Okanogan County Electric Cooperative , Inc.

July 23, 2018, 2:00 Strategic Planning

BOARD OF DIRECTORS MEETING
July 23, 2018 at 3:00 PM

AGENDA

1. Meeting Called to Order
2. Determination of Quorum
3. Approval of Agenda
4. Approval of Consent Agenda **(Tab 2)**

   a) Minutes from June 25, 2018
   b) New Members
   c) June 2018 – Form 7
   d) Statement of Operations
   e) Cash Flow
   f) Capital Expenditures by Project
   g) Cap Ex / O&M Labor Distribution
   h) Revolving Loan Fund
   i) Power & Service Data
   j) Outage Report
   k) PNGC Newsletter
   l) WRECA Newsletter

5. Committee Reports

   No committee reports

6. Meetings Attended

   a) PNGC Board Meeting – July 3rd & 4th – Portland – Dale

7. Meetings to Attend
   a) PNGC Monthly Meeting – August 6th & 7th – Portland – David
   b) PNGC Annual Meeting – Oct. 1st and 2nd – David and Interested Board Members

Meetings Not Attending
   a) NRECA Regional Meeting – Anchorage, AK – September 25th to 27th
   b) CFC IBEC Forum – Amelia Island, Florida – Nov. 5th to 7th.

8. General Managers Report **(Tab 3)**
   1) Office Update
   2) Operations Update
   3) Propane Update

ITEMS OF BUSINESS

1) Methownet
2) Review of Policy 30-155 New Single Large Loads **(Tab 4)**
3) Expense Budget Review **(Tab 5)**
4) KRTA Ratios (**Tab 6** includes Introduction Letter from CFC, KRTA Definitions and 2017 results)
5) 2nd Quarter Balanced Scorecard Goals Results **(Tab 7)**

MEMBER COMMUNICATIONS

EXECUTIVE SESSION

1) 2nd Quarter Subsidiary Financials
2) 2nd Quarter Management Goal Results
3) Solar Update
4) Litigation Update
5) Consumer Correspondence

BOARD MEETING
June 25, 2018

Present: Curtis Edwards, Sara Carlberg, Ray Peterson, Dale Sekijima, John Kirner, Alan Watson and (via telephone) Chuck Armstrong.

Absent: Ray Peterson.

Attending: Lynn Northcott; Assistant General Manager/CFO, Deanna Melton; Staking Tech, Tracy McCabe; OCEI Propane Manager and Teri Parker; Office Staff.

Members in Attendance: None

PRELIMINARY

1. MEETING CALLED TO ORDER

President Curtis Edwards called the meeting of the Board of Directors of Okanogan County Electric Cooperative, Inc. (OCEC) to order at 3:00 pm.

2. DETERMINATION OF QUORUM

A quorum was present.

3. APPROVAL OF AGENDA

Lynn Northcott noted that business Item 1) Review of Policy 30-155 New Single Large Loads has not received attorney review and will need to be postponed to the July meeting.

Agenda as amended approved by Board consensus.

4. APPROVAL OF CONSENT AGENDA ITEMS

Sara asked to pull the consent agenda to discuss the expense financials during the business portion of the meeting.

5. COMMITTEE REPORT

No report.

6. MEETINGS ATTENDED

a. PNGC Strategic Planning Meeting – June 4th & 5th - Stevenson WA - Portland – Dale Sekijima

Dale reported the principle topic of discussion centered on speculation of what the new 2028 BPA contracts might look like and what steps to consider in response to the contracts.

Further discussion included speculation on expanding membership to other Cooperatives or other types of Utilities, and, if membership were expanded what types of memberships or services could be offered.

b. WRECA Annual Meeting – June 4th – Wenatchee – Sara, Alan & Chuck

Chuck Armstrong noted they met interesting contacts and all felt it was a worthwhile meeting.

Sara Carlberg reviewed the meeting topics and speakers.

c. Grand Coulee Dam Tour – June 8th – Alan Watson & guest, Chuck Armstrong, Sara Carlberg & guest, Teri Parker & guest and Callie Fink

Attendees reviewed their experience.

d. OCEC Open House – June 20th

Lynn Northcott reviewed the attendance and lessons learned for the next event.

e. NRECA Director's Summer School - Coeur D'Alene ID – June 23rd – Sara

Sara gave a report on the class and felt it worth attending.

7. MEETINGS TO ATTEND

a. PNGC Monthly Meeting – July 3rd – Portland – Dale

b. PNGC Annual Meeting – Oct 1st & 2nd – David and interested Board Members

Meetings Not Attending

a. NRECA Regional Meeting – Anchorage AK – September 25th to 27th
b. CFC IBEC Forum – Amelia Island FL – Nov 5th to 7th

8. GENERAL MANAGERS REPORT & OFFICE REPORT

Lynn Northcott presented the comparison of BPA power costs. She discussed the OCEC open house and ideas for future Open House.

Lynn presented newly designed and printed informational brochures for OCEC and OCEI. She complimented CSR, Jessica Blethen, for the work put into the project.

1. Operations Update

Deanna Melton reported:

- Outage: Due to last night's severe storm, the transmission line was down for approximately 3-hrs this morning, from around 2:30 am to 5:30 am. Power is restored to all but one service at this time. Outages were caused by high winds and trees.
- OCEC's fire extinguishers were tested today.
- Costs Estimate load was reviewed.
- Underground projects: Davis Lake is complete, Stud Horse- the contractor has scheduled for September, and Edelweiss is scheduled to start in July.

2. OCEI Propane Update

Tracy reviewed propane operations – OCEI has been teaming up with Deanna on new construction site visits.

Tracy reported a new bobtail truck is due to be delivered July 10th.

ITEMS OF BUSINESS

1. **Review of Policy 30-155 New Single Large Loads**

   Postponed to the July Board Meeting.

   Curtis proposed to move Revolving Loan fund to item 2 and discuss Possible OCEC Involvement in Broadband to the end of Items of Business.

2. **Revolving Loan Fund**

   Lynn Northcott discussed the Revolving Loan Fund status. She noted that there is $60, 000 in each loan fund and advised that OCEC should begin advertising that loans are available. The RLF Committee members are John Kirner and Alan Watson; Curtis Edwards is the substitute if needed.

3. **Consent Agenda**

   Sara noted that the Board had agreed to review the expense portion of the budget each June for tracking and see if the budget needs any adjustment. She asked that it be put on next month's agenda.

   Board consensus is to include monitored expenses on next month's agenda.

4. **Possible OCEC involvement in Broadband Services**

   Sara and Alan reviewed the topic as discussed at the WRECA Annual Meeting.

   Discussion points included:
   - Rural Co-ops and Broadband/Fiber are a good fit
   - What are the benefits or drawbacks to OCEC involvement or ownership?
   - Who are the existing providers? Could OCEC be of help to existing ISP Providers?
   - A feasibility study would be a first step: Risk vs. Value, easement questions to be answered

   The Board expressed general support for adding discussion of the possibility of Broadband Services to the OCEC Strategic Plan.

MEMBER COMMUNICATION

None.

Adjourn to executive session at 4:30 pm.

EXECUTIVE SESSION

1. **Large Solar Installation Proposal**

5:31 out of executive session.

Alan moved to authorize Curtis to draft a letter to the developer of the large solar installation proposal. David Gottula will be the point of contact. Second. Carried.

Meeting adjourned at 5:35 pm.

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Alan Watson, Secretary

New Members OCEC

July 23, 2018

REINSTATE

1.	GODE, GEOFFREY	197135
2.	FISCH, PETE & WARNER, ANN	115081

NEW MEMBERS

1.	ORVIS, CONI & HESS, GARY	118066
2.	GIVENS, DON & KITTLESON, JAN	118067
3.	VOID	118068
4.	SCHARNICKEL, BRADLEY	118069
5.	VERNON, GWENDOLYN R	118070
6.	MURRAY MICHAEL	118071
7.	WYSS, ANDREW & SHARON	118072
8.	MATHESON, JAMES D JR & WRANGLE, CHERYL	118073
9.	ASLANIAN, JOEL	118074
10.	PREWITT, BONNI & WHITE, DAN	118075
11.	EMERY, ROBYN	118076
12.	APOLONIO, PACHECO PASCACIO	118077
13.	SMILING WOODS YURTS (SCHOLZ HANZ)	118078
14.	TALBOT, ALISON & MCDONALD, JEFF	118079
15.	FREEZE, JON & JILL	118080
16.	BROWN. MARC & TARA	118081
17.	BEDLINGTON, RYAN	118082
18.	TIMBERS, CHARLES & JANICE	118083
19.	BRISBIN, JERRY & ANNETTE	118084
20.	CHILDS, STEVE	118085
21.	KWOK, HEEMUN	118086

National Rural Utilities Cooperative Finance Corporation

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Okanogan County Electric Coop Inc
	BORROWER DESIGNATION	WA032
	ENDING DATE	6/30/2018

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

CERTIFICATION

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

Bill Northcott 7/11/18

Signature of Office Manager or Accountant — Date

Signature of Manager — Date

BALANCE CHECK RESULTS

8 Needs Attention

6 Please Review

4 Matches

AUTHORIZATION CHOICES

A. NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA?

(●) YES ( ) NO

B. Will you authorize CFC to share your data with other cooperatives?

(●) YES ( ) NO

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	3,036,489	2,910,442	2,719,491	360,366
2. Power Production Expense	0	0	0	0
3. Cost of Purchased Power	1,466,572	1,455,939	1,372,400	165,471
4. Transmission Expense	0	0	0	0
5. Regional Market Operations Expense	0	0	0	0
6. Distribution Expense - Operation	38,950	52,821	38,545	24,435
7. Distribution Expense - Maintenance	331,035	322,341	318,884	36,614
8. Consumer Accounts Expense	143,068	151,212	150,840	25,153
9. Customer Service and Informational Expense	3,761	4,196	3,622	257
10. Sales Expense	1,579	6,074	0	1,030
11. Administrative and General Expense	438,307	295,381	341,843	24,915
12. Total Operation & Maintenance Expense (2 thru 11)	**2,423,271**	**2,287,963**	**2,226,134**	**277,875**
13. Depreciation & Amortization Expense	184,367	190,943	197,340	31,872
14. Tax Expense - Property & Gross Receipts	21,355	22,459	21,564	3,766
15. Tax Expense - Other	93,852	91,260	86,750	11,291
16. Interest on Long-Term Debt	105,674	101,792	100,886	16,582
17. Interest Charged to Construction (Credit)	0	0	0	0
18. Interest Expense - Other	0	0	0	0
19. Other Deductions	0	0	0	0
20. Total Cost of Electric Service (12 thru 19)	**2,828,518**	**2,694,417**	**2,632,674**	**341,386**
21. Patronage Capital & Operating Margins (1 minus 20)	**207,971**	**216,024**	**86,817**	**18,980**
22. Non Operating Margins - Interest	5,026	11,329	10,645	3,474
23. Allowance for Funds Used During Construction	0	0	0	0
24. Income (Loss) from Equity Investments	5,002	1,723	5,000	0
25. Non Operating Margins - Other	9,000	9,000	9,000	1,500
26. Generation & Transmission Capital Credits	0	0	0	0
27. Other Capital Credits & Patronage Dividends	0	0	0	0
28. Extraordinary Items	0	0	0	0
29. Patronage Capital or Margins (21 thru 28)	**227,000**	**238,076**	**111,462**	**23,954**

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)
1. New Services Connected	18	16	5. Miles Transmission	0	0
2. Services Retired	1	1	6. Miles Distribution Overhead	301	302
3. Total Services In Place	3,688	3,747	7. Miles Distribution Underground	210	212
4. Idle Services (Exclude Seasonal)	107	103	**8. Total Miles Energized (5+6+7)**	**511**	**514**

National Rural Utilities Cooperative Finance Corporation

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Okanogan County
	BORROWER DESIGNATION	WA032
	ENDING DATE	06/30/2018

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	13,740,204	29. Memberships	16,025
2. Construction Work in Progress	329,972	30. Patronage Capital	7,368,479
3. Total Utility Plant (1+2)	**14,070,176**	31. Operating Margins - Prior Years	888,188
4. Accum. Provision for Depreciation and Amort	4,568,445	32. Operating Margins - Current Year	229,076
5. Net Utility Plant (3-4)	**9,501,731**	33. Non-Operating Margins	9,000
6. Nonutility Property - Net	0	34. Other Margins & Equities	477,952
7. Investment in Subsidiary Companies	662,742	**35. Total Margins & Equities (29 thru 34)**	**8,988,720**
8. Invest. in Assoc. Org. - Patronage Capital	324,323	36. Long-Term Debt CFC (Net)	0
9. Invest. in Assoc. Org. - Other - General Funds	0	37. Long-Term Debt - Other (Net)	3,434,341
10. Invest in Assoc. Org. - Other - Nongeneral Funds	147,136	**38. Total Long-Term Debt (36 + 37)**	**3,434,341**
11. Investments in Economic Development Projects	0	39. Obligations Under Capital Leases - Non current	0
12. Other Investments	13,500	40. Accumulated Operating Provisions - Asset Retirement Obligations	0
13. Special Funds	0	**41. Total Other Noncurrent Liabilities (39+40)**	**0**
14. Total Other Property & Investments (6 thru 13)	**1,147,701**	42. Notes Payable	0
15. Cash-General Funds	939,887	43. Accounts Payable	364,307
16. Cash-Construction Funds-Trustee	0	44. Consumers Deposits	148,255
17. Special Deposits	138,690	45. Current Maturities Long-Term Debt	0
18. Temporary Investments	138,460	46. Current Maturities Long-Term Debt-Economic Dev.	0
19. Notes Receivable - Net	0	47. Current Maturities Capital Leases	0
20. Accounts Receivable - Net Sales of Energy	388,004	48. Other Current & Accrued Liabilities	280,716
21. Accounts Receivable - Net Other	681,178	**49. Total Current & Accrued Liabilities (42 thru 48)**	**793,278**
22. Renewable Energy Credits	0	50. Deferred Credits	0
23. Materials & Supplies - Electric and Other	261,870	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**13,216,340**
24. Prepayments	17,852		
25. Other Current & Accrued Assets	966	**ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION**	
26. Total Current & Accrued Assets (15 thru 25)	**2,566,908**	Balance Beginning of Year	0
27. Deferred Debits	0	Amounts Received This Year (Net)	227,137
28. Total Assets & Other Debits (5+14+26+27)	**13,216,340**	**TOTAL Contributions-In-Aid-Of-Construction**	**227,137**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

OKANOGAN COUNTY ELECTRIC COOPERATIVE, INC.

STATEMENT OF OPERATIONS

June 30, 2018

	ANNUAL BUDGET	Y-T-D BUDGET	Y-T-D ACTUAL	MONTH BUDGET	MONTH ACTUAL
OPERATING REVENUE	$5,501,400	$2,719,491	$2,910,442	$381,898	$360,366
COST OF POWER	$2,710,581	$1,372,400	$1,455,939	$181,698	$165,471
GROSS MARGINS	$2,790,819	$1,347,091	$1,454,503	$200,200	$194,895
OPERATING EXPENSES:					
DISTRIBUTION OPERATIONS	$69,955	$38,545	$52,821	$16,650	$24,435
DISTRIBUTION MAINTENANCE	$574,972	$318,884	$322,341	$60,146	$36,614
CONSUMER ACCOUNTING	$299,885	$150,840	$151,212	$23,623	$25,153
CONSUMER SERVICE & INFO	$5,700	$3,622	$4,196	$0	$257
SALES EXPENSE	$0	$0	$6,074	$0	$1,030
ADMIN & GENERAL	$674,637	$341,843	$295,381	$45,672	$24,915
TOTAL OPERATING EXPENSES	$1,625,149	$853,734	$832,024	$146,091	$112,404
FIXED EXPENSES:					
DEPRECIATION	$394,680	$197,340	$190,943	$32,890	$31,872
TAXES-PROPERTY	$43,128	$21,564	$22,459	$3,594	$3,766
TAXES-OTHER	$185,500	$86,750	$91,260	$14,458	$11,291
INTEREST	$201,772	$100,886	$101,792	$16,814	$16,582
OTHER DEDUCTIONS	$0	$0	$0	$0	$0
TOTAL FIXED EXPENSES	$825,080	$406,540	$406,454	$67,757	$63,511
TOTAL EXPENSES	$2,450,229	$1,260,274	$1,238,478	$213,848	$175,915
OPERATING MARGINS	$340,590	$86,817	$216,024	-$13,648	$18,980
NONOPERATING MARGINS:					
INTEREST	$51,154	$15,645	$13,052	$3,716	$3,474
OTHER	$18,000	$9,000	$9,000	$1,500	$1,500
NET MARGINS	$409,744	$111,462	$238,076	-$8,432	$23,954
T.I.E.R.	3.03	2.10	3.34	0.50	2.44

Okanogan County Electric Cooperative Inc
Budget Year: 2018

		Budget year	Actual						Forecasted					
	2017	Jan - Dec	January	February	March	April	May	June	July	August	September	October	November	December
Patronage Capital or Margins	$0	$409,744	$58,852	$57,189	$56,676	$10,948	$30,456	$23,954	$11,037	($3,268)	$53,114	($25,672)	$112,177	$149,896
Plus Depreciation Expense	$0	$394,680	$31,740	$31,717	$31,834	$31,882	$31,899	$31,872	$32,890	$32,890	$32,890	$32,890	$32,890	$32,890
Less Capital Credit Allocations	$0	$0	($29)	($751)	$1,566	($120)	($683)	$0	$0	$0	$0	$0	$0	$0
Plus FAS 158 Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total (Funds From Operations)	$0	$804,424	$90,563	$88,155	$90,076	$42,710	$61,672	$55,826	$43,927	$29,622	$86,004	$7,218	$145,067	$182,786
Cash Construction Funds - Trustee	$0	$0												
Special Deposit	$0	($76,899)	($5,575)	($7,241)	($5,575)	($7,242)	($6,408)	($6,408)	($6,408)	($6,408)	($6,408)	($6,408)	($6,408)	($6,408)
Temporary Investment	$0	$0												
Accounts Receivable - Sale of Energy (Net)	$0	$30,158	$113,538	$1,368	$100,351	$118,126	$61,068	($451)	($21,852)	$18,420	$4,282	$10,106	($188,438)	($121,979)
Accounts Receivable - Other (Net)	$0	$137,184	$24,009	($18,747)	$13,552	$8,459	$47,501	$11,416	$7,405	$7,405	$11,345	$7,405	$7,405	$40,985
Regulatory Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Debits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Prepayments	$0	$0	($32,729)	$2,976	$2,975	$2,975	$2,976	$2,975	$0	$0	$0	$0	$0	$0
Other Current & Accrued Asset	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(Increase)/Decrease in Operating Assets	$0	$894,867	$99,243	($21,644)	$111,304	$122,318	$105,137	$7,532	($20,855)	$19,417	$9,219	$11,103	($187,441)	($87,402)
Notes Payable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accounts Payable	$0	$0	$29,509	($50,356)	($134,397)	$20,489	($78,408)	$113,082	$0	$0	$0	$0	$0	$0
Accumulated Operating Provisions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Regulatory Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Deferred Credits	$0	$0	($45,076)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Current and Accrued Liabilities	$0	($40,797)	$27,839	$31,381	($13,147)	($20,843)	$24,095	($36,981)	($13,599)	$0	$0	$0	$0	$0
Increase/(Decrease) in Operating Liabilities	$0	($40,797)	$12,272	($18,975)	($147,544)	($354)	($54,313)	$76,101	($13,599)	$0	$0	$0	$0	$0
CASH FROM OPERATING ACTIVITIES	$0	$854,070	$202,078	$47,535	$53,835	$164,674	$112,496	$139,459	$9,473	$49,039	$95,223	$18,321	($42,374)	$95,384
INVESTMENT ACTIVITIES														
Total Utility Plant	$0	($863,521)	($360,896)	$44,051	($14,092)	($5,776)	($2,007)	($10,754)	($81,703)	($52,852)	($63,646)	($52,212)	($52,147)	($55,768)
Cost to Retire Utility Plant	$0	$0	$521	$7,500	($12,262)	$242	$6,504	($12,477)	$0	$0	$0	$0	$0	$0
Construction Work-in-Progress	$0	$0	$202,273	($36,843)	($33,795)	($67,376)	($58,546)	($143,843)	$0	$0	$0	$0	$0	$0
Contributions in aid of construction (CIAC)	$0	$277,356	$1,152	$302	$11,411	$64,525	$73,167	$76,580	$30,000	$30,000	$30,000	$30,000	$20,000	$13,678
Total Other Property and Investments	$0	$0	$247	($762)	$453	$0	$0	$0	$0	$0	$0	$0	$0	$0
Materials & Supplies - Electric and Other	$0	$0	($1,394)	$113	($2,104)	($8,140)	$1,869	($5,149)	$0	$0	$0	$0	$0	$0
Notes Receivable (Net)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CASH FROM INVESTMENT ACTIVITIES	$0	($586,165)	($158,097)	$14,361	($50,389)	($16,525)	$20,987	($95,643)	($51,703)	($22,852)	($33,646)	($22,212)	($32,147)	($42,090)
FINANCING ACTIVITIES														
Margins & Equities	$0	($200,000)												($200,000)
LT Debt - Additional Debt		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LT Debt - Debt Service Payment		($132,239)	$0	$0	($32,316)	$0	$0	($32,807)	$0	$0	($33,305)	$0	$0	($33,811)
LT Debt - Other		$0												
Total LT Debt	$0	($132,239)	$0	$0	($32,316)	$0	$0	($32,807)	$0	$0	($33,305)	$0	$0	($33,811)
LT Debt - Payments Unapplied	$0	$0	$0	$0										
LT Debt - Current maturities	$0	$0	$0	$0										
Consumer Membership	$0	$0	$20	$0	$5	$35	$15	$40	$0	$0	$0	$0	$0	$0
Consumers Deposits	$0	$0	$1,250	($1,432)	($4,550)	$1,850	$1,460	$1,150	$0	$0	$0	$0	$0	$0
CASH FROM FINANCING ACTIVITIES	$0	($332,239)	$1,270	($1,432)	($36,861)	$1,885	$1,475	($31,617)	$0	$0	($33,305)	$0	$0	($233,811)
CASH FROM ALL ACTIVITIES	$0	($64,334)	$45,252	$60,464	($33,414)	$150,034	$134,958	$12,199	($42,230)	$26,187	$28,272	($3,891)	($74,521)	($180,517)
TOTAL CASH BEGINNING OF PERIOD	$570,393	$570,393	$570,393	$615,645	$676,109	$642,695	$792,729	$927,687	$939,886	$897,656	$923,843	$952,115	$948,224	$873,703
TOTAL CASH END OF PERIOD	$570,393	$506,059	$615,645	$676,109	$642,695	$792,729	$927,687	$939,886	$897,656	$923,843	$952,115	$948,224	$873,703	$693,186

Capital Expenditures by Project
Jun-18

	Current Month Actual	Current Month Budget	Current Month Variance		Year to Date Actual	Year to Date Budget	Year to Date Variance	Annual Budget	Annual Balance
Member Requested Facilities	51,693.79	24,118.00	(27,575.79)		82,390.92	88,433.00	6,042.08	200,983.00	118,592.08
Replacements (Poles & Transformers)	36,133.53	8,656.00	(27,477.53)		142,924.67	63,487.00	(79,437.67)	103,872.00	(39,052.67)
OCEC Projects:	0.00	0.00	0.00		0.00	0.00	0.00	62,675.00	62,675.00
Replace 2500' of URD at Stud Horse - Part 2	0.00	0.00	0.00		0.00	0.00	0.00	49,718.00	49,718.00
Replace 2500' of URD at Edelweiss - Part 1	0.00	0.00	0.00		0.00	28,979.00	28,979.00	57,957.00	57,957.00
Convert 3500' of OH to URD at Bear Crk	0.00	41,859.00	41,859.00		0.00	41,859.00	41,859.00	41,859.00	41,859.00
Replace 3000' of URD at Davis Lake	6,784.03	0.00	(6,784.03)		17,674.73	12,000.00	(5,674.73)	50,718.00	33,043.27
Metering projects -upgrades	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00
Pole Inspections	233.41	10,000.00	9,766.59		3,092.13	10,000.00	6,907.87	10,000.00	6,907.87
Fire Retardant/Treatment on Poles	0.00	17,479.00	17,479.00		0.00	17,479.00	17,479.00	17,479.00	17,479.00
Test/Rebuild 2 sets of Regulators Sub	24,678.94	0.00	(24,678.94)		48,453.93	0.00	(48,453.93)	32,791.00	(15,662.93)
Paint/protect crew hallway	0.00	0.00	0.00		0.00	0.00	0.00	5,000.00	5,000.00
Redo Asphalt in front & back, fix drain	0.00	0.00	0.00		0.00	25,000.00	25,000.00	25,000.00	25,000.00
Major Storm Damage	12,748.31	0.00	(12,748.31)		12,748.31	0.00	(12,748.31)	0.00	(12,748.31)
subtotal	132,272.01	102,112.00	(30,160.01)		307,284.69	287,237.00	(20,047.69)	658,052.00	350,767.31
Un Allocated Overhead	55,814.25				55,814.25	0.00	(55,814.25)		
Member CIAC CIAC	(76,580.36)	(30,000.00)	(46,580.36)	*	(227,137.31)	(123,687.00)	(103,450.31)	(277,356.00)	(50,218.69)
Total less CIAC	111,505.90				135,961.63				
								* $124,294.19 holding in CIAC 06/30/18	
Meters Purchases	0.00	0.00	0.00		21,180.00	20,000.00	(1,180.00)	20,000.00	(1,180.00)
Computers & Software Upgrades	7,200.00	0.00	0.00		7,200.00	5,000.00	(2,200.00)	5,000.00	(2,200.00)
Transformers Purchases	12,249.32	0.00	(12,249.32)		80,685.84	70,000.00	(10,685.84)	70,000.00	(10,685.84)
Vehicle Replacement	0.00	0.00	0.00		0.00	0.00	0.00	135,000.00	135,000.00
Total	130,955.22	72,112.00			245,027.47	258,550.00		230,000.00	120,934.16
						Total Capital Budget less CIAC		610,696.00	365,668.53

	Line Crew Direct Labor	Materials	* Note 107.25 Labor	Consultants Contractors	Transportation	Benefits	Total
January	2,086.84	0.00	3,436.90	0.00	2,424.24	2,020.44	9,968.42
February	2,963.79		3,041.61	0.00	1,617.04	2,183.49	9,805.93
March	8,853.87	2,671.68	9,500.00	0.00	5,729.34	6,237.56	32,992.45
April	16,562.77	10,492.77	26,772.52	0.00	9,520.08	11,719.23	75,067.37
May	14,115.42	134.06	16,434.36	0.00	6,233.76	10,260.91	47,178.51
June	16,712.98	52,849.74	20,000.00	24,678.94	7,579.99	10,450.36	132,272.01
July							
August							
September							
October							
November							
December							
	61,295.67	66,148.25	79,185.39	24,678.94	33,104.45	42,871.99	307,284.69

* Note: 107.25 is Capitalized Labor that includes: cost estimates, line staking, development & research for construction projects that no work order has been established. Along with Stores account 163.00 material stocking.

Okanogan County Electric Cooperative Inc
Capital Expenditures by Project
Jun-18

W.O. #	Monthly Allocation		Contractor	Labor	Labor O/H	AP Vendor & Material	Material O/H	Material Retire/Scrap	Benefits	Trans	Total
11978	4993.57	7		537.8	643.57	1862.45	1038.01		473.38	438.36	4,993.57
12056	300.00	7				300.00					300.00
12060	3,808.26	7		1,059.61	1,268.01				932.69	547.95	3,808.26
12078	24,678.94	16	24,678.94								24,678.94
12092	10,125.43	8		2,839.64	3,398.13				2,499.52	1,388.14	10,125.43
12093	746.20	8		177.49	212.40	143.50	79.98	(96.46)	156.23	73.06	746.20
12094	419.81	8				291.04	128.77				419.81
12096	30.04	8				19.29	10.75				30.04
12100	1,511.50	8				1,511.50					1,511.50
12101	(2,573.06)	12				2,919.15	1,626.96	(7,119.17)			(2,573.06)
12102	7,041.15	8				4,521.27	2,519.88				7,041.15
12111	14,099.34	8		3,893.72	4,659.52				3,427.36	2118.74	14,099.34
12112	6,274.13	7				4,028.75	2,245.38				6,274.13
12116	9,357.09	12				8364.33	4,661.76	-3669.00			9,357.09
12125	22,099.00	7				22,099.00					22,099.00
12128	(244.20)	8				226.22	126.08	(596.50)			(244.20)
12130	1,161.73	7		306.61	366.91	22.90	12.77		269.89	182.65	1,161.73
12131	233.41	14				468.65	261.20	-496.44			233.41
12132	2,138.81	7		86.08	103.01	1,179.85	657.57		75.77	36.53	2,138.81
12134	88.57	7				88.57					88.57
12138	737.97	8				731.71	407.81	-401.55			737.97
12141	708.64	7		182.82	218.78				160.92	146.12	708.64
12143	53.49	8				34.35	19.14				53.49
12147	1,460.25	7		403.35	482.68				355.04	219.18	1,460.25
12148	2,622.83	7		709.96	849.59				624.92	438.36	2,622.83
12150	159.00	7				159.00					159.00
12152	4,519.06	7		605.03	724.02	1425.15	739.12		532.57	493.17	4,519.06
12156	99.00	7				99.00					99.00
12158	99.00	7				99.00					99.00
12162	1,612.80	8		441.06	527.81				388.22	255.71	1,612.80
12163	12,748.31	19		5195.58	6217.42				312.47	1022.84	12,748.31
12164	99.00	7				99.00					99.00
12169	1,062.94	7		274.23	328.15				241.38	219.18	1,062.94
	132,272.01		24,678.94	16,712.98	20,000.00	50,693.68	14,535.18	(12,379.12)	10,450.36	7,579.99	132,272.01

7 Member Requested Facilities
8 Replacements (Poles & Transformers)
OCEC Projects:
9 Replace 2500' of URD at Stud Horse - Part 2
10 Replace 2500' of URD at Edelweiss - Part 1
11 Convert 3500' of OH to URD at Bear Crk
12 Replace 3000' of URD at Davis Lake
13 Metering projects -upgrades
14 Pole Inspections
15 Fire Retardant/Treatment on Poles
16 Test/Rebuild 2 sets of Regulators Sub
17 Paint/protect crew hallway
18 Redo Asphalt in front & back, fix drain
19 Major Storm Damage

OCEC Work Orders

16	12078	OCEC-Regulator	24678.94
8	12092	Service Orders Temp Disc	10,125.43
8	12093	Cutouts	746.20
8	12094	Transformers 2018.1	419.81
8	12096	OCEC-Conduit 2018.1	30.04
8	12100	OCEC-Deed's Wood Lot	1,511.50
12	12101	OCEC-Foster Davis Rd	(2,573.06)
8	12102	OCEC-Airport Line	7,041.15
8	12111	OCEC-Twisp River Rd 591	14,099.34
12	12116	OCEC- Davis Lake 2018	9,357.09
8	12128	OCEC-Mclean Hill	(244.20)
14	12131	OCEC-Pole Test RPLC 2017.1	233.41
8	12138	OCEC-T70 3R 12L	737.97
8	12143	RW Thorpe Retirement	53.49
8	12162	OCEC-C77 5A 18R 1L	1,612.80
19	12163	OCEC-2018.06.25 Storm	12,748.31
			80,578.22

CApEx/O&M Labor Distribution

Labor is split between Capital and O&M based on work performed. The following is a comparison between how labor was split.

