718,206**	$2,181,397	$2,390,509	$485,313	$498,907	$55,803	$94,264	$7,713	$4,301
Surcharge									
Total	**$5,718,206**	$2,181,397	$2,390,509	$485,313	$498,907	$55,803	$94,264	$7,713	$4,301
Actual Revenue 2018	$5,541,648.83	$1,847,460	$2,310,712	$373,682	$458,793	$59,157	$95,417	$10,748	$4,178
difference	3.2%	15.3%	3.3%	23.0%	8.0%	-6.0%	-1.2%	-39.4%	2.9%

Okanogan County Electric Cooperative

RECORDED CUSTOMERS AND ENERGY SALES
Schedule 8.4

Number of Customers / Services		**Total**	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18	3,640	2,225	1,118	71	11	102	87	24	2
	Feb-18	3,637	2,231	1,108	72	12	102	87	23	2
	Mar-18	3,631	2,228	1,107	71	11	102	87	23	2
	Apr-18	3,637	2,233	1,108	71	11	102	87	23	2
	May-18	3,650	2,249	1,104	71	11	103	87	23	2
	Jun-18	3,665	2,271	1,099	71	11	102	86	23	2
	Jul-18	3,683	2,294	1,095	71	11	102	86	22	2
	Aug-18	3,682	2,291	1,095	71	11	103	87	22	2
	Sep-18	3,686	2,302	1,091	71	11	102	86	21	2
	Oct-18	3,704	2,317	1,090	72	11	102	88	22	2
	Nov-18	3,702	2,318	1,089	71	11	102	87	22	2
	Dec-18	3,700	2,321	1,083	72	11	102	87	22	2
Total Average		3,668	2,273	1,099	71	11	102	87	23	2

Historic Energy, Demand And Customer Count
Historic Year

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Input Recorded Data									
Energy Sales (kWh)	58,120,088	15,501,591	25,086,739	7,306,671	8,422,988	547,952	1,194,613	13,905	45,629
Total Billing Capacity (kVa)	53,622			22,256	24,967	2,036	4,362		
Avg. Monthly Billing Capacity (kVa)	4,468			1,855	2,081	170	363		
Number of Customers	3,668	2,273	1,099	71	11	102	87	23	2
Ratio of NCP to Avg. Billing Capacity				1	1	2	2		
Rate Classes NCP Demand at Meter	19,882	6,959	9,461	1,191	1,242	306	686	17	19
Estimated Based on Recorded Data									
Annual NCP Load Factor	33%	25%	30%	70%	77%	20%	20%	9%	27%
Rate Classes CP Demand at Input Voltage	20,239	7,425	10,196	1,279	1,338			1	
Annual CP Load Factor	33%	24%	28%	65%	72%			292%	
Average On-Peak kWh as a % of Total kWh		59%	59%	59%	59%	61%	61%	60%	59%
Average Off-Peak kWh as a % of Total kWh		41%	41%	41%	41%	39%	39%	40%	41%

Load Data And Customer Sales
By Rate Class
-- Recorded Year --

kWh Sales at the Meter	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23

	Jan-18	7,295,865	2,075,139	3,499,883	803,492	909,564			755	7,032
	Feb-18	6,858,070	1,967,802	3,275,391	743,583	864,544			584	6,166
	Mar-18	5,535,972	1,538,798	2,641,312	622,137	727,684			521	5,520
	Apr-18	3,778,334	1,033,520	1,767,050	445,599	527,684			431	4,050
	May-18	3,140,274	723,086	1,168,321	474,267	531,264	75,747	164,455	1,567	1,567
	Jun-18	3,159,201	696,888	1,128,314	491,348	545,664	101,998	191,102	2,612	1,275
	Jul-18	3,998,854	866,892	1,374,875	599,882	637,124	150,605	365,807	2,758	911
	Aug-18	3,670,994	784,836	1,248,222	569,907	619,844	140,738	304,520	2,007	920
	Sep-18	3,201,172	729,368	1,135,818	486,522	608,244	75,269	163,300	1,056	1,595
	Oct-18	4,016,934	1,061,435	1,678,730	555,597	708,124	3,595	5,429	431	3,593
	Nov-18	5,616,231	1,614,422	2,531,094	674,345	790,204			484	5,682
	Dec-18	7,848,187	2,409,405	3,637,729	839,992	953,044			699	7,318
Total Sales		58,120,088	15,501,591	25,086,739	7,306,671	8,422,988	547,952	1,194,613	13,905	45,629

Okanogan County Electric Cooperative

RECORDED CUSTOMER DEMAND
Schedule 8.5

Metered Demand - kVA		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18	4,889			2,317	2,572				
	Feb-18	5,241			2,481	2,760				
	Mar-18	4,041			2,006	2,035				
	Apr-18	3,523			1,704	1,819				
	May-18	4,752			1,804	1,549	438	961		
	Jun-18	4,388			1,433	1,610	453	892		
	Jul-18	4,933			1,725	1,775	512	920		
	Aug-18	3,740			1,339	1,344	292	764		
	Sep-18	4,165			1,449	1,607	309	800		
	Oct-18	3,649			1,628	1,966	31	25		
	Nov-18	4,859			2,066	2,794				
	Dec-18	5,441			2,305	3,137				
Total		53,622			22,256	24,967	2,036	4,362		

Individual Load Factor			General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18		14.79%	22.77%	46.61%	47.53%			6.74%	38.21%
	Feb-18		14.31%	22.15%	44.60%	46.61%			6.41%	39.55%
	Mar-18		13.00%	16.20%	41.68%	48.07%			4.15%	32.45%
	Apr-18		7.50%	12.00%	36.31%	40.30%			3.33%	24.10%
	May-18		6.50%	10.00%	35.00%	46.10%	23.24%	23.01%	6.32%	13.72%
	Jun-18		5.50%	10.00%	47.63%	47.08%	31.25%	29.76%	6.96%	8.98%
	Jul-18		10.00%	11.00%	46.73%	48.24%	39.54%	53.43%	7.28%	5.15%
	Aug-18		7.50%	10.00%	57.19%	61.97%	64.73%	53.55%	9.91%	8.78%
	Sep-18		5.73%	9.70%	46.65%	52.58%	33.79%	28.34%	5.84%	7.87%
	Oct-18		6.80%	10.04%	45.88%	48.40%	15.60%	29.64%	3.40%	16.74%
	Nov-18		12.50%	19.00%	45.34%	39.28%			6.02%	31.82%
	Dec-18		16.00%	21.00%	48.99%	40.84%			5.25%	34.66%

