Revenue Requirement, Cost of Service, & Rate Design

Ontonagon County Rural Electric Association
Management Presentation
September 12, 2023

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Financial Analysis & Products

Strategic Facilitation Services

Utility Research & Policy

Utility Pricing, Policy & Analytics (formerly Regulatory Affairs)

Ontonagon County Rural Electric Association Retained CFC's Utility Pricing, Policy, & Analytics Team To:

1. Revenue Requirement Study
2. Cost of Service Study
3. Rate Design

We were informed that the goal of this review is to evaluate the general accuracy of the cooperative's rates and revenue collection.

Target Dates

✓ Present Cost of Service Study Findings to Board?

CFC Objectives

1. Ratemaking Process Overview
2. Revenue Requirement Study Results
3. Fundamentals of Cost of Service
4. Cost of Service Study Results
5. Rate Design Implementation Options

Ratemaking Process Overview

“Ratemaking never fails to stir up an argument.”

-Unknown

Ratemaking Steps

Revenue Requirement (How Much?)

- Suggests Operating Revenue & Patronage Capital to Meet Prudent (1) Operating Expenses; and (2) Financial Goals (Debt Service, Margins, Equity Levels, Plant Additions & Patronage Capital Retirement)

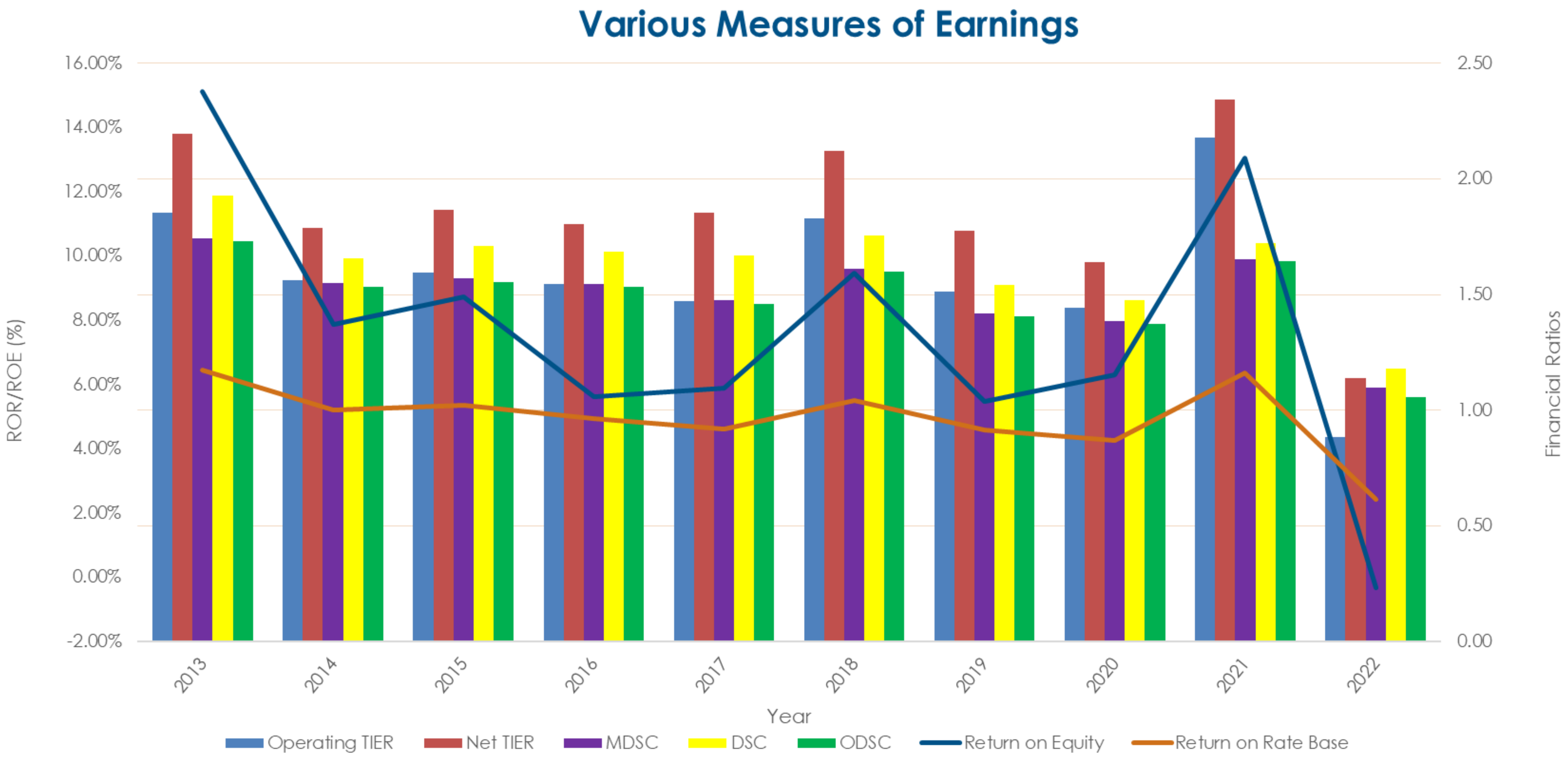
Cost of Service (From Whom?)

- A method to equitably allocate the revenue requirements of the utility among various service classes
  - Identifies Cost to Serve Each Rate Classification (Cost Causation)
  - Identifies Existing Subsidies (and Magnitude) Between Rate Classifications
  - Identifies Cost-Based (Unit-Based) Rate Structure

Rate Design (How?)

- Revenues to Collect from Each Rate Classification
- Cost of Service Guides Rate Design by Aligning Costs & Revenue Collection
- Cost of Service Provides Insights to More Precisely Apply Rate Increase/Rate Re-Design to Align with Rate Policy

Revenue Requirement Study Results


Various Measures of Earnings
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
-2.00%
ROR/ROE (%)
2.50
2.00
1.50
1.00
0.50
0.00
Financial Ratios
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Operating TIER
Net TIER
MDSC
DSC
ODSC
Return on Equity
Return on Rate Base

Revenue Requirement Study - General Findings

2022 – Actual	**2022 – 1.50 MDSC Target**
$6,667,377 Op. Rev/Pat. Cap	$7,232,220 Op. Rev/Pat. Cap
$582,626 Operating Income	$1,147,469 Operating Income
-$123,794 Operating Margins	$441,049 Operating Margins
0.88 Operating TIER	1.73 Operating TIER
1.10 MDSC	1.50 MDSC
-0.34% Return on Equity	6.78% Return on Equity
2.43% Return on Rate Base	4.60% Return on Rate Base

Revenue Requirements Study – Summary

Revenue Requirements Study Summary
(MDSC Method)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		2017 Unadjusted	2018 Unadjusted	2019 Unadjusted	2020 Unadjusted	2021 Unadjusted	2022 Unadjusted	2022 Adjusted	2022 Proposed Rate Increase
1	Rate Base	$ 21,085,664	$ 21,577,931	$ 21,857,894	$ 21,986,508	$ 22,927,143	$ 23,978,447	$ 24,968,707	$ 24,968,707
2	Return on Rate Base (ROR)	4.62%	5.51%	4.59%	4.27%	6.36%	2.43%	2.33%	4.60%
3	(Margins) Operating Income (Line 1 * Line 2)	$ 973,946	$ 1,188,075	$ 1,003,685	$ 938,399	$ 1,458,992	$ 582,626	$ 582,626	$ 1,147,469
4	Operating Expenses	$ 5,166,016	$ 5,193,461	$ 5,328,991	$ 5,458,262	$ 5,367,455	$ 6,084,751	$ 6,084,751	$ 6,084,751
5	Revenue Requirement (Line 3 + Line 4)	$ 6,139,962	$ 6,381,536	$ 6,332,676	$ 6,396,661	$ 6,826,447	$ 6,667,377	$ 6,667,377	$ 7,232,220
6	2022 Electric Revenue						$ 6,604,452	$ 6,604,452	$ 6,604,452
7	2022 PCA Revenue								$ -
8	2022 Misc. Revenue						$ 62,925	$ 62,925	$ 62,925
9	Total Operating Revenue & Patronage Capital (SUM Lines 6-8)	$ 6,139,962	$ 6,381,536	$ 6,332,676	$ 6,396,661	$ 6,826,447	$ 6,667,377	$ 6,667,377	$ 6,667,377
10	Revenue Increase / (Decrease) (Line 5 - Line 9)								$ 564,843
11	% Increase in Operating Revenue & Patronage Capital (Line 10 / Line 9)								8.47%
12	% Increase in Electric Revenue (Line 10 / Line 6)								8.55%
13	Return on Equity (ROE)	5.89%	9.47%	5.47%	6.29%	13.06%	-0.34%	-0.65%	6.78%
14	Operating TIER	1.47	1.83	1.51	1.44	2.18	0.88	0.88	1.73
15	Net TIER	1.85	2.12	1.78	1.64	2.34	1.14	1.14	1.98
16	MDSC	1.48	1.61	1.42	1.39	1.65	1.10	1.10	1.50
17	DSC	1.67	1.75	1.54	1.47	1.72	1.18	1.18	1.58
18	ODSC	1.46	1.60	1.40	1.37	1.64	1.06	1.06	1.46