1) YTD Actual 2018 2) YTD Budget 2018 3) YTD Actual 2017

Capitalization in Percentage

Labor Capitalized	Jan	Feb	March	April	May	June	July	August	September	October	November	December	YTD
2018 Actual	5%	12%	18%	27%	23%	25%							
2018 Budget	3%	12%	15%	15%	35%	37%	41%	37%	37%	37%	15%	3%	24%
2017 Actual	1%	1%	2%	8%	22%	29%	35%	49%	55%	41%	43%	12%	25%

Capitalization in Dollars

Capitalization in Dollars

	Jan	Feb	March	April	May	June	July	August	September	October	November	December	YTD
2018 Work Order Actual	$ 7,222	$ 9,924	$ 16,540	$ 24,183	$ 23,318	$ 23,747		$ -	$ -	$ -	$ -	$ -	
2018 Budget	$ 3,611	$ 11,284	$ 13,541	$ 13,541	$ 31,595	$ 33,851	$ 37,462	$ 33,851	$ 33,851	$ 33,851	$ 13,541	$ 3,159	$ 263,138
2017 Actual	$ 1,648	$ 436	$ 1,992	$ 6,742	$ 21,066	$ 25,337	$ 31,850	$ 47,668	$ 49,075	$ 39,586	$ 39,459	$ 10,259	$ 275,119

O& M Expense in Percentage

O&M Labor Expensed	Jan	Feb	March	April	May	June	July	August	September	October	November	December	YTD
2018 Actual	98%	88%	82%	73%	77%	75%							
2018 Budget	97%	88%	85%	85%	65%	63%	59%	63%	63%	63%	85%	97%	76%
2017 Actual	99%	99%	98%	92%	78%	71%	65%	51%	45%	59%	77%	88%	77%

O&M Expense in Dollars

	Jan	Feb	March	April	May	June	July	August	September	October	November	December	YTD
2018 Actual	$ 128,782	$ 74,657	$ 75,912	$ 65,816	$ 78,925	$ 69,568	$ -	$ -	$ -	$ -	$ -	$ -	$ 493,660
2018 Budget	$ 131,896	$ 70,236	$ 75,888	$ 72,552	$ 61,788	$ 51,623	$ 54,649	$ 62,333	$ 50,115	$ 62,333	$ 78,570	$ 84,880	$ 856,863
2017 Actual	$ 125,143	$ 82,097	$ 88,798	$ 77,316	$ 74,643	$ 60,689	$ 58,310	$ 48,695	$ 39,823	$ 56,821	$ 52,041	$ 77,734	$ 842,110

Total Labor YTD	**2018**	$ 136,004	$ 84,581	$ 92,451	$ 89,999	$ 102,243	$ 93,316							**$ 598,593**
Total Labor YTD	**2017**	$ 126,790	$ 82,533	$ 90,790	$ 84,058	$ 95,709	$ 86,026	$ 90,161	$ 96,363	$ 88,898	$ 96,407	$ 91,500	$ 87,993	**$ 1,117,229**

OKANOGAN COUNTY ELECTRIC COOPERATIVE INC
REVOLVING LOAN FUND #1
MONTHLY REPORT

For the Month Ending
June 30, 2018

Beginning RLF Balance		**$67,164.20**
LOUP LOUP SKI ED FOUNDATION LOAN #2		
PAYOFF AUGUST 01, 2019	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$425.00	$46,700.36
ADMINISTRATIVE FEE (1%)	$8.33	$2,700.00
PRINCIPLE PAYMENT TO LOAN	$416.67	$45,000.35
ORIGINAL AMOUNT OF LOAN		$50,000.00
BALANCE REMAINING ON LOANS		$4,999.65
LOUP LOUP SKI ED FOUNDATION LOAN #3		
PAYOFF OCTOBER 01, 2024	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$445.83	$20,295.81
ADMINISTRATIVE FEE (1%)	$29.16	$1,545.66
PRINCIPLE PAYMENT TO LOAN	$416.67	$18,750.15
ORIGINAL AMOUNT OF LOAN		$50,000.00
BALANCE REMAINING ON LOANS		$31,249.85
TOWN OF TWISP		
PAYOFF AUGUST 01, 2019	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$79.05	$7,453.09
ADMINISTRATIVE FEE (1%)	$2.30	$467.54
PRINCIPLE PAYMENT TO LOAN	$76.75	$6,984.01
ORIGINAL AMOUNT OF LOAN		$9,210.00
BALANCE REMAINING ON LOANS		$2,225.99
MVSTA LOAN #2		
PAYOFF JULY 01, 2022	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$875.00	$66,229.72
ADMINISTRATIVE FEE (1%)	$41.67	$4,563.30
PRINCIPLE PAYMENT TO LOAN	$833.33	$60,833.09
ORIGINAL AMOUNT OF LOAN		$100,000.00
BALANCE REMAINING ON LOANS		$39,166.91
MEDICINE WHEEL WEB DESIGN		
PAYOFF OCTOBER 01, 2024	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$510.00	$23,300.00
ADMINISTRATIVE FEE (1%)	$10.00	$810.00
PRINCIPLE PAYMENT TO LOAN	$500.00	$22,500.00
ORIGINAL AMOUNT OF LOAN		$30,000.00
BALANCE REMAINING ON LOANS		$7,500.00
TOWN OF WINTHROP		
PAYOFF NOVEMBER 01, 2027	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$870.83	$6,095.81
ADMINISTRATIVE FEE (1%)	$79.17	$554.19
PRINCIPLE PAYMENT TO LOAN	$791.67	$5,541.69
ORIGINAL AMOUNT OF LOAN		$95,000.00
BALANCE REMAINING ON LOANS		$89,458.31
TOTAL BALANCE REMAINING ON LOANS		$174,600.71
ENDING RLF BALANCE		**$70,199.29**

OKANOGAN COUNTY ELECTRIC COOPERATIVE INC
REVOLVING LOAN FUND #2
MONTHLY REPORT

For the Month Ending
June 30, 2018

Beginning RLF Balance		**$65,117.67**
AERO RESCUE		
PAYOFF NOVEMBER 1, 2020	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$2,060.00	$196,180.00
ADMINISTRATIVE FEE (1%)	$60.00	$12,240.00
PRINCIPLE PAYMENT TO LOAN	$2,000.00	$184,000.00
ORIGINAL AMOUNT OF LOAN		$240,000.00
BALANCE REMAINING ON LOANS		$56,000.00
TOWN OF WINTHROP LOAN #2		
PAYOFF JUNE 01, 2022	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$179.37	$13,222.32
ADMINISTRATIVE FEE (1%)	$8.54	$922.56
PRINCIPLE PAYMENT TO LOAN	$170.83	$12,299.76
ORIGINAL AMOUNT OF LOAN		$20,500.00
BALANCE REMAINING ON LOANS		$8,200.24
MVSTA LOAN #3		
PAYOFF OCTOBER 01, 2024	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$624.16	$28,353.71
ADMINISTRATIVE FEE (1%)	$40.84	$2,269.21
PRINCIPLE PAYMENT TO LOAN	$583.33	$26,249.85
ORIGINAL AMOUNT OF LOAN		$70,000.00
BALANCE REMAINING ON LOANS		$43,750.15
PINETOOTH CREATIVE		
PAYOFF July 01, 2026	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$84.25	$1,949.51
ADMINISTRATIVE FEE (1%)	$6.96	$171.04
PRINCIPLE PAYMENT TO LOAN	$77.29	$1,778.65
ORIGINAL AMOUNT OF LOAN		$9,275.00
BALANCE REMAINING ON LOANS		$7,496.35
EQPD		
PAYOFF February 01, 2027	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$297.92	$4,866.72
ADMINISTRATIVE FEE (1%)	$27.08	$433.30
PRINCIPLE PAYMENT TO LOAN	$270.84	$4,333.42
ORIGINAL AMOUNT OF LOAN		$32,500.00
BALANCE REMAINING ON LOANS		$28,166.58
Little Star Montessorri School		
PAYOFF February 01, 2027	**MONTH**	**TO DATE**
PAYMENTS RECEIVED	$295.21	$5,053.40
ADMINISTRATIVE FEE (1%)	$24.38	$449.69
PRINCIPLE PAYMENT TO LOAN	$270.83	$4,604.11
ORIGINAL AMOUNT OF LOAN		$32,500.00
BALANCE REMAINING ON LOANS		$27,895.89
ENDING RLF BALANCE		**$68,490.79**

OKANOGAN COUNTY ELECTRIC COOPERATIVE, INC.

POWER & SERVICE DATA

June-18

	March 2018	April 2018	May 2018	**June 2018**	June 2017
POWER DATA:					
COST OF POWER	$261,103	$212,906	$145,406	**$165,471**	$155,255
KWH PURCHASED	5,927,840	4,105,730	3,443,600	**3,472,835**	3,421,650
KWH SOLD & OCEC USE	5,546,608	3,785,326	3,144,751	**3,162,798**	3,139,360
KWH LOST	381,232	320,404	298,849	**310,037**	282,290
LINE LOSS %	6.43%	7.80%	8.68%	**8.93%**	8.25%
COST PER KWH	$0.0440	$0.0519	$0.0422	**$0.0476**	$0.0454
BILLING DATA:					
ACCOUNTS BILLED	3,529	3,536	3,733	**3,745**	3,686
AVG. KWH/CONSUMER	1,572	1,071	842	**845**	852
BILLING REVENUE	$517,635	$397,993	$360,224	**$356,762**	$348,506
AVERAGE BILL	$146.68	$112.55	$96.50	**$95.26**	$94.55
REVENUE/KWH SOLD	$0.0933	$0.1051	$0.1145	**$0.1128**	$0.1110
SERVICE DATA:					
NEW	0	1	6	**9**	9
RETIRED	0	1	0	**0**	0
TOTAL END OF MONTH	3732	3732	3738	**3747**	3688
IDLE SERVICES	106	103	102	**103**	107
TRANSPORTATION:					
TOTAL MILES	6,481	5,405	5,148	**5,379**	6,624
COST OF OPERATION	$17,384	$16,752	$17,104	**$14,373**	$14,540
AVG. COST PER MILE	$2.682	$3.099	$3.322	**$2.672**	$2.195
MATERIALS:					
ISSUES	$1,894	$9,843	$7,235	**$38,106**	$4,200
INVENTORY	$250,450	$258,590	$256,721	**$261,870**	$317,477

OCEC 2018 Outage
Summary

Substation	Power Supply Int.	Major	Planned Int.	All Other Int.	Feeder Total Hours Out	% of Total	Total # of Meters	# of Meters w/ outage	SAIDI	SAIFI	CAIDI
Winthrop Substation (1)	***11,832***	***-***	***-***	***6,356***	17,938	77.0%	*2958*	5252	6.064	1.776	3.463
Feeder 1 = Chewuch	2,360	-	-	390	2,750	11.8%	*590*	878	4.662	1.488	3.132
Feeder 2 = Mazama	3,764	-	-	5,930	9,694	41.6%	*941*	2896	10.302	3.078	3.347
Feeder 3 = Sun Mtn	2,984	-	-	20	3,004	12.9%	*746*	766	4.027	1.027	3.922
Feeder 4 = Winthrop	2,724	-	-	15	2,739	11.7%	*681*	712	4.022	1.046	3.847
Twisp Substation (2)	***2,456***	***-***	***-***	***2,917***	5,373	23.0%	*614*	1289	8.751	2.099	4.169
Feeder 1 = Airport	112	-	-	866	978	4.2%	*28*	227	34.916	8.107	4.307
Feeder 2 = Loup	776	-	-	122	898	3.9%	*194*	222	4.628	1.144	4.044
Feeder 3 = Twisp	1,568	-	-	1,930	3,498	15.0%	*392*	840	8.923	2.143	4.164
Totals					**23,311**		**3572**	**6541**	**6.526**	**1.831**	**3.60**
CFC Summary	**240**	**-**	**-**	**155.76**							

SAIDI = Defined as sum of customer interruption durations divided by the total # of customers server
SAIFI = Defined as total number of customers interrupted divided by the total numbers of customers served
CAIDI = Defined as the average amount of time that a customer is without power for a typical interruption
ASAI = Total minutes during reported time frame divided by total minutes power was available

NUMBER OF OUTAGES = 38

Interruption: a loss of electricity for any period longer than 5 minutes

Power supply interruption: any interruption originating from the transmission system, sub-transmission system, or the substation regardless of ownership

Planned interruption: any interruption scheduled by the distribution system to safely perfome routine maintenance

All other interruptions: all excluding power supply, major event, and those that are planned

Major Event: an interruption or group of interruptions caused by conditions that exceed the design & operationa limits of a system. (IEEE 1366-2003 / RUS 1730a - Exhibit E).

OCEC 2018 Outage
Summary By Cause

SUMMARY BY CAUSE

POWER SUPPLY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
LARGE SCALE	-	-	-	-	-	-	-	-	-	-	-	-	-
OK PUD	14,288	-	-	-	-	-	-	-	-	-	-	-	14,288
OCEC SUB	-	-	-	-	-	-	-	-	-	-	-	-	-
PLANNED													TOTAL
CONSTRUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-
MAINTENANCE	-	-	-	-	-	-	-	-	-	-	-	-	-
OTHER PLANNED	-	-	-	-	-	-	-	-	-	-	-	-	-
EQUIPMENT OR INSTALLATION DESIGN													TOTAL
MATERIAL OR EQUIP FAILURE	-	-	4,123	-	2,948	-	-	-	-	-	-	-	7,071
INSTALLATION FAULT	-	-	-	-	-	-	-	-	-	-	-	-	-
CONDUCTOR SAG OR INADEGUATE CLEARANCE	-	-	-	-	-	-	-	-	-	-	-	-	-
OVERLOAD	-	-	-	-	-	-	-	-	-	-	-	-	-
MISCOORDINATION OF PROTECTION DEVICES	-	-	-	-	-	-	-	-	-	-	-	-	-
OTHER EQUIPMENT INSTALLATION / DESIGN	-	-	120	-	-	-	-	-	-	-	-	-	120
MAINTENANCE													TOTAL
DECAY / AGE OF MATERIAL / EQUIP	-	-	2	1	56	-	-	-	-	-	-	-	59
CORROSION / ABRASION OR MATERIAL / EQUIPMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
TREE GROWTH	-	-	-	-	-	-	-	-	-	-	-	-	-
TREE FAILURE FROM OVERHAND OR DEAD TREE WITHOU	-	-	-	-	-	-	-	-	-	-	-	-	-
TREES WITH ICE / SNOW	-	-	-	-	-	-	-	-	-	-	-	-	-
CONTAMINATION (LEAKING / EXTERNAL)	-	-	-	-	-	-	-	-	-	-	-	-	-
MOISTURE	-	-	-	-	-	-	-	-	-	-	-	-	-
OCEC CREW CUTS TREE	-	-	-	-	-	-	-	-	-	-	-	-	-
MAINTENANCE, OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER													TOTAL
LIGHTNING	-	-	-	-	-	-	-	-	-	-	-	-	-
WIND NOT TREE	-	-	-	-	-	-	-	-	-	-	-	-	-
ICE, SLEET, FROST, NOT TREE	-	-	-	-	-	-	-	-	-	-	-	-	-
FLOOD	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
ANIMALS													TOTAL
SMALL ANIMAL / BIRD	-	0	-	1	-	-	-	-	-	-	-	-	2
LARGE ANIMAL	-	-	-	-	-	-	-	-	-	-	-	-	-
ANIMAL DAMAGE - GNAW OR BORE	-	-	-	-	-	-	-	-	-	-	-	-	-
ANIMAL , OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-

SUMMARY BY CAUSE

PUBLIC													TOTAL
CUSTOMER CAUSED	-	-	-	-	-	-	-	-	-	-	-	-	-
MOTOR VEHICLE	-	-	1,802	-	-	-	-	-	-	-	-	-	1,802
AIRCRAFT	-	-	-	-	-	-	-	-	-	-	-	-	-
FIRE	-	-	-	-	-	-	0	-	-	-	-	-	0
PUBLIC CUTS TREE	-	-	-	-	-	-	-	-	-	-	-	-	-
VANDALISM	-	-	-	-	-	-	-	-	-	-	-	-	-
SWITCHING ERROR OR CAUSED BY CONSTRUCTION / MAI	-	-	-	-	-	-	-	-	-	-	-	-	-
PUBLIC, OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
OTHER													TOTAL
OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
UNKNOWN													TOTAL
CAUSE UNKNOWN	57	-	19	1	2	9	-	-	-	-	-	-	87

****Cause listing shows total number of HOURS for all members out of power:**
*(minutes of outage * number of members effected)/60*

OCEC 2018 Outage
Detailed Summary By Cause

DETAILED SUMMARY BY CAUSE

GENERATION	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
GEN-GENERATION	-	-	-	-	-	-	-	-	-	-	-	-	-
GEN-TOWERS, POLES, FIXTURES	-	-	-	-	-	-	-	-	-	-	-	-	-
GEN-CONDUCTORS AND DEVICES	-	-	-	-	-	-	-	-	-	-	-	-	-
GEN-TRANSMISSION SUB	14,288	-	-	-	-	-	-	-	-	-	-	-	14,288
GEN-GENERATION OR TRANSMISSION, OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTALS:	14,288												14,288
DISTRIBUTION SUBSTATION													
DIST-POWER TRANSFORMER	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST-VOLTAGE REGULATOR	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST-LIGHTNING ARRESTER	-	-	4,123	-	-	-	-	-	-	-	-	-	4,123
DIST-SOURCE SIDE FUSE	-	-	2	-	-	-	-	-	-	-	-	-	2
DIST-CIRCUIT BREAKER	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST-SWITCH	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST-METERING EQUIPMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST-DISTRIBUTION SUBSTATION , OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTALS:	-												4,126
POLES AND FIXTURES													
POL-POLES	-	-	-	-	-	-	-	-	-	-	-	-	-
POL-CROSSARM OR CROSSARM BRACE	-	-	-	-	-	-	-	-	-	-	-	-	-
POL-ANCHOR OR GUY	-	-	-	-	-	-	-	-	-	-	-	-	-
POL-POLES AND FIXTURES, OTHER	-	-	113	-	-	-	-	-	-	-	-	-	113
TOTALS:	-												113
OVERHEAD													
OVR-OVERHEAD	-	-	-	-	-	-	-	-	-	-	-	-	-
OVR-LINE CONDUCTOR	-	-	1,809	1	2,912	-	-	-	-	-	-	-	4,721
OVR-CONNECTOR OR CLAMP	-	-	-	-	-	-	-	-	-	-	-	-	-
OVR-SPLICE OR DEAD END	-	-	-	-	-	-	-	-	-	-	-	-	-
OVR-JUMPER	-	-	-	-	32	-	-	-	-	-	-	-	32
OVR-INSULATOR	-	-	-	-	10	-	-	-	-	-	-	-	10
OVR-LIGHTNING ARRESTER LINE	-	-	-	-	-	-	-	-	-	-	-	-	-
OVR-FUSE CUTOUT	57	0	19	2	36	9	-	-	-	-	-	-	124
OVR-RECLOSER OR SECTIONALIZER	-	-	-	-	-	-	-	-	-	-	-	-	-
OVR-OVERHEAD LINE CONDUCTORS AND DEVICES	-	-	-	-	-	133	-	-	-	-	-	-	133
TOTALS:	57												5,019

OCEC 2018 Outage
Detailed Summary By Cause

DETAILED SUMMARY BY CAUSE

UNDERGROUND													
UG-PRIMARY CABLE	-	-	-	-	15	-	-	-	-	-	-	-	15
UG-SPLICE OR FITTING	-	-	-	-	-	-	-	-	-	-	-	-	-
UG-SWITCH ELBOW ARRESTER	-	-	-	-	-	-	-	-	-	-	-	-	-
UG-SECONDARY CABLE OR FITTINGS	-	-	-	-	-	-	-	-	-	-	-	-	-
UG-ELBOW	-	-	-	-	-	-	-	-	-	-	-	-	-
UG-POTHEAD OR TERMINATOR	-	-	-	-	-	-	-	-	-	-	-	-	-
UG-UNDERGROUND, OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTALS:	-												15
TRANSFORMER													
XFMR-TRANSFORMER BAD	-	-	-	-	-	-	-	-	-	-	-	-	-
XFMR-TRANSFORMER FUSE OR BREAKER	-	-	-	-	-	-	-	-	-	-	-	-	-
XFMR-TRANSFORMER ARRESTER	-	-	-	-	-	-	-	-	-	-	-	-	-
XFMR-LINE TRANSFORMER, OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
**SECONDARY	-	-	-	-	-	-	-	-	-	-	-	-	-
SEC-SECONDARY OF SERVICE CONDUCTOR	-	-	-	-	-	-	-	-	-	-	-	-	-
SEC-METERING EQUIPMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
SEC-SECURITY OR STREET LIGHT	-	-	-	-	-	-	-	-	-	-	-	-	-
SEC-SECONDARY AND SERVICE, OTHER	-	-	-	-	-	-	0	-	-	-	-	-	0
SEC-XFMR-NO EQUIP FAILURE	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTALS:	-												0
WEATHER													
WTR-RAIN	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-LIGHTNING	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-WIND	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-SNOW ICE	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-SLEET	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-EXTREME COLD	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-EXTREME HEAT	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-WEATHER OTHER	-	-	-	-	-	-	-	-	-	-	-	-	-
WTR-CLEAR, CALM	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTALS:	-												-

ISSUE #4

PNGC Power Pulse

June 2018

Inside This Issue

Charting the Course

The PNGC Board of Directors met at Skamania Lodge in Stevenson, Washington for their annual Strategic Planning session June 4-6, 2018. This intensive meeting is held in lieu of an official Board meeting during the month of June and gives the Board a chance to deep dive into the subjects that concern the future of PNGC.

"This year we had a chance to look out past 2028, when the new Bonneville contract will go into effect," said Beth Looney, President and CEO of PNGC Power. "There is so much for us to consider, both internal and external factors, as we plan for the success of PNGC and its cooperatives moving forward. This meeting gives us the opportunity to talk about what we'll look like post-2028, and also all the steps we need to be making between now and then."

The view from Skamania Lodge

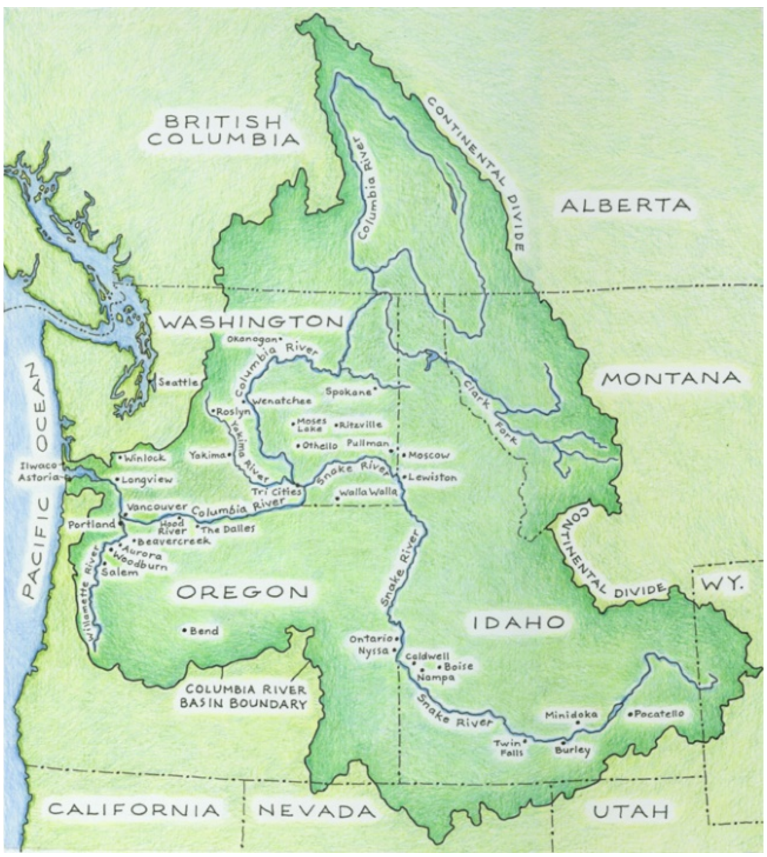
This year's session included topics like Real World Scenario planning, long-term financial planning, and extensive discussion on PNGC's Wholesale Power Contract. The Board also looked at the results from the survey they were given prior to the Strategic Planning session that asked for their appetite and opinions on various regional, legislative, and power related questions.

"I think we made great progress setting a path for PNGC's continued success and growth into the future," said Roman Gillen, PNGC Power Board Chair. "I am confident that the framework established by this year's Strategic Planning session places us in the best position to meet the major challenges and uncertainties of the NW power market in the years ahead."

A River Runs Through It

On May 22, 2018 the U.S. Department of State released a statement announcing the start of negotiations with Canada to modernize the Columbia River Treaty. This 1964 Treaty has provided flood risk and hydropower operations with benefits to millions of people living in both Canada and the Pacific Northwest of The United States. Modernizing the Treaty will ensure these benefits continue fairly into the future.

Talks between the United States and Canada began on May 29-30 in Washington, D.C. and by all accounts were productive in terms of laying out high-level objectives and re-affirming cooperation between the parties. This came before the G7 summit held in La Malbaie, Quebec, Canada June 8-9, and the ensuing tensions between our two allied countries caught the news cycle. What does this mean for Treaty negotiations moving forward? And what can we expect from our Canadian counterparts as the U.S. Department of State (along with The Bonneville Power Administration, the U.S. Army Corp of Engineers, the Department of Interior, and the National Oceanic and Atmospheric Administration) looks to ensure the objectives of the United States?



It's important to remember that discussions about The Columbia River Treaty have been ongoing for many years now among the Northwest's Tribes, states, key stakeholders, and both public and federal agencies. In 2013, consensus was reached by these groups around a 2013 Regional Recommendation, which will guide U.S. negotiators. Ashley Slater, PNGC Power's Vice President of Government Affairs and Policy said, "As members of the Columbia River Treaty Power Group (a coalition of 80 electric utilities, industry associations and other entities that depend on power produced by Columbia River hydropower generating plants) PNGC Power has taken a leadership role to ensure that Treaty discussions prioritize the fundamental need to reestablish an equitable distribution of power benefits between the U.S. and Canada."

The key objectives of the Treaty negotiations, according to a press release issued by the U.S. Department of State, are careful management of flood risk, ensuring reliable and economic power supply, and better addressing ecosystem concerns. Sustaining these objectives far into the future is the goal; hopefully, current tensions will not have an effect. "Our primary objective is to ensure that these negotiations result in a net positive benefit for Northwest electric ratepayers," Slater stated, saying this will require a steadfast commitment to correcting the current inequity of the U.S. obligation under the Canadian Entitlement – a continuous power and energy delivery to the Canadian government paid for by Northwest electricity customers. Slater said, “Without agreement, the Northwest region faces a loss of approximately $1 million every two to three days, and the associated carbon-free energy.”

PNGC Power has been at the table representing its members’ interests in these discussions and will continue to monitor their development. The next round of negotiations will take place August 15-16 in British Columbia, Canada.

Employee Spotlight: Teresa Skreen

Teresa Skreen has been with PNGC Power for 17 years. She began her career here when PNGC still shared the building with a bank. In fact, in her first role as Administrative Services Manager, the first project she undertook was to revamp the current PNGC building to get it ready for the Slice contract and a 24-hour trading floor. Teresa says she has seen and lived the changes of the building, the contracts, and leadership of PNGC. Teresa is the second-longest tenured employee of PNGC now (our CFO Jon Wissler has a few years on her.)

Teresa is the Vice President of Administration, which is a role that covers a multitude of areas. She oversees Human Resources and Benefits, IT, the building, administrative services, she supervises the marketing and communications department, and functions as counselor and all-around office Mom. “I see my main job as fostering the culture of the company,” Teresa said. “I try to make a positive environment where people can be their best.” Teresa went on to say that it’s always been her job to deal with the little things, so that the little things don’t become big things that distract people from PNGC’s core mission.