Individual NCP (kW)		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
		Power Factor:			100%	100%	100%	100%		
	Jan-18	44,455	18,865	20,662	2,317	2,572			15	25
	Feb-18	47,749	20,468	22,003	2,481	2,760			14	23
	Mar-18	41,905	15,910	21,915	2,006	2,035			17	23
	Apr-18	43,156	19,139	20,452	1,704	1,819			18	23
	May-18	35,456	14,952	15,703	1,804	1,549	438	961	33	15
	Jun-18	37,729	17,598	15,671	1,433	1,610	453	892	52	20
	Jul-18	33,459	11,652	16,800	1,725	1,775	512	920	51	24
	Aug-18	34,624	14,065	16,777	1,339	1,344	292	764	27	14
	Sep-18	38,151	17,671	16,262	1,449	1,607	309	800	25	28
	Oct-18	47,159	20,980	22,484	1,628	1,966	31	25	17	29
	Nov-18	41,335	17,938	18,502	2,066	2,794			11	25
	Dec-18	49,011	20,240	23,283	2,305	3,137			18	28
Maximum		49,011	20,980	23,283	2,481	3,137	512	961	52	29

Group Coincidence Factor			General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18		28.48%	37.10%	48.00%	43.00%			45.05%	72.18%
	Feb-18		34.00%	43.00%	48.00%	45.00%			45.32%	78.49%
	Mar-18		25.00%	34.00%	44.00%	46.00%			30.35%	75.20%
	Apr-18		16.92%	25.59%	35.46%	35.70%			21.42%	54.77%
	May-18		15.89%	18.32%	31.41%	34.73%	50.96%	50.96%	25.56%	61.26%
	Jun-18		11.74%	15.76%	37.18%	34.49%	48.24%	48.24%	22.21%	48.54%
	Jul-18		14.72%	21.50%	40.12%	35.52%	59.68%	59.68%	34.36%	52.70%
	Aug-18		17.17%	21.13%	42.35%	44.45%	89.79%	89.79%	37.32%	61.81%
	Sep-18		15.32%	16.96%	33.52%	36.36%	59.36%	59.36%	27.43%	47.99%
	Oct-18		13.26%	21.86%	32.71%	36.11%	50.96%	50.96%	20.42%	59.55%
	Nov-18		23.49%	34.40%	42.35%	37.74%			56.12%	67.40%
	Dec-18		29.77%	37.24%	47.74%	38.76%			52.96%	67.40%

Rate Class NCP @ Meter (kW)			General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18	15,282	5,374	7,666	1,112	1,106			7	18
	Feb-18	18,878	6,959	9,461	1,191	1,242			6	18
	Mar-18	13,269	3,977	7,451	883	936			5	17
	Apr-18	9,741	3,238	5,233	604	649			4	13
	May-18	7,088	2,375	2,877	567	538	223	490	9	9
	Jun-18	6,293	2,066	2,470	533	555	219	430	12	10
	Jul-18	7,534	1,715	3,612	692	631	306	549	17	13
	Aug-18	8,092	2,415	3,545	567	598	262	686	10	9
	Sep-18	7,215	2,708	2,758	486	584	184	475	7	14
	Oct-18	8,988	2,783	4,914	532	710	16	13	3	17
	Nov-18	12,531	4,214	6,365	875	1,054			6	17

	Dec-18	17,040	6,026	8,670	1,100	1,216			9	19
Maximum		18,878	6,959	9,461	1,191	1,242	306	686	17	19

Rate Class NCP @ Primary Voltage (kW)			General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
		Line Losses:	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%
	Jan-18	16,139	5,675	8,095	1,174	1,168			7	19
	Feb-18	19,936	7,350	9,992	1,258	1,312			6	19
	Mar-18	14,014	4,201	7,869	932	989			5	18
	Apr-18	10,288	3,420	5,526	638	686			4	14
	May-18	7,486	2,509	3,039	598	568	236	517	9	10
	Jun-18	6,646	2,182	2,608	563	586	231	454	12	10
	Jul-18	7,957	1,811	3,814	731	666	323	580	18	13
	Aug-18	8,546	2,550	3,744	599	631	277	725	11	9
	Sep-18	7,619	2,860	2,912	513	617	194	502	7	14
	Oct-18	9,493	2,939	5,190	562	750	17	13	4	18
	Nov-18	13,234	4,450	6,722	924	1,114			7	18
	Dec-18	17,996	6,364	9,156	1,162	1,284			10	20
Maximum		19,936	7,350	9,992	1,258	1,312	323	725	18	20

Rate Class NCP @ Input Voltage (kW)			General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
		Line Losses:	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	Jan-18	16,468	5,791	8,261	1,198	1,192			7	19
	Feb-18	20,343	7,500	10,196	1,283	1,338			7	20
	Mar-18	14,300	4,286	8,029	951	1,009			6	19
	Apr-18	10,498	3,490	5,639	651	700			4	14
	May-18	7,638	2,560	3,101	611	580	241	528	9	10
	Jun-18	6,782	2,226	2,661	574	598	236	464	12	10
	Jul-18	8,119	1,848	3,892	746	679	329	592	19	14
	Aug-18	8,720	2,602	3,820	611	644	283	739	11	9
	Sep-18	7,775	2,918	2,972	523	630	198	512	7	15
	Oct-18	9,686	2,999	5,296	574	765	17	14	4	19
	Nov-18	13,504	4,541	6,859	943	1,136			7	18
	Dec-18	18,363	6,494	9,343	1,186	1,310			10	21
Maximum		20,343	7,500	10,196	1,283	1,338	329	739	19	21

System Coincidence Factor			General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18		100.00%	100.00%	99.35%	83.17%	58.15%	64.95%	46.95%	57.32%
	Feb-18		99.00%	100.00%	99.69%	100.00%	99.87%	100.00%	8.21%	
	Mar-18		97.39%	100.00%	98.95%	100.00%	47.54%	31.34%	38.85%	78.11%
	Apr-18		100.00%	100.00%	100.00%	92.50%	4.64%	19.01%	24.11%	32.73%
	May-18		100.00%	85.64%	100.00%	78.04%	58.95%	60.44%	36.96%	21.68%
	Jun-18		88.83%	100.00%	99.85%	84.29%	70.93%	64.20%	56.85%	17.54%
	Jul-18		96.57%	98.00%	100.00%	97.16%	93.72%	99.36%	46.75%	11.54%
	Aug-18		75.79%	100.00%	94.63%	93.65%	90.02%	91.59%	76.50%	4.17%

