RETAIL RATE GUIDE

Volume I

NRECA
America's Electric Cooperatives

National Rural Utilities
Cooperative Finance Corporation

This Rate Guide is jointly owned by the National Rural Electric Cooperative Association (NRECA) and the National Rural Utilities Cooperative Finance Corporation (CFC) with authorship contributions from C.H. Guernsey & Company.

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Foreword

Proper ratemaking remains a cornerstone of electric cooperative financial strength. Rates also offer a terrific touch point and opportunity for enhancing member education, discussing the cooperative difference, and establishing your cooperative as a trustworthy source of information.

Today's evolving utility marketplace raises important concerns regarding how electric cooperative rates are structured. New technologies such as advanced metering infrastructure (AMI) and behind-the-meter communications devices are making new rate designs possible, while advancements in efficiency, distributed generation and energy storage are challenging the viability of traditional ratemaking structures. At the same time, electric cooperative member-consumer preferences are evolving. In many cases, member-consumers are demanding new services and asking for more control over their energy use.

To best mitigate risks and advance opportunities, CFC and NRECA offer this guide, and its companion communications toolkit, *Introducing a Rate Change to Member-Consumers*, as a comprehensive resource on ratemaking. Given the diversity of electric cooperatives, no one-size-fits-all solution exists. The guide is meant to provide electric cooperatives with a suite of rate options and considerations that will help you tailor rates to fit your own system needs and member-consumer preferences.

We hope that this guide is a valuable resource to America's Electric Cooperatives as you navigate a fast-changing industry environment.

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Overview

Technology is driving profound changes in the electric utility industry. The changes are especially apparent in three areas:

1. **Power Supply Resources**: The proliferation of distributed energy resources (DER) has created a paradigm shift. The old paradigm was the utility-owned central station resource model with power flow from the source to the load. The emerging paradigm is a portfolio model with resources located, owned, and operated across the energy value chain from central station to the retail member-consumer with option of power flow from the member-consumer to the grid.
2. **System Operations**: The application of new technology will provide opportunities to accommodate the portfolio resource model, improve distribution system reliability and reduce the cost of providing service to the retail member-consumer. This is being realized by a transition of the distribution system from a radial design to an intelligent network design involving smart grid and micro grid applications with the two-way flow of electrons and data.
3. **Member-consumer Involvement**: Many of the technology changes are at the retail level and directly involve the retail member-consumer. As a result the retail member-consumer will be seeking opportunities to participate in the economic benefits and other benefits associated with the application of the technology. The member-consumer will transition from a passive to an active agent. The results are increased opportunities for energy conservation and service from alternative energy resources which means a decrease in energy sales by the distribution cooperative.

"The utility of the future will need to recognize that pricing will become increasing complex"[2]

Along with these changes, there is evolving within the industry a new entity, the Distribution System Operator ("DSO"). The DSO will be responsible for implementation of, and optimization of investments in, technology at the distribution level and the allocation of the economic benefits of the technology to the participants and system. The DSO may take many shapes, from the existing distribution wires provider to a new third party. Distribution cooperatives are uniquely positioned to take on the role of a DSO.

In "The 51st State | Phase II, The Consumer-Centric Utility Future"[1], NRECA introduced the concept of the Consumer-Centric Utility (CCU) business model and proposed that the distribution cooperative is best positioned to perform the DSO functions of optimizing technology and allocating economic benefits. The report identified specific issues related to pricing and rates that the distribution cooperative will need to address:

"The utility of the future will need to recognize that pricing will become increasing complex."[2]

"Improper cost recovery implementation and management can lead to sending wrong signals to consumers regarding investments. That said, the Future State will require rate and price setting that will require balancing far more levels of complex inputs…."[3]

[1] The 51st State Phase II, The Consumer-Centric Utility future, Prepared by: The National Rural Electric Cooperative Association, March 23, 2016, page 4.

[2] Ibid, page 35.

[3] Ibid, page 35.

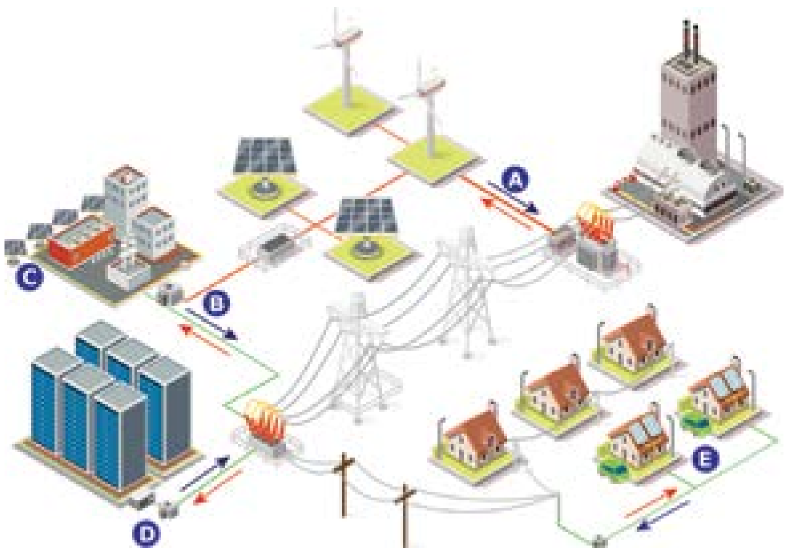
Each distribution cooperative is unique and will determine its best strategy to recognize changing technology and define its role as system optimizer