Teresa and Flynn

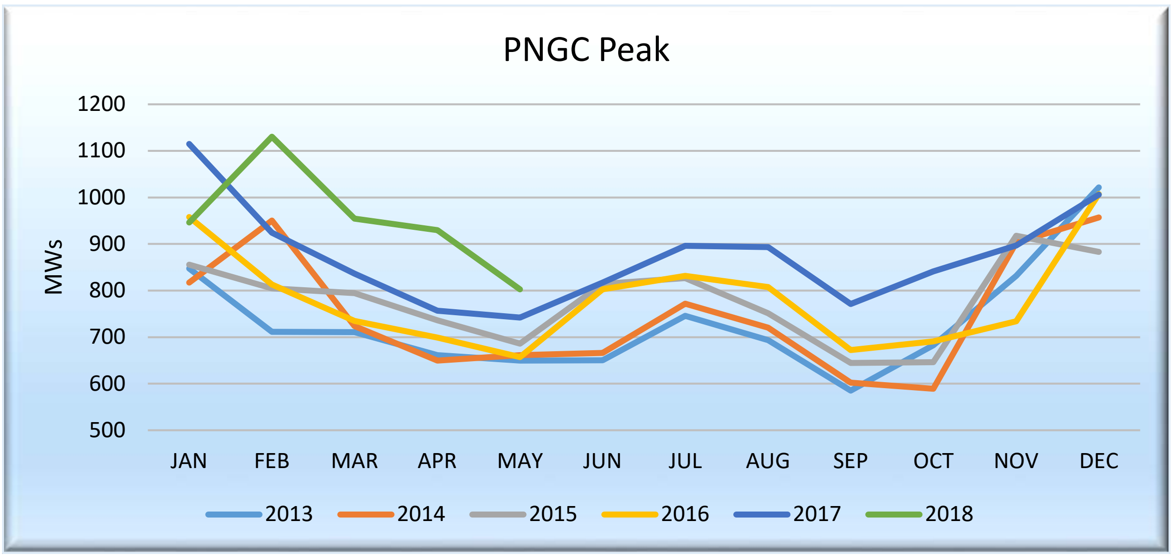
Teresa lives in Oregon City with her husband Mitch, and their lively animal companions, which include 4 Maine Coon cats that range between 20-30 lbs. each (named Bacco, Tino, Fuego, and Pippa), and two Boxers, Kipper who is a wise 12 years old, and their newest addition, Flynn, who is 6 months old. Teresa and Mitch have two grown daughters, and two granddaughters. In her free time, Teresa volunteers with organizations that make the world a better place.

BPA Happenings

June 20-21	2018 Integrated Program Review Workshop
June 26	TC-20 Tariff Customer Workshop
July 11	TPIP Review
July 17	2018 Integrated Program Review Workshop
July 18	BP-20 Rate Case Workshop
July 23	TC-20 Tariff Customer Workshop

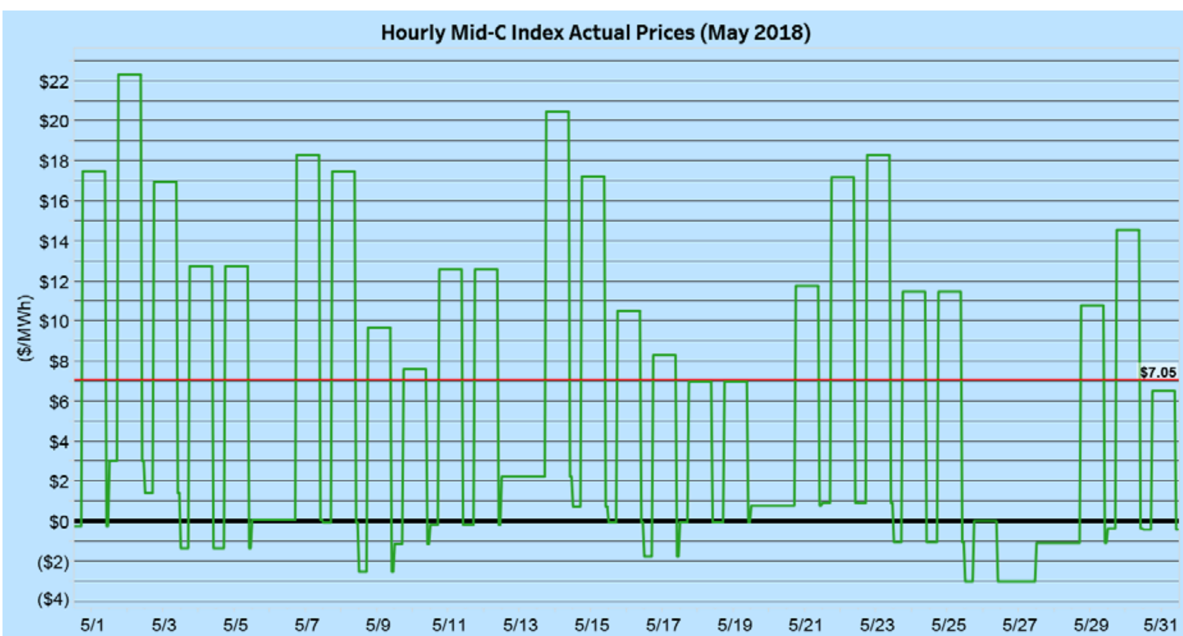
PNGC Peak by Month & Year

The graph below compares PNGC Power's peak demand by month for the last 5 years.



Mid-C Pricing

The graph below shows Mid-C Pricing for the month of May 2018



Upcoming PNGC Events

June 21	Coos-Curry Annual Meeting
July 3	PNGC Board Meeting
July 4	4th of July – PNGC Office closed
July 10-12	ORECA Mid-year Meeting
July 12	EE Collaborative Meeting

PNGC Power
Smart. Local. Connected.

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Portland, OR 97232
(503) 288-1234
www.pngcpower.com

About PNGC Power:
PNGC Power is a Portland-based electric generation and transmission (G & T) cooperative owned by 15 Northwest electric distribution cooperative utilities with service territory in seven western states (Oregon, Washington, Idaho, Montana, Utah, Nevada and Wyoming). The company creates value for its member systems by providing power supply, transmission, and other management services. PNGC Power is an aggregator of geographically diverse loads in the region.

Washington Rural Electric Cooperative Association **Update**

To: WRECA Members **June 29, 2018**

From: Kent Lopez, General Manager

Summer has finally arrived and Olympia is getting ready for the 2019 Legislative Session – It doesn't take long for people to start making plans for the legislative proposals they want to make in the upcoming Legislative Session. That includes WRECA and its members. We're already meeting with legislators and stakeholders concerning several issues that will impact the WRECA membership.

And then there is also an election before the next Legislative Session. The impacts will be more significant than most mid-term elections. In Olympia, we expect the Democrats will increase their majorities in both the House of Representatives and the Senate. In addition, the leadership in the Senate will change. The current majority leader is not running for re-election. A new majority leader will be elected after the November elections. But there is no clear front-runner for the position, at least that we can tell at this point.

Those who attended the 2018 WRECA Annual Meeting three weeks ago heard NRECA Government Relations VP Kirk Johnson discuss the potential changes in the U.S. Congress following the upcoming elections. During the meeting of statewide association general managers last week, we got into more details on a state-by-state basis about what to expect in November. One item of interest – the race for Washington's 5th Congressional District is being watched as an "indicator". That means that if the incumbent, Rep. Cathy McMorris Rodgers, is re-elected, the Republicans probably have a good chance of retaining a majority in the U.S. House of Representatives, or at least being in the minority by just a few seats. If Rep. McMorris Rodgers is defeated, that indicates to the people who watch this stuff that it will be a good day for the Democrats in the U.S. House.

Meanwhile, we're working on several issues that we anticipate dealing with in the upcoming state legislature – specifically attempts to expand the state's exiting renewable portfolio standard, revise the net metering requirements, and establish a clean energy standard. All of these efforts were started in the 2018 Legislative Session, but died ultimately because it was a short session and the stakeholders were never able to agree on a specific proposal.

A couple of factors make that a different scenario for the 2019 Legislative Session.

First of all, it's a long session – 104 days to be exact. Several key legislators have told us that they believe that a long session will give them time to get the votes they need to enact at least one of their legislative proposals, if not all three.

Another factor is that we, the utility stakeholders, have been given an opportunity to make a "scientific" case for our opposition to some of the proposals that were introduced during the 2018 Legislative Session. We're working hard to get that done, and think we're making progress.

At a high level, here are the proposals that are being prepared for the 2019 Legislature:

<u>Renewable Portfolio Standard</u> – increase to 50 percent by 2030 with no changes in the definition of "eligible" renewables. Maybe expand to all utilities, regardless of size. Maybe adjust the "off-ramps" to address grid reliability concerns. *Besides insisting that federal incremental hydro be included in the "eligible" definition, we are also expressing concerns about increasing the standard to 50 percent. And, of course, we're opposing proposals to extend the standard to cover all utilities.*

<u>Net Metering</u> – increase the minimum requirement for accepting net metering at the retail credit level. Attempts to update the state's solar incentive program have so far failed to pass the legislature. This means that the current solar incentive program will abruptly end in 2020. That has the stakeholders in the solar industry very nervous. Their response is a proposal to increase the amount of solar capacity a utility must accept at the retail credit level. Other proposals would increase the size of the solar installation that would be eligible for the net metering credit. *Our concern is that none of the proposals would deal with cost that shifts from utility customers who install solar systems to those who do not generate their own power.*

<u>Clean Energy Standard</u> – would require that all electricity sold in the state be generated by resources that don't emit carbon. The most common proposal is that 100 percent of the electricity be carbon free by 2045. *Our concerns are that the proposals to date have not addressed the need for peaking capacity needed to address system reliability concerns.*

<u>Rural Broadband</u> – the Governor's office is not giving up on a push to expand broadband internet service to the rural areas of the state. The Governor's office has held initial stakeholder meetings to look at options to encourage rural broadband deployment. Benton REA was invited to participate in those discussions and has been the rural co-op voice at the table.

In the background is the voter initiative to impose a pollution fee (a.k.a. carbon tax) starting in 2020 – and supporters of the initiative , I-1631, have scheduled an event in Olympia for this coming Monday when they plan to turn in the signatures to put the initiative on the ballot.

To refresh your memory, if I-1631 passes in November, here is what it would do:

1. A tax is collected from "large emitters" based on carbon content of:
    a. Fossil fuels sold or used within the state;
    b. Electricity generated within or imported for consumption within the state.
2. The tax is $15 per metric ton beginning 1/1/2020, increasing two dollars every year beginning 1/1/2021 plus inflation. The tax is fixed at inflation only when the state's 2035 greenhouse gases reduction goal, as it exists now or is amended later, is met and trajectory indicated compliance with the 2050 goal.
3. For BPA power, the Dept. of Ecology must publish a default annual emissions factor.
4. The revenues from the tax would be deposited in a fund established in state treasury.
5. After reasonable administrative costs, the money in the fund would be spent:
    a. 70% on clean air/clean energy

   b. 25% on clean water and healthy forests
   c. 5% on healthy communities
6. The Public Oversight Board (POB) is established to oversee the spending of the money.
7. Within the percentages listed above:
   a. At least 35% of funds must provide "direct and meaningful benefits" to Pollution and Health Action Areas (PHAAs).
   b. At least 10% must fund programs inside PHAAs.
   c. At least 10% must be used for tribes – which can be counted towards the 35% overlay for PHAAs.
8. Utilities may claim credits for up to 100% of the fee, authorized for programs/activities/projects consistent with a Clean Energy Investment Plan (CEIP) approved by the Dept. of Commerce – not the co-op's board of directors.

There will doubtless be further analysis of the impacts of I-1631 on electric cooperatives and the ratepayers across the state. Stay tuned.

Registrations are now being accepted for the 2018 NRECA Regional Meeting – Sept. 25-27 in Anchorage. For more information and to register, go to www.cooperative.com.

The 2018 WRECA Annual Meeting was a huge success – primarily because of the solid support we received from the WRECA members and our industry friends who sponsored the meeting. In addition, all the speakers showed up on time (that's a big deal) and there was enough food for everyone (a bigger deal).

Our Annual Meeting sponsors were:

Dinner:	Federated Rural Electric Insurance Exchange
Reception:	Asplundh Tree Expert Co.
	Cooperative Finance Corporation (CFC)
	General Pacific
	National Information Solutions Cooperative (NISC)
Breaks:	Brown & Kysar
	CoBank
	Cooperative Response Center (CRC)
	McFarland Cascade
	Potelco
	Ruralite Services
	USIC Locating Services

Please thank these industry friends for their support of WRECA and its members at the first opportunity that you have.

We've posted copies of the presentations on our website, www.wreca.coop, in the Meetings section on the 2018 Annual Meeting Recap page.

We also raised some cash for WECPAC – the state political action committee sponsored by WRECA. The golf tournament netted WECPAC $7,252. Again, there were sponsors who contributed to the success of tournament. They were:

Tee Sponsors: Big Bend EC
Columbia REA
CFC
DP&C
EES Consulting
Elmhurst Mutual
Evergreen Consulting Group
Modern EWC
Tanner EC

Refreshments: Brown & Kysar
General Pacific
Lakeview L&P
NRECA
Public Power Council

Finally, we had a very successful auction which raised $5,800 for WECPAC (if everyone pays up for their purchases).

The 2019 WRECA Annual Meeting is June 11 – 12 at the Hotel RL in Spokane – and we already have one speaker lined up for it. Put it on your calendar.

Important dates – please put the following on your calendars:

Sept. 17 – WRECA Governance Overview, Spokane Valley WA
Sept. 18 – WRECA Board of Directors, Spokane Valley, WA
Sept. 25-27 – NRECA Region 9 Meeting, Anchorage, AK
Nov. 5-7 – CFC IBES Conference, Amelia Island, FL
Nov. 6 – National Election Day
Dec. 10 – WRECA Legislative Process Overview, SeaTac, WA
Dec. 11 – WRECA Board of Directors, SeaTac, WA
Jan. 14, 2019 – 2019 Legislative Session Begins
Mar. 11-14, 2019 – 2019 NRECA Annual Meeting, Orlando, FL
Apr. 29-May1, 2019 – 2019 NRECA Legislative Conference, Washington, DC
June 10, 2019 – 2019 WECPAC Golf Tournament, Spokane, WA
June 11-12, 2019 – 2019 WRECA Annual Meeting, Spokane, WA

Please let me know if you have any questions. – Kent

Comparison of BPA Power Costs for YTD FY 2017 and FY 2018

	FY 2017 KWH Purchased	Cost	Cents per KWH	FY 2018 KWH Purchased	Cost	Cents per KWH
Oct	4,247,850	$ 179,765	4.2	4,617,795	$ 199,417	4.3
Nov	4,840,000	$ 167,067	3.5	6,039,500	$ 211,428	3.5
Dec	9,195,205	$ 354,871	3.9	8,870,180	$ 339,203	3.8
Jan	9,911,795	$ 412,865	4.2	7,789,025	$ 310,626	4.0
Feb	7,558,410	$ 333,045	4.4	7,309,665	$ 361,998	5.0
March	5,913,945	$ 243,202	4.1	5,927,840	$ 262,674	4.4
April	4,152,605	$ 191,448	4.6	4,105,730	$ 214,477	5.2
May	3,623,220	$ 133,899	3.7	3,443,600	$ 145,406	4.2
June	3,421,650	$ 155,255	4.5	3,472,835	$ 165,471	4.8
Total	52,864,680	2,171,417		51,576,170	2,210,700	
Overall Cents/KWH	4.11			4.29		
Overall % Increase	4.4%					

Note: PNGC Credit is backed out of December's costs.

Comparison of BPA Power Costs for CY 2017 and CY2018

	CY 2017 KWH Purchased	Cost	Cents per KWH	CY 2018 KWH Purchased	Cost	Cents per KWH
Jan	9,911,795	$ 412,865	4.2	7,789,025	$ 310,626	4.0
Feb	7,558,410	$ 333,045	4.4	7,309,665	$ 361,998	5.0
March	5,913,945	$ 243,202	4.1	5,927,840	$ 262,674	4.4
April	4,152,605	$ 191,448	4.6	4,105,730	$ 214,477	5.2
May	3,623,220	$ 133,899	3.7	3,443,600	$ 145,406	4.2
June	3421650	$ 155,255	4.5	3,472,835	$ 165,471	4.8
Total	34,581,625	1,469,714		32,048,695	$ 1,460,652	
Overall Cents/KWH	4.25			4.56		
Overall % Increase	7.2%					

Estimated $ in CY 2018 Attribuble to Increase in KWH rate $ 98,587

Estimated $ in FY 2018 Attribuble to Increase in KWH rate $ 92,209

POLICY: 30-155

DATE: April 25, 2016

SUBJECT: New Single Large Loads

I. **PURPOSE:**

To set forth the procedure for serving OCEC members with large electrical loads.

II. **TYPE OF SERVICE:** New single or cumulative loads of one (1) megawatt or higher, served by three phase, 60 cycle, at a voltage available and approved by OCEC.

III. **POLICY CONTENT:**

Any single customer ("single large load customer") seeking electrical service (whether a new service or expansion of an existing service), resulting in a use of one (1) megawatt or more in a single month (a "large load"~~-~~) must enter into a separate written power sale agreement with OCEC prior to any ~~the~~OCEC expenditure or investment in new or expanded facilities to serve the large load. ~~provision of such electric service.~~

The separate power sale agreement with the large load customer shall identify terms, rates, and conditions for providing the electrical service and shall address any special provisions applicable to the provision of the electrical service to the particular large load customer. These special provisions may include, by way of example and without limitation, the allocation of specific costs directly to the large load customer that are not allocated to or shared with other OCEC member, such as the loss or reduction of any discount or preferred wholesale rates the OCEC would receive but for the addition of the single large load customer, and any increase in the cost of compliance or monitoring by governmental or regulatory agencies, all as determined by OCEC.

This requirement applies to a "single large load customer" regardless of the number or billing name or names of the metering points resulting in the creation of the large load, and the separate agreement may not be avoided by spreading the large load over multiple metering points or different billing names.

For the purpose of this policy, a "single large load customer" shall include all persons or entities "under common control" that obtain power from the OCEC. "Under common control" shall mean those persons or entities of whatsoever nature (whether trusts, partnerships, corporations, limited liability companies) in which the same individual or individuals directly or indirectly hold more than 50% of the voting or capital or profit and loss interest. For the purpose of calculating ownership of voting, capital or profit and loss, the interests of spouses, domestic partners, siblings and lineal descendants shall be aggregated to determine whether or not the 50% ownership threshold exists.

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The OCEC will not consider any separate power sale agreement until the prospective single large load customer has provided ~~Prior to negotiating a power sales agreement the requesting customer shall provide~~ OCEC with a detailed and verifiable estimate of the electrical power they require.

IV. RESPONSIBILITY:

The General Manager is responsible for implementation of the policy.

~~1~~

ATTESTING:

__________________________________ __________________________________

President **Secretary**

____

Date

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2018 Midyear Financial Assessment

OCEC's financial performance for the first half of 2018 measured against budget is, by most measures, quite robust. The following summarizes the most important financial results.

Operations Results For First Half Of 2018

- 8% above budget KWh usage
- The above budget energy usage resulted in gross margins ~100K (8%) above budget.
- Both "controllable" operations expenses (customer accounts, service, sales, and G&A) and distribution expense were relatively tight to budget; ~$40K (8%)below budget and ~22K (5%) above budget respectively.
- Higher gross margins and lower operating costs resulted in operating margins ~$130K (114%) above budget.
- Debt service coverage, measured by the TIER, is very strong.
- No long term debt was added in the first half year.
- Cash at the end of June was ~$940K, well above both the $450K minimum desirable and the $750K budget target[1]. Refer to Exhibit 3 for detail.

Rate Revenue

Exhibit 2 shows the distribution of revenue by rate component by service category.

- General service categories 1 and 2 generate 80+% of total rate revenue.
- For the customer base as a whole, almost 70% of rate revenue is driven by the per KWh charge. As you can imagine, a prolonged outage would cause a severe financial burden. For example, a 2 week outage in January would reduce rate revenue by ~$250K.
- Comparison of the average per KWh charge between 2018 an 2017 for each service class shows that the new 2018 rate structure did not generate significant per KWh price swings in any of the service classes; a primary objective.

CapEx

Capital expenditures vs the CapEx budget for the first half of 2018 are shown in Exhibit 4.

- At the half year mark transformer purchases are already 33% over budget. This is a potential problem depending on transformer purchases in the second half of 2018. Discussion is needed regarding both the adequacy of existing inventory and better projections through the end of the year.
- The regulator rebuild at the substation is 50% over budget. How come?
- Pole and transformer replacements are 38% over the annual budget.
- The above 3 items are a combined $75K over their combined annual budget.

[1] Budgeted cash position assumes no change in accounts payable and accounts receivable levels. That's a pretty coarse grain assumption but probably the best we can make.

Exhibit 1: Operations statement, actual to budget for 2018 first half year

	2018 jan-jun actual	**2018 jan-jun budget**	**actual to budget $**	**actual to budget %**
MWh sold + OCEC usage	**29,807**	**27,622**	2,185	8%
Operating Revenue	$2,910,442	$2,719,491	$190,951	7%
Cost of Purchased Power (555 - 567)	$1,455,939	$1,372,400	$83,539	6%
Gross Margins	$1,454,503	$1,347,091	$107,412	8%
total "controllable" expense	$456,863	$496,302	-$39,439	-8%
total of distribution expense	$375,162	$357,429	$17,733	5%
Total O&M Expense excluding Purchased Power	$832,025	$853,731	-$21,706	-3%
Depreciation, Interest and Tax	$406,454	$406,536	-$82	0%
Total Cost of Electric Service (O&M including COP and depreciation/interest/tax)	$2,694,418	$2,632,667	$61,751	2%
Operating Margins	$216,024	$86,824	$129,200	149%
Non operating margins	$22,051	$24,645	-$2,594	-11%
Patronage Capital or operating+non operating Margins	$238,075	$111,469	$126,606	114%
KRTA #7 TIER (excludes non operating margin)	3.12	1.86		

OCEC 2018 rate revenue by service class HALF YEAR vs 2017 for same period

Usage class	Rate Component	2018 HALF YEAR	2017 HALF YEAR	2018 % of OCEC total	2017 % of OCEC total
General service 1 (G1)					
	KWh sold	8,066,732	9,892,107	27%	31%
	Base charge	$434,874	$453,958	52%	57%
	KWh charge	$645,338	$791,368	33%	37%
	Demand charge	$0	$0	0%	0%
	Total revenue	$1,080,212	$1,245,326	38%	42%
	avg # meters	2,270	2,333	65%	68%
	average monthly bill	$79.31	$88.95		
	average cost/KWh	$0.134	$0.126		
General service 2 (G2)					
	KWh sold	13,474,350	14,052,217	45%	44%
	Base charge	$343,720	$292,450	41%	37%
	KWh charge	$904,360	$932,052	46%	44%
	Demand charge	$0	$0	0%	0%
	Total revenue	$1,248,080	$1,224,502	44%	41%
	avg # meters	1,102	975	31%	28%
	average monthly bill	$188.82	$209.35		
	average cost/KWh	$0.093	$0.087		
General service 3 (G3)					
	KWh sold	3,579,916	3,391,408	12%	11%
	Base charge	$26,474	$21,660	3%	3%
	KWh charge	$178,996	$162,788	9%	8%
	Demand charge	$39,328	$38,138	50%	46%
	Total revenue	$244,798	$222,585	9%	7%
	avg # meters	71	60	2%	2%
	average monthly bill	$573.30	$616.58		
	average cost/KWh	$0.068	$0.066		
General service 4 (G4)					
	KWh sold	4,106,260	4,436,220	14%	14%
	Base charge	$10,050	$9,570	1%	1%
	KWh charge	$197,100	$208,502	10%	10%
	Demand charge	$33,251	$38,834	42%	47%
	Total revenue	$240,402	$256,907	8%	9%
	avg # meters	11	11	0%	0%
	average monthly bill	$3,588.09	$3,892.53		
	average cost/KWh	$0.059	$0.058		
irrigation					
	KWh sold	533,302	424,219	2%	1%
	Base charge	$19,486	$19,309	2%	2%
	KWh charge	$26,665	$20,787	1%	1%
	Demand charge	$6,625	$6,495	8%	8%
	Total revenue	$52,777	$46,591	2%	2%
	avg # meters (active months)	188	186	5%	5%
	average cost/KWh	$0.10	$0.11		
TOTALS (excludes idle meters)	KWh sold	29,760,560	32,196,171		
	avg # meters	3,517	3,441		
	Base charge	$834,604	$796,947	29%	27%
	KWh charge	$1,952,460	$2,115,497	68%	71%
	Demand charge	$79,205	$83,467	3%	3%
	Total revenue	$2,866,269	$2,995,910	100%	100%
	average revenue/KWh sold	$0.0963	$0.0931		
	power cost for half year	$1,460,652	$1,469,714		
	gross margin/KWh SOLD	$0.0472	$0.0474		

Cash categories -- 2018 first half actual vs 2018 budget

Exhibit 3

Key cash categories					
Summary category			significant components in category		
	2018 actual first half year	original budget first half year		2018 actual first half year	2018 budget first half year
Total (Funds From Operations)	$429,002	$281,599			
			Patronage Capital or Margins	$238,075	$84,259
			Plus Depreciation Expense	$190,944	$197,340
(Increase)/Decrease in Operating Assets	$423,889	$346,404			
			Special Deposit	-$38,449	-$38,448
			Accounts Receivable - Sale of Energy (Net	$394,000	$329,619
			Accounts Receivable - Other (Net)	$86,190	$55,233
			Prepayments	-$17,852	$0
Increase/(Decrease) in Operating Liabilities	-$132,813	$0			
			Accounts Payable	-$100,081	$0
			Other Deferred Credits	-$45,076	$0
			Other Current and Accrued Liabilities	$12,344	$0
TOTAL CASH FROM OPERATING ACTIVITIES	$720,078	$628,003			
CASH FROM INVESTMENT ACTIVITIES	-$285,206	-$381,515			
			Total Utility Plant	-$349,474	-$505,193
			Cost to Retire Utility Plant	-$9,972	$0
			Construction Work-in-Progress	-$138,130	$0
			Contributions in aid of construction (CIAC	$227,137	$123,678
			Materials & Supplies - Electric and Other	-$14,705	$0
CASH FROM FINANCING ACTIVITIES	-$65,280	-$65,123			
			LT Debt - Debt Service Payment	-$65,123	-$65,123

CASH FROM ALL ACTIVITIES	$369,592	$181,365
TOTAL CASH BEGINNING OF PERIOD	$570,393	$570,393
TOTAL CASH END OF PERIOD	$939,985	$751,758

Exhibit 4

YTD CAPITAL+ BUDGET IN REMAINING MONTHS ARRANGED FOR 4 YEAR PLAN LAYOUT

	2018 actual Jan-Jun	**2018 budget**	**over/under budget**	**% of budget used**
Members Requested Facilities (CIAC)	82,391	200,983	-118,592	41%
Replacements (Pole and Transformers)	142,925	103,872	39,053	138%
Misc. URD/OH Replacement Projects	0	62,675	-62,675	0%
Replace 2500' of URD at Stud Horse - Part 2	0	49,718	-49,718	0%
Replace 2500' of URD at Edelweiss - Part 1	0	57,957	-57,957	0%
Convert 3500' ofOH to URD at Bear Creek	0	41,859	-41,859	0%
Replace 3000' of URD at Davis Lakes	17,674	50,718	-33,044	35%
Metering projects-upgrades	0		0	
Pole Inspections	3,092	10,000	-6,908	31%
Fire Retardant/Treatment on Poles	0	17,479	-17,479	0%
Test/Rebuild 2 sets of Regulators at Sub	48,453	32,791	15,662	148%
Paint/protect crew hallway	0	5,000	-5,000	0%
Redo Asphalt, fix drain - Carryover	0	25,000	-25,000	0%
Major Storm Damage	12,748	0	12,748	
Misc Tools	0	0	0	
Meter Purchases/ Software	21,180	20,000	1,180	106%
Transformer Purchases	92,935	70,000	22,935	133%
computer & software upgrades	7,200	13,000	-5,800	55%
Vehicle Replacements	0	135,000	-135,000	0%
subtotal for capital line work	307,283	658,052	-350,769	47%
Total Capital Budget	428,598	896,052		
unallocated overhead (not cumulative, show value in current month's cell)				
CIAC Collected (member CIAC on report)	227,137	277,356	-50,219	82%
Total Capital Budget less CIAC	502,450	618,696	-116,246	81%

National Rural Utilities Cooperative Finance Corporation

Created and Owned by America's Electric Cooperative Network

CFC KRTA

YOUR KEY RATIO TREND ANALYSIS

Introductions and Definitions

An Introduction to Key Ratio Trend Analysis

The Key Ratio Trend Analysis (KRTA) is a tool to help managers and board members comprehend a complete picture of their system's performance. CFC developed the KRTA in 1975 to analyze distribution system operations, highlight strengths and weaknesses, help gauge past and present performance, and to support predictions of future performance. It should be interpreted by reference to financial statements, year-end operating reports, CPA audits and other relevant operating information.

Data Gathering

Data used to generate the KRTA comes from the RUS and CFC Form 7. CFC provides a KRTA input package (Form 7) on its Web site each December. All distribution cooperatives are welcome to provide data and receive a KRTA regardless of their membership status with CFC. A major determinant of CFC's schedule for producing and distributing the report is how quickly the member cooperatives are able to complete and provide their calendar year-end financial data (Form 7).

Finished Product

Once the results are compiled, cooperative staff can access their system's KRTA through CFC's Extranet; reports may be viewed online or downloaded in an Excel format for individual cooperative use.

Report Types

The makeup of the electric distribution systems is evolving as quickly as the electric industry in general. Therefore, to meet the changing needs of electric distribution systems, CFC has produced derivatives of the standard, or national KRTA. For example, an annual "Independent" KRTA is created, including and comparing only those systems that have exited the government-lending program; it is a subset in addition to the standard, or national, report.

Types of Ratios

The KRTA shows the absolute and relative position as well as trends of each distribution system in 145 key financial and statistical ratios. Its ratios are displayed from two viewpoints:

1. It shows individual system trends for the most recent five years, and
2. It shows a comparison of each system's ratios relative to five peer groups:

    Nationally For each ratio, the KRTA shows the median value for all distribution cooperatives nationally and shows where an individual cooperative ranks in a national listing. This gives a cooperative the "big picture" of how it compares nationally.