	Sep-18		100.00%	91.95%	96.28%	92.50%	75.71%	84.90%	71.34%	19.23%
	Oct-18		98.64%	100.00%	87.52%	100.00%	4.29%	11.54%	15.12%	57.07%
	Nov-18		99.53%	100.00%	95.51%	100.00%	27.19%	22.98%	78.80%	56.25%
	Dec-18		100.00%	99.07%	98.33%	96.93%	40.63%	56.80%	61.40%	70.00%

Coincident Peak (CP) @ Input (kW)		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18	16,248	5,791	8,261	1,191	991			3	11
	Feb-18	20,239	7,425	10,196	1,279	1,338			1	
	Mar-18	14,170	4,174	8,029	941	1,009			2	14
	Apr-18	10,433	3,490	5,639	651	647			1	5
	May-18	6,745	2,560	2,656	611	452	142	319	3	2
	Jun-18	6,190	1,978	2,661	573	504	167	298	7	2
	Jul-18	7,912	1,784	3,814	746	660	309	588	9	2
	Aug-18	7,914	1,972	3,820	578	603	255	677	8	0
	Sep-18	7,330	2,918	2,733	504	582	150	435	5	3
	Oct-18	9,535	2,958	5,296	502	765	1	2	1	11
	Nov-18	13,431	4,520	6,859	900	1,136			5	10
	Dec-18	18,206	6,494	9,255	1,166	1,270			6	14
Total		138,352	46,063	69,219	9,643	9,959	1,023	2,318	52	74
Peak Month		20,239	7,425	10,196	1,279	1,338			1	

Okanogan County Electric Cooperative

RECORDED kWh AT INPUT
Schedule 8.6

kWh @ Input Voltage		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18	7,871,328	2,238,816	3,775,937	866,868	981,306			815	7,587
	Feb-18	7,399,002	2,123,013	3,533,738	802,233	932,735			630	6,652
	Mar-18	5,972,623	1,660,171	2,849,646	671,208	785,080			562	5,955
	Apr-18	4,076,351	1,115,039	1,906,427	480,746	569,305			465	4,369
	May-18	3,387,964	780,120	1,260,473	511,675	573,168	81,722	177,426	1,691	1,691
	Jun-18	3,408,384	751,855	1,217,310	530,103	588,703	110,043	206,175	2,818	1,376
	Jul-18	4,314,265	935,268	1,483,319	647,198	687,377	162,484	394,660	2,976	983
	Aug-18	3,960,545	846,740	1,346,676	614,859	668,734	151,839	328,539	2,165	993
	Sep-18	3,453,665	786,897	1,225,406	524,897	656,219	81,206	176,180	1,139	1,721
	Oct-18	4,333,771	1,145,156	1,811,140	599,420	763,977	3,879	5,857	465	3,876
	Nov-18	6,059,213	1,741,760	2,730,735	727,534	852,532			522	6,130
	Dec-18	8,467,215	2,599,447	3,924,656	906,247	1,028,216			754	7,895
Total Purchases - Bottom Up		62,704,326	16,724,283	27,065,462	7,882,987	9,087,354	591,172	1,288,838	15,002	49,228

Historic Load Reconciliation	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Secondary Line Losses		5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%
Primary Line Losses		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18

Recorded Energy Purchases kWh	62,704,330	7,789,025	7,309,665	5,927,840	4,105,730	3,443,600	3,472,835	4,348,875	4,000,505
Bottom-Up Energy Purchases kWh	62,704,326	7,871,328	7,399,002	5,972,623	4,076,351	3,387,964	3,408,384	4,314,265	3,960,545
% Difference	0.00%	-1%	-1%	-1%	1%	2%	2%	1%	1%

Measured System Demand kW	138,515	16,235	20,165	14,195	10,500	6,755	6,215	7,935	7,915
CP @ Input Demand kW	138,352	16,248	20,239	14,170	10,433	6,745	6,190	7,912	7,914
% Difference	0.1%	-0.1%	-0.4%	0.2%	0.6%	0.2%	0.4%	0.3%	0.0%

On-Peak Energy Use by Percentage	Average	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-18	56%	56%	56%	56%	56%	56%	56%	56%	56%
Feb-18	60%	60%	60%	60%	60%	60%	60%	60%	60%
Mar-18	61%	61%	61%	61%	61%	61%	61%	61%	61%
Apr-18	61%	61%	61%	61%	61%	61%	61%	61%	61%
May-18	58%	58%	58%	58%	58%	58%	58%	58%	58%
Jun-18	63%	63%	63%	63%	63%	63%	63%	63%	63%
Jul-18	61%	61%	61%	61%	61%	61%	61%	61%	61%
Aug-18	62%	62%	62%	62%	62%	62%	62%	62%	62%
Sep-18	61%	61%	61%	61%	61%	61%	61%	61%	61%
Oct-18	61%	61%	61%	61%	61%	61%	61%	61%	61%
Nov-18	57%	57%	57%	57%	57%	57%	57%	57%	57%
Dec-18	56%	56%	56%	56%	56%	56%	56%	56%	56%
Total (Derived)	60%	*59%*	*59%*	*59%*	*59%*	*61%*	*61%*	*60%*	*59%*

On-Peak kWh @ Input Voltage	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-18	4,443,916	1,263,968	2,131,781	489,407	554,016			460	4,283
Feb-18	4,445,079	1,275,437	2,122,955	481,956	560,357			379	3,997
Mar-18	3,613,577	1,004,442	1,724,102	406,097	474,992			340	3,603
Apr-18	2,492,454	681,782	1,165,670	293,948	348,097			284	2,672
May-18	1,961,358	451,626	729,712	296,219	331,818	47,310	102,716	979	979
Jun-18	2,138,677	471,771	763,832	332,627	369,397	69,049	129,370	1,768	863
Jul-18	2,635,435	571,323	906,108	395,351	419,895	99,256	241,084	1,818	600
Aug-18	2,439,240	521,495	829,398	378,682	411,864	93,515	202,342	1,334	611
Sep-18	2,095,778	477,511	743,610	318,522	398,212	49,278	106,911	691	1,044
Oct-18	2,660,505	703,012	1,111,860	367,984	469,006	2,381	3,596	285	2,380
Nov-18	3,457,758	993,955	1,558,325	415,176	486,507			298	3,498
Dec-18	4,772,001	1,465,011	2,211,880	510,748	579,488			425	4,450
Total On-Peak Energy - Bottom-Up	37,155,777	9,881,333	15,999,232	4,686,715	5,403,648	360,790	786,019	9,061	28,980