Line No.		(a) 2019	(b) 2020	(c) 2021	(d) 2022	(e) Ratemaking Adjustments	(f) 2022 Adjusted	(g) 2022 Proposed Rate Increase
	Rate Base							
1	Total Utility Plant in Service	$30,566,525	$31,417,829	$32,475,722	$34,661,520	$1,883,006	$36,544,526	$36,544,526
2	Construction Work in Progress (CWIP)	$877,591	$739,169	$1,387,291	$1,693,944	$0	$1,693,944	$1,693,944
3	**Total Utility Plant** (SUM Lines 1-2)	**$31,444,116**	**$32,156,998**	**$33,863,013**	**$36,355,464**		**$38,238,470**	**$38,238,470**
4	Accum. Provision for Depreciation & Amort.	$10,067,567	$10,780,029	$11,493,016	$12,398,398	$892,746	$13,291,144	$13,291,144
5	**Net Utility Plant** (Line 3 LESS Line 4)	**$21,376,549**	**$21,376,969**	**$22,369,997**	**$23,957,066**		**$24,947,326**	**$24,947,326**
6	Cash Working Capital (Net O&M * 0.125) "45 Day Rule"	$244,620	$266,552	$263,559	$334,845	$0	$334,845	$334,845
7	Materials & Supplies - Electric Other	$224,073	$251,217	$254,779	$370,227	$0	$370,227	$370,227
8	Prepayments	-$2,337	$23,568	$37,968	$2,844	$0	$2,844	$2,844
9	Regulatory Assets	$0	$0	$0	$0	$0	$0	$0
10	Other Deferred Debits	$105,315	$152,783	$95,543	$73,750	$0	$73,750	$73,750
11	Consumer Deposits	-$14,550	-$14,850	-$13,800	-$14,700	$0	-$14,700	-$14,700
12	Regulatory Liabilities	-$41,967	-$30,343	-$27,504	-$34,475	$0	-$34,475	-$34,475
13	Other Deferred Credits	-$33,809	-$39,388	-$53,399	-$711,110	$0	-$711,110	-$711,110
14	**Total Rate Base** (Line 5 + SUM Lines 6-13)	**$21,857,894**	**$21,986,508**	**$22,927,143**	**$23,978,447**		**$24,968,707**	**$24,968,707**
15	**Return on Rate Base** (Operating Income / Total Rate Base)	**4.59%**	**4.27%**	**6.36%**	**2.43%**		**2.33%**	**4.60%**
16	**Operating Income** (Line 14 * Line 15)	**$1,003,685**	**$938,399**	**$1,458,992**	**$582,626**		**$582,626**	**$1,147,469**
17	Power Production Expense	$0	$0	$0	$0	$0	$0	$0
18	Cost of Purchased Power	$2,196,418	$2,162,866	$2,099,223	$2,170,246	$0	$2,170,246	$2,170,246
19	Transmission Expense	$0	$0	$0	$0	$0	$0	$0
20	Distribution Expense - Operation	$334,122	$325,079	$355,938	$271,285	$0	$271,285	$271,285
21	Distribution Expense - Maintenance	$721,547	$929,393	$811,438	$1,210,820	$0	$1,210,820	$1,210,820
22	Consumer Accounts Expense	$205,115	$216,701	$274,978	$305,695	$0	$305,695	$305,695
23	Customer Service & Informational Expense	$120,818	$121,849	$114,996	$81,732	$0	$81,732	$81,732
24	Sales Expense	$0	$0	$0	$0	$0	$0	$0
25	Administrative & General Expense	$575,355	$539,396	$551,124	$809,227	$0	$809,227	$809,227
26	Depreciation & Amortization Expense	$834,069	$854,590	$849,456	$892,746	$0	$892,746	$892,746
27	Tax Expense - Property & Gross Receipts	$341,547	$308,388	$310,302	$343,000	$0	$343,000	$343,000
28	Tax Expense - Other	$0	$0	$0	$0	$0	$0	$0
29	**Operating Expenses** (SUM Lines 17-28)	**$5,328,991**	**$5,458,262**	**$5,367,455**	**$6,084,751**		**$6,084,751**	**$6,084,751**
30	**Revenue Requirement (Line 16 + 29)**	**$6,332,676**	**$6,396,661**	**$6,826,447**	**$6,667,377**		**$6,667,377**	**$7,232,220**
31	**Existing Revenue**	**$6,332,676**	**$6,396,661**	**$6,826,447**	**$6,667,377**		**$6,667,377**	**$6,667,377**
32	**Increase / (Decrease)**	**$0**	**$0**	**$0**	**$0**		**$0**	**$564,843**

33	Debt - $	$16,117,064	$19,025,914	$19,163,811	$18,409,469	$0	$18,409,469	$18,409,469
34	Equity - $	$6,407,149	$6,838,171	$7,955,045	$8,047,194	$0	$8,047,194	$8,047,194
35	**Total - $ (SUM Lines 33-34)**	**$22,524,213**	**$25,864,085**	**$27,118,856**	**$26,456,663**		**$26,456,663**	**$26,456,663**
36	Debt - % (Line 33 / Line 35)	71.55%	73.56%	70.67%	69.58%		69.58%	69.58%
37	Equity - % (Line 34 / Line 35)	28.45%	26.44%	29.33%	30.42%		30.42%	30.42%
38	**Total - %**	**100.00%**	**100.00%**	**100.00%**	**100.00%**		**100.00%**	**100.00%**
39	Debt Cost - % (Interest on Long-Term Debt Expense / Line 33)	4.24%	3.54%	3.59%	3.64%		3.64%	3.64%
40	**Earned Return on Equity - % (Line 42 / Line 37)**	**5.47%**	**6.29%**	**13.06%**	**-0.34%**		**-0.65%**	**6.78%**
41	Weighted Debt Costs - % (Line 36 x Line 39)	3.04%	2.60%	2.53%	2.53%		2.53%	2.53%
42	Weighted Equity Costs - % (Line 43 LESS Line 41)	1.56%	1.66%	3.83%	-0.10%		-0.20%	2.06%
43	**Earned Return on Rate Base - % (Operating Income / Rate Base)**	**4.59%**	**4.27%**	**6.36%**	**2.43%**		**2.33%**	**4.60%**

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.		2019 Unadjusted	2020 Unadjusted	2021 Unadjusted	2022 Unadjusted	Ratemaking Adjustments	2022 Adjusted	2022 Proposed Rate Increase
1	**Operating Revenue & Patronage Capital**	**$6,332,676**	**$6,396,661**	**$6,826,447**	**$6,667,377**	**$0**	**$6,667,377**	**$6,667,377**
2	**Increase / (Decrease)**							**$564,843**
3	**Proposed Revenue Requirement**							**$7,232,220**
4	Power Production Expense	$0	$0	$0	$0	$0	$0	$0
5	Cost of Purchased Power	$2,196,418	$2,162,866	$2,099,223	$2,170,246	$0	$2,170,246	$2,170,246
6	Transmission Expense	$0	$0	$0	$0	$0	$0	$0
7	Distribution Expense - Operation	$334,122	$325,079	$355,938	$271,285	$0	$271,285	$271,285
8	Distribution Expense - Maintenance	$721,547	$929,393	$811,438	$1,210,820	$0	$1,210,820	$1,210,820
9	Consumer Accounts Expense	$205,115	$216,701	$274,978	$305,695	$0	$305,695	$305,695
10	Customer Service & Informational Expense	$120,818	$121,849	$114,996	$81,732	$0	$81,732	$81,732
11	Sales Expense	$0	$0	$0	$0	$0	$0	$0
12	Administrative & General Expense	$575,355	$539,396	$551,124	$809,227	$0	$809,227	$809,227
13	Depreciation & Amortization Expense	$834,069	$854,590	$849,456	$892,746	$0	$892,746	$892,746
14	Tax Expense - Property & Gross Receipts	$341,547	$308,388	$310,302	$343,000	$0	$343,000	$343,000
15	Tax Expense - Other	$0	$0	$0	$0	$0	$0	$0
16	**Operating Expenses** (SUM Lines 4-15)	**$5,328,991**	**$5,458,262**	**$5,367,455**	**$6,084,751**		**$6,084,751**	**$6,084,751**
17	**Operating Income (Line 1 LESS Line 16)**	**$1,003,685**	**$938,399**	**$1,458,992**	**$582,626**		**$582,626**	**$1,147,469**
18	Interest on Long-Term Debt Expense	$683,671	$673,724	$687,082	$670,040	$0	$670,040	$670,040
19	Interest Charged to Construction (Credit)	$0	$0	$0	$0	$0	$0	$0
20	Interest Expense - Other	$2,658	$4,675	$700	$192	$0	$192	$192
21	Other Deductions	$20,598	$20,235	$20,484	$36,188	$0	$36,188	$36,188
22	**Total Cost of Electric Service** (Line 16 + SUM Lines 18-21)	**$6,035,918**	**$6,156,896**	**$6,075,721**	**$6,791,171**		**$6,791,171**	**$6,791,171**
23	**Patronage Capital & Operating Margins** (Line 1 LESS Line 22)	**$296,758**	**$239,765**	**$750,726**	**-$123,794**		**-$123,794**	**$441,049**
24	Non Operating Margins - Interest	$10,075	$7,592	$8,963	$31,882	$0	$31,882	$31,882
25	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
26	Income (Loss) from Equity Investments	$59,059	$61,653	$59,300	$33,335	$0	$33,335	$33,335
27	Non Operating Margins - Other	$66,644	$21,223	-$121	$55,774	$0	$55,774	$55,774
28	Generation & Transmission Capital Credits	$0	$0	$0	$0	$0	$0	$0
29	Other Capital Credits & Patronage Dividends	$98,888	$100,793	$104,784	$94,984	$0	$94,984	$94,984
30	Extraordinary Items	$0	$0	$0	$0	$0	$0	$0
31	**Patronage Capital or Margins** (Line 23 + SUM Lines 24-30)	**$531,425**	**$431,027**	**$923,652**	**$92,181**		**$92,181**	**$657,024**
32	**Percent Increase / Decrease** (Line 2 / Line 1)							**8.47%**
33	**Operating TIER** (See KRTA Formula)	**1.51**	**1.44**	**2.18**	**0.88**		**0.88**	**1.73**
34	**Net TIER** (See KRTA Formula)	**1.78**	**1.64**	**2.34**	**1.14**		**1.14**	**1.98**
35	**MDSC** (See KRTA Formula)	**1.42**	**1.39**	**1.65**	**1.10**		**1.10**	**1.50**
36	**DSC** (See KRTA Formula)	**1.54**	**1.47**	**1.72**	**1.18**		**1.18**	**1.58**
37	**ODSC** (See KRTA Formula)	**1.40**	**1.37**	**1.64**	**1.06**		**1.06**	**1.46**
38	**Earned Return On Rate Base** (Operating Income / Total Rate Base)	**4.59%**	**4.27%**	**6.36%**	**2.43%**		**2.33%**	**4.60%**
39	**Earned Return on Equity** ((Return on Rate Base / Weighted Debt Cost) / Equity %)	**5.47%**	**6.29%**	**13.06%**	**-0.34%**		**-0.65%**	**6.78%**