For each of the peer groups, the system rankings are always displayed from high to low. So, if a system is ranked #8 for TIER ratio in the state listing, that means that seven systems in the state have higher TIER ratios.

The KRTA ratio definitions explain the specific ratios and considerations associated with ratio rankings.

State The KRTA shows the median value for all of the distribution cooperatives in a state, and it shows where a system ranks within the state grouping.

Consumer Size The KRTA shows the median value for all of the distribution cooperatives nationally in a consumer size group, and it shows rankings within that group.

Major Current Power Supplier The KRTA shows the median value for all of the distribution cooperatives that are served by a power supplier and a system's ranking in that group.

If a power supplier serves a multi-state area, the KRTA will compare a particular ratio value on a regional basis.

Plant Growth The KRTA shows the median value for all of the distribution cooperatives in the nation with a similar five-year rate of growth in total utility plant and it shows a system's ranking within that grouping.

Interpreting the Ratios

Ratio analysis must be supplemented with knowledge of the particular system and any extraordinary events that may have had an impact on a certain ratio. System staff should consider whether any unusual events may have occurred during the year, which could affect a particular ratio, such as a wet spring, snow storm, an ice storm, flooding or a one-time expense charge-off.

The interpretation of a ratio's significance will often depend on many factors including:

- financial goals;
- peculiar operating characteristics; and,
- the geographic and socio-economic characteristics of the service territory.

Whether a system's ratios are "desirable" or not is dependent upon the ratio value itself and the specific operating characteristics of the system. A very high or low ratio could result from a unique one-time system event. A multi-year trend in a particular ratio, such as a dwindling TIER, may indicate the need to increase rates or face the prospect of eventual mortgage default.

Ratio Definitions

BASE RATIOS

Ratio 1 Average Total Consumers Served

This value is represented as a number, not a ratio. It represents the measurement of the average number of consumers receiving service during the year reported. For purposes of this report, "average total consumers" is defined as the sum of total consumers in January plus total consumers in December divided by two.

Ratio 2 Total KWH Sold (1,000)

This value is represented as a number, not a ratio. It is a measurement of total kwh sales, in mwh, at December 31 of the reporting year. The total amount of kwh sold is related to the types and volume of loads served (i.e., residential or commercial) and consumer density.

Ratio 3 Total Utility Plant (TUP) ($1,000)

This is represented as a number, not a ratio, expressed in thousands of dollars, indicating the size of the utility plant.

TUP consists of all distribution, general, headquarters, intangible plant, transmission and all other utility plant. Along with electric plant in service, TUP includes electric plant purchased, sold or leased to others, other utility plant, nuclear fuel items and all incomplete construction work that is under way by cooperative staff or contractors, including expenditures on research, development and demonstration projects for construction of utility facilities.

Ratio 4 Total Number of Employees (Full-Time)

This value is a number, not a ratio, representing the total number of full-time employees at the cooperative as of December 31.

Analysis of this ratio allows the cooperative to identify opportunities to hire contract staff for large projects to prevent carrying more employees on the payroll than needed for normal system operations.

Ratio 5 Total Miles of Line

This value is a number, not a ratio, representing total miles of transmission, overhead and underground miles energized as of December 31.

A transmission line is a line serving as a source of supply to a point where the voltage is transformed to a voltage used for distribution purposes. Distribution lines are those that deliver electric energy from the substation or metering point to the point of attachment to the consumer's wiring and include primary, secondary and service facilities.

FINANCIAL RATIOS

Ratio 6 TIER (Times Interest Earned Ratio)

TIER is a measurement of the system's annual ability to earn margins sufficient to cover the interest expense on long-term debt. TIER is a primary indicator of a utility's financial health to lending institutions. A TIER of greater than 1.0 indicates that a system is generating revenues sufficient to cover its long-term interest expense 1.0 plus times. A TIER of 1.0 indicates payment of interest with no margins left for financing new projects. A TIER of less than 1.0 indicates a system could not pay its interest from margins earned after deducting expenses before interest. A negative TIER indicates borrowed funds are needed to pay all of the interest and some part of operating expenses for that year. A very high TIER value indicates that the system has very little long-term debt resulting in low long-term interest costs.

The RUS loan contract generally requires a borrower maintain a specified TIER ratio. The CFC loan contract no longer has a TIER requirement. CFC requires a modified debt service coverage ratio.

Ratio 7 TIER (2 of 3-year High Average)

An extension of TIER, generally found in an RUS loan contract. The requirement is generally to achieve a specified average for the two highest TIER ratios of the three most current years.

Ratio 8 Operating TIER (OTIER)

A measure of the cooperative's ability to generate sufficient revenues from electric operations to repay the interest on its long-term debt.

Ratio 9 Operating TIER (2 of 3-year High Average)

This ratio is an extension of OTIER. The requirement is generally to achieve a specified average for the two highest OTIER ratios of the three most current years. A variation of this ratio may be found in an RUS loan contract.

A low ratio could indicate the cooperative is losing money on its electric operations. A high ratio could mean the cooperative has little long-term debt resulting in low long-term interest costs.

Ratio 10 MDSC (Modified Debt Service Coverage)

Like DSC, MDSC is a measurement of a system's ability to generate sufficient operating funds to cover its cash requirements, but adjusted to eliminate non-cash amounts that are included in margins—such as G&T capital credit allocations to a distribution cooperative—for the true cash impact of non-operating margins of its long-term total debt service (principal and interest) on an annual basis. The non-cash expense of depreciation and amortization expenses is taken into consideration as a cash generator. A ratio value of 1.0 indicates the system generated only enough cash to cover its principal and interest payments (total debt service) on its long-term debt for the year. The CFC loan contract requires a MDSC of 1.35 for the best two of the last three years.

Ratio 11 MDSC (Modified Debt Service Coverage) (2 of 3-year High Average)

An extension of MDSC, generally found in a CFC loan contract. The requirement is to achieve a specified average value using the two highest MDSC ratios of the three most current years. The average value is generally used to determine loan covenant compliance requirements as well as to determine potential eligibility for long-term interest rate discounts associated with some CFC long-term loans.

Ratio 12 DSC (Debt Service Coverage)

Debt Service Coverage (DSC) is a measurement of the system's ability to generate sufficient funds to cover the cash requirements of its long-term debt service (principal and interest) on an annual basis. The non-cash expense of depreciation and amortization expenses is taken into consideration as a cash generator. A ratio value of 1.0 indicates that the system generated only enough cash to cover its principal and interest payments (total debt service) on its long-term debt.

The RUS loan contract generally requires a borrower to maintain a specified DSC level. The CFC loan contract no longer has a DSC requirement as defined in this ratio.

Ratio 13 DSC (Debt Service Coverage) (2 of 3-year High Average)

An extension of DSC, generally found in an RUS loan contract. The requirement is generally to achieve a specified average for the two highest DSC ratios of the three most current years.

Ratio 14 ODSC (Operating DSC)

A financial coverage ratio indicating the cooperative's ability to generate sufficient operating margins, excluding G&T and other capital credit allocations, to cover the annual debt service payments on its total long-term principal and interest due.

A low ratio could indicate the cooperative is generating low margins and/or financing most of its plant additions with debt. A high ratio could indicate the cooperative is generating adequate margins and/or financing a significant portion of its plant additions with its own funds.

Ratio 15 ODSC (Operating DSC) (2 of 3-year High Average)

An extension of ODSC, generally found in an RUS loan contract. The requirement is generally to achieve a specified average of the two highest ODSC ratios of the three most current years.

Ratio 16 Equity Level as a Percentage of Assets

Measures the extent to which the cooperative's consumers have financed plant and other assets with their own funds, as distinguished from assets that were financed with borrowed capital. Equity represents the percent of total assets the member actually owns. It is an indicator to the member of his/her ability to recover principal investment should the utility system default on its loans.

A high equity ratio is an indication that the system has financed plant additions primarily with internally generated funds over the years. A low ratio could indicate that the cooperative has utilized long-term debt capital to finance most of its plant additions and replacements.

Ratio 17 Distribution Equity (Excludes Equity in Assoc. Org.–Pat. Cap.)

Identifies that portion of the member's equity, invested in the assets of the core business, that has come from cash the system has generated either from borrowings or member rates. This equity is exclusive of non-cash patronage capital allocated by associated organizations such as CFC, the cooperative's G&T or data vender.

Ratio 18 Equity Level as a Percentage of Total Capitalization

This ratio is similar to Ratio 16 without the influence of the change in current assets and current liability balances. This ratio represents the percent of total capitalization (debt and equity) that members own. Since current assets/liabilities is ignored, permanent long-term growth is better expressed in this ratio.

LONG-TERM DEBT RATIOS

Ratio 19 Long-term Debt as a Percentage of Total Assets

Ratio 20 Long-term Debt to KWH Sold (Mills)

Ratio 21 Long-term Debt Per Consumer ($)

Ratio 19 measures the portion of assets that are financed with debt as opposed to internally generated funds. The ratio includes all long-term debt used to finance plant in service.

A high ratio could indicate greater risk for the lender. A cooperative's access to outside financing could be limited because equity is a primary criterion outside lenders evaluate when considering loans. High debt indicates financial ratios, such a TIER, DSC and MDSC could be much more difficult to meet.

Ratio 20 measures the portion of each kwh sold funded by long-term debt.

Ratio 21 measures each member's share of the cooperative's long-term debt obligation. The higher the debt ratio, the greater sales and revenues required to service the debt.

Ratio 22 Non-government Debt as a Percentage of Total Long-term Debt

Measures non-government debt to total long-term debt. Since 1973, most borrowers were required by RUS to obtain a portion of their long-term debt capital from non-government sources. Plant expansion since that time has resulted in a higher non-RUS debt ratio. Most systems that borrow concurrently from RUS and supplemental lenders borrow 30 percent of their long-term debt capital needs from non-RUS lenders. The supplemental percentage is based on an RUS ratio of total utility plant to total system revenues (plant revenue ratio—PRR). If the PRR is less than 8.0, the system is required to obtain 30 percent of its financing from supplemental sources. Systems that have bought out their RUS notes will have a 100-percent ratio value.

This ratio was modified for 2004 calculations to exclude Federal Financing Bank (FFB) debt as a non-government lending source.

Ratio 23 Blended Interest Rate

This ratio measures the cost of long-term borrowed funds, both RUS and/or supplemental funds. This ratio shows the blended cost of long-term debt, and is weighted to reflect the respective amounts of long-term debt at each interest rate. A very low value probably indicates that the system has financed plant additions using the RUS hardship rate or 100-percent municipal rate financing.

This blended interest rate does not reflect any lender capital credits distributions that may be available to a utility that would result in a reduced net blended rate.

Ratio 24 Annual Capital Credits Retired Per Total Equity (%)

Indicates the portion of a system's total equity that is being returned to the members as patronage capital. Retirement of patronage capital to members is one of the seven cooperative principles generally followed by all types of cooperatives. Regular retirement of capital credits provides evidence to the membership that the cooperative seeks to furnish electric and other services "at or slightly above cost," unlike most "for profit" utilities.

Cooperative systems are generally required by the IRS to allocate patronage capital to members' accounts based on electric usage for each year or risk losing federal tax-exempt status. There are many methodologies for retiring patronage capital to members, including percentage retirements to current members used by many suburban (higher consumer turnover) systems; first-in, first-out retirements of capital based on a board-approved rotation cycle; and discounting methods used for decedent estates.

Ratio 25 Long-term Interest as a Percentage of Revenue

This ratio measures the percentage of a system's total annual revenue that is required to meet interest expense on all long-term debt. Systems with high equity would typically show a lower value in this ratio because they have financed most of their plant additions with equity capital instead of long-term debt capital.

Ratio 26 Cumulative Patronage Capital Retired to Total Patronage Capital (%)

A measure of all patronage capital retired over time to a cooperative's members as a percentage of total patronage capital (total margins and equities) currently on the cooperative's books. It is a reflection of the overall philosophy of the cooperatives toward the retirement of capital credits. Most cooperatives operate under established bylaws that define the contract between the cooperative and the members for the retirement of patronage capital. It is highly recommended that the cooperative develop board policies on equity development, including policies for the retirement of capital. Cooperatives are encouraged to retire patronage capital by one of several recommended methods: a) First-In, First-Out, b) Last-In, First-Out, c) Percentage Method, or d) a combination of the above.

A retirement of capital credits is legally made when the board passes a resolution to retire and the board action is funded through an accounting entry setting up the retirement as accounts payable regardless of when the patronage capital is actually paid to the patrons.

Ratio 27 Rate of Return on Equity

A measurement of the cost of equity to the system as compared to total equity dollars in the system. A proper return is generally a function of the system's rate of growth (in total capitalization), its capital credits rotation cycle and its TIER goals.

Ratio 28 Rate of Return on Total Capitalization

A measurement of the system's annual ability, as a percent of total capitalization (sum of debt and equity on the Balance Sheet), to cover the cost of equity (margins and debt interest). The lower this ratio can be kept and still achieve the necessary financial ratios to maintain financial stability, the more cost-effective the system is in balancing its debt and equity dollars.

The composite cost of debt and equity make up the total cost of capital. This total cost of capital can be managed by maintaining the proper mix of debt and equity. When the cost of debt is less than the cost of equity, you would want to use as much debt as possible and still be able to maintain a stable financial picture to the lender. If the cost of equity is less than the cost of debt, you would want to use as much equity as possible, consistent with the goals set forth in your system's equity management plan.

Ratio 29 Current Ratio

A measure of short-term solvency. Current assets include cash, temporary investments, accounts receivable and inventory. Current liabilities include notes and accounts payable, current maturities, consumer deposits and other accrued expenses. A current ratio of less than 1.0 may indicate a cash flow problem, depending on turnovers of various current assets and liabilities. A ratio of between 1.5 and 2.0 is generally considered adequate for most operations.

Ratio 30 General Funds Per TUP (%)

A measure of general funds available to meet the cash needs and construction activity of the cooperative at a point in time. General funds levels can fluctuate during the year. Cooperatives are encouraged to develop monthly cash flow analyses to identify seasonal cash shortages, scheduled debt payments, capital credit retirements, etc. An appropriate general funds level depends on the size of the system, cash needs and construction activity.

Ratio 31 Plant Revenue Ratio (PRR) (One Year)

A measure of the relative productivity of the cooperative's plant. PRR indicates a cooperative's ability to generate revenues relative to the physical plant investment that it has made. A high ratio could indicate the cooperative is not generating adequate margins relative to the cost of plant investment. A low ratio could reflect the fact that investment in plant and revenues received are reasonable.

Ratio 32 Investment in Subsidiaries to Total Assets (%)

A measure of the cooperative's investment in, and ownership of, subsidiary business(es) relative to the cooperative's total assets. A high ratio is an indication of the magnitude of non-electric business ownership. A low, or no ratio, indicates the cooperative has little or no investments in subsidiary businesses.

TOTAL OPERATING REVENUE RATIOS

Ratio 33 Total Operating Revenue Per KWH Sold (Mills)

Ratio 34 Total Operating Revenue Per TUP Investment (Cents)

Ratio 35 Total Operating Revenue Per Consumer ($)

Ratio 33 measures all revenues generated from the total operations of the system on a per-kwh-sold basis. This ratio includes revenues generated from all cooperative operations, both electric and non-electric. A high value could indicate either high revenues or low kwh sales for that year.

Ratio 34 measures all revenues generated from each consumer classification and other electric and non-electric revenue sources of the cooperative per dollar of total utility plant investment.

Ratio 35 measures each member's contribution to revenues generated from all consumer classes and other electric and non-electric revenue sources of the cooperative.

Ratio 36 Electric Revenue Per KWH Sold (Mills)

A measure of the revenue generated from the sale of electric energy on a per-kwh-sold basis.

High or low values for ratios 33, 38 and 39 could indicate high revenues received by the system or it could indicate low kwh sales for that year, which would inflate the ratio value. The difference between Ratio 33 and Ratio 36 is the revenue generated by non-energy sources of operations on a per-kwh-sold basis.

Ratio 37 Electric Revenue Per Consumer ($)

A measure of the revenue generated from the sale of electric energy on a per-consumer basis. High or low values could indicate high revenues received by the system or it could indicate low kwh sales for that year, which would distort the ratio value.

REVENUE PER KWH SOLD RATIOS

Ratio 38 Residential Revenue Per KWH Sold (Mills)

Ratio 39 Non-residential Revenue Per KWH Sold (Mills)

Ratio 40 Seasonal Revenue Per KWH Sold (Mills)

Ratio 41 Irrigation Revenue Per KWH Sold (Mills)

Ratio 42 Small Commercial Revenue Per KWH Sold (Mills)

Ratio 43 Large Commercial Revenue Per KWH Sold (Mills)

Ratio 44 Sales for Resale Revenue Per KWH Sold (Mills)

Ratio 45 Street & Highway Lighting Revenue Per KWH Sold (Mills)

Ratio 46 Other Sales to Public Authorities Revenue Per KWH Sold (Mills)

Ratio 38 measures the revenue-generating capability of a system's residential rate structure(s). High values could indicate primarily residential loads and minor commercial and irrigation loads. Many cooperatives do cost-of-service studies to equitably allocate costs to various rate classes.

Ratio 39 measures the revenue-generating capability of a system's non-residential loads. Commercial and industrial loads can greatly affect the system's overall load factor (the percentage of a system's facilities that are fully utilized shown on a daily, monthly or annual basis).

Ratios 38 and 39 together can indicate whether the system's rate structures are properly distributing costs proportionally between residential users and non-residential users.

Ratios 40-46 measure the revenue-generating capability of a system's various seasonal rate classes. For example, a high Ratio 40 could indicate a significant seasonal load, while a low ratio indicates little or no seasonal activity in the cooperative's territory.

Ratio 41 can be somewhat volatile following weather patterns each year. A high ratio generally indicates a significant lack of rain or other weather-related extreme in the area while a low ratio will result from a wet weather pattern.

Ratio 41 is a measurement of the revenue-generating capability of a system's small commercial and industrial (less than 1,000 kwh) rate class. A low ratio could indicate little small commercial activity or a loss of small commercial loads. A high ratio could indicate growth in small commercial loads in the service territory.

A low Ratio 43 could indicate little large commercial activity or a loss of one or more large commercial loads (greater than 1,000 kwh). A high ratio could indicate growth in large commercial loads in the service territory.

Ratio 44 indicates the revenue-generating capability of a system's sales to other electric utilities (both RUS and non-RUS borrowing cooperatives) or to public authorities for resale. A low ratio is indicative of little if any sales for resale to others. A high ratio indicates excess capacity that can be resold.

A system's sales of electricity for lighting streets, highways, parks and other public places or for traffic or signal system service for municipalities or other divisions or agencies of state or federal governments are reflected in Ratio 45.

OPERATING-MARGINS RATIOS

Ratio 47 Operating Margins Per KWH Sold (Mills)

Ratio 48 Operating Margins Per Consumer ($)

Ratio 47 indicates the operating margins resulting from the sale of electricity to the members. This ratio indicates the margins generated on a per-kwh-sold basis without the effects of G&T capital credits or income from equity investments in subsidiary organizations, among other items below the operating margins line. This is a measure of the margins that represent "real" cash to the system.

Ratio 48 is a measure of the operating margins received per consumer resulting from the sale of electricity. A low ratio would indicate the need to evaluate an adjustment to the rate structure or fuel adjustment to meet an increased cost of providing service.

NON-OPERATING-MARGINS RATIOS

Ratio 49 Non-operating Margins Per KWH Sold (Mills)

Ratio 50 Non-operating Margins Per Consumer ($)

Both 49 and 50 measure non-operating margins resulting from non-operating interest and other margins, margins from equity investments and extraordinary items. A high ratio indicates a substantial portion of the utility's total net margins are being generated from services other than the provision of electric service, measured on a per-kwh-sold basis.

TOTAL MARGINS LESS ALLOCATIONS RATIOS

Ratio 51 Total Margins Less Allocations Per KWH Sold (Mills)

Ratio 52 Total Margins Less Allocations Per Consumer ($)

A measurement of total operating margins resulting from the sale of electricity to the members. These ratios indicate the margins generated on, respectively, a per-kwh-sold basis (Ratio 51) and per consumer (Ratio 52), without the effects of G&T and other patronage capital credits. This is a measure of "real" cash to the system.

Ratio 53 Income (Loss) From Equity Investments Per Consumer ($)

A measure of the income or loss from distribution cooperative investments in subsidiary companies per consumer. A low or negative ratio value may indicate the need to re-evaluate current subsidiary business activity and evaluation of an exit plan. A high ratio generally indicates a successful subsidiary business venture.

ASSOCIATED ORGANIZATION'S CAPITAL CREDITS RATIOS

Ratio 54 Associated Organization's Capital Credits Per KWH Sold (Mills)

Ratio 55 Associated Organization's Capital Credits Per Consumer ($)

These ratios measure the portion of a system's costs that is supporting equity contributions to associated organization(s) shown respectively, on a per-kwh-sold basis (Ratio 54) and per consumer (Ratio 55). These allocations generally include CFC, the utility's G&T, and statewide and other cooperative-provided services.

TOTAL MARGINS RATIOS

Ratio 56 Total Margins Per KWH Sold (Mills)

Ratio 57 Total Margins Per Consumer ($)

Ratios 56 and 57 measure revenue received over and above the total cost of providing electric service, either from the sale of electricity or non-operating sources such as interest income and non-cash items such as G&T and other capital credit allocations.

High ratios could indicate that rates are higher than necessary or that the G&T capital credit allocations or other investment income is very high relative to the number of consumers. A low ratio could indicate margins inadequate to meet TIER requirements or the equity goals of the cooperative.

Ratio 58 A/R Over 60 Days as a Percentage of Operating Revenue

A measure of credit problems and accounting practices. Since, over time, past-due electric bills from consumers become more difficult to collect, the larger this ratio, the greater chance for a loss or eventual write-off. A higher ratio may indicate that uncollectable accounts are not written off in a timely manner, or a need for a more aggressive board policy on collections. The stability of the membership as well as the general economy are also issues of consideration in evaluating the ratio ranking.

Ratio 59 Amount Written Off as a Percentage of Operating Revenue

A measure of the percentage of electric billings that is related to consumer accounts that cannot be collected. Most systems lave a board policy covering write-offs.

Ratio 60 Total MWH Sold Per Mile of Line

Lower ratio values may indicate difficulty in meeting fixed costs, indicating a need for higher rates to meet fixed costs. Very low mwh sales per mile of line accompanied by growing equity, can maintain healthy financial ratios. In general, higher mwh sales per mile result in lower line loss, indicating a more compact service territory or a higher saturation of large commercial loads. A low ratio could indicate a more sparsely settled service territory or an area with few or no large commercial loads.

AVERAGE KWH USAGE PER MONTH RATIOS

Ratio 61 Average Residential KWH Usage Per Month

Ratio 62 Average Seasonal KWH Usage Per Month

Ratio 63 Average Irrigation KWH Usage Per Month

Ratio 64 Average Small Commercial KWH Usage Per Month

Ratio 65 Average Large Commercial KWH Usage Per Month

Ratio 66 Average Street & Highway Lighting KWH Usage Per Month

Ratio 67 Average Sales for Resale KWH Usage Per Month

Ratio 68 Average Sales to Public Authorities KWH Usage Per Month

Ratios 61-68 are helpful in showing usage patterns of different ratepayer classes. Residential usage could be expected to be lower in northern or mountainous service areas, where cooler summer weather is normal and where electric heat saturation is low.

Ratio 62 is measure of seasonal usage patterns, if any. A high ratio could indicate substantial recreational or vacation loads that could introduce noticeable fluctuations in the system's overall usage pattern.

Ratio 63 is a measure of irrigation usage patterns. A high ratio could indicate a long growing season due to inadequate rainfall.

Ratio 64 is a measure of usage patterns of commercial loads of less than 1,000 kva per month.

Rate 65 is a measure of usage patterns of commercial loads of more than 1,000 kva per month.

Rate 66 is a measure of streetlight and highway lighting usage patterns per month. This ratio should not include installation of photo-electric controlled lighting equipment, often referred to as security or yard lights.

Rate 67 is a measure of monthly kwh sales for resale to both RUS borrowers and others.

Rate 68 is a measure of monthly kwh sales to public authorities.

KWH SOLD PER TOTAL KWH SOLD RATIOS

Ratio 69 Residential KWH Sold Per Total KWH Sold (%)

Ratio 70 Seasonal KWH Sold Per Total KWH Sold (%)

Ratio 71 Irrigation KWH Sold Per Total KWH Sold (%)

Ratio 72 Small Commercial KWH Sold Per Total KWH Sold (%)

Ratio 73 Large Commercial KWH Sold Per Total KWH Sold (%)

Ratio 74 Street & Highway Lighting KWH Sold Per Total KWH Sold (%)

Ratio 75 Sales for Resale Per Total KWH Sold (%)

Ratio 76 Sales to Public Authorities Per Total KWH Sold (%)

Ratios 69-76 measure kwh sales by rate class to total energy sales for the year.

A high Ratio 69 is an indication of a concentration of residential consumer load and tends to result in a stable sales volume each year. A low ratio indicates the cooperative's primary load is not residential and is highly dependent upon large and small commercial loads.

A high Ratio 70 could indicate substantial recreation or vacation property loads that could introduce noticeable fluctuations in the system's overall usage pattern.

Ratio 71 may swing significantly based on weather patterns year to year.

A low Ratio 73 indicates limited large commercial loads in the service territory. A high ratio indicates a substantial portion of the cooperative's load is tied to the large commercial class. Care should be taken to monitor the needs and growth of large commercial loads.

Ratios 74-76 are generally going to be small, as they make up a minor portion of a cooperative's load.

O&M EXPENSES RATIOS

Ratio 77 O&M Expenses Per KWH Sold (Mills)

Ratio 78 O&M Expenses Per Dollar of Total Utility Plant (Mills)

Ratio 79 O&M Expenses Per Consumer

Ratio 77 is a measure of the system's cost of operations and maintenance per each kwh sold. This is one expense area over which a system has significant control. A high value for a year may be due to lower-than-normal kwh sales for that year or extraordinary expenses related to a storm.

Larger utility plants require larger expenditures for the operation and maintenance of plant. Ratio 78 looks at expenses in relation to the size of utility plant, providing a comparative value regardless of plant size. Systems in heavily forested, mountainous or coastal areas could be expected to spend greater amounts on normal maintenance of the system. Right-of-way clearing expense can be a very large expense to systems located in heavily wooded areas.

Ratio 79 is a measure of the system's cost of operations and maintenance per consumer. This is one expense area over which a system has significant control.

Ratio 80 Consumer Accounting Expenses Per KWH Sold (Mills)

The ratio indicates the system's cost of accounting functions on a kwh-sold basis. This is another area of potentially controllable expenses.

Ratio 81 Consumer Accounting Expenses Per Consumer ($)

As the number of consumers per system goes up, the accounting expenses per consumer generally comes down. The basic accounting costs: computers, billing machines, postage meters, etc. are spread over a larger base of consumers with relatively little change in dollar expenditures.

Ratio 82 Customer Sales and Service Expense Per KWH Sold (Mills)

This ratio shows the expense allocation on each kwh sold that is contributed to Consumer Services & Information and general Sales Expense.

Ratio 83 Customer Sales and Service Expense Per Consumer ($)

This ratio indicates the cost to each consumer for Consumer Service & Information and General Sales Expense.

Ratio 84 A&G Expenses Per KWH Sold (Mills)

A measurement of the Administrative and General expenses, not specifically provided for in other accounts, on a per-kwh-sold basis. A&G expenses include employees' salaries and bonuses, office supplies, property and casualty insurance, employee pension and benefits, and board and trust expenses. A&G expenses are overhead expenses that cannot be charged to specific plant work orders or to plant operation and maintenance.

Ratio 85 A&G Expenses Per Consumer

This is a measurement of the cost of Administrative and General Expenses to each consumer. Small systems tend to have higher per-consumer A&G expenses because the smaller consumer base provides fewer consumers over which to spread certain administrative costs common to all systems. A high ratio in a particular year could also mean that the cooperative should evaluate its staffing and consulting services.

Ratio 86 Total Controllable Expenses Per KWH Sold (Mills)

A measure of the total controllable expenses on a kwh-sold basis. Controllable expenses include O&M, A&G, consumer accounts and service and information expenses, and sales expense. A high ratio could indicate the need to evaluate these expense categories for possible efficiencies.

Ratios 86 and 103 represent alternative ways to achieve the same information under different groupings.

Ratio 87 Total Controllable Expenses Per Consumer

A measure of the total controllable expenses on a per-consumer basis. Controllable expenses include O&M, A&G, consumer accounts and service and information expenses, and sales expense.

Ratios 87 and 104 represent alternative ways to achieve the same information under different groupings.

POWER COST PER KWH RATIOS

Ratio 88 Power Cost Per KWH Purchased (Mills)

Ratio 89 Power Cost Per KWH Sold (Mills)

These ratios show the average cost of each kwh, respectively, the system purchased and actually sold. Power costs can vary significantly from one power supplier to the next causing a wide variance in power costs.

Power costs also can vary widely from one distribution system to the next within the same G&T group because of unique operating characteristics, such as system load factor and total system kw demand placed on the G&T system. The peak demands affect the cost of power through application of demand charges by the power supplier.

Lost kwh sales, purchased but not sold, translate into additional expenses for the system, which must be spread among consumers.

Ratio 90 Power Cost as a Percentage of Revenue

This ratio shows the portion of the system's total revenue that goes toward the purchase of energy for resale. A typical distribution system in the United States spends about 60 percent of its revenues on wholesale power purchases, which is the largest single expense to the distribution system.

LONG-TERM INTEREST EXPENSE RATIOS

Ratio 91 Long-term Interest Expense Per KWH Sold (Mills)

Ratio 92 Long-term Interest Expense Per $ of Total Utility Plant

Ratio 93 Long-term Interest Expense Per Consumer ($)

This blended interest rate does not reflect any lender patronage capital distributions that may be available to a utility that would result in a reduced net blended rate.