Off-Peak Energy Use by Percentage	Average	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-18	44%	44%	44%	44%	44%	44%	44%	44%	44%
Feb-18	40%	40%	40%	40%	40%	40%	40%	40%	40%
Mar-18	39%	39%	39%	39%	39%	39%	39%	39%	39%
Apr-18	39%	39%	39%	39%	39%	39%	39%	39%	39%
May-18	42%	42%	42%	42%	42%	42%	42%	42%	42%

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jun-18	37%	37%	37%	37%	37%	37%	37%	37%	37%
	Jul-18	39%	39%	39%	39%	39%	39%	39%	39%	39%
	Aug-18	38%	38%	38%	38%	38%	38%	38%	38%	38%
	Sep-18	39%	39%	39%	39%	39%	39%	39%	39%	39%
	Oct-18	39%	39%	39%	39%	39%	39%	39%	39%	39%
	Nov-18	43%	43%	43%	43%	43%	43%	43%	43%	43%
	Dec-18	44%	44%	44%	44%	44%	44%	44%	44%	44%
Total (Derived)		40%	*41%*	*41%*	*41%*	*41%*	*39%*	*39%*	*40%*	*41%*

Off-Peak kWh @ Input Voltage		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-18	3,427,413	974,848	1,644,156	377,460	427,290			355	3,303
	Feb-18	2,953,923	847,576	1,410,784	320,278	372,378			252	2,656
	Mar-18	2,359,047	655,729	1,125,544	265,112	310,088			222	2,352
	Apr-18	1,583,897	433,257	740,756	186,797	221,208			181	1,698
	May-18	1,426,606	328,493	530,761	215,456	241,350	34,411	74,711	712	712
	Jun-18	1,269,707	280,085	453,478	197,477	219,307	40,994	76,805	1,050	512
	Jul-18	1,678,830	363,945	577,211	251,847	267,482	63,228	153,576	1,158	382
	Aug-18	1,521,304	325,246	517,278	236,176	256,871	58,324	126,197	832	381
	Sep-18	1,357,887	309,387	481,796	206,375	258,008	31,928	69,269	448	677
	Oct-18	1,673,266	442,144	699,280	231,436	294,971	1,498	2,261	180	1,497
	Nov-18	2,601,455	747,805	1,172,410	312,359	366,025			224	2,632
	Dec-18	3,695,214	1,134,436	1,712,776	395,499	448,728			329	3,446
Total Off-Peak Energy - Bottom-Up		25,548,549	6,842,950	11,066,231	3,196,272	3,683,706	230,382	502,820	5,941	20,248

Okanogan County Electric Cooperative

SUMMARY OF
FORECAST ENERGY, DEMAND AND CUSTOMER COUNT

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Energy Sales (kWh)	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Total Billing Capacity (kVa)	53,622			22,256	24,967	2,036	4,362		
Avg. Monthly Billing Capacity (kVa)	4,468			1,855	2,081	170	363		
Number of Customers	3,684	2,290	1,099	71	11	102	87	22	2
Ratio of NCP to Avg. Billing				61%	57%	172%	180%		
Rate Classes NCP Demand at Meter	23,678	9,148	11,221	1,138	1,187	292	656	17	18
Annual NCP Load Factor	29%	20%	26%	74%	81%	20%	20%	9%	27%
Rate Classes CP Demand at Input Voltage	24,355	9,760	12,092	1,223	1,279			1	
Annual CP Load Factor	28%	19%	24%	69%	75%			213%	
On-Peak kWh as a % of Total kWh	59%	59%	59%	59%	59%	61%	61%	60%	59%
Off-Peak kWh as a % of Total kWh	41%	41%	41%	41%	41%	39%	39%	40%	41%

Okanogan County Electric Cooperative

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Current kWh Forecast:									
2019	58,120,088	15,501,591	25,086,739	7,306,671	8,422,988	547,952	1,194,613	13,905	45,629
Forecast Year: 2019	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614
Forecast Year: 2020	60,162,202	16,347,808	25,964,092	7,523,703	8,574,521	532,605	1,161,154	13,968	44,351
Forecast Year: 2021	60,854,067	16,535,807	26,262,679	7,610,226	8,673,128	538,730	1,174,507	14,129	44,861
Forecast Year: 2022	61,553,889	16,725,969	26,564,700	7,697,743	8,772,869	544,925	1,188,014	14,291	45,377
Forecast Year: 2023	62,261,759	16,918,318	26,870,194	7,786,267	8,873,757	551,192	1,201,676	14,456	45,899
Current Customer Forecast:									
2019	3,668	2,273	1,099	71	11	102	87	23	2
Forecast Year: 2019	3,685	2,290	1,099	71	11	102	87	22	2
Forecast Year: 2020	3,684	2,289	1,099	71	11	102	87	22	2
Forecast Year: 2021	3,720	2,313	1,110	72	11	103	87	22	2
Forecast Year: 2022	3,756	2,336	1,121	73	11	104	87	22	2
Forecast Year: 2023	3,792	2,359	1,132	74	11	105	87	22	2

Forecast Rate Class Customer Count	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	3,702	2,296	1,111	71	11	102	87	22	2
Feb-19	3,696	2,289	1,111	72	11	102	87	22	2
Mar-19	3,704	2,295	1,112	73	11	102	87	22	2
Apr-19	3,636	2,233	1,108	71	11	102	87	22	2
May-19	3,649	2,249	1,104	71	11	103	87	22	2
Jun-19	3,664	2,271	1,099	71	11	102	86	22	2
Jul-19	3,683	2,294	1,095	71	11	102	86	22	2
Aug-19	3,682	2,291	1,095	71	11	103	87	22	2
Sep-19	3,687	2,302	1,091	71	11	102	86	22	2
Oct-19	3,704	2,317	1,090	72	11	102	88	22	2
Nov-19	3,702	2,318	1,089	71	11	102	87	22	2
Dec-19	3,700	2,321	1,083	72	11	102	87	22	2
Total Average Forecast Customers	3,684	2,290	1,099	71	11	102	87	22	2