Percentage Increase is on Operating Revenue

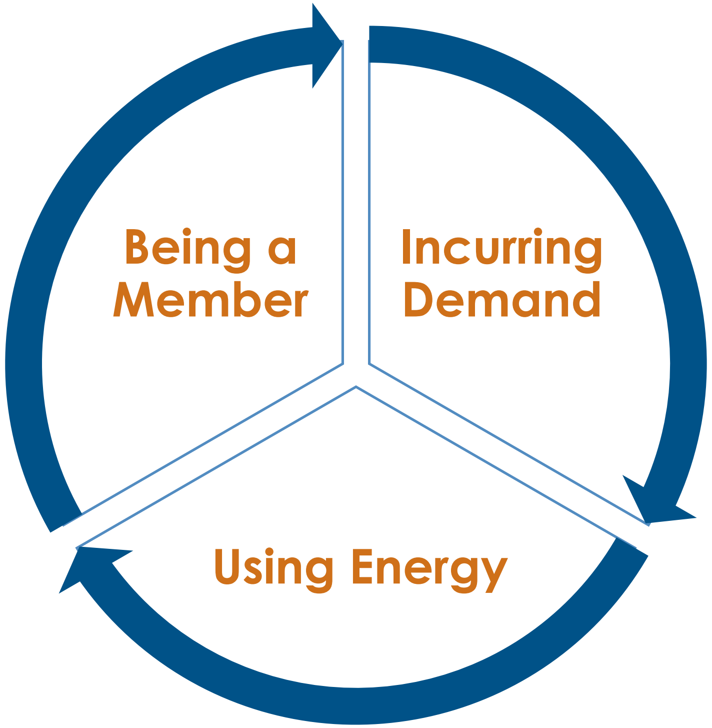
Fundamentals of Cost of Service

Cost of Service Study (From Whom?)

A process which assigns costs to the classes of members to determine who incurred the costs.

Cost Causation

How are costs incurred on an electric system?



Costs are incurred by:

- Being a customer (connectivity to grid)
- By incurring demand (kW) (Purchased Power & Distribution)
- By using energy

Objectives of a Cost of Service Study

Cost Causation

- Individual rate class revenue requirement or "cost to serve"
- Investment & operating expenses incurred by rate class

Equity & Fairness

- Identifies inter-rate class subsidies
- Identifies potential inequities between & within rate classes

Improve Price Signals

Cost Recovery

- Customer-related
- Demand-related
- Energy-related

** Provides a reasonable guide for identifying average cost responsibility of consumers within a class; results cannot be used to identify the specific cost of providing service to an individual consumer; allocating costs is subject to numerous assumptions, philosophies, and methodologies.

Cost of Service Study Process

Define Rate Classes
- Revenue Class (Form 7)
- Rate Schedule (Billed)
- Rate Code

Functionalize
- Generation, Transmission, Distribution, General

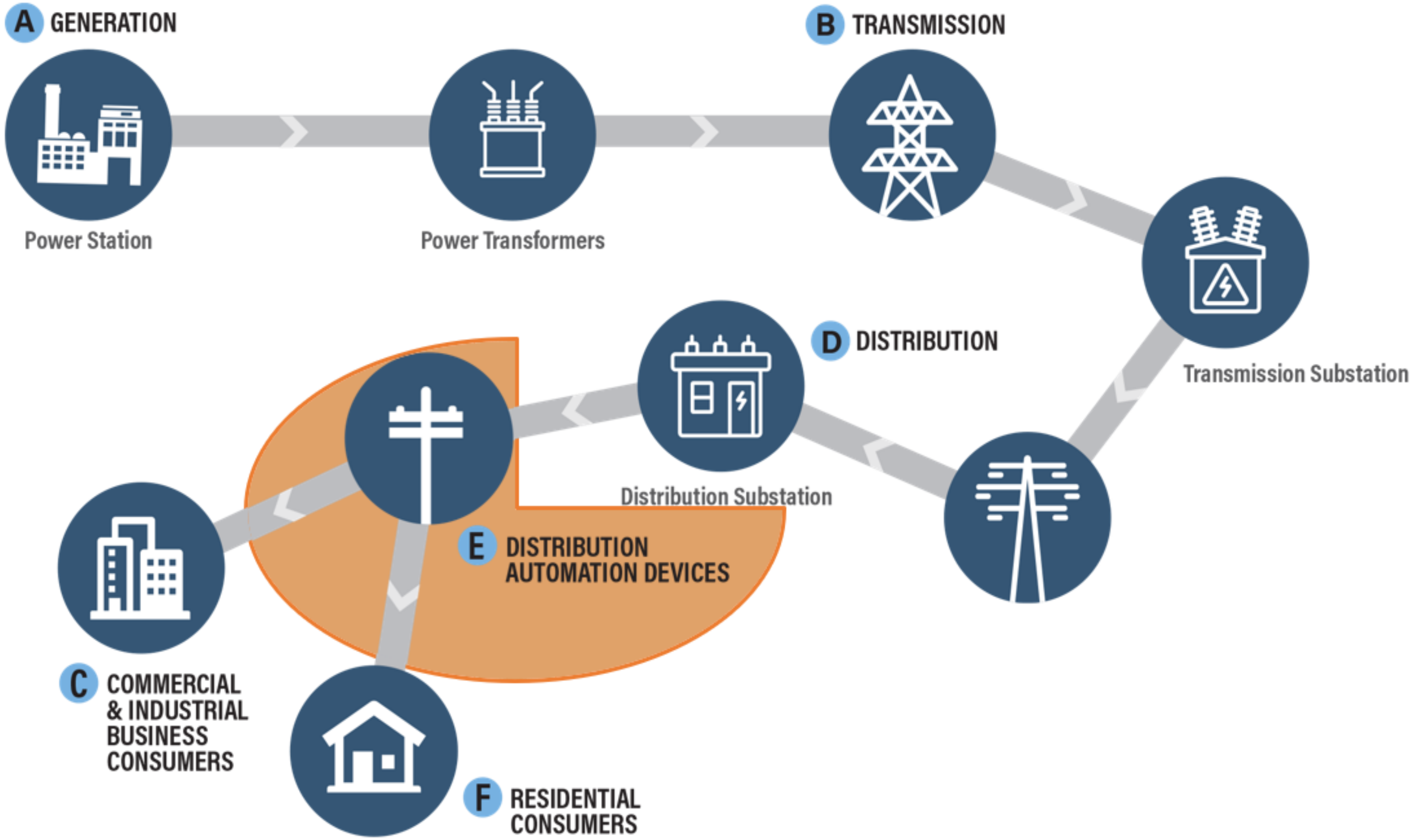
Classify
- Customer, Demand, Energy

Allocate
- # of Customers/ Weighted Customers, CP/NCP (kW), Energy (kWh), Labor Ratios, Direct Assignment