Ratio 91 shows the cost of long-term debt on each kwh sold. A high value could indicate either high interest expense or lower-than-normal kwh sales for that year. Higher-than-normal values in this ratio would normally indicate that the cooperative has higher-than-normal levels of long-term debt, making it more difficult to achieve satisfactory TIER and DSC ratios required by some lenders.

Ratio 92 provides a method of measuring the system long-term debt cost per dollar of total utility plant. Different capital management plans and the average age of outstanding debt influence this value.

DEPRECIATION EXPENSE RATIOS

Ratio 94 Depreciation Expense Per KWH Sold (Mills)

Ratio 95 Depreciation Expense as a % of Total Utility Plant

Ratio 96 Depreciation Expense Per Consumer ($)

Total depreciation expense is dependent on the useful life of the various types of facilities and equipment included in total utility plant. This ratio is a gauge to evaluate overall depreciation rates. A strong deviation from the median would generally indicate the system should re-evaluate its depreciation schedules to more accurately match the useful lifetime of the asset.

Ratio 94 indicates the cost of depreciation expense on total utility plant per each kwh sold. Since this ratio is expressed on a per-kwh-sold basis, it may vary from year to year, depending on the kwh sales for a particular year.

A very high Ratio 95 also may indicate an older system while a low ratio value could may a newer system where substantial plant replacement has occurred in recent years.

Ratio 97 Accumulative Depreciation as a Percentage of Plant in Service

This ratio represents an accumulation of expired costs of plant assets acquired as a percent of total plant in service.

TOTAL TAX EXPENSE RATIOS

Ratio 98 Total Tax Expense Per KWH Sold (Mills)

Ratio 99 Total Tax Expense Per $ of Total Utility Plant

Ratio 100 Total Tax Expense Per Consumer

Tax expense ratios may be more meaningful than absolute amounts for tracking individual cooperative trends as many cooperatives spread these expenses.

Ratio 98 measures taxes paid per kwh sold. This is an uncontrollable expense in the short term. Variations exist from state to state in the amount of taxes paid. Systems pay local and state property and sales taxes. Most are exempt from federal income taxes.

Ratio 99 is a measurement of total tax expense per dollar of total utility plant. This ratio may be more meaningful if compared with a peer group of cooperatives.

TOTAL FIXED-EXPENSES RATIOS

Ratio 101 Total Fixed Expenses Per KWH Sold (Mills)

Ratio 102 Total Fixed Expenses Per Consumer ($)

Ratios 101 and 102 measure, respectively, the total fixed expenses per kwh sold and per consumer. The cooperative has little ability to affect this expense in the short term.

TOTAL OPERATING-EXPENSES RATIOS

Ratio 103 Total Operating Expenses Per Total KWH Sold (Mills)

Ratio 104 Total Operating Expenses Per Consumer ($)

Ratio 105 Total Operating Expenses Per KWH Sold

Operating expenses include O&M, A&G, consumer accounts and service and information expenses, and sales expense. A high ratio could indicate the need to evaluate these expense categories for possible efficiencies. The expense items included in this group are the expenses that the system probably has the “most” control over.

Ratios 103 and 86 represent alternative ways to achieve the same information as Ratio 103 under different groupings.

Ratios 104 and 87 represent alternative ways to achieve the same information as Ratio 104 under different groupings.

TOTAL COST OF ELECTRIC-SERVICE RATIOS

Ratio 106 Total Cost of Electric Serice Per KWH (Mills)

Ratio 107 Total Cost of Electric Serice Per Consumer ($)

Ratios 106 and 107 measure the total cost of providing electricity on a, respectively, per-kwh-sold and per-consumer basis. A high value could indicate higher-than-normal expenses or lower-than-normal kwh sales for the year.

Year-end expenses on the Income Statement (Form 7) should be examined to determine whether expenses exceeded budget in any category.

Ratio 108 Average Wage Rate Per Hour ($)

The average rate per hour reflects the economy and relative pay scales of the service territory. A high value could indicate that the cooperative's pay scale is too high or that too much overtime is being authorized. Cooperatives need to find a balance of offering competitive wages to attract highly qualified people and build and maintain a quality organization.

Some related ratios are "Total Consumers" indicating the size of the system. "Consumers per Employee" can identify possible overstaffing. "Overtime Hours to Total Hours" and "Average Total Outage Per Consumer" can indicate excessive overtime or explain high overtime hours.

TOTAL WAGES RATIOS

Ratio 109 Total Wages Per Total KWH Sold (Mills)

Ratio 110 Total Wages Per Consumer ($)

A measurement of total wages of full-time employees on a, respectively, per-kwh-sold basis and per consumer basis. An extremely low or high ratio, relative to other peer groups, could indicate a need to evaluate the wage and salary scale.

Ratio 111 Overtime Hours/Total Hours (%)

This ratio represents the percent of overtime worked to the total hours worked. Significant outages due to extreme storms, accelerated right-of-way clearing and other work related to deferred maintenance may require significant overtime to restore service. Variances from state medians could also be an indication of understaffing resulting in high overtime hours.

Related ratios may be "Consumers Per Employee" indicating possible over- or under-staffing. "O&M Expenses/$1,000 of Plant" indicating a possible accelerated O&M program, and "Avg. Total Outage Per Consumer" indicating whether large outages, resulting from storms, required overtime hours.

Ratio 112 Capitalized Payroll/Total Payroll (%)

Indicates the percent of payroll that is capitalized to the total payroll expenses. Most employee wages are expensed as part of the cost of operating and maintaining distribution and transmission plant and are included in the A&G accounts.

Overcapitalizing results in overstating the value of the plant. Undercapitalizing results in understating the value of plant and reduces the rate base used in rate-making.

Capitalized payroll will tend to be high if the cooperative is adding significant net new plant or if the cooperative is adding a large amount of consumers.

Ratio 113 Average Consumers Per Employee

A measurement of the staffing patterns of a cooperative. Smaller cooperatives must maintain a minimal number of employees to conduct normal utility operations and will generally show a lower number of consumers per employee while a larger cooperative will show a higher number. Different management strategies and the number of services provided may make this ratio vary significantly.

Ratio 114 Annual Growth in KWH Sold (%)

This ratio compares the current year total kwh sales to the prior year's total kwh sales. This ratio can vary widely in a one-year period due to weather effects, so trends should be observed over a multi-year period. Trends in this ratio should be used when considering trends in any of the expense ratios on a per-kwh basis. Acquiring or losing a large load could result in a variance in this ratio from one year to the next.

Ratio 115 Annual Growth in Number of Consumers (%)

Measures the annual growth in the total average number of consumers served from the prior year. (The definition of "average" for this ratio is January plus December divided by two.)

Ratio 116 Annual Growth in Total Utility Plant ($)

This ratio measures current year's Total Utility Plant size with the prior year's Total Utility Plant size. America's rural electric cooperatives are becoming increasingly suburban. Most systems near cities or in "Sunbelt" areas are experiencing more rapid plant growth. Systems that are growing rapidly have greater difficulty increasing equity levels or maintaining healthy equity levels.

Ratio 117 Construction Work-in-progress to Plant Additions (%)

A measure of the construction work-in-progress that has not been closed out compared to the total construction closed out for the year. This ratio can indicate high growth systems with significant work-in-progress at year-end or a system where work orders are not being closed out in a timely manner. A large project carried over into another year can distort this ratio.

Construction work-in-progress status is determined at the end of the year and can vary widely from year to year, depending on whether projects are closed out at that time. Also, this ratio is highly affected by the number of large projects that are in progress that have not been completed at year-end. A review should be made of the work-order process to determine if the cooperative is behind.

Ratio 118 Net New Services to Total Services (%)

Measures the growth in services during the year. A high ratio would indicate a fast-growing system while a low ratio could indicate that new service connections are substantially reduced or that the cooperative has retired a lot of services.

Ratio 119 Annual Growth in Total Capitalization (%)

This ratio compares current-year Total Capitalization (debt and equity) with the prior year's Total Capitalization.

It would be ideal if the growth in consumers, kwh sales, total utility plant and total capitalization were similar. Unfortunately, if consumer growth is all residential, total growth in sales will probably lag. The reverse is generally true if growth in consumers is all non-residential. Growth in kwh sales greater than consumer growth generally means a larger kwh base over which system operating costs can be spread, which is a competitive advantage over other electric suppliers.

Growth in Total Utility Plant will generally exceed growth in consumers and growth in kwh sales due to the increased value of plant caused by normal routine maintenance. Because of inflation over the life of the system, the cost of a new pole structure in place has a greater plant value than the old pole structure that it replaced. Therefore, normal maintenance of the system without any increased kwh sales or an increase in consumers can result in a growth in Total Utility Plant of approximately 2 percent or 3 percent.

Growth in Total Capitalization is dependent upon Total Utility Plant and capital management plans. Under a stable capital management plan, growth in Total Capitalization and Total Utility Plant will be similar.

Ratio 120 Two-year Compound Growth in Total Capitalization (%)

As an aid to normalizing the growth in Total Capitalization, this ratio provides the compound growth over a two-year cycle.

Ratio 121 Five-year Compound Growth in Total Capitalization (%)

As an aid to normalizing the growth in Total Capitalization, this ratio provides the compound growth over a five-year cycle.

Ratio 122 Total Utility Plant Investment Per KWH Sold (Cents)

This ratio measures the total investment in all classes of utility plant on a per-kwh-sold basis. Low monthly kwh usage (see ratios 61 through 68) will result in higher plant investment per kwh sold. Conversely, those systems with high average usage will usually experience a lower plant investment per kwh sold.

Ratio 123 Total Utility Plant Per Consumer ($)

This ratio shows a system's investment in Total Utility Plant per consumer served. Systems serving remote, thinly populated areas will normally have higher ratio values. Conversely, systems serving more densely populated areas will usually have lower ratios, unless they have significant investment in transmission lines or larger transformers and substations to serve commercial loads. Recent higher-cost plant can drive the average unit cost of plant up to the point where a fairly dense system may well have a higher investment per consumer that a less dense system. The consumer size group would provide a good peer group for comparison purposes.

Ratio 124 Total Utility Plant Investment Per Mile of Line ($)

This ratio shows the average cost of Total Utility Plant investment per mile of line in service. This is a reflection of the type of area served by the system, the characteristics of the loads served and the consumer density. A high ratio value could indicate a system serving around a metropolitan area where consumer density is high, requiring heavier construction of three-phase facilities, or more substations and transformers to serve the commercial loads.

Ratio 125 Average Consumers Per Mile of Line

This ratio measures the density of the utility system in terms of number of consumers (meters) per mile of line constructed and in service. This ratio gives no indication of the type of consumers served or sizes of loads served, only the number of meters per mile of line. The terms "meters" and "consumers" are used interchangeably. Consumer density, as well as types of loads served, greatly affects the revenue-producing potential of the system. These ratios tend to "drive" all other system ratios.

Ratio 126 Distribution Plant Per Total KWH Sold (Mills)

A measurement of the distribution plant investment required to serve all loads. Lower ratios usually indicate a cooperative with high average residential usage levels, greater density and/or a high saturation of commercial loads. A high ratio value could indicate over-investment in distribution plant or that the utility is in a service territory with low kwh sales.

Ratio 127 New Distribution Plant Per Consumer ($)

Measures the growth in distribution plant in dollars during a particular year on a per-consumer basis. Such growth could result from new consumers, including large power loads, or from increased energy demands from existing loads on the system. A low ratio is an indication that the utility has experienced little or no growth and has not required significant distribution plant additions. A high ratio could indicate that substantial distribution facilities have been constructed or improved.

Ratio 128 New Distribution Plant Per Employee ($)

Measures the growth in distribution plant in dollars during a particular year on a per-employee basis. A low ratio may be an indication that the cooperative has adequate employees on the payroll to manage the increased plant. A high ratio could indicate an excess of employees needed to run the new distribution plant. It could also indicate excessive overtime due to understaffing.

Ratio 129 General Plant Per Total KWH Sold (Mills)

A measure of the level of support facilities needed to supply service per kwh of sales. Lower ratios can be the result of lower fixed costs or older, less reliable equipment. The ratio also can vary based on the size and makeup of the service area.

Ratio 130 General Plant Per Consumer ($)

Indicates the level of support facilities needed to supply adequate service. Lower ratios generally mean lower fixed costs. Lower ratios, however, also may be the result of older, less reliable equipment that can result in higher operating costs. This ratio varies widely depending on the size and unique conditions of service areas.

Ratio 131 General Plant Per Employee ($)

A measurement of dollars of general plant per employee. A lower value is an indication of efficiencies. A higher ratio value could indicate an excess of staff needed to run the operations of the utility.

Ratio 132 Headquarters Plant Per Total KWH Sold (Mills)

A measurement of headquarters component of total utility plant to total kwh sold. A lower ratio may indicate established facilities while a higher ratio is indicative of newer headquarters facilities with higher investment per kwh sold.

Ratio 133 Headquarters Plant Per Consumer ($)

Measurement of the headquarters component of general plant per consumer. Utilities with newer headquarters facilities or the need for additional service facilities in remote areas may result in a higher investment per consumer. Older facilities or systems with greater density over which to spread the investment would tend to show a lower ratio value.

Evaluate in conjunction with "Average Total Consumers Served" and "Consumers per Mile of Line" to identify density-related variables.

Ratio 134 Headquarters Plant Per Employee ($)

A measurement of the headquarters component of general plant per employee. A low ratio might indicate the utility is carrying more employees on the payroll that needed for normal operations. The use of contractors for large projects may need to be evaluated.

TRANSMISSION PLANT RATIOS

Ratio 135 Transmission Plant Per Total KWH Sold (Mills)

Ratio 136 Transmission Plant Per Consumer ($)

Ratio 137 Transmission Plant Per Employee ($)

Measurements of investment in transmission plant, respectively, per each kwh sold, per consumer and per employee.

Utilities with transmission plant to operate and maintain will generally have higher ratios because of the additional equipment required.

Ratio 138 Idle Services to Total Service (%)

A measurement of idle service to total service. Lower ratios are preferable within limits. Higher ratios may indicate a loss of consumers, a change in load characteristics or a failure to retire old services. An evaluation of a line extension policy and removal practices may be needed to reduce high percentages of idle service.

The utility must maintain idle services. If a pole or conductor is broken on an idle service, it must be replaced. These costs are spread to the cost of service for the remaining active consumers. The costs of maintaining idle facilities in place and their salvage value while waiting for the load to return must be considered by the utility.

If a utility is taxed on plant investment, it may be paying needless taxes. Also, idle services provide an opportunity for additional line loss and outages, creating a liability while in place.

Ratio 139 Line Loss (%)

The measurement of electricity purchased but not sold or otherwise accounted for. Lost kwh sales means additional expense for the system, which must be spread among current consumers. Lost kwh sales are really lost revenues. Distribution cooperatives should have policies on idle services, which is one among several reasons for line losses. Line losses are typically higher in very rural systems that have longer line segments out of each substation and lower consumer density. Line loss can be distorted on the low side for cooperatives serving a very large load directly from a "dedicated' substation where virtually no line loss occurs between the load and the substation.

Ratio 140 System Average Interruption Duration Index (SAIDI)–Power Supplier

A measure of service interruption for consumers served during a specified time attributed to the cooperative's power supplier, measured in minutes. This ratio provides a benchmark that assists in determining if the cooperative is meeting industry standards and providing quality electric service. It also assists in identifying areas that experience multiple or frequent outages for other than maintenance.

Ratio 141 System Average Interruption Duration Index (SAIDI)–Extreme Storm

A measure of service interruption for consumers served during a specified time attributed to extreme storms, measured in minutes. Provides a benchmark that assists in determining if the cooperative is meeting industry expectations for service resumption following extreme storms.

Ratio 142 System Average Interruption Duration Index (SAIDI)–Prearranged

A measure of service interruption for consumers served during a specified time attributed to the cooperative's prearranged maintenance scheduling, measured in minutes. Provides a benchmark that assists in evaluating effective maintenance scheduling.

Ratio 143 System Average Interruption Duration Index (SAIDI)–All Other

A measure of service interruption for consumers served during a specified time attributed to the causes other than those indicated by ratios 140-142, measured in minutes. Provides a benchmark for monitoring and evaluating the level miscellaneous service interruptions.

Ratio 144 System Average Interruption Duration Index (SAIDI)–Total

A measure of total service interruption for consumers for any reason, measured in minutes.

Service reliability is clearly related to overall consumer satisfaction. Consumers who experience more frequent and longer service interruptions are less satisfied with the overall level of service they receive.

Ratio 145 Average Service Availability in Index (ASAI)–Total (%)

The ratio of total consumers that service was available to versus total consumer minutes demanded for the period, expressed as a percentage. Each system should determine an acceptable ASAI annual goal.

National Rural Utilities
Cooperative Finance Corporation
Created and Owned by America's Electric Cooperative Network

20701 Cooperative Way
Dulles, Virginia 20166
703-467-1800 | www.nrucfc.coop

MEMORANDUM

DATE:	June 29, 2018
TO:	Managers of CFC Independent Cooperative Distribution Systems
FROM:	Sheldon C. Petersen, CEO
SUBJECT:	CFC Independent Key Ratio Trend Analysis (KRTA) for the Five Years Ending December 31, 2017

Each year, CFC is pleased to provide every independent rural electric distribution system with an independent Key Ratio Trend Analysis (KRTA) in addition to the standard national KRTA. The independent KRTA uses the identical system ratios as the national KRTA, but it is unique in that it specifically benchmarks only independent cooperatives. An independent system is defined as one that is no longer borrowing from the federal government.

CFC is committed to ensuring your cooperative's financial success by helping you identify strengths and weaknesses, predict future performance, and make strategic business decisions. Your cooperative's Independent Executive Summary, a one-page snapshot of 11 primary ratios that shows where your system ranks within various peer groups, is enclosed.

All independent KRTA reports are located on the CFC Member Website at www.nrucfc.coop. If you have questions about accessing the Member Website, please contact the CFC Member Center at 800-424-2955.

For questions or comments regarding your 2017 KRTA data, please contact your CFC regional vice president or Bettina Kimmel in the Financial Analysis Products & Services Group at 800-424-2954.

Sheldon C. Petersen

CFC KRTA

2017 KEY RATIO TREND ANALYSIS (KRTA)
EXECUTIVE SUMMARY FOR INDEPENDENT COOPERATIVES

06/27/2018 - V120 2018/06/26

OKANOGAN COUNTY ELECTRIC COOPERATIVE, INC.
WA032

	RATIO CATEGORIES	SYSTEM VALUE	U.S. MEDIAN	STATE WA MEDIAN	CONSUMER SIZE (2,500 - 3,999) MEDIAN
FINANCIAL RATIOS					
11	MDSC (2 OF 3 YEAR HIGH AVERAGE)	2.81	2.09	3.18	2.15
7	TIER (2 OF 3 YEAR HIGH AVERAGE)	5.03	2.92	5.03	3.68
23	BLENDED INTEREST RATE (%)	5.86	4.09	4.42	3.94
16	EQUITY AS A % OF ASSETS	66.41	48.36	66.41	64.81
24	ANNUAL CAPITAL CREDITS RETIRED PER TOTAL EQUITY (%)	2.16	2.34	1.93	2.16
REVENUE & EXPENSE RATIOS					
89	POWER COST PER TOTAL KWH SOLD (MILLS)	44.31	69.73	40.63	67.16
103	TOTAL OPERATING EXPENSES PER TOTAL KWH SOLD (MILLS)	26.47	23.54	22.69	26.80
36	ELECTRIC REVENUE PER KWH SOLD (MILLS)	94.56	110.57	89.17	108.34
GROWTH RATIOS					
115	ANNUAL GROWTH IN NUMBER OF CONSUMERS (%)	1.74	0.64	1.45	0.60
114	ANNUAL GROWTH IN KWH SOLD (%)	12.29	-0.30	5.17	2.41
PLANT RATIO					
123	TUP INVESTMENT PER CONSUMER ($)	3,741.45	6,397.67	5,804.38	9,287.57

HIGHS & LOWS BY RATIO CATEGORIES	# OF RATIOS IN TOP 10% OF U.S.	# OF RATIOS IN LOW 10% OF U.S.
BASE GROUP (RATIOS 1-5)	0	5
FINANCIAL (RATIOS 6-32)	2	2
REVENUE & MARGINS (RATIOS 33-59)	4	7
SALES (RATIOS 60-76)	2	1
CONTROLLABLE EXPENSES (RATIOS 77-87)	0	2
FIXED EXPENSES (RATIOS 88-102)	1	3
TOTAL EXPENSES (RATIOS 103-107)	0	1
EMPLOYEES (RATIOS 108-113)	0	1
GROWTH (RATIOS 114-121)	2	0
PLANT (RATIOS 122-145)	1	3

National Rural Utilities
Cooperative Finance Corporation
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20701 Cooperative Way
Dulles, Virginia 20166
703-467-1800 | www.nrucfc.coop

MEMORANDUM

DATE: June 29, 2018

TO: Managers of CFC Member Distribution Systems

FROM: Sheldon C. Petersen, CEO

SUBJECT: CFC Key Ratio Trend Analysis (KRTA) for the Five Years Ending December 31, 2017

Since 1975, CFC has provided rural electric distribution systems with a copy of its annual Key Ratio Trend Analysis (KRTA). This report shows a range of key system operating, expense, growth and other performance indicators.

Your cooperative's single-page Executive Summary identifies 11 primary KRTA ratios including national, state and consumer size median comparisons. The summary also highlights if your cooperative falls into the top or bottom 10 percent of 10 ratio categories compared nationally. Such indicators can be a valuable early alert of business challenges.

The full KRTA report containing 145 ratios is available on CFC's secure Member Website. You can choose to view your KRTA by ratio group, by choosing a range of ratios or by viewing or downloading the complete file in a PDF or Excel format. All ancillary reports also may be accessed on the Member Website.

CFC was created by the electric cooperative network in 1969, and nearly five decades later we continue to be focused on strengthening our members and the entire network through not only financing but also tools such as the KRTA that help our members make better business decisions.

If you have questions about registration for CFC's Member Website please contact the Member Center at 800-424-2955. For questions or comments concerning this year's KRTA, please contact your CFC regional vice president or Bettina Kimmel of the Financial Analysis Products & Services Group at 800-424-2954. We are happy to review or explain any facet of the KRTA at your convenience.

Sheldon C. Petersen

CFC KRTA

2017 KEY RATIO TREND ANALYSIS (KRTA)
EXECUTIVE SUMMARY

06/27/2018 - V120 2018/06/26

OKANOGAN COUNTY ELECTRIC COOPERATIVE, INC.
WA032

RATIO CATEGORIES		SYSTEM VALUE	U.S. MEDIAN	STATE WA MEDIAN	CONSUMER SIZE (2,500 - 3,999) MEDIAN
FINANCIAL RATIOS					
11	MDSC (2 OF 3 YEAR HIGH AVERAGE)	2.81	1.95	2.81	1.98
7	TIER (2 OF 3 YEAR HIGH AVERAGE)	5.03	2.77	4.50	2.90
23	BLENDED INTEREST RATE (%)	5.86	3.96	4.06	3.81
16	EQUITY AS A % OF ASSETS	66.41	45.27	54.62	50.39
24	ANNUAL CAPITAL CREDITS RETIRED PER TOTAL EQUITY (%)	2.16	2.38	1.93	2.55
REVENUE & EXPENSE RATIOS					
89	POWER COST PER TOTAL KWH SOLD (MILLS)	44.31	72.41	40.99	65.79
103	TOTAL OPERATING EXPENSES PER TOTAL KWH SOLD (MILLS)	26.47	24.38	22.69	25.47
36	ELECTRIC REVENUE PER KWH SOLD (MILLS)	94.56	112.81	89.17	111.14
GROWTH RATIOS					
115	ANNUAL GROWTH IN NUMBER OF CONSUMERS (%)	1.74	0.64	1.41	0.40
114	ANNUAL GROWTH IN KWH SOLD (%)	12.29	-1.02	6.34	1.91
PLANT RATIO					
123	TUP INVESTMENT PER CONSUMER ($)	3,741.45	6,089.47	8,387.07	9,077.95

HIGHS & LOWS BY RATIO CATEGORIES	# OF RATIOS IN TOP 10% OF U.S.	# OF RATIOS IN LOW 10% OF U.S.
BASE GROUP (RATIOS 1-5)	0	5
FINANCIAL (RATIOS 6-32)	3	1
REVENUE & MARGINS (RATIOS 33-59)	3	7
SALES (RATIOS 60-76)	2	2
CONTROLLABLE EXPENSES (RATIOS 77-87)	0	3
FIXED EXPENSES (RATIOS 88-102)	1	6
TOTAL EXPENSES (RATIOS 103-107)	0	2
EMPLOYEES (RATIOS 108-113)	1	1
GROWTH (RATIOS 114-121)	1	0
PLANT (RATIOS 122-145)	1	3

INDEPENDENT COOPERATIVES

CFC KRTA

Okanogan County Electric Cooperative, Inc.
WA032

PRODUCED BY:

NRUCFC
20701 Cooperative Way
Dulles, VA 20166
1-800-424-2954

06/27/2018

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	**System Value**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**
BASE GROUP (RATIOS 1-5)																
RATIO 1 --- AVERAGE TOTAL CONSUMERS SERVED																
2013	3,542	13,715	271	253	8,750	7	7	3,423	18	9	12,120	26	25	14,212	65	64
2014	3,561	14,281	296	276	8,837	7	7	3,561	21	11	11,307	28	27	15,644	59	56
2015	3,576	14,092	308	289	8,950	7	7	3,623	23	13	9,766	30	29	12,998	74	68
2016	3,628	14,239	313	293	9,086	7	7	3,618	23	11	9,896	31	29	18,944	61	58
2017	3,691	13,904	332	305	9,214	7	7	3,623	25	10	10,026	32	30	11,486	90	85
RATIO 2 --- TOTAL KWH SOLD (1,000)																
2013	54,989	336,534	271	259	327,482	7	7	84,491	18	15	309,005	26	25	392,086	65	64
2014	53,049	338,554	296	285	351,234	7	7	81,080	21	19	301,424	28	28	376,757	59	58
2015	53,150	324,027	308	295	354,246	7	7	92,760	23	19	282,518	30	29	296,180	74	68
2016	54,787	319,688	313	300	340,027	7	7	98,849	23	19	284,311	31	30	373,760	61	60
2017	61,521	323,541	332	312	342,522	7	7	97,496	25	18	300,697	32	31	278,496	90	84
RATIO 3 --- TOTAL UTILITY PLANT (1,000)																
2013	11,765.50	76,533.18	271	264	74,475.20	7	7	23,415.03	18	17	72,032.76	26	25	85,228.49	65	65
2014	12,381.44	81,046.15	296	288	78,271.52	7	7	25,349.89	21	20	75,705.18	28	27	83,000.66	59	58
2015	12,814.22	83,177.72	308	302	79,971.56	7	7	26,642.81	23	22	74,946.51	30	29	81,984.67	74	72
2016	13,338.94	89,597.34	313	306	81,623.63	7	7	29,512.71	23	22	74,684.76	31	30	105,778.84	61	61
2017	13,809.70	91,968.66	332	323	84,410.96	7	7	30,841.71	25	23	74,209.92	32	31	82,715.48	90	89
RATIO 4 --- TOTAL NUMBER OF EMPLOYEES (FULL TIME ONLY)																
2013	11	47	271	267	35	7	7	16	18	18	47	26	26	48	65	65
2014	12	48	296	287	34	7	7	16	21	20	46	28	28	49	59	57
2015	12	49	308	301	36	7	7	16	23	21	43	30	30	45	74	70
2016	12	49	313	308	36	7	7	16	23	22	43	31	31	53	61	61
2017	12	47	332	322	38	7	7	15	25	24	40	32	32	42	90	89
RATIO 5 --- TOTAL MILES OF LINE																
2013	520	2,506	270	257	1,003	7	5	864	18	16	1,579	26	21	2,778	65	65
2014	529	2,567	295	281	1,002	7	5	981	21	19	1,657	28	23	2,704	59	57
2015	534	2,504	307	292	1,026	7	5	1,022	23	20	1,546	30	25	2,548	74	70
2016	511	2,534	312	300	1,026	7	5	1,025	23	21	1,633	31	27	2,871	61	59
2017	514	2,441	331	315	1,039	7	5	987	25	21	1,548	32	28	2,274	90	89
FINANCIAL (RATIOS 6-32)																
RATIO 6 --- TIER																
2013	4.46	2.93	271	61	4.46	7	4	3.65	18	6	2.34	26	6	2.86	65	22
2014	3.58	2.85	296	93	3.07	7	3	2.96	21	8	2.27	28	7	2.99	59	19
2015	4.82	2.69	308	65	4.82	7	4	2.53	23	7	2.25	30	9	2.78	74	13
2016	4.42	2.72	313	71	4.42	7	4	3.69	23	7	2.75	31	8	2.89	61	18
2017	5.24	2.73	332	70	5.24	7	4	3.66	25	7	3.19	32	7	2.88	90	19