Customer Information	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Weighting Factors for:									
Customers Meters & Services		$ 50.00	$ 50.00	$ 250.00	$ 350.00	$ 125.00	$ 250.00	$ 50.00	$ 50.00
Customer Billing and Collection		1.00	1.00	1.00	1.00	0.42	0.42	1.00	1.00
Customer Meter Reading		1.00	1.00	1.00	1.00	0.42	0.42	1.00	1.00
Weighted Number of Customers									
Customers Meters & Services	226,796	114,483	54,950	17,854	3,850	12,792	21,667	1,100	100
Customer Billing and Collection	3,574	2,290	1,099	71	11	43	36	22	2

	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Customer Meter Reading	3,574	2,290	1,099	71	11	43	36	22	2
Provided Services									
Power Purchased from Utility*		1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1	1	1	1	1	1
Uses Secondary Distribution*		1	1	1	1	1	1	1	1

Test Date Forecast Rate Class Sales kWh	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	7,929,659	2,310,929	3,764,217	876,339	970,604			849	6,721
Feb-19	8,344,644	2,586,788	3,884,667	875,619	990,884			792	5,894
Mar-19	6,155,003	1,696,626	2,905,569	736,126	810,824			582	5,276
Apr-19	3,611,474	987,877	1,689,013	425,920	504,380			412	3,871
May-19	3,001,592	691,153	1,116,725	453,322	507,802	72,402	157,192	1,498	1,498
Jun-19	3,019,683	666,112	1,078,485	469,649	521,566	97,494	182,662	2,497	1,219
Jul-19	3,822,255	828,608	1,314,157	573,390	608,987	143,954	349,652	2,636	871
Aug-19	3,508,875	750,176	1,193,098	544,739	592,470	134,523	291,072	1,918	879
Sep-19	3,059,801	697,157	1,085,658	465,036	581,383	71,945	156,088	1,009	1,525
Oct-19	3,839,537	1,014,560	1,604,593	531,061	676,852	3,436	5,189	412	3,434
Nov-19	5,368,205	1,543,125	2,419,315	644,564	755,307			463	5,431
Dec-19	7,501,593	2,303,000	3,477,079	802,896	910,955			668	6,995
Total Sales	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614

Forecast Rate Class Sales kWh	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	7,929,659	2,310,929	3,764,217	876,339	970,604			849	6,721
Feb-19	8,344,644	2,586,788	3,884,667	875,619	990,884			792	5,894
Mar-19	6,155,003	1,696,626	2,905,569	736,126	810,824			582	5,276
Apr-19	3,611,474	987,877	1,689,013	425,920	504,380			412	3,871
May-19	3,001,592	691,153	1,116,725	453,322	507,802	72,402	157,192	1,498	1,498
Jun-19	3,019,683	666,112	1,078,485	469,649	521,566	97,494	182,662	2,497	1,219
Jul-19	3,822,255	828,608	1,314,157	573,390	608,987	143,954	349,652	2,636	871
Aug-19	3,508,875	750,176	1,193,098	544,739	592,470	134,523	291,072	1,918	879
Sep-19	3,059,801	697,157	1,085,658	465,036	581,383	71,945	156,088	1,009	1,525
Oct-19	3,839,537	1,014,560	1,604,593	531,061	676,852	3,436	5,189	412	3,434
Nov-19	5,368,205	1,543,125	2,419,315	644,564	755,307			463	5,431
Dec-19	7,501,593	2,303,000	3,477,079	802,896	910,955			668	6,995
Total Sales	59,162,323	16,076,112	25,532,576	7,398,661	8,432,014	523,753	1,141,856	13,736	43,614

Okanogan County Electric Cooperative

FORECAST CUSTOMER DEMAND

Schedule 8.2

Billing Demand - kVa	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23

	Jan-19	4,673			2,214	2,458				
	Feb-19	5,010			2,372	2,638				
	Mar-19	3,863			1,918	1,945				
	Apr-19	3,368			1,629	1,738				
	May-19	4,542			1,724	1,480	419	918		
	Jun-19	4,194			1,370	1,539	433	852		
	Jul-19	4,715			1,649	1,697	489	880		
	Aug-19	3,575			1,280	1,285	279	731		
	Sep-19	3,981			1,385	1,536	296	765		
	Oct-19	3,488			1,556	1,880	30	24		
	Nov-19	4,645			1,974	2,670				
	Dec-19	5,201			2,203	2,998				
Total		51,254			21,274	23,865	1,946	4,169		

Individual Load Factor		General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	15%	23%	47%	48%			7%	38%
	Feb-19	14%	22%	45%	47%			6%	40%
	Mar-19	13%	16%	42%	48%			4%	32%
	Apr-19	8%	12%	36%	40%			3%	24%
	May-19	7%	10%	35%	46%	23%	23%	6%	14%
	Jun-19	6%	10%	48%	47%	31%	30%	7%	9%
	Jul-19	10%	11%	47%	48%	40%	53%	7%	5%
	Aug-19	8%	10%	57%	62%	65%	54%	10%	9%
	Sep-19	6%	10%	47%	53%	34%	28%	6%	8%
	Oct-19	7%	10%	46%	48%	16%	30%	3%	17%
	Nov-19	13%	19%	45%	39%			6%	32%
	Dec-19	16%	21%	49%	41%			5%	35%

Individual NCP (kW)		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	47,944	21,008	22,222	2,214	2,458			17	24
	Feb-19	58,052	26,907	26,095	2,372	2,638			18	22
	Mar-19	45,552	17,542	24,107	1,918	1,945			19	22
	Apr-19	41,250	18,294	19,549	1,629	1,738			17	22
	May-19	33,890	14,292	15,010	1,724	1,480	419	918	32	15
	Jun-19	36,063	16,821	14,979	1,370	1,539	433	852	50	19
	Jul-19	31,981	11,137	16,058	1,649	1,697	489	880	49	23
	Aug-19	33,095	13,444	16,036	1,280	1,285	279	731	26	13
	Sep-19	36,466	16,890	15,544	1,385	1,536	296	765	24	27
	Oct-19	45,077	20,054	21,491	1,556	1,880	30	24	16	28
	Nov-19	39,510	17,146	17,685	1,974	2,670			11	24
	Dec-19	46,846	19,346	22,255	2,203	2,998			17	27
Maximum		58,052	26,907	26,095	2,372	2,998	489	918	50	28