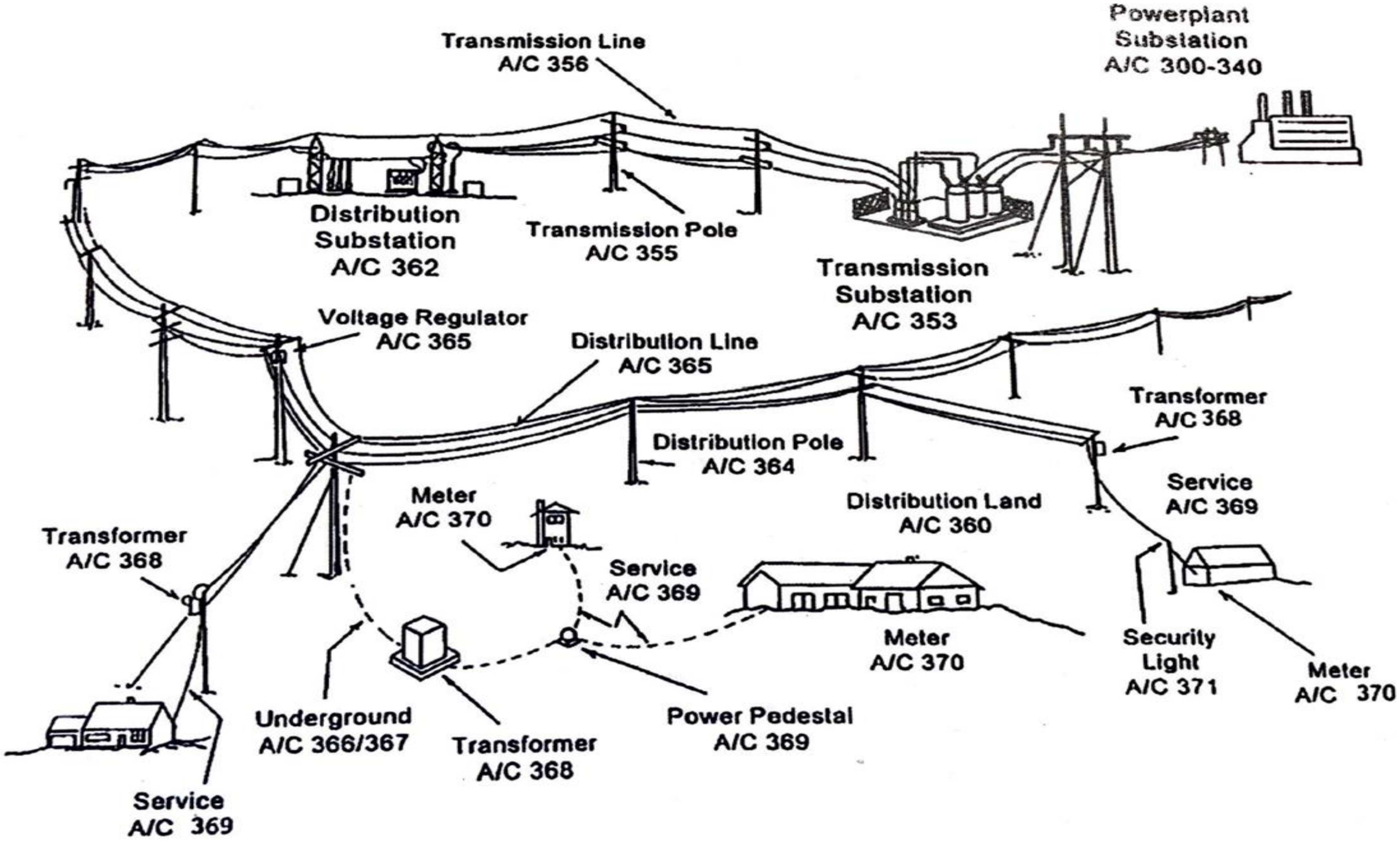
- Several industry standard methods exist to classify & allocate costs
- Reasonable people can disagree
- Methods/Procedures can differ based on unique circumstances, philosophical approach & intended outcome

Distribution System Costs

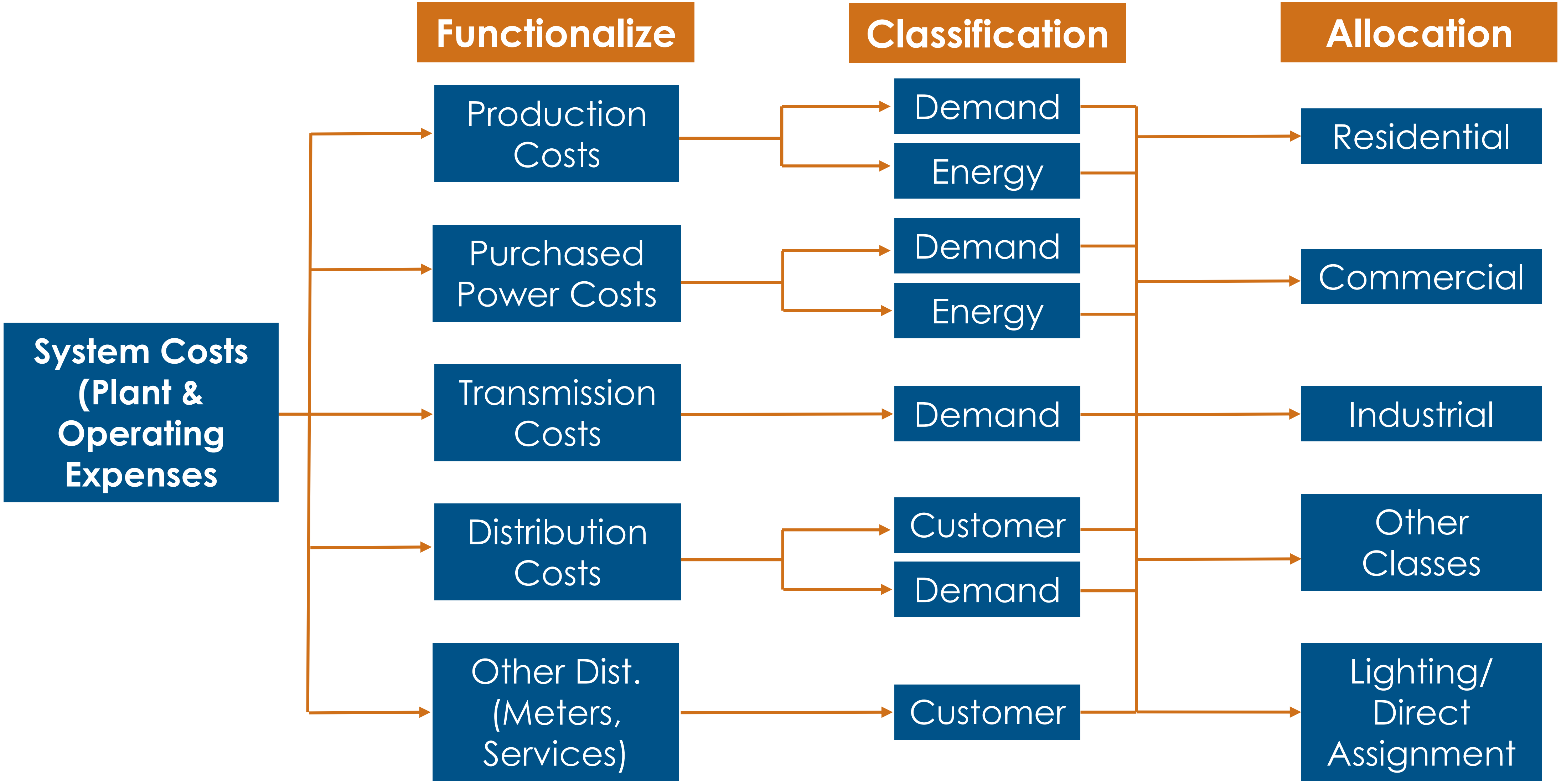
- **Minimum System Method** is a generally accepted methodology to separate shared costs of the distribution system between customer-related and demand (capacity)-related costs.
  - This methodology seeks to establish the cost of the portion of the distribution system utilized for connectivity (zero load) vs. portion of the distribution system in place for peak load
  - 50% of distribution system costs classified as customer-related (on average)
  - Zero-Intercept is an alternative methodology



Distribution System Layout



Cost of Service Study Process Recap



Functionalize

Classification

Allocation

System Costs (Plant & Operating Expenses)

Production Costs

Purchased Power Costs

Transmission Costs

Distribution Costs

Other Dist. (Meters, Services)

Demand

Energy

Demand

Energy

Demand

Customer

Demand

Customer

Residential

Commercial

Industrial

Other Classes

Lighting/ Direct Assignment

Utility Tariffs Do Not Reflect Utility Cost Structures

Cost Categories

Fixed ($/Consumer):
- Metering & Billing
- Customer Service
- Meter & Service Drop
- Portion of Distribution System

Capacity-Related (Demand) ($/kW) Distribution System:
- Distribution Capacity
- Portion of Distribution System Sized to Meet Capacity Needs

Capacity-Related (Demand) ($/kW) Generation/Purchased Power:
- Transmission Capacity
- Generation Capacity

Variable (Energy) ($/kWh):
- Fuel
- Operations & Maintenance

Cost Based or Policy

Fixed = $50

Demand = $15

Demand = $35

Variable = $30

Actual Bill

Fixed = $25

Variable = $105

*Illustrative Example Only, Total Bill Based on Typical Usage

Interpreting Cost of Service Results

Rate Realignment

- Subsidy exists when there is a difference between the current rate revenue collected and identified cost of service
- Subsidy can be positive or negative
- Not uncommon to experience commercial and/or industrial members paying more and residential members paying less

Policy Considerations

- Determined by cooperative's objectives, goals & rate policy (and State Commission, if applicable)
  - Who provides and receives subsidy (if any)?
  - What is the degree & magnitude of the subsidy?
  - Rate design & rate increases/decreases applied to modify subsidies out of alignment with rate policy goals rather than apply rate increase equally to all rates.
  - What is fair & equitable is in the eye of the beholder
- Subsidies may send incorrect economic signal
- Commercial and/or industrial rates set above cost of service can have negative effect on their ability to compete
- Many State Commissions will require uniform rate increases rather than eliminate/correct subsidies