"New additions to the grid, like solar panels, energy storage, micro grids and DSO functions will require new thinking in terms of how people are paying for their energy."[4]

Each distribution cooperative is unique and will determine its best strategy to recognize changing technology and define its role as system optimizer. The degree of involvement will vary and clearly one size will not fit all. However, to be successful the cooperative must provide:

"..rate and price setting that will require balancing far more levels of complex inputs than in the past."[5]

Technologies and Power Flow



A. Utility-scale renewables impact wholesale markets with periods of low cost generation.

B. Utility-scale renewables provide resources for C&I member-consumers.

C. On-site renewables reduce retail kWh or capacity depending on the rate pricing signal.

D. On-site DER can provide peak load shaving.

E. DER, electric car-charging and battery storage alter load profiles. Member-consumers may be compensated for excess generation.

Understanding the factors involved in achieving a fair and equitable balance of complex inputs is a process that will take some time given our starting point. Historically, the rate and price setting reflected the source of power and the nature of distribution:

1. Power flow was from the central station resource to the member-consumer with the distribution cooperative serving as the aggregator of wholesale power supply and providing the distribution wires for service to the member-consumer. The cooperative bundled the total cost of providing service, averaging allocations across wide classes of member-consumers.

2. The cooperative would develop prices for electric service by grouping together member-consumers with a similar load profile and design rates to serve that profile. The concept of homogeneity within a member-consumer class has always been an approximation, although it has served the industry well in developing rates that reflect cost and are generally viewed as fair and equitable.

So what is changing? The notion of homogeneity within a customer class and the concept of fixed load profile based on the rate classification begin to erode as technological advances allow the member-consumer to become an active agent. With DER, micro grids, home energy management systems, electric storage capability, etc., the member-consumer transitions from a passive load center to an active agent on the electric grid with the ability to change individual load profiles. Given traditional rate design and the expansion of new technology that changes the member-consumer's load profile in a rate class, the end result can be both inter- and

[4] Ibid, page 35.

[5] Ibid, page 35.

The distribution cooperatives face a paradigm shift with the application of new technology

intra-class cross subsidies and instability in revenue recovery. The most apparent example is the unintended consequences of the rooftop solar photo voltaic (PV) applications through net metering.

The distribution cooperatives face a paradigm shift with the application of new technology and this extends to their suppliers, whether generation and transmission associations, independent suppliers, wholesale markets, etc. What will be the path forward to effectively address this shift? Over the near term the focus will likely be on "innovative rates" or "innovative pricing." Although these terms can have different meanings to different people, for many they likely mean the development of tariffs and pricing that:

- include incentives to reward particular behavior.
- increase fixed charges and minimize the reliance on consumption-based pricing for fixed-cost recovery.[6]
- develop "valuation methodology" including:
  - value of service[7]
  - value of resource[8]
  - transactive energy[9]
- respond to member-consumer expectations related to conservation.
- accommodate technology specific applications.

Chasing technology and chasing value are difficult tasks that can create uncertainty for not only the member-consumer but, more importantly, the cooperative. Even within a particular application of a technology, there can be differences in the resultant member-consumer load profile. For example, tariffs based on "value of solar" end up reflecting an average of load profiles that ignore the ratio of solar capacity vs. the load served and the angle of inclination for different arrays. The member-consumer may want value recognized for a service that a cooperative has not previously quantified, such as certain distribution ancillary services.

Advances in advanced metering infrastructure (AMI) technology may in the extreme case result in treating each consumer as a unique node. The cost incurred in serving a load in an interval may be independent of how the energy in that interval is used. Rather than pricing based on a rate class, the pricing may reflect attributes of the service at the node, i.e., voltage, real and reactive power requirements, and frequency that reflect real time conditions at the node. Perhaps one future state involves the cooperative's development of a single set of pricing metrics that are applied independently of the rate classification.

6 Some proposals suggest increasing the customer charge to recover total distribution wires cost.

7 Value of Service requires a functional unbundling of the distribution services and a value placed on each service. The cooperative would then pay the DER for the service provided. The VOS focuses on services provided and not on a specific type of resource or technology.