Group Coincidence Factor	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23

Jan-19		28%	37%	48%	43%			45%	72%
Feb-19		34%	43%	48%	45%			45%	78%
Mar-19		25%	34%	44%	46%			30%	75%
Apr-19		17%	26%	35%	36%			21%	55%
May-19		16%	18%	31%	35%	51%	51%	26%	61%
Jun-19		12%	16%	37%	34%	48%	48%	22%	49%
Jul-19		15%	21%	40%	36%	60%	60%	34%	53%
Aug-19		17%	21%	42%	44%	90%	90%	37%	62%
Sep-19		15%	17%	34%	36%	59%	59%	27%	48%
Oct-19		13%	22%	33%	36%	51%	51%	20%	60%
Nov-19		23%	34%	42%	38%			56%	67%
Dec-19		30%	37%	48%	39%			53%	67%

Rate Class NCP @ Meter (kW)	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	16,373	5,984	8,245	1,063	1,057			8	17
Feb-19	22,721	9,148	11,221	1,138	1,187			8	17
Mar-19	14,342	4,385	8,196	844	895			6	16
Apr-19	9,311	3,095	5,002	578	621			4	12
May-19	6,775	2,271	2,750	542	514	213	468	8	9
Jun-19	6,016	1,975	2,360	509	531	209	411	11	9
Jul-19	7,201	1,639	3,452	662	603	292	525	17	12
Aug-19	7,734	2,308	3,388	542	571	251	656	10	8
Sep-19	6,896	2,588	2,636	464	558	176	454	7	13
Oct-19	8,591	2,660	4,697	509	679	15	12	3	16
Nov-19	11,978	4,028	6,084	836	1,008			6	16
Dec-19	16,288	5,760	8,287	1,052	1,162			9	18
Maximum	22,721	9,148	11,221	1,138	1,187	292	656	17	18

Rate Class NCP @ Meter (kW) - Winter	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	16,373	5,984	8,245	1,063	1,057			8	17
Feb-19	22,721	9,148	11,221	1,138	1,187			8	17
Mar-19	14,342	4,385	8,196	844	895			6	16
Apr-19									
May-19									
Jun-19									
Jul-19									
Aug-19									
Sep-19									
Oct-19	8,591	2,660	4,697	509	679	15	12	3	16
Nov-19	11,978	4,028	6,084	836	1,008			6	16
Dec-19	16,288	5,760	8,287	1,052	1,162			9	18
Maximum	22,721	9,148	11,221	1,138	1,187	15	12	9	18

Rate Class NCP @ Meter (kW) - Summer	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19									
Feb-19									

	Mar-19									
	Apr-19	9,311	3,095	5,002	578	621			4	12
	May-19	6,775	2,271	2,750	542	514	213	468	8	9
	Jun-19	6,016	1,975	2,360	509	531	209	411	11	9
	Jul-19	7,201	1,639	3,452	662	603	292	525	17	12
	Aug-19	7,734	2,308	3,388	542	571	251	656	10	8
	Sep-19	6,896	2,588	2,636	464	558	176	454	7	13
	Oct-19									
	Nov-19									
	Dec-19									
Maximum		9,311	3,095	5,002	662	621	292	656	17	13

Rate Class NCP @ Primary Voltage (kW)		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
		Line Losses:	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%
	Jan-19	17,292	6,320	8,707	1,123	1,116			8	18
	Feb-19	23,995	9,661	11,850	1,202	1,254			9	18
	Mar-19	15,147	4,631	8,656	891	945			6	17
	Apr-19	9,833	3,269	5,282	610	655			4	13
	May-19	7,155	2,398	2,905	572	543	225	494	9	9
	Jun-19	6,353	2,085	2,493	538	561	221	434	12	10
	Jul-19	7,605	1,731	3,646	699	637	308	554	18	13
	Aug-19	8,168	2,437	3,578	573	603	265	693	10	9
	Sep-19	7,283	2,733	2,784	490	590	185	480	7	14
	Oct-19	9,073	2,809	4,961	537	717	16	13	4	17
	Nov-19	12,650	4,254	6,425	883	1,064			6	17
	Dec-19	17,201	6,083	8,751	1,111	1,227			10	19
Maximum		23,995	9,661	11,850	1,202	1,254	308	693	18	19

NCP @ Primary Voltage (kW) - Winter		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	17,292	6,320	8,707	1,123	1,116			8	18
	Feb-19	23,995	9,661	11,850	1,202	1,254			9	18
	Mar-19	15,147	4,631	8,656	891	945			6	17
	Apr-19									
	May-19									
	Jun-19									
	Jul-19									
	Aug-19									
	Sep-19									
	Oct-19	9,073	2,809	4,961	537	717	16	13	4	17
	Nov-19	12,650	4,254	6,425	883	1,064			6	17
	Dec-19	17,201	6,083	8,751	1,111	1,227			10	19
Maximum		23,995	9,661	11,850	1,202	1,254	16	13	10	19

NCP @ Primary Voltage (kW) - Summer		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19									
	Feb-19									

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Mar-19									
	Apr-19	9,833	3,269	5,282	610	655			4	13
	May-19	7,155	2,398	2,905	572	543	225	494	9	9
	Jun-19	6,353	2,085	2,493	538	561	221	434	12	10
	Jul-19	7,605	1,731	3,646	699	637	308	554	18	13
	Aug-19	8,168	2,437	3,578	573	603	265	693	10	9
	Sep-19	7,283	2,733	2,784	490	590	185	480	7	14
	Oct-19									
	Nov-19									
	Dec-19									
Maximum		9,833	3,269	5,282	699	655	308	693	18	14

Rate Class NCP @ Input Voltage (kW)

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
		Line Losses:	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	Jan-19	17,645	6,449	8,885	1,145	1,139			8	18
	Feb-19	24,485	9,859	12,092	1,227	1,279			9	19
	Mar-19	15,456	4,726	8,833	909	964			6	18
	Apr-19	10,034	3,336	5,390	622	669			4	13
	May-19	7,301	2,447	2,964	584	554	230	504	9	10
	Jun-19	6,483	2,128	2,544	549	572	225	443	12	10
	Jul-19	7,761	1,766	3,720	713	649	315	566	18	13
	Aug-19	8,335	2,487	3,651	584	616	270	707	10	9
	Sep-19	7,431	2,789	2,841	500	602	189	489	7	14
	Oct-19	9,258	2,866	5,062	548	731	16	13	4	18
	Nov-19	12,908	4,341	6,556	901	1,086			6	17
	Dec-19	17,552	6,207	8,930	1,133	1,252			10	20
Maximum		24,485	9,859	12,092	1,227	1,279	315	707	18	20