Cost of Service Study Results

Cost of Service Study – General Findings

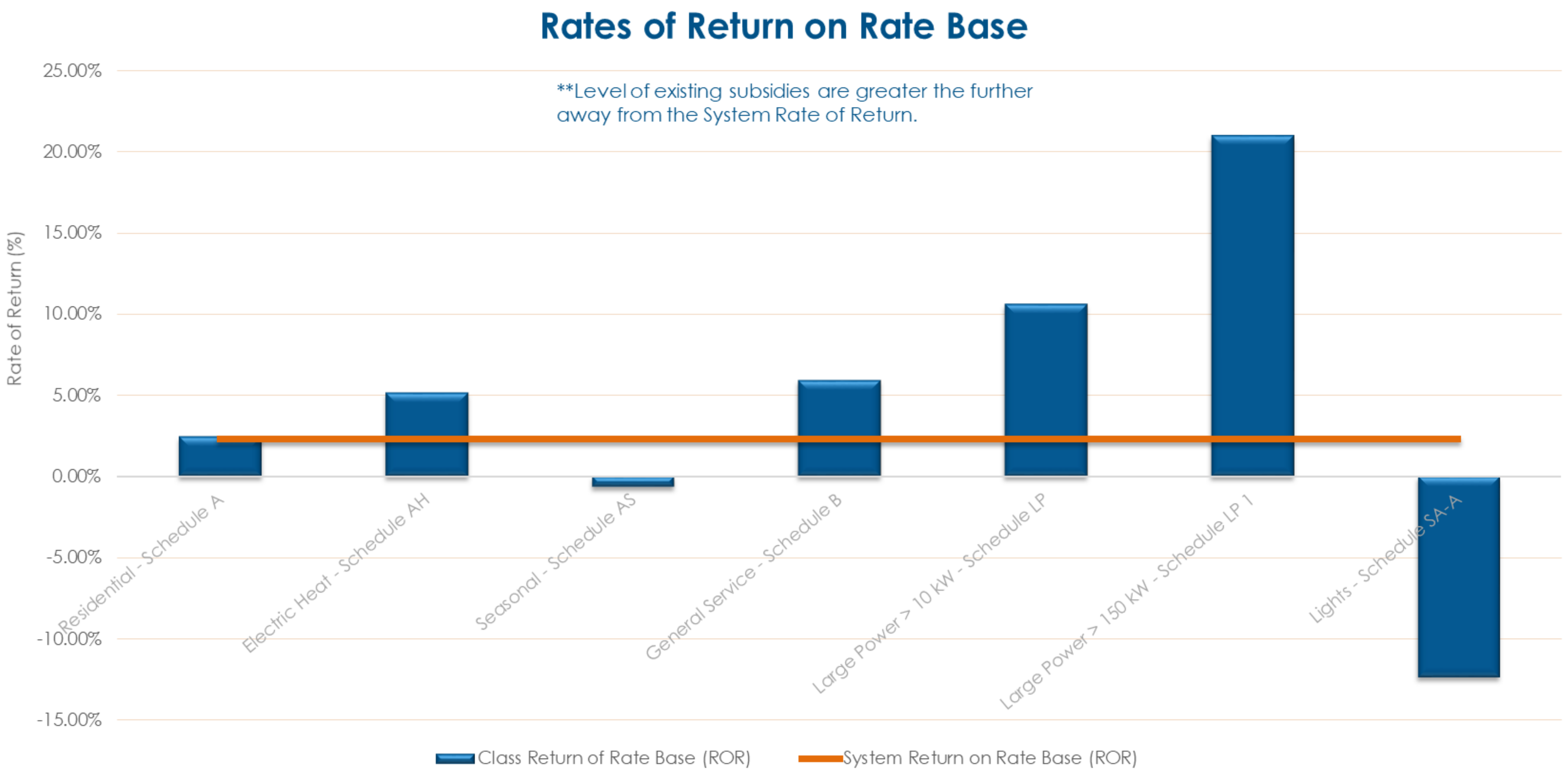
- Revenue at Cost of Service
  - Residential
- Revenue Below Cost of Service
  - Seasonal, Lighting
- Revenue Above Cost of Service
  - Electric Heat, General Service, Large Power

Cost of Service Study – Revenue Comparison

Comparison Between Adjusted COSS and Existing Revenue Allocation

Line No.	Class	Cost-of-Service Revenue Allocation	Existing Revenue Collection	Difference	Percent Difference	Return on Rate Base
1	Residential - Schedule A	$ 4,488,617	$ 4,513,063	$ (24,446)	-0.54%	2.48%
2	Electric Heat - Schedule AH	$ 107,367	$ 117,214	$ (9,847)	-8.40%	5.17%
3	Seasonal - Schedule AS	$ 1,174,942	$ 1,014,449	$ 160,493	15.82%	-0.63%
4	General Service - Schedule B	$ 388,551	$ 434,032	$ (45,481)	-10.48%	5.94%
5	Large Power > 10 kW - Schedule LP	$ 356,453	$ 432,908	$ (76,455)	-17.66%	10.62%
6	Large Power > 150 kW - Schedule LP 1	$ 52,079	$ 72,335	$ (20,256)	-28.00%	21.02%
7	Lights - Schedule SA-A	$ 36,443	$ 20,451	$ 15,992	78.19%	-12.35%
8	Electric Revenues	$ 6,604,452	$ 6,604,452	$ (0)		
9	PCA Revenues	--	--	--		
10	Misc. Revenues	$ 62,925	$ 62,925	--		
11	Operating Revenue & Patronage Capital	$ 6,667,377	$ 6,667,377	$ (0)	0.00%	
12	System Return on Rate Base					2.33%