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 7 --- TIER (2 OF 3 YEAR HIGH AVERAGE)																
2013	3.79	2.90	271	85	3.79	7	4	4.27	18	11	2.51	26	9	2.89	65	23
2014	4.02	3.06	296	90	4.02	7	4	4.02	21	11	2.21	28	9	3.34	59	22
2015	4.64	3.03	308	79	4.64	7	4	3.31	23	8	2.42	30	9	3.20	74	15
2016	4.62	2.92	313	84	4.62	7	4	3.49	23	8	2.67	31	10	3.26	61	20
2017	5.03	2.92	332	81	5.03	7	4	3.68	25	9	2.95	32	8	2.92	90	18
RATIO 8 --- OTIER																
2013	3.64	2.13	271	58	3.64	7	4	3.11	18	7	1.92	26	6	2.14	65	21
2014	3.19	2.10	296	68	2.78	7	3	2.33	21	7	1.90	28	6	2.20	59	14
2015	4.21	2.05	308	58	4.21	7	4	1.82	23	6	2.08	30	7	2.11	74	15
2016	3.81	2.10	313	67	3.81	7	4	2.54	23	8	2.29	31	7	2.33	61	19
2017	4.50	2.17	332	66	4.50	7	4	2.00	25	5	2.60	32	6	2.18	90	16
RATIO 9 --- OTIER (2 OF 3 YEAR HIGH AVERAGE)																
2013	3.31	2.22	271	70	3.31	7	4	3.52	18	10	2.25	26	8	2.19	65	21
2014	3.41	2.22	296	74	3.41	7	4	3.38	21	10	2.06	28	7	2.34	59	19
2015	3.92	2.24	308	65	3.92	7	4	3.06	23	7	2.11	30	7	2.40	74	14
2016	4.01	2.28	313	67	4.01	7	4	2.63	23	7	2.25	31	7	2.46	61	16
2017	4.35	2.28	332	74	4.35	7	4	2.74	25	8	2.44	32	8	2.27	90	17
RATIO 10 --- MODIFIED DSC (MDSC)																
2013	2.48	2.09	271	95	2.48	7	4	2.37	18	7	2.05	26	8	2.29	65	29
2014	2.23	2.02	296	112	2.56	7	5	2.21	21	10	2.11	28	12	2.11	59	25
2015	2.70	1.96	308	84	2.70	7	4	2.17	23	5	2.27	30	8	1.99	74	20
2016	2.57	1.93	313	92	2.89	7	5	2.05	23	6	2.34	31	13	2.12	61	22
2017	2.91	2.08	332	85	3.48	7	5	1.87	25	6	2.37	32	12	2.01	90	22
RATIO 11 --- MDSC (2 OF 3 YEAR HIGH AVERAGE)																
2013	2.37	2.18	271	112	2.68	7	5	2.39	18	10	2.20	26	11	2.25	65	30
2014	2.37	2.17	296	121	2.45	7	5	2.37	21	11	2.23	28	13	2.36	59	29
2015	2.59	2.14	308	99	2.59	7	4	2.34	23	7	2.31	30	8	2.23	74	24
2016	2.64	2.07	313	100	2.73	7	5	2.24	23	7	2.31	31	13	2.42	61	24
2017	2.81	2.09	332	98	3.18	7	5	2.15	25	7	2.30	32	13	2.05	90	23
RATIO 12 --- DEBT SERVICE COVERAGE (DSC)																
2013	2.89	2.37	271	90	2.89	7	4	2.50	18	7	2.08	26	7	2.40	65	27
2014	2.43	2.25	296	136	2.43	7	4	2.43	21	11	2.15	28	10	2.40	59	29
2015	3.00	2.21	308	83	2.81	7	3	2.45	23	7	2.16	30	7	2.32	74	21
2016	2.88	2.19	313	88	2.88	7	4	2.37	23	6	2.24	31	11	2.45	61	21
2017	3.29	2.27	332	82	3.29	7	4	2.26	25	6	2.35	32	8	2.15	90	18

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 13 --- DSC (2 OF 3 YEAR HIGH AVERAGE)																
2013	2.61	2.43	271	124	2.74	7	5	2.61	18	10	2.30	26	11	2.37	65	29
2014	2.66	2.48	296	125	2.66	7	4	2.59	21	10	2.18	28	8	2.68	59	31
2015	2.94	2.42	308	103	2.94	7	4	2.55	23	9	2.27	30	8	2.68	74	27
2016	2.94	2.41	313	98	2.94	7	4	2.60	23	6	2.47	31	8	2.74	61	25
2017	3.15	2.37	332	92	3.15	7	4	2.58	25	6	2.45	32	9	2.30	90	20
RATIO 14 --- ODSC																
2013	2.48	1.99	271	87	2.48	7	4	2.15	18	7	1.91	26	7	2.27	65	28
2014	2.24	1.92	296	103	2.24	7	4	2.16	21	9	1.92	28	10	2.01	59	23
2015	2.71	1.93	308	78	2.71	7	4	2.10	23	5	1.98	30	7	1.99	74	20
2016	2.59	1.86	313	85	2.59	7	4	2.05	23	6	2.09	31	9	2.08	61	20
2017	2.94	2.00	332	79	2.94	7	4	1.71	25	6	2.13	32	11	1.97	90	18
RATIO 15 --- ODSC (2 OF 3 YEAR HIGH AVERAGE)																
2013	2.37	2.10	271	103	2.63	7	5	2.37	18	9	2.10	26	10	2.28	65	31
2014	2.37	2.07	296	107	2.37	7	4	2.28	21	9	1.97	28	9	2.17	59	27
2015	2.60	2.07	308	93	2.60	7	4	2.19	23	6	1.97	30	7	2.14	74	24
2016	2.65	2.01	313	94	2.65	7	4	2.16	23	7	2.06	31	10	2.22	61	23
2017	2.82	2.02	332	87	2.82	7	4	2.05	25	5	2.14	32	8	2.00	90	22
RATIO 16 --- EQUITY AS A % OF ASSETS																
2013	56.94	47.18	271	77	56.94	7	4	58.99	18	11	45.23	26	10	47.31	65	21
2014	55.05	47.46	296	93	55.05	7	4	56.75	21	12	48.16	28	10	48.23	59	20
2015	60.72	47.25	308	78	60.72	7	4	60.72	23	12	47.92	30	11	47.25	74	16
2016	64.20	47.85	313	64	64.20	7	4	62.77	23	10	49.76	31	10	49.42	61	13
2017	66.41	48.36	332	68	66.41	7	4	64.81	25	12	50.41	32	10	50.53	90	16
RATIO 17 --- DISTRIBUTION EQUITY (EXCLUDES EQUITY IN ASSOC. ORG'S PATRONAGE CAPITAL)																
2013	55.96	40.27	271	63	55.96	7	4	56.56	18	10	43.50	26	10	40.27	65	18
2014	54.03	40.10	296	76	54.03	7	4	52.95	21	10	46.25	28	10	40.31	59	16
2015	59.76	39.40	308	62	59.76	7	4	51.09	23	11	46.49	30	11	40.22	74	13
2016	63.30	39.70	313	58	63.30	7	4	53.05	23	9	48.55	31	10	41.64	61	13
2017	65.56	40.06	332	63	65.56	7	4	51.00	25	10	48.90	32	10	43.00	90	14
RATIO 18 --- EQUITY AS A % OF TOTAL CAPITALIZATION																
2013	61.82	54.56	271	94	61.82	7	4	69.12	18	12	52.91	26	11	53.57	65	26
2014	60.31	55.17	296	115	60.31	7	4	65.20	21	13	55.05	28	11	55.80	59	26
2015	66.09	54.95	308	87	66.09	7	4	66.26	23	13	56.48	30	12	54.16	74	19
2016	69.59	55.17	313	76	69.59	7	4	69.59	23	12	58.42	31	12	56.00	61	17
2017	72.21	55.99	332	76	72.21	7	4	72.21	25	13	56.97	32	11	57.71	90	20

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 19 --- LONG TERM DEBT AS A % OF TOTAL ASSETS																
2013	35.17	39.38	265	159	50.15	6	4	24.39	18	6	40.99	24	15	40.95	63	38
2014	36.23	39.04	291	165	49.52	6	4	33.24	21	8	41.06	26	17	39.83	56	31
2015	31.16	39.59	303	210	46.33	6	4	31.16	23	12	40.11	28	18	40.64	72	55
2016	28.06	39.48	308	230	43.36	6	4	28.06	23	12	38.61	29	20	39.58	59	45
2017	25.56	38.47	327	255	57.56	5	4	26.27	25	14	37.30	30	22	37.07	89	71
RATIO 20 --- LONG TERM DEBT PER KWH SOLD (MILLS)																
2013	71.16	100.29	265	170	125.86	6	5	74.02	18	11	96.38	24	17	105.42	63	40
2014	84.14	99.32	291	167	123.15	6	4	83.60	21	10	104.46	26	15	87.39	56	31
2015	72.36	107.85	303	206	119.76	6	5	85.89	23	15	104.98	28	20	113.71	72	55
2016	64.05	110.15	308	219	124.72	6	5	88.54	23	15	103.86	29	21	114.56	59	42
2017	54.73	109.39	327	246	186.55	5	5	79.46	25	17	91.23	30	23	113.35	89	69
RATIO 21 --- LONG TERM DEBT PER CONSUMER ($)																
2013	1,104.73	2,125.02	265	215	3,260.93	6	5	1,995.63	18	15	1,917.98	24	19	2,055.86	63	49
2014	1,253.52	2,161.81	291	229	2,996.04	6	5	2,450.15	21	15	2,122.34	26	19	2,257.60	56	47
2015	1,075.42	2,260.88	303	253	2,911.52	6	5	2,354.34	23	18	2,159.99	28	21	2,331.64	72	63
2016	967.18	2,308.29	308	267	2,681.74	6	5	2,240.08	23	20	2,165.90	29	24	2,200.70	59	51
2017	912.28	2,304.39	327	283	4,110.16	5	5	2,155.84	25	22	2,233.42	30	26	2,193.70	89	79
RATIO 22 --- NON-GOVERNMENT DEBT AS A % OF TOTAL LONG TERM DEBT																
2013	100.00	100.00	265	247	100.00	6	4	100.00	18	17	100.00	24	21	100.00	63	58
2014	100.00	100.00	291	264	100.00	6	4	100.00	21	19	100.00	26	22	100.00	56	50
2015	100.00	100.00	303	280	100.00	6	4	100.00	23	20	100.00	28	24	100.00	72	63
2016	100.00	100.00	308	289	100.00	6	5	100.00	23	21	100.00	29	27	100.00	59	54
2017	100.00	100.00	327	306	100.00	5	4	100.00	25	23	100.00	30	27	100.00	89	81
RATIO 23 --- BLENDED INTEREST RATE (%)																
2013	5.79	4.78	264	25	4.48	5	1	4.57	18	3	4.82	23	2	4.80	63	7
2014	5.54	4.45	290	26	4.38	5	1	4.29	21	2	4.45	25	1	4.51	56	8
2015	5.31	4.30	302	31	4.28	5	1	3.97	23	2	4.43	27	2	4.41	72	7
2016	5.72	4.18	306	9	4.39	5	1	3.93	23	3	4.26	28	1	4.39	58	2
2017	5.86	4.09	326	8	4.42	5	1	3.94	25	1	4.08	30	1	4.19	89	2
RATIO 24 --- ANNUAL CAPITAL CREDITS RETIRED PER TOTAL EQUITY (%)																
2013	2.09	2.14	218	114	1.89	5	2	2.16	14	10	2.84	24	17	2.29	49	28
2014	2.63	2.13	247	97	1.54	5	2	2.00	17	6	2.84	26	14	2.23	47	20
2015	2.23	2.42	253	138	1.74	5	2	2.16	19	8	3.25	28	19	2.46	58	34
2016	2.92	2.39	262	96	1.67	5	2	2.00	19	7	3.23	29	18	2.53	53	22
2017	2.16	2.34	279	158	1.93	5	2	2.16	21	11	3.69	30	23	2.44	78	48

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 25 --- LONG-TERM INTEREST AS A % OF REVENUE																
2013	4.90	4.15	264	103	9.75	5	4	2.52	18	2	5.60	23	15	4.02	63	27
2014	4.59	3.97	290	116	9.28	5	4	2.95	21	6	5.54	25	16	4.12	56	21
2015	4.30	4.16	303	144	8.82	5	4	3.46	23	8	5.55	27	17	4.53	72	39
2016	4.06	4.14	306	160	8.75	5	4	3.03	23	10	4.78	28	17	4.49	58	32
2017	3.57	4.07	326	188	7.84	5	4	2.87	25	11	4.00	30	18	4.07	89	53
RATIO 26 --- CUMULATIVE PATRONAGE CAPITAL RETIRED AS A % OF TOTAL PATRONAGE CAPITAL																
2013	25.65	22.00	227	88	25.65	5	3	25.65	13	7	34.53	23	15	20.09	52	19
2014	25.85	22.36	257	109	25.85	5	3	28.56	16	10	32.75	25	15	22.27	52	21
2015	23.18	24.25	268	140	25.73	5	4	26.00	19	14	33.06	27	20	22.78	61	29
2016	23.71	24.92	272	139	25.93	5	4	27.78	19	12	33.51	28	20	23.01	52	24
2017	23.48	24.86	288	149	26.04	5	4	27.83	21	13	32.66	29	22	26.09	78	46
RATIO 27 --- RATE OF RETURN ON EQUITY (%)																
2013	13.35	6.98	271	27	8.70	7	3	6.28	18	1	5.33	26	3	6.70	65	7
2014	9.12	6.66	296	69	7.55	7	2	6.46	21	5	6.13	28	5	6.71	59	13
2015	11.61	6.20	308	24	6.33	7	1	4.95	23	1	5.46	30	1	6.34	74	6
2016	9.29	6.13	313	38	5.05	7	1	6.22	23	4	5.63	31	1	6.24	61	5
2017	10.15	6.01	332	35	7.00	7	1	5.74	25	4	6.85	32	4	6.33	90	14
RATIO 28 --- RATE OF RETURN ON TOTAL CAPITALIZATION (%)																
2013	10.63	5.98	271	10	7.04	7	2	5.86	18	2	4.71	26	2	5.79	65	4
2014	7.63	5.68	296	44	5.87	7	2	5.26	21	5	5.39	28	4	5.93	59	10
2015	9.68	5.31	308	11	5.84	7	1	5.09	23	1	5.14	30	1	5.56	74	2
2016	8.35	5.24	313	15	5.04	7	1	5.20	23	2	5.05	31	1	5.45	61	2
2017	9.06	5.21	332	12	5.62	7	1	5.01	25	3	5.42	32	2	5.45	90	4
RATIO 29 --- CURRENT RATIO																
2013	2.09	1.08	271	51	2.61	7	5	1.90	18	7	1.67	26	9	1.19	65	14
2014	2.66	1.06	296	31	2.27	7	3	1.76	21	4	1.28	28	5	1.06	59	7
2015	2.42	1.09	308	39	2.23	7	3	1.50	23	7	1.26	30	4	1.15	74	10
2016	2.15	1.07	313	44	1.70	7	3	1.74	23	7	1.65	31	4	1.09	61	12
2017	2.57	1.10	332	44	2.10	7	3	1.84	25	10	1.45	32	4	1.06	90	8
RATIO 30 --- GENERAL FUNDS PER TUP (%)																
2013	5.63	3.14	271	95	9.60	7	5	9.74	18	12	3.53	26	11	3.28	65	24
2014	5.71	3.11	296	96	11.13	7	5	7.23	21	12	2.80	28	10	2.79	59	20
2015	3.75	3.10	308	140	7.17	7	5	3.90	23	14	2.66	30	11	3.26	74	34
2016	5.49	3.20	313	104	5.49	7	4	5.49	23	12	3.14	31	11	2.57	61	19
2017	5.23	3.30	332	122	5.23	7	4	6.83	25	14	3.39	32	11	2.78	90	32

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 31 --- PLANT REVENUE RATIO (PRR) ONE YEAR																
2013	4.33	6.52	271	261	5.49	7	6	6.64	18	15	6.43	26	23	6.50	65	64
2014	4.49	6.66	296	283	5.72	7	6	6.79	21	17	6.35	28	25	6.65	59	57
2015	4.44	6.79	308	297	5.23	7	6	7.20	23	21	6.41	30	28	6.60	74	72
2016	4.59	6.89	313	304	5.98	7	6	6.78	23	21	6.53	31	28	7.02	61	59
2017	4.40	6.97	332	325	5.76	7	6	7.01	25	23	6.55	32	30	6.96	90	89
RATIO 32 --- INVESTMENT IN SUBSIDIARIES TO TOTAL ASSETS (%)																
2013	2.98	0.83	71	19	4.10	4	3	5.42	6	5	6.39	8	6	0.25	16	4
2014	3.06	0.92	76	21	4.79	4	3	3.68	7	5	7.28	8	6	1.25	11	4
2015	3.73	1.01	81	19	5.74	4	3	3.73	7	4	6.86	9	6	0.62	17	3
2016	4.37	0.98	82	20	6.87	4	3	3.74	8	4	5.79	9	6	1.07	14	3
2017	5.03	0.81	86	19	7.78	4	3	3.17	8	3	5.03	9	5	1.44	21	6
REVENUE & MARGINS (RATIOS 33-59)																
RATIO 33 --- TOTAL OPERATING REVENUE PER KWH SOLD (MILLS)																
2013	90.69	107.44	271	219	85.67	7	2	98.64	18	13	78.15	26	6	107.00	65	56
2014	98.40	111.49	296	218	90.66	7	2	105.19	21	13	86.09	28	7	112.47	59	39
2015	99.59	111.49	308	215	98.73	7	2	108.60	23	15	87.12	30	8	115.28	74	60
2016	98.00	110.64	313	230	97.22	7	3	114.46	23	16	89.53	31	9	109.60	61	44
2017	95.31	113.42	332	264	95.31	7	4	108.60	25	19	89.42	32	10	117.84	90	75
RATIO 34 --- TOTAL OPERATING REVENUE PER TUP INVESTMENT (CENTS)																
2013	42.39	41.94	271	129	34.23	7	2	42.60	18	10	30.90	26	8	40.01	65	26
2014	42.16	41.70	296	145	32.21	7	2	42.16	21	11	30.32	28	7	41.83	59	29
2015	41.31	38.82	308	126	31.75	7	3	35.34	23	10	28.16	30	7	38.98	74	28
2016	40.25	37.72	313	127	30.48	7	3	38.21	23	10	28.97	31	8	40.08	61	29
2017	42.46	36.35	332	103	31.56	7	2	36.80	25	8	30.74	32	5	36.27	90	26
RATIO 35 --- TOTAL OPERATING REVENUE PER CONSUMER ($)																
2013	1,408.02	2,340.77	271	263	1,966.12	7	7	2,934.87	18	17	1,729.90	26	23	2,358.62	65	65
2014	1,465.87	2,413.21	296	286	2,241.45	7	7	2,992.46	21	20	1,761.35	28	25	2,324.97	59	57
2015	1,480.18	2,321.42	308	295	2,179.80	7	7	2,746.22	23	22	1,785.04	30	27	2,283.83	74	69
2016	1,479.95	2,313.36	313	299	2,215.43	7	7	2,802.07	23	22	1,823.72	31	29	2,251.99	61	58
2017	1,588.64	2,342.01	332	313	2,404.52	7	7	2,610.46	25	23	1,853.78	32	29	2,214.46	90	84
RATIO 36 --- ELECTRIC REVENUE PER KWH SOLD (MILLS)																
2013	89.93	105.04	271	216	77.71	7	2	96.80	18	13	76.85	26	6	104.37	65	55
2014	97.60	109.46	296	212	85.55	7	2	101.32	21	13	83.78	28	6	107.72	59	38
2015	98.77	109.12	308	212	91.27	7	2	107.34	23	15	86.24	30	7	111.97	74	58
2016	97.18	108.64	313	226	89.48	7	2	102.46	23	16	89.14	31	8	106.41	61	42
2017	94.56	110.57	332	259	89.17	7	2	108.34	25	19	88.86	32	8	116.00	90	75

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 37 --- ELECTRIC REVENUE PER CONSUMER ($)																
2013	1,396.12	2,286.74	271	261	1,783.38	7	7	2,907.20	18	17	1,658.07	26	23	2,301.49	65	65
2014	1,453.93	2,352.08	296	285	2,139.82	7	7	2,938.03	21	20	1,688.64	28	25	2,321.73	59	57
2015	1,467.97	2,280.63	308	293	2,113.78	7	7	2,738.46	23	22	1,716.35	30	27	2,250.31	74	69
2016	1,467.51	2,269.52	313	298	2,154.76	7	7	2,795.62	23	22	1,717.76	31	29	2,190.04	61	58
2017	1,576.06	2,310.31	332	308	2,279.82	7	7	2,556.63	25	22	1,826.96	32	29	2,185.47	90	83
RATIO 38 --- RESIDENTIAL REVENUE PER KWH SOLD (MILLS)																
2013	93.53	116.69	271	234	88.92	7	2	125.90	18	15	89.48	26	8	115.05	65	58
2014	100.83	119.91	296	237	89.47	7	3	125.79	21	17	93.32	28	8	120.51	59	48
2015	102.64	121.10	308	242	97.23	7	3	125.71	23	18	96.09	30	10	122.68	74	65
2016	102.43	121.04	313	246	96.15	7	3	122.53	23	19	96.91	31	13	120.92	61	48
2017	99.59	124.06	332	290	97.53	7	3	135.32	25	21	97.00	32	14	127.33	90	80
RATIO 39 --- NON-RESIDENTIAL REVENUE PER KWH SOLD (MILLS)																
2013	67.80	93.95	271	243	67.80	7	4	83.48	18	15	67.27	26	13	95.39	65	58
2014	73.90	97.45	296	263	73.90	7	4	86.28	21	17	74.81	28	15	95.88	59	50
2015	74.03	96.28	308	269	74.03	7	4	98.48	23	19	76.18	30	16	100.61	74	66
2016	73.46	96.17	313	278	74.04	7	5	99.14	23	19	74.04	31	18	92.03	61	55
2017	72.20	96.78	332	302	77.36	7	5	99.23	25	21	78.37	32	20	99.45	90	80
RATIO 40 --- SEASONAL REVENUE PER KWH SOLD (MILLS)																
2013	113.66	174.36	89	82	134.26	4	3	163.12	7	7	118.96	10	7	174.09	21	20
2014	123.78	176.07	93	78	142.39	4	3	151.03	8	8	133.37	11	7	180.58	23	21
2015	127.73	188.49	93	81	145.26	4	3	179.99	8	8	134.86	11	7	211.78	23	23
2016	122.49	190.90	97	87	144.73	4	3	180.55	8	8	156.05	12	10	194.37	19	18
2017	115.87	197.97	99	96	169.13	3	3	190.54	9	9	153.76	12	11	194.27	31	31
RATIO 41 --- IRRIGATION REVENUE PER KWH SOLD (MILLS)																
2013	79.88	120.23	143	121	56.76	4	1	133.38	13	12	72.34	22	8	124.28	37	32
2014	87.18	127.38	159	136	58.68	4	1	161.17	15	14	78.00	24	9	126.10	30	25
2015	81.50	129.91	164	138	59.98	4	1	136.39	17	15	75.26	26	9	131.16	35	31
2016	87.62	129.73	171	145	62.39	4	1	140.89	18	16	79.75	27	12	133.76	36	33
2017	88.52	128.58	180	153	64.59	4	1	142.79	18	16	76.59	28	12	133.13	45	37
RATIO 42 --- SMALL COMMERCIAL REVENUE PER KWH SOLD (MILLS)																
2013	74.19	105.12	268	250	78.81	7	5	106.09	18	15	74.63	26	14	102.05	65	60
2014	80.38	108.79	295	273	81.69	7	5	115.07	21	18	80.62	28	15	107.70	59	54
2015	81.03	107.50	308	283	88.21	7	5	106.47	23	18	80.20	30	15	108.59	74	71
2016	81.57	108.36	313	287	88.53	7	6	109.17	23	19	85.21	31	18	103.76	61	55
2017	80.23	109.91	332	312	87.69	7	6	109.08	25	21	83.13	32	21	112.13	90	84

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	**System Value**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**
RATIO 43 --- LARGE COMMERCIAL REVENUE PER KWH SOLD (MILLS)																
2013	55.11	77.36	246	225	61.06	6	5	75.13	16	14	58.45	24	14	81.24	60	56
2014	59.78	80.46	270	246	63.27	7	6	78.36	18	15	62.44	27	15	75.70	52	50
2015	60.29	79.26	283	244	74.95	7	6	77.97	21	18	65.55	29	17	80.06	66	61
2016	58.51	79.78	284	248	64.88	7	7	80.51	21	18	67.17	30	20	76.10	55	48
2017	57.54	79.86	300	272	75.20	7	7	90.55	23	21	70.37	31	22	81.04	80	74
RATIO 45 --- STREET & HIGHWAY LIGHTING REVENUE PER KWH SOLD (MILLS)																
2013	110.00	157.38	200	170	123.28	5	5	185.61	12	11	155.83	21	19	154.70	50	40
2014	188.57	162.48	219	71	163.73	5	2	188.57	13	7	188.57	23	12	162.01	48	18
2015	754.29	164.10	229	3	176.21	6	1	176.05	15	1	187.73	26	1	164.10	57	1
2016	754.29	169.74	228	4	205.35	5	1	203.30	15	3	203.77	26	1	171.06	52	1
2017	754.29	175.02	244	4	293.18	4	1	215.35	15	3	208.19	25	1	172.41	57	1
RATIO 47 --- OPERATING MARGINS PER KWH SOLD (MILLS)																
2013	11.42	4.85	271	24	11.42	7	4	4.22	18	4	3.70	26	4	5.71	65	4
2014	9.63	4.65	296	25	7.04	7	2	4.30	21	3	4.49	28	2	4.70	59	5
2015	13.46	4.48	308	14	5.46	7	3	2.06	23	1	4.77	30	3	5.31	74	4
2016	10.79	4.14	313	30	4.37	7	2	4.28	23	4	4.69	31	4	4.45	61	6
2017	11.42	4.69	332	30	9.45	7	3	3.83	25	2	6.12	32	3	5.34	90	9
RATIO 48 --- OPERATING MARGINS PER CONSUMER ($)																
2013	177.23	103.49	271	66	229.49	7	5	157.97	18	8	105.04	26	7	115.31	65	19
2014	143.46	97.81	296	96	143.46	7	4	133.47	21	9	122.43	28	8	106.18	59	19
2015	200.03	92.48	308	50	258.92	7	5	75.21	23	5	104.72	30	7	106.17	74	13
2016	162.96	90.24	313	79	184.27	7	5	112.32	23	9	112.32	31	12	95.49	61	14
2017	190.39	92.82	332	63	190.39	7	4	107.94	25	9	143.10	32	10	90.72	90	18
RATIO 49 --- NON-OPERATING MARGINS PER KWH SOLD (MILLS)																
2013	3.96	0.32	271	12	1.22	7	2	0.37	18	5	0.36	26	5	0.28	65	2
2014	2.03	0.29	296	34	1.13	7	3	0.27	21	5	0.48	28	7	0.28	59	6
2015	2.91	0.28	308	28	1.68	7	2	0.75	23	5	0.45	30	5	0.43	74	9
2016	2.82	0.30	313	29	0.84	7	2	0.34	23	6	0.41	31	6	0.43	61	7
2017	3.01	0.38	330	29	0.45	7	2	0.41	25	5	0.42	32	5	0.45	90	10
RATIO 50 --- NON-OPERATING MARGINS PER CONSUMER ($)																
2013	61.51	7.12	271	15	35.71	7	3	21.43	18	4	10.71	26	6	6.77	65	2
2014	30.23	8.00	296	52	20.50	7	3	12.18	21	8	18.96	28	9	6.16	59	7
2015	43.25	7.12	308	38	29.07	7	3	20.47	23	8	9.93	30	7	7.60	74	11
2016	42.60	6.89	313	39	32.22	7	3	10.11	23	8	8.36	31	9	8.49	61	10
2017	50.25	8.54	330	42	25.93	7	3	12.08	25	6	8.53	32	9	8.76	90	15

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 51 --- TOTAL MARGINS LESS ALLOCATIONS PER KWH SOLD (MILLS)																
2013	15.38	5.43	271	8	12.00	7	3	6.21	18	2	4.36	26	3	5.95	65	1
2014	11.66	5.24	296	21	7.10	7	1	4.99	21	3	6.36	28	1	5.30	59	4
2015	16.37	5.12	308	10	5.63	7	2	3.95	23	1	5.41	30	2	6.08	74	4
2016	13.61	4.92	313	18	4.92	7	1	5.30	23	4	5.03	31	1	5.27	61	5
2017	14.44	5.23	332	21	6.66	7	2	4.42	25	2	6.60	32	3	5.94	90	7
RATIO 52 --- TOTAL MARGINS LESS ALLOCATIONS PER CONSUMER ($)																
2013	238.74	116.23	271	45	246.71	7	5	174.97	18	6	143.59	26	6	128.30	65	14
2014	173.69	108.74	296	78	173.69	7	4	143.27	21	8	132.70	28	9	106.82	59	16
2015	243.28	104.26	308	41	243.28	7	4	113.69	23	5	121.87	30	5	125.83	74	11
2016	205.56	101.83	313	60	198.98	7	3	155.44	23	9	135.70	31	8	108.20	61	13
2017	240.64	107.57	332	53	197.56	7	3	136.31	25	8	169.27	32	7	111.30	90	15
RATIO 53 --- INCOME (LOSS) FROM EQUITY INVESTMENTS PER CONSUMER ($)																
2013	54.56	3.91	72	6	21.69	3	1	18.44	4	1	16.19	7	1	6.24	14	2
2014	23.57	2.49	87	14	18.11	4	2	12.85	7	2	12.75	8	2	4.54	13	3
2015	36.49	1.38	88	10	23.41	4	2	20.18	5	2	7.75	8	3	5.84	20	4
2016	34.69	1.57	96	12	24.39	4	2	6.39	7	3	14.08	9	4	1.19	17	4
2017	41.16	0.79	101	15	8.91	4	1	1.28	6	2	0.73	10	2	1.66	28	8
RATIO 56 --- TOTAL MARGINS PER KWH SOLD (MILLS)																
2013	15.38	8.52	271	29	13.23	7	3	7.49	18	4	4.90	26	3	8.50	65	7
2014	11.66	8.05	296	61	7.71	7	1	7.23	21	5	6.80	28	2	7.73	59	11
2015	16.37	7.89	308	19	5.90	7	2	6.13	23	1	5.84	30	2	8.72	74	6
2016	13.61	7.85	313	41	5.43	7	1	8.33	23	5	5.85	31	2	8.14	61	9
2017	14.44	8.33	332	43	6.66	7	2	8.50	25	3	7.16	32	3	9.32	90	16
RATIO 57 --- TOTAL MARGINS PER CONSUMER ($)																
2013	238.74	187.29	271	85	252.00	7	5	224.59	18	8	160.85	26	6	200.23	65	19
2014	173.69	173.77	296	149	173.69	7	4	237.41	21	14	142.76	28	11	166.78	59	28
2015	243.28	162.98	308	78	243.28	7	4	170.58	23	9	136.85	30	6	194.38	74	24
2016	205.56	159.53	313	107	201.07	7	3	236.50	23	13	152.87	31	9	164.69	61	20
2017	240.64	167.89	332	89	209.84	7	3	222.93	25	12	176.49	32	7	179.60	90	24
RATIO 58 --- A/R OVER 60 DAYS AS A % OF OPERATING REVENUE																
2013	0.08	0.13	264	175	0.13	6	5	0.08	17	8	0.09	25	14	0.13	63	38
2014	0.15	0.13	290	133	0.09	7	3	0.12	20	9	0.08	28	9	0.16	59	31
2015	0.03	0.12	296	253	0.05	7	6	0.08	21	14	0.06	29	23	0.14	67	58
2016	0.02	0.11	307	278	0.04	7	6	0.10	23	18	0.05	31	28	0.14	60	59
2017	0.02	0.10	323	275	0.04	7	6	0.09	25	20	0.06	32	23	0.10	87	78