NCP @ Input Voltage (kW) - Winter

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	17,645	6,449	8,885	1,145	1,139			8	18
	Feb-19	24,485	9,859	12,092	1,227	1,279			9	19
	Mar-19	15,456	4,726	8,833	909	964			6	18
	Apr-19									
	May-19									
	Jun-19									
	Jul-19									
	Aug-19									
	Sep-19									
	Oct-19	9,258	2,866	5,062	548	731	16	13	4	18
	Nov-19	12,908	4,341	6,556	901	1,086			6	17
	Dec-19	17,552	6,207	8,930	1,133	1,252			10	20
Maximum		24,485	9,859	12,092	1,227	1,279	16	13	10	20

NCP @ Input Voltage (kW) - Summer

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19									
	Feb-19									

		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Mar-19									
	Apr-19	10,034	3,336	5,390	622	669			4	13
	May-19	7,301	2,447	2,964	584	554	230	504	9	10
	Jun-19	6,483	2,128	2,544	549	572	225	443	12	10
	Jul-19	7,761	1,766	3,720	713	649	315	566	18	13
	Aug-19	8,335	2,487	3,651	584	616	270	707	10	9
	Sep-19	7,431	2,789	2,841	500	602	189	489	7	14
	Oct-19									
	Nov-19									
	Dec-19									
Maximum		10,034	3,336	5,390	713	669	315	707	18	14

System Coincidence Factor		General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	100%	100%	99%	83%	58%	65%	47%	57%
	Feb-19	99%	100%	100%	100%	100%	100%	8%	
	Mar-19	97%	100%	99%	100%	48%	31%	39%	78%
	Apr-19	100%	100%	100%	93%	5%	19%	24%	33%
	May-19	100%	86%	100%	78%	59%	60%	37%	22%
	Jun-19	89%	100%	100%	84%	71%	64%	57%	18%
	Jul-19	97%	98%	100%	97%	94%	99%	47%	12%
	Aug-19	76%	100%	95%	94%	90%	92%	77%	4%
	Sep-19	100%	92%	96%	92%	76%	85%	71%	19%
	Oct-19	99%	100%	88%	100%	4%	12%	15%	57%
	Nov-19	100%	100%	96%	100%	27%	23%	79%	56%
	Dec-19	100%	99%	98%	97%	41%	57%	61%	70%

Coincident Peak (CP) @ Input (kW)		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	17,433	6,449	8,885	1,138	947			4	11
	Feb-19	24,355	9,760	12,092	1,223	1,279			1	
	Mar-19	15,315	4,602	8,833	900	964			2	14
	Apr-19	9,972	3,336	5,390	622	619			1	4
	May-19	6,447	2,447	2,538	584	432	136	305	3	2
	Jun-19	5,917	1,890	2,544	548	482	160	284	7	2
	Jul-19	7,563	1,706	3,646	713	631	295	562	8	1
	Aug-19	7,565	1,885	3,651	553	576	243	647	8	0
	Sep-19	7,006	2,789	2,612	482	557	143	416	5	3
	Oct-19	9,114	2,827	5,062	480	731	1	1	1	10
	Nov-19	12,838	4,320	6,556	861	1,086			5	10
	Dec-19	17,402	6,207	8,847	1,114	1,214			6	14
Total CP Demand - Bottom Up		140,926	48,218	70,656	9,217	9,520	978	2,216	51	71
Peak Month		24,355	9,760	12,092	1,223	1,279			1	

Okanogan County Electric Cooperative

FORECAST kWh AT INPUT

Schedule 8.3

kWh @ Input Voltage	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	8,555,114	2,493,204	4,061,121	945,460	1,047,161			916	7,252
Feb-19	9,002,830	2,790,822	4,191,071	944,684	1,069,040			854	6,359
Mar-19	6,640,481	1,830,448	3,134,747	794,188	874,778			628	5,692
Apr-19	3,896,330	1,065,797	1,822,234	459,515	544,163			444	4,176
May-19	3,238,344	745,668	1,204,807	489,078	547,855	78,113	169,591	1,616	1,616
Jun-19	3,257,862	718,652	1,163,551	506,693	562,705	105,183	197,070	2,694	1,315
Jul-19	4,123,737	893,965	1,417,812	618,616	657,021	155,308	377,231	2,844	939
Aug-19	3,785,638	809,346	1,287,204	587,705	639,202	145,133	314,030	2,070	949
Sep-19	3,301,144	752,146	1,171,289	501,716	627,239	77,620	168,400	1,089	1,645
Oct-19	4,142,382	1,094,583	1,731,156	572,948	730,238	3,707	5,599	444	3,705
Nov-19	5,791,624	1,664,840	2,610,139	695,405	814,882			499	5,859
Dec-19	8,093,283	2,484,650	3,751,334	866,225	982,807			721	7,547
Total Purchases - bottom up	63,828,768	17,344,119	27,546,465	7,982,233	9,097,092	565,064	1,231,920	14,820	47,054
growth in Purchases against Recorded (bottom-up)		*4%*	*2%*	*1%*	*0%*	*-4%*	*-4%*	*-1%*	*-4%*

On-Peak Energy Use by Percentage	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	*56%*	56%	56%	56%	56%	56%	56%	56%	56%
Feb-19	*60%*	60%	60%	60%	60%	60%	60%	60%	60%
Mar-19	*61%*	61%	61%	61%	61%	61%	61%	61%	61%
Apr-19	*61%*	61%	61%	61%	61%	61%	61%	61%	61%
May-19	*58%*	58%	58%	58%	58%	58%	58%	58%	58%
Jun-19	*63%*	63%	63%	63%	63%	63%	63%	63%	63%
Jul-19	*61%*	61%	61%	61%	61%	61%	61%	61%	61%
Aug-19	*62%*	62%	62%	62%	62%	62%	62%	62%	62%
Sep-19	*61%*	61%	61%	61%	61%	61%	61%	61%	61%
Oct-19	*61%*	61%	61%	61%	61%	61%	61%	61%	61%
Nov-19	*57%*	57%	57%	57%	57%	57%	57%	57%	57%
Dec-19	*56%*	56%	56%	56%	56%	56%	56%	56%	56%
Total	*59%*	*59%*	*59%*	*59%*	*59%*	*61%*	*61%*	*60%*	*59%*