Rates of Return Comparison



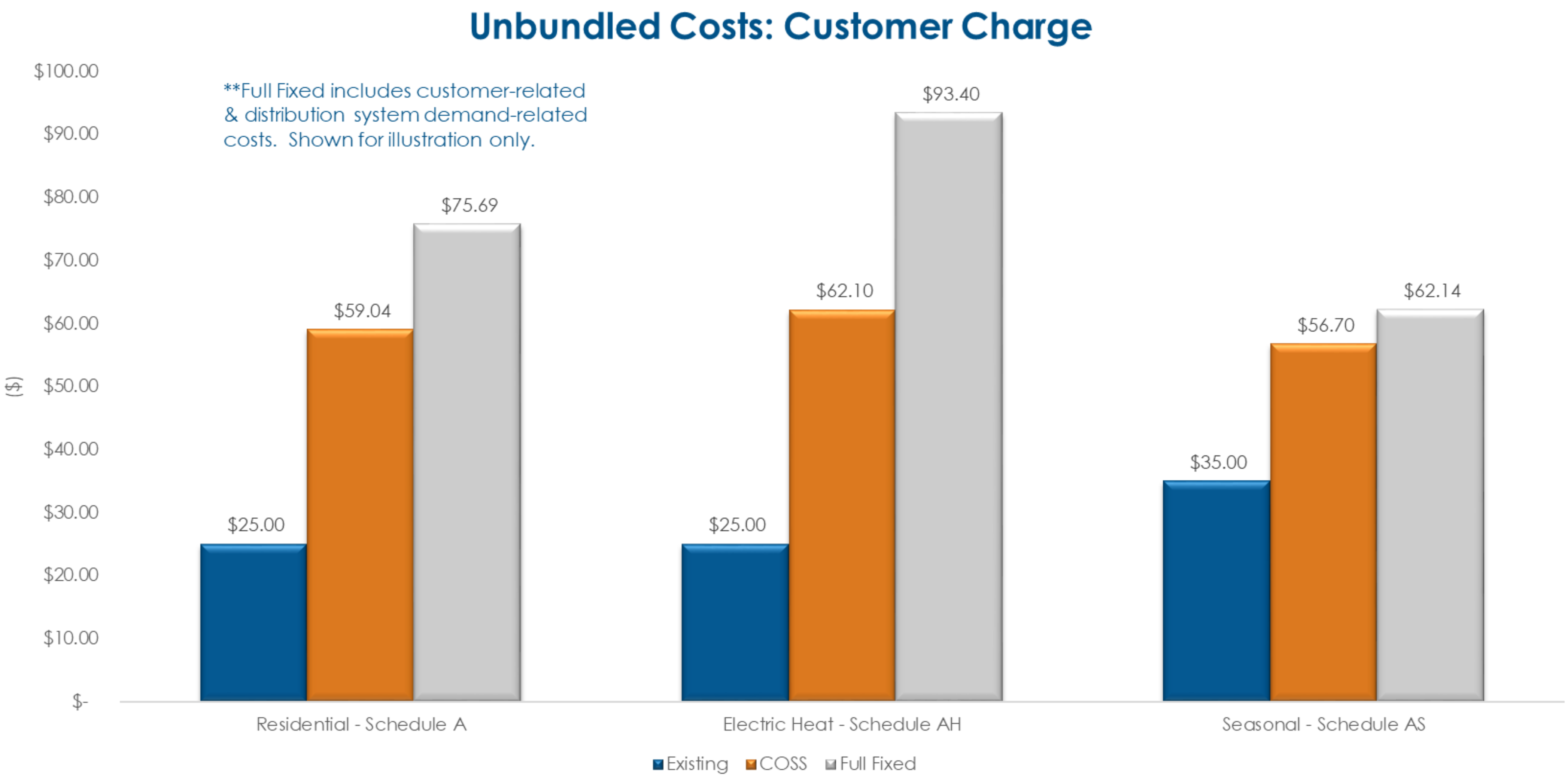
Cost-Based Rates

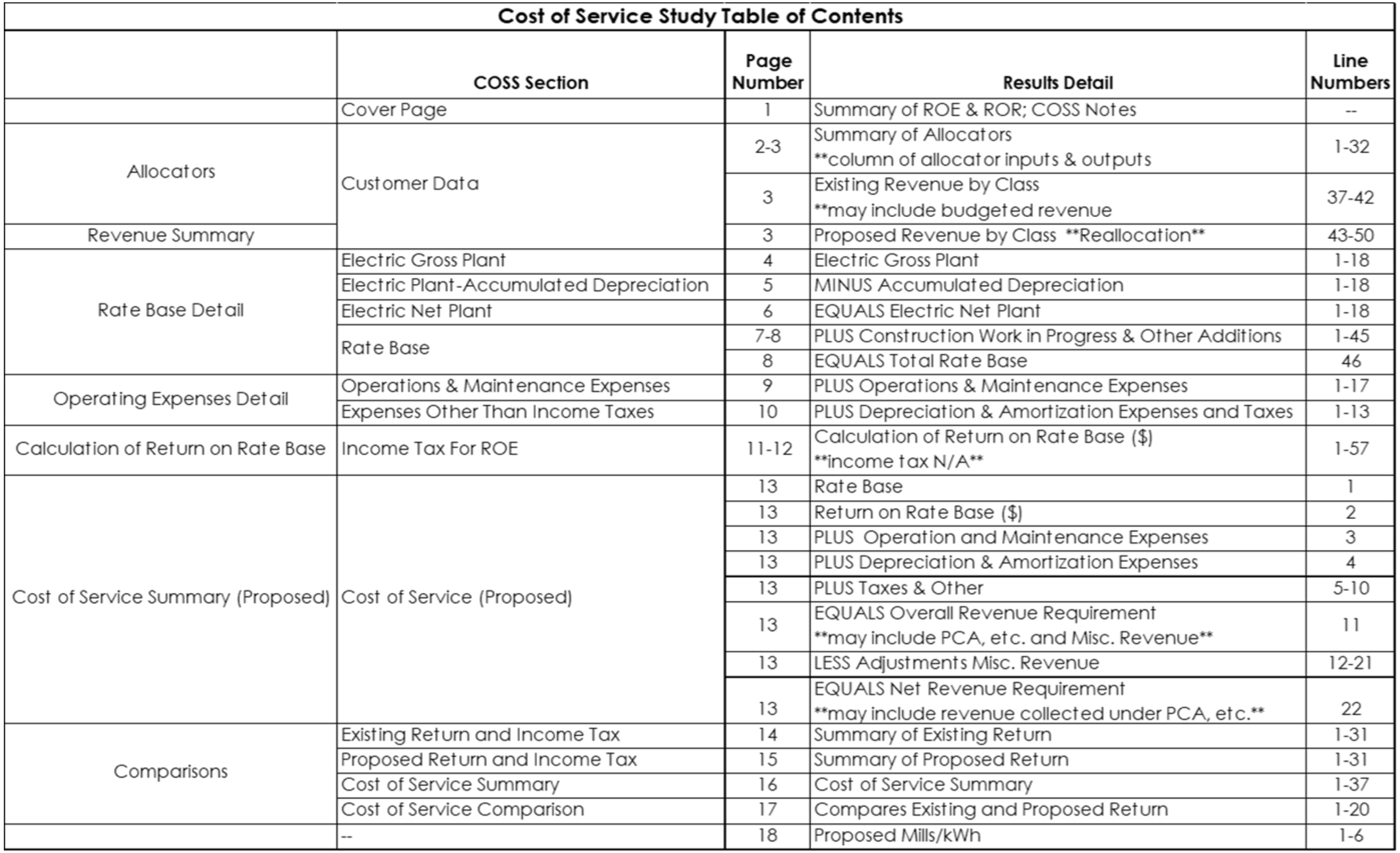
Adjusted Cost of Service Study Cost-Based Rates

Line No.	Class	Customer Related	Demand Related (Dist. Sys.)	Demand Related (Pur. Pwr.)	Energy Related
1	Residential - Schedule A	$ 59.04	$ 14.99	$ 17.49	$ 0.04560
2	Electric Heat - Schedule AH	$ 62.10	$ 14.99	$ 17.49	$ 0.04560
3	Seasonal - Schedule AS	$ 56.70	$ 14.99	$ 17.49	$ 0.04560
4	General Service - Schedule B	$ 62.05	$ 14.99	$ 17.49	$ 0.04560
5	Large Power > 10 kW - Schedule LP	$ 213.13	$ 14.99	$ 17.49	$ 0.04560
6	Large Power > 150 kW - Schedule LP 1	$ 395.17	$ 14.99	$ 17.49	$ 0.04561
7	Lights - Schedule SA-A	$ 9.50	$ 14.63	$ 17.49	$ 0.04561

*** Cost-Based Rates are not rate design recommendations, nor are they intended to be directly implemented as a rate design. Cost-Based Rates illustrate the per unit cost-of-service from a cost causation (cost per unit) perspective, notwithstanding existing policies. Rate design is driven by cost causation, policy, member acceptance, etc.

Unbundled Costs Comparison





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Rate Design Considerations

Rate Design Considerations

- Modeling suggests overall revenue shortfall of $564,843 (8.47%) based on Target of 1.50 MDSC
    - Seasonal and Lighting are currently being subsidized by other classes
    - However, it is not uncommon for Commercial classes to subsidize Residential/Incentive classes
    - Any future rate adjustments could be applied to these classes to modify the perceived subsidy being received

Rate Design Implementation Options

Rate Increase Option #1

- Increase all billing components for all rates by an equal percentage to achieve overall revenue increase of $564,843

Residential - Schedule A

	Existing	Proposed
Service Charge	$ 25.00	$ 27.15
Energy Charge	$ 0.19391	$ 0.21059

Electric Heat - Schedule AH

	Existing	Proposed
Service Charge	$ 25.00	$ 27.15
Energy Charge (Summer)	$ 0.19391	$ 0.21059
Energy Charge (Winter <500 kWh)	$ 0.19391	$ 0.21059
Energy Charge (Winter >500 kWh)	$ 0.16391	$ 0.17801

Seasonal - Schedule AS

	Existing	Proposed
Service Charge	$ 35.00	$ 38.01
Energy Charge	$ 0.19391	$ 0.21059

Lights - RS SA-A

	Existing	Proposed
Regular Lights	$ 9.45	$ 10.26
LED Lights	$ 8.41	$ 9.13

General Service - Schedule B

	Existing	Proposed
Service Charge (1P)	$ 33.00	$ 35.84
Service Charge (3P)	$ 47.00	$ 51.04
Energy Charge	$ 0.17791	$ 0.19322

Large Power Over 10k - Schedule LP

	Existing	Proposed
Service Charge	$ -	$ -
Demand Charge	$ 16.40	$ 17.81
Energy Charge	$ 0.11591	$ 0.12588

Large Power Over 150k - Schedule LP1

	Existing	Proposed
Service Charge	$ -	$ -
Demand Charge	$ 17.80	$ 19.33
Energy Charge	$ 0.08761	$ 0.09515

Rate Increase Option #1

Revenue from Proposed Rates

Line No.	Class		Existing Revenue		Proposed Revenue		$ Difference	% Difference
1	Residential - Schedule A	$	4,513,063	$	4,899,090	$	386,028	8.55%
2	Electric Heat - Schedule AH	$	117,214	$	127,527	$	10,313	8.80%
3	Seasonal - Schedule AS	$	1,014,449	$	1,101,223	$	86,774	8.55%
4	General Service - Schedule B	$	434,032	$	471,676	$	37,644	8.67%
5	Large Power > 10 kW - Schedule LP	$	432,908	$	468,897	$	35,989	8.31%
6	Large Power > 150 kW - Schedule LP 1	$	72,335	$	78,671	$	6,335	8.76%
7	Lights - Schedule SA-A	$	20,451	$	22,211	$	1,759	8.60%
8	Electric Revenues	$	6,604,452	$	7,169,295	$	564,843	8.55%
9	Misc. Revenues	$	62,925	$	62,925		--	
10	Operating Revenue & Patronage Capital	$	6,667,377	$	7,232,220	$	564,843	8.47%

Rate Increase Option #2

- Apply increase as follows:
  - Increase all Service Charges by $5 per Member per Month
  - Increase all Demand Charges by $1 per kW
  - Increase all Lights by $1 per Light per Month
  - Remaining Increase collected through Energy Charge (5.52%)

Residential - Schedule A

	Existing	Proposed
Service Charge	$ 25.00	$ 30.00
Energy Charge	$ 0.19391	$ 0.20462

Electric Heat - Schedule AH

	Existing	Proposed
Service Charge	$ 25.00	$ 30.00
Energy Charge (Summer)	$ 0.19391	$ 0.20462
Energy Charge (Winter <500 kWh)	$ 0.19391	$ 0.20462
Energy Charge (Winter >500 kWh)	$ 0.16391	$ 0.17296

Seasonal - Schedule AS

	Existing	Proposed
Service Charge	$ 35.00	$ 40.00
Energy Charge	$ 0.19391	$ 0.20462

Lights - RS SA-A

	Existing	Proposed
Regular Lights	$ 9.45	$ 10.45
LED Lights	$ 8.41	$ 9.41

General Service - Schedule B

	Existing	Proposed
Service Charge (1P)	$ 33.00	$ 38.00
Service Charge (3P)	$ 47.00	$ 52.00
Energy Charge	$ 0.17791	$ 0.18774

Large Power Over 10k - Schedule LP

	Existing	Proposed
Service Charge	$ -	$ -
Demand Charge	$ 16.40	$ 17.40
Energy Charge	$ 0.11591	$ 0.12231

Large Power Over 150k - Schedule LP1

	Existing	Proposed
Service Charge	$ -	$ -
Demand Charge	$ 17.80	$ 18.80
Energy Charge	$ 0.08761	$ 0.09245

Rate Increase Option #2

Revenue from Proposed Rates

Line No.	Class	Existing Revenue	Proposed Revenue	$ Difference	% Difference
1	Residential - Schedule A	$ 4,513,063	$ 4,903,223	$ 390,161	8.65%
2	Electric Heat - Schedule AH	$ 117,214	$ 126,224	$ 9,010	7.69%
3	Seasonal - Schedule AS	$ 1,014,449	$ 1,118,388	$ 103,939	10.25%
4	General Service - Schedule B	$ 434,032	$ 465,650	$ 31,619	7.28%
5	Large Power > 10 kW - Schedule LP	$ 432,908	$ 456,729	$ 23,821	5.50%
6	Large Power > 150 kW - Schedule LP 1	$ 72,335	$ 76,435	$ 4,100	5.67%
7	Lights - Schedule SA-A	$ 20,451	$ 22,645	$ 2,194	10.73%
8	Electric Revenues	$ 6,604,452	$ 7,169,295	$ 564,843	8.55%
9	Misc. Revenues	$ 62,925	$ 62,925	--	
10	Operating Revenue & Patronage Capital	$ 6,667,377	$ 7,232,220	$ 564,843	8.47%

Next Steps

Recommendations

Near-Term

- Adopt MDSC Benchmark?
- Adjustments to Revenue Requirement Study?
- Adjustments to Cost of Service Study?