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 59 --- AMOUNT WRITTEN OFF AS A % OF OPERATING REVENUE																
2013	0.02	0.14	259	243	0.09	6	6	0.06	17	15	0.11	25	24	0.14	64	57
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	0.06	0.12	292	206	0.10	6	5	0.06	22	9	0.09	28	21	0.13	66	48
2016	0.01	0.10	303	278	0.04	7	6	0.03	20	18	0.06	31	29	0.10	60	57
2017	0.00	0.08	319	302	0.01	6	5	0.04	24	24	0.06	31	28	0.07	89	84
SALES (RATIOS 60-76)																
RATIO 60 --- TOTAL MWH SOLD PER MILE OF LINE																
2013	105.75	142.10	270	179	250.37	7	7	107.22	18	10	215.65	26	22	138.60	65	44
2014	100.28	137.05	295	206	263.49	7	7	85.95	21	10	215.85	28	24	134.76	59	42
2015	99.53	131.03	307	208	260.48	7	7	84.94	23	11	183.23	30	25	117.65	74	47
2016	107.22	130.84	312	192	249.47	7	7	86.87	23	10	177.34	31	24	127.48	61	39
2017	119.69	131.43	331	189	251.85	7	7	90.92	25	10	184.40	32	25	113.36	90	40
RATIO 61 --- AVERAGE RESIDENTIAL USAGE KWH PER MONTH																
2013	1,308.63	1,177.93	271	81	1,308.63	7	4	1,276.79	18	8	1,205.22	26	10	1,162.38	65	20
2014	1,261.21	1,196.18	296	120	1,261.21	7	4	1,257.19	21	10	1,174.14	28	11	1,243.92	59	26
2015	1,241.20	1,170.85	308	113	1,241.20	7	4	1,176.89	23	9	1,126.31	30	11	1,127.94	74	24
2016	1,250.27	1,143.75	313	97	1,246.89	7	3	1,212.15	23	11	1,098.56	31	10	1,158.15	61	22
2017	1,382.40	1,124.57	332	39	1,357.18	7	3	1,184.54	25	9	1,217.93	32	10	1,137.39	90	15
RATIO 62 --- AVERAGE SEASONAL KWH USAGE PER MONTH																
2013	763.75	314.11	89	11	522.66	4	1	349.36	7	1	474.70	10	1	351.79	21	3
2014	729.00	329.69	93	9	529.02	4	1	345.08	8	1	465.77	11	1	380.20	23	5
2015	707.53	291.26	93	7	514.22	4	1	312.08	8	1	458.52	11	1	291.26	23	2
2016	719.41	303.21	97	9	535.47	4	1	324.16	8	1	459.66	12	1	303.21	19	2
2017	824.97	317.17	98	9	612.09	3	1	330.02	8	1	482.79	12	1	345.63	31	4
RATIO 63 --- AVERAGE IRRIGATION KWH USAGE PER MONTH																
2013	687.93	2,564.31	143	134	14,635.45	4	4	1,674.05	13	12	3,916.66	22	20	2,646.33	37	35
2014	769.53	1,815.95	159	142	14,346.14	4	4	1,000.53	15	11	3,547.17	24	21	2,011.09	30	27
2015	917.11	1,688.38	164	130	12,964.39	4	4	1,074.89	17	10	3,738.53	26	23	1,763.70	35	26
2016	795.01	1,882.39	170	148	12,324.68	4	4	1,205.81	18	13	3,847.75	27	25	1,455.67	35	26
2017	768.17	1,982.26	180	162	11,402.44	4	4	1,420.52	18	15	3,299.58	28	25	1,878.47	45	37
RATIO 64 --- AVERAGE SMALL COMMERCIAL KWH USAGE PER MONTH																
2013	2,595.56	3,516.14	268	189	4,646.21	7	7	3,638.15	18	13	3,731.37	26	23	3,662.44	65	52
2014	2,459.03	3,556.66	295	216	3,788.82	7	6	3,649.74	21	16	3,669.39	28	24	3,509.49	59	48
2015	2,442.24	3,406.63	308	223	3,967.12	7	6	4,142.86	23	18	3,619.80	30	25	3,434.33	74	58
2016	2,456.69	3,449.96	313	226	4,163.83	7	5	4,098.91	23	18	3,569.10	31	24	3,710.25	61	51
2017	2,705.96	3,413.87	332	216	4,342.92	7	5	4,179.89	25	17	3,785.11	32	24	3,272.51	90	61

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 65 --- AVERAGE LARGE COMMERCIAL KWH USAGE PER MONTH																
2013	63,708.33	451,425.00	246	213	136,981.95	6	6	297,071.43	16	14	334,286.27	24	23	438,546.50	60	54
2014	59,466.67	435,885.42	270	234	141,401.52	7	6	242,166.67	18	17	367,495.10	27	24	606,395.83	52	47
2015	51,013.89	422,263.16	283	253	150,560.61	7	6	164,194.44	21	18	342,650.00	29	26	448,117.69	66	60
2016	56,611.11	427,753.97	283	257	127,174.42	7	6	177,650.00	21	19	269,675.60	30	26	457,758.15	55	52
2017	61,326.39	412,656.75	300	267	120,380.43	7	5	161,611.11	23	20	297,250.00	31	27	330,435.90	80	70
RATIO 66 --- AVERAGE STREET & HIGHWAY LIGHTING KWH USAGE PER MONTH																
2013	4,000.00	1,119.14	193	41	881.94	5	1	500.00	12	3	1,022.32	20	7	1,520.83	47	11
2014	2,333.33	1,116.40	214	74	881.94	5	1	416.67	13	3	1,092.26	22	8	1,263.89	47	17
2015	583.33	1,132.46	223	154	3,097.22	6	4	583.33	15	8	2,137.25	25	19	1,020.49	54	35
2016	583.33	1,194.44	223	160	583.33	5	3	734.85	15	9	1,194.44	25	19	1,118.28	51	34
2017	583.33	1,161.07	238	171	503.27	4	2	673.61	15	9	1,100.69	24	18	957.54	56	37
RATIO 69 --- RESIDENTIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2013	41.52	56.36	271	193	42.91	7	5	44.33	18	10	55.42	26	19	53.87	65	47
2014	41.57	57.45	296	212	41.57	7	4	41.57	21	11	54.28	28	20	54.73	59	41
2015	41.64	57.48	308	216	41.64	7	4	35.14	23	11	54.78	30	21	57.06	74	54
2016	41.84	56.33	313	215	41.84	7	4	34.93	23	10	52.83	31	21	58.04	61	44
2017	42.50	55.41	332	221	42.87	7	5	37.63	25	12	54.47	32	23	60.84	90	69
RATIO 70 --- SEASONAL KWH SOLD PER TOTAL KWH SOLD (%)																
2013	24.95	1.26	89	2	1.26	4	1	0.60	7	1	0.72	10	1	2.98	21	1
2014	25.07	1.31	93	1	1.27	4	1	0.73	8	1	0.86	11	1	2.53	23	1
2015	23.88	1.42	93	1	1.29	4	1	0.67	8	1	0.86	11	1	3.35	23	1
2016	23.65	1.51	97	1	1.30	4	1	0.78	8	1	0.74	12	1	1.77	19	1
2017	24.54	1.54	99	2	1.76	3	1	0.66	9	1	0.67	12	1	2.80	31	1
RATIO 71 --- IRRIGATION KWH SOLD PER TOTAL KWH SOLD (%)																
2013	2.94	1.59	143	63	31.99	4	4	1.65	13	6	1.89	22	10	2.13	37	18
2014	3.34	1.54	159	62	33.72	4	4	1.61	15	5	1.88	24	11	3.04	30	14
2015	3.93	1.79	164	61	33.42	4	4	2.56	17	6	2.40	26	12	2.58	35	14
2016	3.26	1.69	171	70	31.71	4	4	1.73	18	7	2.25	27	13	0.65	36	12
2017	2.82	1.51	180	84	29.47	4	4	2.17	18	9	2.82	28	15	0.84	45	20
RATIO 72 --- SMALL COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2013	16.60	17.92	268	149	16.01	7	3	12.33	18	7	16.74	26	14	18.53	65	40
2014	16.52	17.63	295	161	15.79	7	3	10.67	21	8	16.71	28	15	17.68	59	35
2015	16.71	17.76	308	172	16.62	7	3	16.63	23	11	17.87	30	18	17.59	74	42
2016	16.36	18.19	313	185	16.16	7	3	16.36	23	12	18.56	31	19	18.18	61	37
2017	15.78	18.45	332	205	15.78	7	4	17.05	25	15	18.70	32	21	15.43	90	45

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	**System Value**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**
RATIO 73 --- LARGE COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2013	13.90	15.21	246	131	11.46	6	2	35.16	16	11	11.00	24	9	13.80	60	29
2014	13.45	14.52	270	143	11.21	7	3	36.08	18	12	11.21	27	12	13.72	52	27
2015	13.82	15.23	283	152	11.56	7	3	30.84	21	13	11.21	29	12	13.31	66	33
2016	14.88	15.28	284	147	14.41	7	3	26.36	21	14	11.73	30	12	15.58	55	29
2017	14.35	15.92	300	163	14.35	7	4	24.70	23	14	10.74	31	13	13.85	80	39
RATIO 74 --- STREET & HIGHWAY LIGHTING KWH SOLD PER TOTAL KWH SOLD (%)																
2013	0.09	0.12	201	117	0.08	5	2	0.05	12	4	0.09	21	11	0.14	50	34
2014	0.05	0.11	220	150	0.06	5	4	0.05	13	5	0.08	23	17	0.14	48	38
2015	0.01	0.12	230	210	0.06	6	6	0.08	15	12	0.11	26	25	0.11	58	50
2016	0.01	0.12	228	206	0.05	5	5	0.08	15	13	0.09	26	25	0.12	52	47
2017	0.01	0.12	244	222	0.05	4	4	0.05	15	13	0.08	25	24	0.09	57	50
CONTROLLABLE EXPENSES (RATIOS 77-87)																
RATIO 77 --- O & M EXPENSES PER TOTAL KWH SOLD (MILLS)																
2013	9.62	10.69	271	154	9.76	7	5	12.06	18	12	10.10	26	15	11.10	65	38
2014	10.43	11.16	296	161	10.12	7	3	13.04	21	14	10.27	28	14	11.20	59	36
2015	9.16	11.87	308	206	11.20	7	5	11.84	23	17	11.10	30	20	12.24	74	54
2016	9.53	11.68	313	210	9.53	7	4	12.79	23	17	10.50	31	21	11.12	61	40
2017	9.86	12.08	332	220	9.86	7	4	13.54	25	17	11.12	32	21	13.85	90	66
RATIO 78 --- O & M EXPENSES PER DOLLARS OF TUP (MILLS)																
2013	44.96	40.88	271	104	42.58	7	2	43.95	18	9	43.29	26	11	41.88	65	26
2014	44.68	41.91	296	120	42.54	7	3	43.67	21	9	43.50	28	13	42.74	59	27
2015	38.01	41.25	308	188	41.27	7	6	40.44	23	13	42.27	30	20	40.29	74	45
2016	39.14	41.37	313	175	36.09	7	3	40.01	23	14	41.92	31	20	40.01	61	33
2017	43.94	39.77	332	129	37.64	7	3	39.30	25	9	43.97	32	17	42.91	90	45
RATIO 79 --- O & M EXPENSES PER CONSUMER ($)																
2013	149.36	243.75	271	233	223.22	7	6	342.17	18	18	266.70	26	22	246.81	65	56
2014	155.34	251.15	296	258	230.24	7	6	303.42	21	21	270.61	28	24	256.81	59	54
2015	136.19	256.02	308	286	254.98	7	6	340.67	23	23	285.64	30	27	251.15	74	71
2016	143.92	259.65	313	293	200.82	7	6	343.35	23	23	288.70	31	29	249.52	61	56
2017	164.40	265.23	332	293	217.72	7	6	317.37	25	25	300.94	32	28	280.51	90	85
RATIO 80 --- CONSUMER ACCOUNTING EXPENSES PER TOTAL KWH SOLD (MILLS)																
2013	4.51	2.68	271	29	2.33	7	1	2.44	18	3	2.64	26	5	2.93	65	9
2014	4.74	2.82	296	28	2.36	7	1	2.41	21	3	2.65	28	4	2.48	59	5
2015	5.23	2.92	308	25	2.45	7	1	2.38	23	3	2.90	30	3	2.94	74	9
2016	6.21	2.85	313	16	2.63	7	1	1.97	23	2	3.03	31	2	2.54	61	3
2017	4.57	2.87	332	52	2.46	7	1	2.15	25	5	2.99	32	4	2.91	90	16

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	**System Value**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**
RATIO 81 --- CONSUMER ACCOUNTING EXPENSES PER CONSUMER ($)																
2013	70.09	58.28	271	78	60.50	7	2	63.37	18	8	63.18	26	10	59.87	65	22
2014	70.59	58.58	296	90	51.50	7	2	65.13	21	9	59.74	28	10	54.93	59	16
2015	77.76	60.03	308	69	52.56	7	2	65.71	23	10	59.98	30	7	58.41	74	20
2016	93.74	58.88	313	38	53.25	7	2	66.41	23	6	64.34	31	6	52.49	61	6
2017	76.12	58.02	332	76	53.57	7	2	68.03	25	10	64.34	32	11	55.79	90	16
RATIO 82 --- CUSTOMER SALES AND SERVICE PER TOTAL KWH SOLD (MILLS)																
2013	-1.03	0.91	266	266	0.24	7	7	0.85	18	18	0.72	26	26	0.84	64	64
2014	0.19	0.87	290	257	0.43	6	5	1.09	21	19	0.98	27	24	0.88	58	53
2015	-0.44	0.92	303	303	0.18	7	7	1.01	23	23	0.76	30	30	0.98	72	72
2016	-0.31	0.95	307	307	0.05	7	7	1.29	23	23	0.79	31	31	0.98	61	61
2017	0.10	0.99	325	309	0.14	7	5	1.18	25	23	0.99	32	28	1.09	90	86
RATIO 83 --- CUSTOMER SALES AND SERVICE PER CONSUMER ($)																
2013	-16.02	19.93	266	266	7.30	7	7	25.82	18	18	16.23	26	26	19.74	64	64
2014	2.82	20.55	290	274	8.74	6	6	31.93	21	21	21.43	27	27	20.91	58	56
2015	-6.58	20.54	303	303	3.06	7	7	32.89	23	23	16.45	30	30	22.07	72	72
2016	-4.69	20.29	307	307	1.18	7	7	38.56	23	23	15.16	31	31	20.11	61	61
2017	1.69	20.35	325	319	2.75	7	5	37.41	25	24	21.28	32	28	22.18	90	88
RATIO 84 --- A & G EXPENSES PER TOTAL KWH SOLD (MILLS)																
2013	10.37	6.14	271	38	7.39	7	2	8.14	18	5	7.54	26	7	6.00	65	8
2014	12.23	6.26	296	29	7.80	7	2	7.92	21	5	7.92	28	3	6.22	59	5
2015	12.12	6.72	308	34	8.14	7	2	8.69	23	5	8.27	30	3	7.42	74	15
2016	12.19	7.06	313	43	8.26	7	2	8.94	23	7	8.50	31	5	7.28	61	8
2017	11.93	7.10	332	49	7.88	7	2	8.26	25	9	8.39	32	4	7.56	90	16
RATIO 85 --- A & G EXPENSES PER CONSUMER ($)																
2013	160.96	142.54	271	100	192.09	7	6	216.53	18	15	183.84	26	17	133.83	65	24
2014	182.17	150.68	296	90	247.34	7	5	230.63	21	17	186.55	28	15	140.94	59	18
2015	180.13	148.59	308	97	239.69	7	5	229.07	23	20	188.21	30	16	158.53	74	28
2016	184.06	150.91	313	103	219.61	7	5	248.47	23	20	203.39	31	17	145.23	61	19
2017	198.92	154.38	332	86	236.92	7	5	247.22	25	19	200.32	32	17	154.86	90	19
RATIO 86 --- TOTAL CONTROLLABLE EXPENSES PER TOTAL KWH SOLD (MILLS) (SAME AS RATIO #103)																
2013	23.47	20.69	271	95	21.01	7	2	23.20	18	9	21.23	26	11	20.98	65	23
2014	27.58	21.05	296	77	20.05	7	2	24.42	21	10	23.09	28	10	20.88	59	10
2015	26.07	22.61	308	108	22.45	7	2	26.04	23	11	23.92	30	12	24.43	74	32
2016	27.62	23.26	313	107	20.82	7	2	24.70	23	9	24.14	31	12	23.75	61	19
2017	26.47	23.54	332	135	22.69	7	2	26.80	25	14	25.01	32	15	26.33	90	45

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 87 --- TOTAL CONTROLLABLE EXPENSES PER CONSUMER ($) (SAME AS RATIO #104)																
2013	364.39	468.13	271	216	458.02	7	6	659.59	18	18	506.55	26	22	455.36	65	54
2014	410.92	479.03	296	206	462.13	7	6	662.46	21	21	523.24	28	23	485.04	59	43
2015	387.51	487.15	308	241	481.11	7	6	676.74	23	23	534.99	30	25	492.21	74	60
2016	417.03	500.46	313	231	417.03	7	4	740.35	23	23	562.68	31	23	484.27	61	43
2017	441.14	508.69	332	227	441.14	7	4	713.90	25	24	584.37	32	26	518.36	90	64
FIXED EXPENSES (RATIOS 88-102)																
RATIO 88 --- POWER COST PER KWH PURCHASED (MILLS)																
2013	38.39	65.43	271	242	33.82	7	1	66.71	18	15	34.01	26	2	65.43	65	59
2014	43.18	68.84	296	262	36.51	7	1	66.40	21	17	36.65	28	1	66.47	59	52
2015	42.15	65.55	307	273	37.01	7	1	67.06	23	18	36.91	30	1	69.82	73	66
2016	41.62	64.14	312	278	38.61	7	2	65.64	23	19	38.16	31	3	67.22	61	52
2017	41.16	65.72	331	297	39.09	7	2	65.38	25	22	38.84	32	5	69.05	90	82
RATIO 89 --- POWER COST PER TOTAL KWH SOLD (MILLS)																
2013	41.28	69.51	271	242	35.52	7	1	69.75	18	15	36.12	26	2	70.35	65	59
2014	46.41	72.44	296	262	38.22	7	1	70.68	21	17	38.48	28	1	70.47	59	51
2015	45.29	68.99	308	273	39.23	7	1	69.50	23	18	39.45	30	1	71.94	74	67
2016	44.94	68.42	313	276	40.39	7	1	69.63	23	18	40.39	31	1	72.00	61	52
2017	44.31	69.73	332	295	40.63	7	1	67.16	25	21	40.98	32	3	72.79	90	81
RATIO 90 --- POWER COST AS A % OF REVENUE																
2013	45.51	63.21	271	249	45.51	7	4	63.82	18	17	45.90	26	14	61.79	65	61
2014	47.17	64.00	296	267	45.74	7	3	60.99	21	20	45.68	28	12	64.27	59	53
2015	45.48	62.05	308	279	42.30	7	3	58.20	23	21	45.61	30	16	60.31	74	66
2016	45.85	61.35	313	282	45.11	7	3	61.50	23	21	45.85	31	16	61.89	61	56
2017	46.49	60.88	332	293	44.21	7	3	59.31	25	23	46.05	32	16	59.72	90	79
RATIO 91 --- LONG-TERM INTEREST COST PER TOTAL KWH SOLD (MILLS)																
2013	4.44	4.78	264	141	6.92	5	4	3.08	18	5	5.02	23	13	4.59	63	34
2014	4.52	4.57	290	147	6.86	5	4	3.41	21	8	5.12	25	14	4.39	56	27
2015	4.28	4.90	303	172	6.88	5	4	3.47	23	9	5.16	27	15	5.39	72	46
2016	3.98	4.81	306	178	7.31	5	4	3.59	23	10	4.58	28	16	4.93	58	37
2017	3.40	4.74	326	201	6.83	5	4	3.40	25	13	3.69	30	17	4.81	89	62
RATIO 92 --- LONG-TERM INTEREST COST AS A % OF TUP																
2013	2.08	1.79	264	86	2.51	5	4	1.09	18	2	1.65	23	7	1.80	63	25
2014	1.94	1.70	290	106	2.49	5	4	1.15	21	4	1.56	25	9	1.70	56	23
2015	1.78	1.64	303	132	2.30	5	4	1.14	23	6	1.55	27	11	1.72	72	34
2016	1.63	1.59	306	145	2.13	5	4	1.17	23	7	1.42	28	10	1.65	58	31
2017	1.52	1.53	326	166	1.99	5	4	1.01	25	9	1.23	30	11	1.52	89	45

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 93 --- LONG-TERM INTEREST COST PER CONSUMER ($)																
2013	68.97	99.09	264	187	175.21	5	5	79.33	18	10	97.44	23	17	92.55	63	40
2014	67.29	98.75	290	205	199.38	5	5	95.78	21	13	95.59	25	19	105.60	56	40
2015	63.61	99.48	303	215	188.82	5	4	78.52	23	14	94.07	27	19	106.63	72	54
2016	60.05	102.09	306	225	173.91	5	4	90.30	23	16	86.08	28	19	99.60	58	40
2017	56.74	97.96	326	247	161.05	5	4	76.99	25	19	83.12	30	21	95.96	89	71
RATIO 94 --- DEPRECIATION EXPENSE PER TOTAL KWH SOLD (MILLS)																
2013	6.49	7.63	271	174	6.49	7	4	6.88	18	10	7.28	26	17	7.91	65	44
2014	6.44	7.97	296	206	6.56	7	5	7.44	21	14	7.83	28	20	7.87	59	39
2015	6.60	8.43	308	224	7.63	7	5	8.37	23	16	8.32	30	22	8.98	74	57
2016	6.89	8.91	313	230	7.66	7	5	8.45	23	17	8.80	31	23	8.84	61	44
2017	6.02	9.33	332	274	7.24	7	5	8.09	25	20	8.95	32	25	9.21	90	77
RATIO 95 --- DEPRECIATION EXPENSE AS A % OF TUP																
2013	3.03	2.98	271	118	3.08	7	5	2.59	18	4	2.82	26	8	3.03	65	33
2014	2.76	2.99	296	215	3.14	7	5	2.65	21	10	2.78	28	16	3.05	59	43
2015	2.74	3.01	308	233	3.30	7	7	2.74	23	12	2.79	30	19	3.02	74	58
2016	2.83	3.00	313	217	3.33	7	6	2.83	23	12	2.77	31	14	3.05	61	45
2017	2.68	2.98	332	262	3.35	7	7	2.75	25	15	2.77	32	22	2.96	90	77
RATIO 96 --- DEPRECIATION EXPENSE PER CONSUMER ($)																
2013	100.75	168.33	271	253	168.77	7	6	193.88	18	17	170.07	26	23	170.04	65	62
2014	95.89	175.43	296	283	173.39	7	6	203.03	21	21	175.90	28	26	173.39	59	58
2015	98.09	183.88	308	295	178.40	7	6	209.90	23	23	188.34	30	28	183.63	74	73
2016	104.09	190.22	313	302	185.28	7	6	245.23	23	23	193.97	31	29	182.67	61	57
2017	100.38	194.32	332	318	192.66	7	6	232.61	25	24	195.09	32	30	187.30	90	88
RATIO 97 --- ACCUMULATIVE DEPRECIATION AS A % OF PLANT IN SERVICE																
2013	29.20	32.21	271	176	33.58	7	6	40.70	18	15	40.62	26	24	32.15	65	43
2014	29.61	32.43	296	191	34.65	7	6	38.26	21	16	41.10	28	25	33.03	59	42
2015	29.47	32.67	308	203	34.87	7	6	38.53	23	16	41.56	30	28	32.13	74	50
2016	30.60	33.25	313	200	37.51	7	6	39.15	23	15	41.76	31	29	33.72	61	41
2017	32.77	33.81	331	183	37.38	7	6	42.06	25	16	42.35	32	29	34.85	90	56
RATIO 98 --- TOTAL TAX EXPENSE PER TOTAL KWH SOLD (MILLS)																
2013	3.60	1.10	231	28	4.21	7	5	0.69	14	2	2.60	26	7	1.37	57	8
2014	3.82	1.07	250	26	4.39	7	5	0.64	16	2	2.81	28	7	1.69	51	9
2015	3.89	1.08	255	21	4.03	7	5	1.12	17	2	2.74	30	7	1.28	62	8
2016	3.79	1.02	257	26	4.28	7	5	1.13	16	1	2.93	30	8	1.13	54	5
2017	3.68	1.05	271	36	4.00	7	6	0.84	17	1	2.73	32	9	1.05	77	9

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 99 --- TOTAL TAX EXPENSE AS A % OF TUP																
2013	1.68	0.47	231	18	1.80	7	5	0.34	14	1	0.88	26	6	0.51	57	6
2014	1.64	0.47	250	16	1.80	7	5	0.40	16	1	0.81	28	6	0.61	51	7
2015	1.61	0.44	255	15	1.70	7	5	0.43	17	2	0.77	30	6	0.44	62	6
2016	1.56	0.43	257	16	1.71	7	5	0.39	16	1	0.80	30	7	0.41	54	3
2017	1.64	0.45	271	15	1.75	7	5	0.30	17	1	0.76	32	7	0.46	77	6
RATIO 100 --- TOTAL TAX EXPENSE PER CONSUMER																
2013	55.86	25.96	231	52	101.75	7	7	27.22	14	2	53.59	26	11	30.72	57	12
2014	56.86	25.21	250	57	103.12	7	7	30.12	16	3	53.16	28	13	36.82	51	16
2015	57.77	24.26	255	53	102.63	7	7	29.97	17	3	53.04	30	13	26.37	62	15
2016	57.20	23.06	257	51	103.05	7	7	31.16	16	3	55.30	30	15	22.99	54	10
2017	61.37	25.09	271	51	112.34	7	7	30.05	17	3	54.01	32	14	26.58	77	16
RATIO 101 --- TOTAL FIXED EXPENSES PER TOTAL KWH SOLD (MILLS)																
2013	55.81	82.31	271	245	54.57	7	2	78.37	18	15	53.85	26	8	84.76	65	59
2014	61.18	86.08	296	261	57.99	7	2	79.73	21	17	57.61	28	3	84.78	59	51
2015	60.06	83.97	308	277	59.27	7	3	81.73	23	19	56.76	30	11	87.42	74	68
2016	59.59	84.33	313	283	59.59	7	4	82.36	23	19	57.39	31	13	84.51	61	55
2017	57.42	85.59	332	305	59.16	7	5	83.43	25	21	57.33	32	16	85.51	90	81
RATIO 102 --- TOTAL FIXED EXPENSES PER CONSUMER ($)																
2013	866.40	1,756.75	271	262	1,253.36	7	7	2,035.05	18	17	1,152.25	26	22	1,761.01	65	64
2014	911.49	1,825.90	296	286	1,359.67	7	7	2,054.07	21	20	1,214.00	28	25	1,838.85	59	57
2015	892.64	1,755.14	308	299	1,334.70	7	7	1,959.46	23	22	1,190.90	30	27	1,712.16	74	71
2016	899.95	1,740.03	313	302	1,341.19	7	7	2,007.72	23	22	1,212.49	31	28	1,694.93	61	59
2017	957.11	1,712.39	332	317	1,413.10	7	7	2,048.11	25	22	1,248.48	32	28	1,634.07	90	86

TOTAL EXPENSES (RATIOS 103-107)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 103 --- TOTAL OPERATING EXPENSES PER TOTAL KWH SOLD (MILLS)																
2013	23.47	20.69	271	95	21.01	7	2	23.20	18	9	21.23	26	11	20.98	65	23
2014	27.58	21.05	296	77	20.05	7	2	24.42	21	10	23.09	28	10	20.88	59	10
2015	26.07	22.61	308	108	22.45	7	2	26.04	23	11	23.92	30	12	24.43	74	32
2016	27.62	23.26	313	107	20.82	7	2	24.70	23	9	24.14	31	12	23.75	61	19
2017	26.47	23.54	332	135	22.69	7	2	26.80	25	14	25.01	32	15	26.33	90	45
RATIO 104 --- TOTAL OPERATING EXPENSES PER CONSUMER ($)																
2013	364.39	468.13	271	216	458.02	7	6	659.59	18	18	506.55	26	22	455.36	65	54
2014	410.92	479.03	296	206	462.13	7	6	662.46	21	21	523.24	28	23	485.04	59	43
2015	387.51	487.15	308	241	481.11	7	6	676.74	23	23	534.99	30	25	492.21	74	60
2016	417.03	500.46	313	231	417.03	7	4	740.35	23	23	562.68	31	23	484.27	61	43
2017	441.14	508.69	332	227	441.14	7	4	713.90	25	24	584.37	32	26	518.36	90	64