On-Peak kWh @ Input Voltage	Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
Jan-19	4,829,960	1,407,588	2,292,787	533,779	591,195			517	4,094
Feb-19	5,408,606	1,676,635	2,517,859	567,535	642,244			513	3,820
Mar-19	4,017,646	1,107,464	1,896,595	480,502	529,261			380	3,444
Apr-19	2,382,382	651,673	1,114,192	280,967	332,725			272	2,554
May-19	1,874,740	431,681	697,486	283,137	317,164	45,221	98,179	935	935
Jun-19	2,044,228	450,936	730,099	317,937	353,083	66,000	123,657	1,690	825
Jul-19	2,519,048	546,092	866,092	377,891	401,351	94,872	230,437	1,737	574
Aug-19	2,331,518	498,464	792,769	361,959	393,675	89,385	193,406	1,275	584
Sep-19	2,003,224	456,423	710,770	304,455	380,626	47,102	102,190	661	998
Oct-19	2,543,011	671,965	1,062,758	351,733	448,294	2,276	3,437	273	2,275
Nov-19	3,305,056	950,060	1,489,505	396,840	465,022			285	3,344
Dec-19	4,561,258	1,400,313	2,114,198	488,192	553,896			406	4,253
Total	37,820,676	10,249,294	16,285,111	4,744,927	5,408,536	344,856	751,306	8,945	27,700

Off-Peak Energy Use by Percentage		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*
	Feb-19	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*
	Mar-19	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
	Apr-19	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
	May-19	*42%*	*42%*	*42%*	*42%*	*42%*	*42%*	*42%*	*42%*	*42%*
	Jun-19	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*
	Jul-19	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
	Aug-19	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*
	Sep-19	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
	Oct-19	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
	Nov-19	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*
	Dec-19	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*	*44%*
Total		*41%*	*41%*	*41%*	*41%*	*41%*	*39%*	*39%*	*40%*	*41%*

Off-Peak kWh @ Input Voltage		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	3,725,153	1,085,616	1,768,334	411,682	455,965			399	3,158
	Feb-19	3,594,224	1,114,187	1,673,212	377,149	426,796			341	2,539
	Mar-19	2,622,835	722,984	1,238,152	313,686	345,517			248	2,248
	Apr-19	1,513,948	414,123	708,043	178,548	211,439			173	1,623
	May-19	1,363,604	313,986	507,321	205,941	230,691	32,892	71,411	680	680
	Jun-19	1,213,634	267,716	433,452	188,756	209,622	39,183	73,413	1,003	490
	Jul-19	1,604,689	347,873	551,720	240,725	255,670	60,436	146,794	1,107	366
	Aug-19	1,454,120	310,882	494,434	225,746	245,527	55,748	120,624	795	364
	Sep-19	1,297,920	295,723	460,519	197,261	246,613	30,518	66,210	428	647
	Oct-19	1,599,371	422,618	668,398	221,215	281,945	1,431	2,162	172	1,431
	Nov-19	2,486,568	714,780	1,120,634	298,564	349,860			214	2,516
	Dec-19	3,532,025	1,084,337	1,637,136	378,033	428,911			315	3,293
Total Off-Peak Energy		26,008,091	7,094,825	11,261,355	3,237,305	3,688,555	220,208	480,614	5,875	19,354

Summary of Future Test Period Seasonal Load Data
Power Supply

- System kWh @ Input Voltage- Winter		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	8,555,114	2,493,204	4,061,121	945,460	1,047,161			916	7,252
	Feb-19	9,002,830	2,790,822	4,191,071	944,684	1,069,040			854	6,359
	Mar-19	6,640,481	1,830,448	3,134,747	794,188	874,778			628	5,692
	Apr-19									
	May-19									
	Jun-19									
	Jul-19									
	Aug-19									
	Sep-19									

	Oct-19	4,142,382	1,094,583	1,731,156	572,948	730,238	3,707	5,599	444	3,705
	Nov-19	5,791,624	1,664,840	2,610,139	695,405	814,882			499	5,859
	Dec-19	8,093,283	2,484,650	3,751,334	866,225	982,807			721	7,547
Total Winter		42,225,713	12,358,547	19,479,568	4,818,910	5,518,906	3,707	5,599	4,063	36,414

-System kWh @ Input Voltage- Summer		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19									
	Feb-19									
	Mar-19									
	Apr-19	3,896,330	1,065,797	1,822,234	459,515	544,163			444	4,176
	May-19	3,238,344	745,668	1,204,807	489,078	547,855	78,113	169,591	1,616	1,616
	Jun-19	3,257,862	718,652	1,163,551	506,693	562,705	105,183	197,070	2,694	1,315
	Jul-19	4,123,737	893,965	1,417,812	618,616	657,021	155,308	377,231	2,844	939
	Aug-19	3,785,638	809,346	1,287,204	587,705	639,202	145,133	314,030	2,070	949
	Sep-19	3,301,144	752,146	1,171,289	501,716	627,239	77,620	168,400	1,089	1,645
	Oct-19									
	Nov-19									
	Dec-19									
Total Summer		21,603,054	4,985,573	8,066,897	3,163,323	3,578,186	561,357	1,226,322	10,757	10,640

CP @ Input Voltage- Winter		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19	17,433	6,449	8,885	1,138	947			4	11
	Feb-19	24,355	9,760	12,092	1,223	1,279			1	
	Mar-19	15,315	4,602	8,833	900	964			2	14
	Apr-19									
	May-19									
	Jun-19									
	Jul-19									
	Aug-19									
	Sep-19									
	Oct-19	9,114	2,827	5,062	480	731	1	1	1	10
	Nov-19	12,838	4,320	6,556	861	1,086			5	10
	Dec-19	17,402	6,207	8,847	1,114	1,214			6	14
Total Winter		96,457	34,165	50,274	5,716	6,222	1	1	19	58

CP @ Input Voltage- Summer		Total	General Service Rate 1	General Service Rate 2	General Service Rate 3	General Service Rate 4	Irrigation Single Phase	Irrigation Poly Phase	2nd Meter	OSIN 22 & 23
	Jan-19									
	Feb-19									
	Mar-19									
	Apr-19	9,972	3,336	5,390	622	619			1	4
	May-19	6,447	2,447	2,538	584	432	136	305	3	2
	Jun-19	5,917	1,890	2,544	548	482	160	284	7	2
	Jul-19	7,563	1,706	3,646	713	631	295	562	8	1
	Aug-19	7,565	1,885	3,651	553	576	243	647	8	0

	Sep-19	7,006	2,789	2,612	482	557	143	416	5	3
	Oct-19									
	Nov-19									
	Dec-19									
Total Summer		44,469	14,053	20,382	3,502	3,297	977	2,214	32	13