Medium-Term

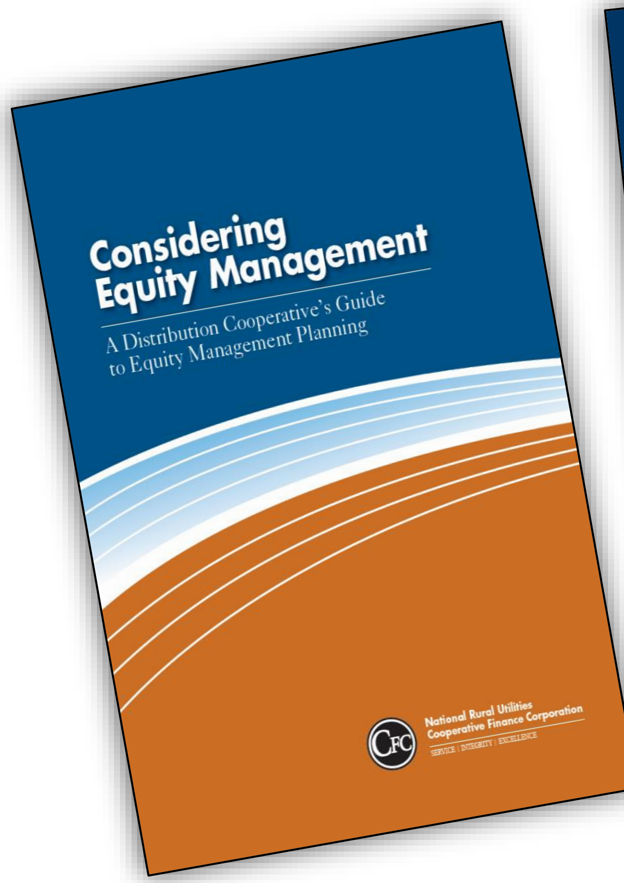
- Work with Board to identify and prioritize rate goals
  - Base on goal prioritization:
    - Develop long-term rate design plan (rate structures, policies, procedures)
    - Consider addressing potential under/over recovery between rate classes

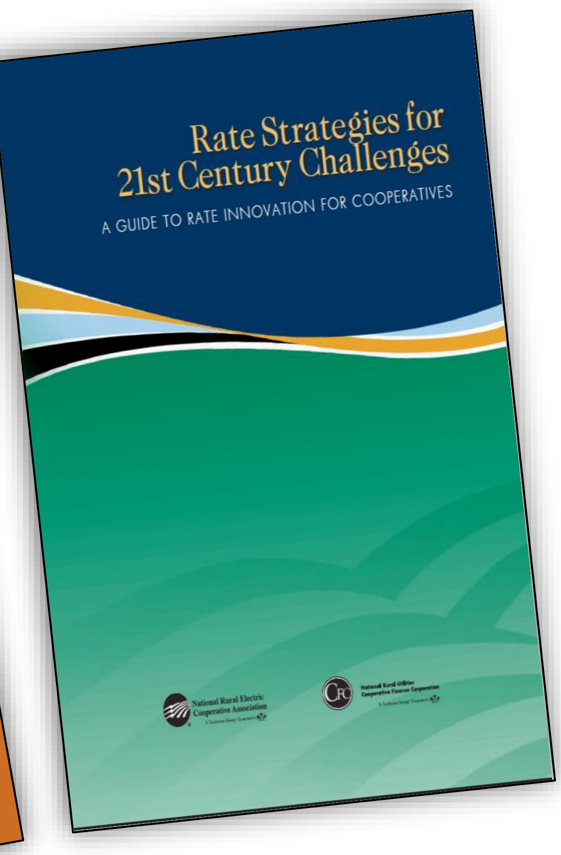
General/Ongoing

- Annual Revenue Requirement Study
- Conduct Cost of Service Study every 5-7 years
  - Unless:
    - Large Load coming on/off
    - Change in G&T Rate Structure
    - Addition/Elimination of Rate Schedules
    - Rate Redesign
    - Hourly AMI
    - Due Diligence

Additional Information

Ratemaking Resources


Considering Equity Management
A Distribution Cooperative's Guide to Equity Management Planning
National Rural Utilities Cooperative Finance Corporation
SERVICE | INTEGRITY | EXCELLENCE


Rate Strategies for 21st Century Challenges
A GUIDE TO RATE INNOVATION FOR COOPERATIVES
National Rural Electric Cooperative Association
National Rural Utilities Cooperative Finance Corporation


RETAIL RATE GUIDE
Volume I
NRECA America's Electric Cooperatives
National Rural Utilities Cooperative Finance Corporation


INTRODUCING A RATE CHANGE TO CONSUMER-MEMBERS
How to create and carry out a successful communications plan
NRECA America's Electric Cooperatives
National Rural Utilities Cooperative Finance Corporation

CFC News | October 5, 2020

CFC Helps Members Adjust to Changing Climate of Rate Design

Co-op News | March 8, 2021

CFC Helps Roanoke EC Launch New EV Subscription Rate Program

Co-op News January 11, 2021

CFC Helps Cobb EMC Offer Multiple Rate Options to Members

Utility Pricing, Policy & Analytics Consulting Services

Rate Services

- Policy & Strategy
- Revenue Requirements
- Formulary Rates
- Rate of Return/Cost of Capital
- Cost of Service (Distribution & G&T) (Embedded & Marginal)
- Retail Rate Design (Customer Charges, TOU, Demand, EV, Subscription Pricing Models, Contracts)
- Wholesale Rate Design
- Transmission Wheeling
- Purchase Power Cost Adjustment Riders
- Line Extension & Pole Attachment
- Lighting

Regulatory Services

- Tariff/Contract Review & Development
- Interconnection/Facilities Agreements
- Rate & Regulatory Planning/ Prudence Review
- PURPA
- Avoided/Stranded Cost/ Net Metering
- Market Power Analysis
- FERC Filing Submission
- State Commission Filing Submission
- Legislative/Regulatory Comment Submission (State/Federal)
- Data Analytics/Predictive Modeling/Load Forecasting/ Weather Normalization

Litigation Support/ Expert Testimony

- Policy & Strategy
- Rate of Return/Cost of Capital
- Patronage Capital/ Member Equity
- Test Year Development
- Pro Forma/Normalization Adjustments
- Regulatory Accounting
- Revenue Requirements
- Cost of Service (Distribution & G&T) (Embedded & Marginal)
- Rate Design (Retail & Wholesale)
- PURPA
- Avoided/Stranded Cost/ Net Metering

Accounting & Tax Services

- Regulatory Accounting
- Tax Guidance
- FASB, RUS, IASB, FERC
- Uniform System of Accounts
- Plant Accounting
- Technical Support

Presentations & Training

- Executive Teams & Board of Directors
- Forum & IBES
- State-Wide Workshops
- Annual Meetings
- Industry Conferences
- CFPC Course
- Financial & Director Workshops
- New Director, CFO, CEO Roundtables

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Jason Strong is the Vice President of Utility Pricing, Policy & Analytics at the National Rural Utilities Cooperative Finance Corporation (NRUCFC or CFC). Jason leads and directs a staff of electric utility consultants and analysts providing electric utility rate-making, policy, economic and advisory consulting services, at the federal and state level, to member-electric cooperatives. Jason is responsible for leading the team in providing member-cooperatives with expertise in areas surrounding the general regulatory and rate-making process, and specific to certain technical requirements including regulatory accounting, rate of return and cost-of-capital, revenue requirement determinations, cost-of-service, wholesale and retail rate design, tariff and rate administration, and econometric modeling and advanced data analytics. In addition, he advises CFC and its members on nascent energy industry economic and legal trends. Since being employed by CFC, Jason has conducted or supervised hundreds of regulatory engagements for electric cooperative members. Jason has been instrumental in rate design efforts and has worked with member-cooperatives in emerging areas in designing residential demand charges, electric vehicle charging, and energy and demand time-of-use rates. Jason has represented member-cooperatives before the New Mexico Public Regulation Commission, Vermont Public Utility Commission, and before the Maine State Legislature.

Prior to joining CFC, Jason was an Economist in the Office of Energy Market Regulation at the Federal Energy Regulatory Commission (FERC). During his twelve-year tenure at the FERC, Jason led inter-disciplinary teams in efforts concerning Commission regulations and policies advising numerous Chairman, Commissioners and key decision makers in hundreds of proceedings involving cost-of-service and rate design, cost allocation methods, regional transmission organization energy and capacity auctions, transmission planning processes, and integration of diverse energy sources and emerging technologies into the marketplace. Jason was a subject matter expert for FERC litigators defending FERC orders on appeal before the U.S. Court of Appeals. Previous to FERC, Jason worked for Exelon Corporation in the Energy Acquisition Division.