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 105 --- TOTAL COST OF SERVICE (MINUS POWER COSTS) PER TOTAL KWH SOLD (MILLS)																
2013	38.00	34.77	271	111	38.00	7	4	34.96	18	8	37.84	26	13	34.32	65	25
2014	42.35	35.66	296	100	39.82	7	3	37.69	21	10	39.17	28	12	34.69	59	17
2015	40.84	38.07	308	122	41.10	7	5	38.57	23	11	40.77	30	15	39.85	74	35
2016	42.27	37.80	313	127	40.96	7	3	37.65	23	9	40.96	31	15	39.45	61	27
2017	39.57	39.20	332	164	39.57	7	4	39.57	25	13	42.27	32	18	41.19	90	51
RATIO 106 --- TOTAL COST OF ELECTRIC SERVICE PER TOTAL KWH SOLD (MILLS)																
2013	79.28	102.85	271	237	74.82	7	2	97.92	18	15	72.63	26	10	105.52	65	59
2014	88.77	106.70	296	240	78.04	7	2	102.74	21	15	76.17	28	8	107.72	59	46
2015	86.13	106.75	308	252	83.45	7	2	107.86	23	17	79.41	30	11	113.28	74	65
2016	87.21	106.52	313	249	79.00	7	2	105.37	23	17	82.37	31	10	107.57	61	49
2017	83.89	108.58	332	287	82.37	7	2	110.23	25	19	82.72	32	15	111.86	90	79
RATIO 107 --- TOTAL COST OF ELECTRIC SERVICE PER CONSUMER ($)																
2013	1,230.79	2,185.90	271	267	1,711.38	7	7	2,690.06	18	18	1,629.29	26	25	2,205.91	65	65
2014	1,322.40	2,314.58	296	291	1,798.59	7	7	2,902.51	21	21	1,684.11	28	27	2,257.90	59	58
2015	1,280.15	2,225.39	308	302	1,792.11	7	7	2,586.08	23	23	1,723.46	30	29	2,184.88	74	73
2016	1,316.98	2,226.86	313	306	1,745.63	7	7	2,590.73	23	23	1,745.63	31	31	2,176.96	61	60
2017	1,398.25	2,220.89	332	322	1,847.89	7	7	2,762.00	25	25	1,804.10	32	30	2,103.19	90	88
EMPLOYEES (RATIOS 108-113)																
RATIO 108 --- AVERAGE WAGE RATE PER HOUR ($)																
2013	41.98	33.88	270	31	41.98	7	4	34.92	18	6	40.73	26	10	34.68	65	9
2014	42.72	34.36	295	34	43.36	7	6	34.63	21	6	42.69	28	14	35.84	59	12
2015	51.80	35.27	307	7	46.50	7	1	36.44	23	3	43.02	30	2	35.75	74	3
2016	42.66	36.58	312	47	45.91	7	6	37.56	23	6	42.66	31	16	36.72	61	9
2017	44.23	37.42	330	47	47.45	7	7	39.24	25	7	44.88	32	18	37.62	89	12
RATIO 109 --- TOTAL WAGES PER TOTAL KWH SOLD (MILLS)																
2013	17.71	11.13	270	38	12.74	7	1	14.21	18	4	12.36	26	6	11.52	65	8
2014	20.71	11.13	295	25	13.31	7	1	14.61	21	4	13.02	28	3	11.11	59	4
2015	20.87	11.94	307	31	14.06	7	1	13.34	23	5	13.85	30	3	12.38	74	11
2016	19.71	12.09	312	40	13.81	7	1	13.76	23	7	14.12	31	4	11.88	61	6
2017	18.16	12.38	331	68	13.45	7	2	15.03	25	9	14.03	32	8	13.89	89	24
RATIO 110 --- TOTAL WAGES PER CONSUMER ($)																
2013	275.01	250.68	270	109	271.20	7	3	345.33	18	18	288.40	26	14	249.84	65	28
2014	308.55	249.15	295	84	293.47	7	3	342.87	21	17	292.86	28	13	248.94	59	16
2015	310.26	259.47	307	92	310.26	7	4	353.09	23	18	305.82	30	15	258.60	74	21
2016	297.69	267.70	312	113	297.69	7	4	396.96	23	20	296.78	31	15	266.85	61	22
2017	302.69	273.75	331	119	302.69	7	4	379.75	25	21	299.69	32	15	280.34	89	34

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	**System Value**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**	**Median**	**NBR**	**Rank**
RATIO 111 --- OVERTIME HOURS/TOTAL HOURS (%)																
2013	1.39	4.28	270	264	3.14	7	5	3.83	18	17	3.02	26	22	4.11	65	63
2014	6.43	4.33	295	58	3.96	7	3	2.87	21	4	3.62	28	7	4.44	58	10
2015	4.80	4.39	307	128	4.80	7	4	3.77	23	7	4.13	30	12	4.55	73	32
2016	1.15	4.41	312	309	4.43	7	6	3.52	23	22	3.52	31	29	4.82	61	61
2017	1.18	4.63	330	325	4.55	7	6	3.21	25	24	3.63	32	30	4.59	90	89
RATIO 112 --- CAPITALIZED PAYROLL / TOTAL PAYROLL (%)																
2013	21.53	22.29	268	153	17.75	7	2	20.18	18	8	18.13	26	6	22.51	65	41
2014	24.02	21.67	293	116	15.52	7	1	16.74	21	6	15.88	28	6	22.58	58	27
2015	26.79	21.58	305	71	17.25	7	1	20.13	23	3	19.24	30	8	20.89	73	16
2016	19.95	21.75	309	192	16.43	7	3	19.49	22	11	16.52	30	12	24.12	61	38
2017	17.36	22.00	328	238	16.86	7	3	17.96	24	14	17.11	32	16	21.89	89	65
RATIO 113 --- AVERAGE CONSUMERS PER EMPLOYEE																
2013	322.00	300.47	271	113	328.50	7	5	217.05	18	1	316.63	26	13	296.08	65	26
2014	296.75	301.72	296	154	310.80	7	5	190.24	21	2	309.53	28	16	302.67	59	32
2015	298.00	304.72	308	160	298.00	7	4	204.75	23	2	295.28	30	15	312.67	74	41
2016	302.33	300.00	313	154	302.33	7	4	206.31	23	1	288.40	31	15	314.95	61	35
2017	307.58	297.56	332	159	307.58	7	4	219.08	25	2	302.64	32	16	305.66	90	45
GROWTH (RATIOS 114-121)																
RATIO 114 --- ANNUAL GROWTH IN KWH SOLD (%)																
2013	1.38	3.18	268	188	2.70	6	5	3.76	18	12	2.88	24	16	2.67	65	39
2014	-3.53	2.26	295	266	-1.73	7	7	0.92	21	17	-1.19	28	25	2.26	59	52
2015	0.19	-1.71	308	97	-2.02	7	3	-5.25	23	4	-2.18	30	6	-2.07	74	25
2016	3.08	0.41	312	66	-0.18	7	2	1.34	23	7	0.63	31	7	0.40	61	10
2017	12.29	-0.30	328	15	5.17	7	1	2.41	25	3	6.21	32	2	-0.24	90	4
RATIO 115 --- ANNUAL GROWTH IN NUMBER OF CONSUMERS (%)																
2013	1.17	0.70	268	76	1.14	6	3	0.46	18	4	0.78	24	5	0.58	65	18
2014	0.54	0.65	295	165	1.32	7	6	0.30	21	9	0.84	28	17	0.55	59	31
2015	0.42	0.58	308	186	1.28	7	6	0.26	23	9	0.64	30	22	0.49	74	43
2016	1.45	0.56	312	60	1.45	7	4	0.43	23	2	0.93	31	11	0.76	61	18
2017	1.74	0.64	328	55	1.45	7	3	0.60	25	2	1.02	32	6	0.55	90	14
RATIO 116 --- ANNUAL GROWTH IN TUP DOLLARS (%)																
2013	3.60	4.04	268	159	4.27	6	5	4.59	18	11	3.29	24	11	3.93	65	39
2014	5.24	3.93	295	86	5.22	7	3	3.19	21	6	2.75	28	4	4.38	59	17
2015	3.50	3.70	308	168	3.68	7	5	3.50	23	12	3.21	30	14	3.83	74	48
2016	4.09	3.65	312	125	4.41	7	5	4.09	23	12	3.07	31	11	4.20	61	36
2017	3.53	3.62	328	173	3.53	7	4	3.53	25	13	3.19	32	13	3.47	90	43

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 117 --- CONST. W.I.P. TO PLANT ADDITIONS (%)																
2013	85.17	23.85	266	40	56.64	6	2	18.78	18	5	18.35	24	2	31.95	65	10
2014	28.01	27.81	292	144	51.21	6	5	11.49	21	7	28.01	27	14	18.43	59	26
2015	34.01	20.43	302	112	34.01	7	4	10.56	22	9	24.57	30	12	20.71	72	24
2016	29.08	22.68	310	121	29.08	7	4	15.33	23	8	21.10	31	12	27.15	61	25
2017	99.93	21.94	327	33	57.68	7	1	23.32	24	4	31.76	31	5	17.47	87	5
RATIO 118 --- NET NEW SERVICES TO TOTAL SERVICES (%)																
2013	0.90	0.71	268	101	1.06	7	5	0.76	18	6	0.40	26	8	0.61	65	27
2014	0.89	0.65	287	112	1.00	7	5	0.36	20	6	0.71	28	12	0.71	59	22
2015	0.47	0.58	303	178	0.66	7	5	0.42	22	10	0.55	29	16	0.56	74	43
2016	1.61	0.63	307	55	1.61	7	4	0.46	23	2	0.71	31	7	0.71	61	12
2017	1.71	0.66	323	50	1.63	6	3	0.49	24	3	0.86	31	6	0.64	89	12
RATIO 119 --- ANNUAL GROWTH IN TOTAL CAPITALIZATION (%)																
2013	2.44	5.39	268	211	4.09	6	5	6.01	18	13	3.20	24	16	5.05	65	50
2014	9.73	3.22	295	35	5.22	7	1	2.50	21	5	1.23	28	1	3.89	59	7
2015	0.83	3.34	308	233	1.25	7	5	2.64	23	15	0.50	30	14	3.82	74	63
2016	1.75	2.86	312	193	1.75	7	4	1.84	23	13	1.98	31	17	3.65	61	42
2017	5.03	2.86	328	93	2.86	7	2	0.96	25	6	2.78	32	9	2.07	90	20
RATIO 120 --- 2 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)																
2013	6.71	4.63	268	75	7.81	6	4	5.03	18	6	3.51	25	5	4.30	65	16
2014	6.02	4.53	292	95	4.63	6	3	4.45	21	10	2.84	26	6	5.47	58	21
2015	5.19	3.56	307	101	2.50	7	3	3.58	23	8	0.88	30	6	4.36	74	27
2016	1.29	3.04	311	240	2.46	7	5	2.52	23	17	1.29	31	17	3.86	61	55
2017	3.38	3.07	327	150	3.38	7	4	2.77	25	9	2.10	32	10	2.42	90	31
RATIO 121 --- 5 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)																
2013	5.96	4.67	266	82	10.45	6	5	5.20	17	6	4.41	25	6	4.50	65	10
2014	6.56	4.48	290	65	7.92	6	4	5.40	20	8	3.95	27	6	4.31	59	8
2015	5.70	4.44	304	85	5.32	6	3	5.58	23	11	3.35	29	4	4.74	74	18
2016	5.09	4.11	307	108	3.98	6	3	5.09	23	12	2.63	30	8	4.66	61	21
2017	3.91	3.90	322	161	3.51	6	3	4.77	24	15	2.44	31	9	3.06	90	30
PLANT (RATIOS 122-145)																
RATIO 122 --- TUP INVESTMENTS PER TOTAL KWH SOLD (CENTS)																
2013	21.40	26.03	271	182	22.92	7	5	24.86	18	12	26.15	26	18	26.08	65	47
2014	23.34	26.69	296	188	23.80	7	5	28.92	21	13	27.63	28	19	26.24	59	39
2015	24.11	28.49	308	203	26.38	7	5	31.72	23	15	29.48	30	22	29.48	74	53
2016	24.35	29.86	313	218	26.16	7	5	32.56	23	14	31.90	31	22	29.67	61	43
2017	22.45	30.92	332	254	24.60	7	5	32.69	25	18	30.39	32	25	31.94	90	73

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 123 --- TUP INVESTMENT PER CONSUMER ($)																
2013	3,321.71	5,645.29	271	256	5,242.15	7	6	7,283.20	18	17	6,164.19	26	23	5,736.36	65	64
2014	3,476.96	5,788.05	296	281	5,483.92	7	6	7,826.86	21	20	6,562.48	28	25	5,737.09	59	57
2015	3,583.40	6,073.92	308	292	5,652.03	7	6	8,046.89	23	22	6,787.19	30	27	5,837.08	74	71
2016	3,676.67	6,278.82	313	296	5,780.29	7	6	9,084.83	23	22	6,988.70	31	28	5,973.42	61	54
2017	3,741.45	6,397.67	332	313	5,804.38	7	6	9,287.57	25	23	7,009.34	32	29	6,356.64	90	88
RATIO 124 --- TUP INVESTMENT PER MILE OF LINE ($)																
2013	22,625.98	33,411.53	270	221	68,960.49	7	7	25,247.79	18	14	48,103.78	26	25	32,405.41	65	55
2014	23,405.38	34,516.02	295	243	71,452.80	7	7	25,840.87	21	16	50,064.55	28	26	32,790.75	59	48
2015	23,996.67	35,477.33	307	258	74,034.98	7	7	26,947.66	23	17	51,294.20	30	28	33,879.98	74	64
2016	26,103.61	36,502.59	312	246	80,376.70	7	7	27,651.05	23	17	53,270.16	31	29	35,537.89	61	52
2017	26,867.14	38,148.98	331	259	84,107.63	7	7	28,982.37	25	18	53,287.50	32	30	34,787.99	90	66
RATIO 125 --- AVERAGE CONSUMERS PER MILE																
2013	6.81	6.31	270	118	6.81	7	4	3.54	18	4	7.47	26	16	6.30	65	27
2014	6.73	6.32	295	129	6.73	7	4	3.50	21	4	7.48	28	17	6.02	59	24
2015	6.70	6.01	307	137	6.70	7	4	3.46	23	4	7.06	30	18	6.01	74	30
2016	7.10	6.07	312	128	7.10	7	4	3.48	23	4	7.10	31	16	6.70	61	27
2017	7.18	6.42	331	138	7.18	7	4	3.62	25	4	7.19	32	17	5.64	90	31
RATIO 126 --- DISTRIBUTION PLANT PER TOTAL KWH SOLD (MILLS)																
2013	168.63	210.72	270	183	185.53	6	5	196.35	18	11	192.75	25	15	214.15	65	50
2014	182.33	217.29	295	195	187.00	6	4	246.22	21	14	199.00	27	16	224.61	59	40
2015	190.83	231.72	308	208	204.95	7	5	253.13	23	16	233.19	30	19	246.72	74	56
2016	192.79	245.49	312	217	219.96	6	5	260.75	23	15	246.73	30	20	247.87	60	44
2017	174.27	254.15	332	254	203.92	7	5	257.55	25	16	242.20	32	22	283.28	90	75
RATIO 127 --- DISTRIBUTION PLANT PER CONSUMER ($)																
2013	2,617.91	4,654.96	270	256	5,968.43	6	6	5,265.16	18	17	4,800.63	25	24	4,705.70	65	64
2014	2,716.26	4,751.58	295	279	6,002.30	6	6	5,663.64	21	20	4,893.22	27	26	4,914.48	59	57
2015	2,836.26	4,930.83	308	291	4,703.76	7	6	5,804.51	23	22	5,062.84	30	28	4,964.87	74	71
2016	2,911.30	5,098.88	312	295	4,677.89	6	5	7,064.46	23	22	5,141.40	30	28	5,078.39	60	55
2017	2,904.75	5,194.22	332	313	4,811.01	7	6	6,273.77	25	23	5,209.64	32	30	5,167.29	90	88
RATIO 128 --- DISTRIBUTION PLANT PER EMPLOYEE ($)																
2013	842,968.56	1,368,475.44	270	252	1,687,532.98	6	6	1,063,394.22	18	15	1,244,840.01	25	24	1,395,118.68	65	62
2014	806,050.40	1,429,882.33	295	283	1,720,949.33	6	6	1,202,378.55	21	18	1,352,995.90	27	26	1,483,402.32	59	57
2015	845,205.30	1,499,364.96	308	296	1,599,135.32	7	7	1,280,366.00	23	20	1,450,549.94	30	29	1,535,395.10	74	71
2016	880,182.08	1,550,521.19	312	300	1,553,893.60	6	6	1,328,849.19	23	20	1,466,906.90	30	29	1,617,581.44	60	58
2017	893,452.20	1,591,373.34	332	318	1,741,312.53	7	7	1,340,528.88	25	22	1,521,626.69	32	31	1,620,217.55	90	87

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 129 --- GENERAL PLANT PER TOTAL KWH SOLD (MILLS)																
2013	21.67	17.84	269	99	20.80	7	3	24.45	18	11	20.25	26	11	18.55	65	24
2014	24.55	18.25	294	83	21.17	7	3	25.29	21	12	20.30	28	8	19.48	59	18
2015	25.07	19.92	304	94	23.79	6	3	29.81	23	13	21.48	29	11	20.42	73	26
2016	27.81	20.47	309	83	27.81	5	3	27.81	23	12	23.65	29	9	20.21	60	13
2017	25.43	21.33	328	121	25.72	6	4	26.91	24	13	22.81	31	11	22.82	89	36
RATIO 130 --- GENERAL PLANT PER CONSUMER ($)																
2013	336.48	402.34	269	171	489.95	7	5	751.72	18	17	460.56	26	20	398.06	65	43
2014	365.67	409.87	294	173	508.40	7	5	788.98	21	19	433.81	28	21	434.12	59	37
2015	372.54	423.26	304	181	562.09	6	5	825.54	23	21	468.66	29	23	388.49	73	39
2016	419.94	442.44	309	170	580.46	5	4	803.07	23	21	471.53	29	21	409.52	60	27
2017	423.90	450.58	328	186	644.61	6	5	858.36	24	22	500.66	31	24	456.79	89	52
RATIO 131 --- GENERAL PLANT PER EMPLOYEE ($)																
2013	108,347.54	116,487.18	269	156	141,879.73	7	6	137,401.16	18	13	140,986.81	26	21	117,856.85	65	41
2014	108,511.30	121,691.95	294	180	152,201.79	7	6	133,687.44	21	15	139,786.03	28	23	132,088.86	59	42
2015	111,017.96	125,861.52	304	195	151,428.87	6	5	139,891.65	23	17	140,345.70	29	25	125,330.29	73	50
2016	126,961.42	129,540.25	309	164	161,027.35	5	4	142,406.65	23	14	141,901.00	29	19	130,192.75	60	34
2017	130,385.14	134,349.78	328	174	168,519.46	6	5	151,841.27	24	16	149,512.93	31	21	141,018.47	89	52
RATIO 132 --- HEADQUARTERS PLANT PER TOTAL KWH SOLD (MILLS)																
2013	19.00	9.44	219	36	16.91	5	2	7.99	13	2	12.69	20	6	9.85	55	7
2014	22.65	10.24	246	32	16.58	5	2	9.67	16	3	11.85	22	4	9.92	44	4
2015	21.44	10.72	258	45	16.07	4	2	9.93	18	3	12.14	23	5	11.37	61	12
2016	19.30	11.45	262	63	19.30	3	2	11.23	20	6	13.80	23	8	12.48	48	8
2017	17.94	12.58	278	80	13.95	4	2	10.59	22	5	11.97	26	7	11.97	74	19
RATIO 133 --- HEADQUARTERS PLANT PER CONSUMER ($)																
2013	295.05	217.69	219	76	295.05	5	3	304.86	13	8	299.95	20	11	217.35	55	18
2014	337.37	230.85	246	68	337.37	5	3	333.94	16	8	300.06	22	8	236.71	44	13
2015	318.66	250.86	258	87	280.19	4	2	335.97	18	11	289.40	23	9	254.44	61	21
2016	291.49	259.99	262	113	291.49	3	2	371.42	20	14	291.49	23	12	250.61	48	17
2017	299.02	278.36	278	121	302.59	4	3	359.64	22	14	286.65	26	11	252.48	74	28
RATIO 134 --- HEADQUARTERS PLANT PER EMPLOYEE ($)																
2013	95,005.64	62,668.35	219	63	95,005.64	5	3	53,769.76	13	4	80,832.71	20	8	60,201.53	55	15
2014	100,114.62	67,136.05	246	70	100,114.62	5	3	55,376.32	16	4	71,973.92	22	9	66,634.44	44	15
2015	94,960.54	70,069.32	258	84	80,390.22	4	2	60,427.55	18	6	68,858.77	23	8	73,681.20	61	22
2016	88,126.13	77,585.66	262	109	88,126.13	3	2	81,835.94	20	9	77,999.66	23	10	76,654.40	48	19
2017	91,972.37	82,305.94	278	118	83,104.29	4	2	81,272.71	22	9	79,542.07	26	10	72,595.71	74	30

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

RATIO 138 --- IDLE SERVICES TO TOTAL SERVICE (%)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2012-2017) Median	Plant Growth (2012-2017) NBR	Plant Growth (2012-2017) Rank
2013	2.47	7.21	257	210	2.47	7	4	9.30	16	13	2.90	25	15	9.24	60	47
2014	2.36	7.23	283	233	2.32	7	3	8.85	19	15	2.45	27	15	6.43	56	44
2015	3.05	7.30	295	227	2.51	7	3	7.80	21	15	3.12	29	16	7.39	70	56
2016	3.00	7.20	301	227	2.67	7	3	5.83	22	14	3.07	30	16	5.33	58	45
2017	2.81	7.07	316	239	2.15	7	1	5.56	24	16	2.80	31	14	6.11	86	64

RATIO 139 --- LINE LOSS (%)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2012-2017) Median	Plant Growth (2012-2017) NBR	Plant Growth (2012-2017) Rank
2013	6.86	5.71	271	77	4.93	7	2	6.19	18	7	5.83	26	6	5.87	65	20
2014	6.83	5.21	295	62	4.67	7	1	5.80	21	9	5.12	28	3	4.89	59	13
2015	6.79	5.11	306	67	5.18	7	2	5.92	23	9	5.61	30	9	5.54	73	20
2016	7.24	5.47	311	76	4.84	7	1	5.91	23	8	6.07	31	10	5.45	60	18
2017	6.97	5.48	330	84	5.08	7	1	6.37	25	10	5.48	32	7	5.79	90	25

RATIO 140 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - POWER SUPPLIER

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2012-2017) Median	Plant Growth (2012-2017) NBR	Plant Growth (2012-2017) Rank
2013	740.00	9.50	271	1	47.88	7	1	7.63	18	1	6.05	26	1	7.07	65	1
2014	11,520.00	9.11	296	2	10.99	7	1	6.60	21	1	3.17	28	1	9.12	59	1
2015	1,933.00	11.71	308	1	108.18	7	1	5.56	23	1	5.94	30	1	12.46	74	1
2016	395.00	10.91	313	4	51.68	7	1	7.75	23	1	7.41	31	1	8.30	61	2
2017	8.00	7.08	332	157	0.40	7	2	6.46	25	12	2.42	32	10	5.41	90	40

RATIO 141 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - EXTREME STORM

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2012-2017) Median	Plant Growth (2012-2017) NBR	Plant Growth (2012-2017) Rank
2013	0.00	17.09	271	263	0.00	7	6	11.28	18	18	4.64	26	24	22.65	65	64
2014	0.00	13.72	296	291	54.48	7	6	2.41	21	21	28.74	28	26	0.96	59	58
2015	715.00	15.28	308	14	245.52	7	3	0.86	23	1	33.65	30	5	2.51	74	3
2016	117.00	13.91	313	60	1.02	7	1	0.60	23	4	2.65	31	3	20.19	61	14
2017	107.69	19.67	332	85	4.80	7	2	0.11	25	5	5.40	32	7	4.55	90	22

RATIO 142 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - PREARRANGED

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2012-2017) Median	Plant Growth (2012-2017) NBR	Plant Growth (2012-2017) Rank
2013	300.22	1.61	271	3	10.16	7	1	1.11	18	2	3.23	26	2	3.91	65	1
2014	25.91	1.63	296	29	0.10	7	1	1.80	21	2	2.35	28	6	4.86	59	8
2015	4.32	2.06	308	120	3.55	7	3	1.83	23	9	4.79	30	16	3.70	74	35
2016	7.56	2.20	313	84	7.56	7	4	3.93	23	7	5.91	31	14	4.96	61	23
2017	64.00	2.53	332	13	4.62	7	2	2.00	25	2	5.62	32	3	1.99	90	4

RATIO 143 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - ALL OTHER

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2012-2017) Median	Plant Growth (2012-2017) NBR	Plant Growth (2012-2017) Rank
2013	3.30	81.78	271	237	103.16	7	6	47.36	18	15	91.23	26	22	92.87	65	59
2014	1,294.19	84.74	296	4	105.31	7	1	55.72	21	1	92.02	28	1	105.12	59	1
2015	64.15	88.45	308	199	64.15	7	4	60.70	23	11	78.71	30	18	94.51	74	48
2016	136.72	97.80	313	103	96.51	7	3	87.95	23	7	108.17	31	10	108.17	61	23
2017	128.73	87.02	332	111	32.90	7	2	70.53	25	5	87.19	32	9	80.38	90	30

2017 Key Ratio Trend Analysis (KRTA) for Independent Cooperatives
Okanogan County Electric Cooperative, Inc. (WA032)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2012-2017)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 144 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - TOTAL																
2013	1,043.52	170.80	271	15	243.05	7	1	189.89	18	2	168.55	26	2	175.86	65	3
2014	12,840.10	161.21	296	2	228.05	7	1	90.08	21	1	157.74	28	1	188.00	59	1
2015	2,716.47	177.39	308	8	306.67	7	2	147.69	23	1	192.69	30	3	171.36	74	1
2016	656.28	170.80	313	35	162.50	7	1	143.40	23	2	162.50	31	3	189.65	61	7
2017	308.42	183.23	332	108	107.65	7	2	187.56	25	7	132.43	32	11	139.32	90	22
RATIO 145 --- AVG. SERVICE AVAILABILITY INDEX (ASAI) - TOTAL (%)																
2013	99.80	99.97	271	257	99.95	7	7	99.96	18	17	99.97	26	25	99.97	65	63
2014	97.56	99.97	296	295	99.96	7	7	99.98	21	21	99.97	28	28	99.96	59	59
2015	99.48	99.97	308	301	99.94	7	6	99.97	23	23	99.96	30	28	99.97	74	74
2016	99.88	99.97	313	279	99.97	7	7	99.97	23	22	99.97	31	29	99.96	61	55
2017	99.94	99.97	332	226	99.98	7	6	99.96	25	19	99.97	32	22	99.97	90	70

Revision Date:
7/18/2018

Okanogan County Electric Cooperative
Okanogan County Energy Incorporated
2018 Balanced Scorecard Goals - 2nd Quarter Results

		Percent of Award	*YTD Results*	*2018 Goals Minimum*	*2018 Goals Target*	*2018 Goals Maximum*	*Comments*	*Bonus Tally*
Strategic Objective	**Operational Performance**							
Increase Subsidiary Revenue and Operational Efficiencies	1) Propane Sales (in Thousands)	10%	481	760	895	Open	Total propane gallons sold. For every 5,000 gallons sold over target, and additional $5 is added to bonus.	
	2) Electric Year-end Inventory Audit Adjustments	10%	N/A	$ 7,237	$ 6,031	Open	Target is calculated from adding together both the positive and the negative differences of the inventory adjustments without regards to whether they are positive or negative adjustments. The goal is to reduce both positive and negative inventory adjustments. There is a $10 increase in bonus for every $1,000 less than target.	
	3) Propane Year-end Inventory Audit Adjustments	10%	N/A	$ 5,656	$ 4,713	Open	See Electric Inventory Audit above for description.	
	4) Installed coop-owned propane tanks - net	10%	28	50	75	Open	Target is a net increase in coop owned tanks. For every net tank over target, an additional $5 added to bonus.	
Maintain Public and Employee Safety	1) Random Vehicle Inspection	5%	4	7	8	9	Randomly inspect 2 or 3 vehicles a month starting in March. Create checklist i.e. windows, interior, exterior, bins, mechanical ect. Pass/Fail per category. Need 80% of each vehicle to pass. Target is to pass 8 months out of the year.	
	2) Increase Office Training on EAP, Bulk Propane, Mayday procedures. Perfom two simulated drill in office.	5%	0	1	2	*	Perform office traniing on EAP, Bulk Tank, Mayday procedures. Target is to conduct two actual simulated drills, one planned and one unplanned..	
	3) Facility Safety Inspection and Remedies	10%	3.5	6	7	8	Safety committee has inspected facilities and noted 8 problems. The goal in to resolve these problems by December 1st.	
Increase Reliability	1) Number of Electric Outages	10%	35	120	100	Open	Target is based on average of 2014 to 2016 total number of outages. For every 10 less outages than target, the bonus will increase by $5.	
Satisfied, Well informed Members	1) Increase number of members that can be texted to update on outages, ect. .	10%	888	800	1000	Open	Our opted-in "Text Outage Alert" count is at ?. The year-end target is 1000 members. The maximum amount is open-ended. For every 50 additional, the incentive comp is increased by $5.	
	2) Open House in June for Community to do an Arc Demo ect.	10%	1	*	1	*	Conduct and open house in June.	
Develop Employees	1) All employees involved in either an off-site or on-line training activity.	10%	29%	*	100%	*	The goal is for all employees to take at least one off-site or on-line training. Only make goal if ALL employees have training .	
		100%						$0.00

Notes:
1) Target Incentive Compensation award for each employee is $1000 and the maximum awarded is $1,500.
2)"Percent Award" is the base contribution of each particular component to the total incentive award.
3) Unless otherwise noted, "Maximum" and "Minimum" for each component provides a method to calculate the range of performance for each component.
4) For each component unless otherwise noted, achieving a "Maximum" contributes 125% of target and achieving a "Minimum" contributes 75% of target.
5) Any component performance below "Minimum" target does not contribute anything to the Incentive Compensation.
6) All Incentive Compensation awards are subject to approval of the Board of Directors before payout and may be adjusted at their prerogative.
7) All components subject to audit and may be adjusted after audit.