Jason holds a Master of Science in Applied Economics with a Sequence in Electricity, Natural Gas and Telecommunications Economics and also a Bachelor of Science in Economics—both from Illinois State University.

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Brian Adams is a Senior Rate & Business Consultant with the Utility Pricing, Policy & Analytics Team at the National Rural Utilities Cooperative Finance Corporation (NRUCFC or CFC). In this role, Brian assists in the preparation of Revenue Requirements and Cost of Service Studies for CFC members.

Prior to joining CFC, Brian was the Vice President of Engineering at the Association of Illinois Electric Cooperatives in Springfield, IL. At the Illinois Statewide, Brian prepared Cost of Service and Rate Design Studies for its member cooperatives. Brian was also responsible for planning and organizing the annual Cooperative Technology Conference, providing training and breakout sessions for engineers and IT personnel.

Brian is a licensed Professional Engineer in Illinois. Brian holds a Master of Business Administration degree from the University of Illinois in Springfield, as well as a Bachelor of Science degree in Electrical Engineering from Southern Illinois University – Edwardsville.

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National Rural Utilities Cooperative Finance Corporation

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Rate Increase Options

Ontonagon County Rural Electric Association
Management Presentation
October 16, 2023

Brian Adams – Sr. Rate and Business Consultant, Utility Pricing, Policy & Analytics

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Rate Increase Option #1

- Increase all billing components for all rates by an equal percentage to achieve overall revenue increase of $564,843

Residential - Schedule A

	Existing	Proposed
Service Charge	$ 25.00	$ 27.15
Energy Charge	$ 0.19391	$ 0.21059

Electric Heat - Schedule AH

	Existing	Proposed
Service Charge	$ 25.00	$ 27.15
Energy Charge (Summer)	$ 0.19391	$ 0.21059
Energy Charge (Winter <500 kWh)	$ 0.19391	$ 0.21059
Energy Charge (Winter >500 kWh)	$ 0.16391	$ 0.17801

Seasonal - Schedule AS

	Existing	Proposed
Service Charge	$ 35.00	$ 38.01
Energy Charge	$ 0.19391	$ 0.21059

Lights - RS SA-A

	Existing	Proposed
Regular Lights	$ 9.45	$ 10.26
LED Lights	$ 8.41	$ 9.13

General Service - Schedule B

	Existing	Proposed
Service Charge (1P)	$ 33.00	$ 35.84
Service Charge (3P)	$ 47.00	$ 51.04
Energy Charge	$ 0.17791	$ 0.19322

Large Power Over 10k - Schedule LP

	Existing	Proposed
Service Charge	$ -	$ -
Demand Charge	$ 16.40	$ 17.81
Energy Charge	$ 0.11591	$ 0.12588

Large Power Over 150k - Schedule LP1

	Existing	Proposed
Service Charge	$ -	$ -
Demand Charge	$ 17.80	$ 19.33
Energy Charge	$ 0.08761	$ 0.09515

Rate Increase Option #1

Revenue from Proposed Rates

Line No.	Class	Existing Revenue	Proposed Revenue	$ Difference	% Difference
1	Residential - Schedule A	$ 4,513,063	$ 4,899,090	$ 386,028	8.55%
2	Electric Heat - Schedule AH	$ 117,214	$ 127,527	$ 10,313	8.80%
3	Seasonal - Schedule AS	$ 1,014,449	$ 1,101,223	$ 86,774	8.55%
4	General Service - Schedule B	$ 434,032	$ 471,676	$ 37,644	8.67%
5	Large Power > 10 kW - Schedule LP	$ 432,908	$ 468,897	$ 35,989	8.31%
6	Large Power > 150 kW - Schedule LP 1	$ 72,335	$ 78,671	$ 6,335	8.76%
7	Lights - Schedule SA-A	$ 20,451	$ 22,211	$ 1,759	8.60%
8	Electric Revenues	$ 6,604,452	$ 7,169,295	$ 564,843	8.55%
9	Misc. Revenues	$ 62,925	$ 62,925	--	
10	Operating Revenue & Patronage Capital	$ 6,667,377	$ 7,232,220	$ 564,843	8.47%

Rate Increase Option #2

- Apply increase as follows:
  - Increase all Service Charges by $5 per Member per Month
  - Increase all Demand Charges by $1 per kW
  - Increase all Lights by $1 per Light per Month
  - Remaining Increase collected through Energy Charge (5.52%)

Residential - Schedule A

		Existing		Proposed
Service Charge	$	25.00	$	30.00
Energy Charge	$	0.19391	$	0.20462

Electric Heat - Schedule AH

		Existing		Proposed
Service Charge	$	25.00	$	30.00
Energy Charge (Summer)	$	0.19391	$	0.20462
Energy Charge (Winter <500 kWh)	$	0.19391	$	0.20462
Energy Charge (Winter >500 kWh)	$	0.16391	$	0.17296

Seasonal - Schedule AS

		Existing		Proposed
Service Charge	$	35.00	$	40.00
Energy Charge	$	0.19391	$	0.20462

Lights - RS SA-A

		Existing		Proposed
Regular Lights	$	9.45	$	10.45
LED Lights	$	8.41	$	9.41

General Service - Schedule B

		Existing		Proposed
Service Charge (1P)	$	33.00	$	38.00
Service Charge (3P)	$	47.00	$	52.00
Energy Charge	$	0.17791	$	0.18774

Large Power Over 10k - Schedule LP

		Existing		Proposed
Service Charge	$	-	$	-
Demand Charge	$	16.40	$	17.40
Energy Charge	$	0.11591	$	0.12231

Large Power Over 150k - Schedule LP1

		Existing		Proposed
Service Charge	$	-	$	-
Demand Charge	$	17.80	$	18.80
Energy Charge	$	0.08761	$	0.09245

Rate Increase Option #2

Revenue from Proposed Rates

Line No.	Class	Existing Revenue	Proposed Revenue	$ Difference	% Difference
1	Residential - Schedule A	$ 4,513,063	$ 4,903,202	$ 390,140	8.64%
2	Electric Heat - Schedule AH	$ 117,214	$ 126,223	$ 9,009	7.69%
3	Seasonal - Schedule AS	$ 1,014,449	$ 1,118,385	$ 103,936	10.25%
4	General Service - Schedule B	$ 434,032	$ 465,677	$ 31,645	7.29%
5	Large Power > 10 kW - Schedule LP	$ 432,908	$ 456,727	$ 23,819	5.50%
6	Large Power > 150 kW - Schedule LP 1	$ 72,335	$ 76,435	$ 4,100	5.67%
7	Lights - Schedule SA-A	$ 20,451	$ 22,645	$ 2,194	10.73%
8	Electric Revenues	$ 6,604,452	$ 7,169,295	$ 564,843	8.55%
9	Misc. Revenues	$ 62,925	$ 62,925	--	
10	Operating Revenue & Patronage Capital	$ 6,667,377	$ 7,232,220	$ 564,843	8.47%

Rate Increase Option #3

- Apply increase as follows:
  - Increase all Service Charges by $5 per Member per Month (per Option 2)
  - Increase all Demand Charges, Lights, and Energy Charge evenly (per Option 1)

Residential - Schedule A

		Existing		Proposed
Service Charge	$	25.00	$	30.00
Energy Charge	$	0.19391	$	0.21059

Electric Heat - Schedule AH

		Existing		Proposed
Service Charge	$	25.00	$	30.00
Energy Charge (Summer)	$	0.19391	$	0.21059
Energy Charge (Winter <500 kWh)	$	0.19391	$	0.21059
Energy Charge (Winter >500 kWh)	$	0.16391	$	0.17801

Seasonal - Schedule AS

		Existing		Proposed
Service Charge	$	35.00	$	40.00
Energy Charge	$	0.19391	$	0.21059

Lights - RS SA-A

		Existing		Proposed
Regular Lights	$	9.45	$	10.26
LED Lights	$	8.41	$	9.13

General Service - Schedule B

		Existing		Proposed
Service Charge (1P)	$	33.00	$	38.00
Service Charge (3P)	$	47.00	$	52.00
Energy Charge	$	0.17791	$	0.19322

Large Power Over 10k - Schedule LP

		Existing		Proposed
Service Charge	$	-	$	-
Demand Charge	$	16.40	$	17.81
Energy Charge	$	0.11591	$	0.12588

Large Power Over 150k - Schedule LP1

		Existing		Proposed
Service Charge	$	-	$	-
Demand Charge	$	17.80	$	19.33
Energy Charge	$	0.08761	$	0.09515

Rate Increase Option #3

Revenue from Proposed Rates

Line No.	Class		Existing Revenue		Proposed Revenue		$ Difference	% Difference
1	Residential - Schedule A	$	4,513,063	$	5,011,139	$	498,076	11.04%
2	Electric Heat - Schedule AH	$	117,214	$	129,408	$	12,194	10.40%
3	Seasonal - Schedule AS	$	1,014,449	$	1,132,501	$	118,052	11.64%
4	General Service - Schedule B	$	434,032	$	476,755	$	42,723	9.84%
5	Large Power > 10 kW - Schedule LP	$	432,908	$	468,897	$	35,989	8.31%
6	Large Power > 150 kW - Schedule LP 1	$	72,335	$	78,671	$	6,335	8.76%
7	Lights - Schedule SA-A	$	20,451	$	22,211	$	1,759	8.60%
8	Electric Revenues	$	6,604,452	$	7,319,581	$	715,129	10.83%
9	Misc. Revenues	$	62,925	$	62,925		--	
10	Operating Revenue & Patronage Capital	$	6,667,377	$	7,382,506	$	715,129	10.73%

National Rural Utilities Cooperative Finance Corporation

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