8 Value of Resource involves identifying the value of benefits and costs to the grid, other customers, and society associated with a specific type of resource. The value can change over time based on different factors such as location on the grid, gas prices, etc.

9 Transactive Energy ("TE") is a concept by which customer-sited resources can be interactive with the grid by using value as a common language to combine economic and control techniques and to align value streams for all parties. The process is highly reliant on price signals and rules allowing for markets to develop that enable a wide variety of participants to interact directly with each other. TE can enable a much larger set of value streams for customer-sited resources. Reference: Distributed Energy Resources Rate Design and Compensation" NARUC November, 2016, page 139. "IEEE Electrification Magazine", December, 2016, page 2.

The path to deal with new technology will be different for each cooperative and will reflect the conditions unique to the cooperative

A cooperative's rate pricing may also recognize value provided by the member-consumer in the form of distribution ancillary services such as voltage support, real and reactive support, reduction in congestion at the node, etc. The value of resource and value of service options require that value be placed on certain distribution ancillary services that, to date, have not been quantified. [10]

This Rate Guide does not attempt to define specifics of the "future state." The path to deal with new technology will be different for each cooperative and will reflect the conditions unique to the cooperative. However, there are certain key steps along the path that the cooperative should take to meet the financial and rate objectives established by the Board. The Rate Guide provides a structure and process to evaluate the issues, analyze the alternatives, and independently develop pricing and rates that balance the complex inputs and are aligned with the needs of the cooperative.

Importantly, statements in the Rate Guide that an electric cooperative, its employees, or its board of directors should, must, or need to take or avoid certain acts, and similar statements, do not suggest, imply, or support a legal conclusion, requirement, or standard.

Reading the Rate Guide

The Rate Guide is developed with three readers in mind:

Board of Directors ("Board"): The Board has ultimate responsibility for the rates charged to the member-consumer consumers of the cooperative. The rates must be adequate to maintain the financial viability of the cooperative and must reinforce Board policies related to strategic financial goals, rate design criteria, and desired DSO participation.

Management: Cooperative management consists of the CEO/General Manager who has responsibility for leading the preparation of a Rate Analysis. The analysis may be prepared by either cooperative staff or cooperative staff working with a third party specialist. Management should have sufficient background knowledge of the process to review the work product for completeness and communicate results to the Board.

Staff: Cooperative staff should be involved in the Rate Analysis process. The degree of involvement will vary depending on staff's availability, resources, and previous experience with Rate Analysis issues.

[10] For years wholesale ancillary services were not recognized as separate services with separate rates. Today, six separate transmission ancillary services are recognized by FERC and markets exist for these services. Distribution ancillary services are also likely to evolve with separate pricing and perhaps, a market for these services.

Each cooperative will have specific issues that need to be addressed and will have its own perspective as how best to address those issues. The Rate Guide describes the complete rate analysis process that will provide the detailed information needed for the cooperative to develop "rate and price setting that balances the complex inputs" specific to the cooperative.

Some cooperatives may already have in place an understanding of the steps involved in the rate analysis process, be aware of the interrelationships of the various elements of the process, have cost data, and understand the cost drivers for their system. Their immediate concern is to evaluate different rate options that will allow their cooperative to deal with new technology and changing consumer expectations. Therefore, the Rate Guide is presented in two volumes. Volume I focuses on the overall process, a discussion of rate options, and the presentation and implementation of the rate proposal to the member-consumers. Volume II focuses on the other steps in the rate analysis process used to develop rates.

VOLUME I

Section 1 is particularly intended for the cooperative director. It describes the rate design process, the issues to consider in the implementation of the process, the importance of the financial and rate policies in the process, and the specific role of the director in the process.

Section 2 explains the importance to the Board of the twelve to twenty four month "look ahead" of cooperative revenue and margins and why it is a critical element of the Rate Analysis process.

Section 3 outlines various rate options, as well as the advantages and disadvantages of the different rate options.

Section 4 describes factors to consider in making final decisions related to the selection of the proposed rates.

Section 5 outlines factors to consider in the "roll-out" of rates to the member-consumers and the communication that needs to occur.

VOLUME II

Section 1 describes the process for developing the revenue requirement including the selection of the Test Year and the development of the appropriate expense adjustments.

Section 2 describes the development of the margin component of the revenue requirement. This section is particularly important because it provides recommendations of how to define the margin component of the revenue requirement based on the Board's financial objectives.

Section 3 describes the steps involved in the development of the cost of service study.

Section 4 describes how the results of the cost of service are used to make decisions related to rate class revenue requirements and provide input data for rate design.

1.0

The Director's Roadmap to the Rate Analysis Process

The following is a summary of the Rate Analysis process and the key issues that need to be considered by the cooperative's Board of Directors.

1.1

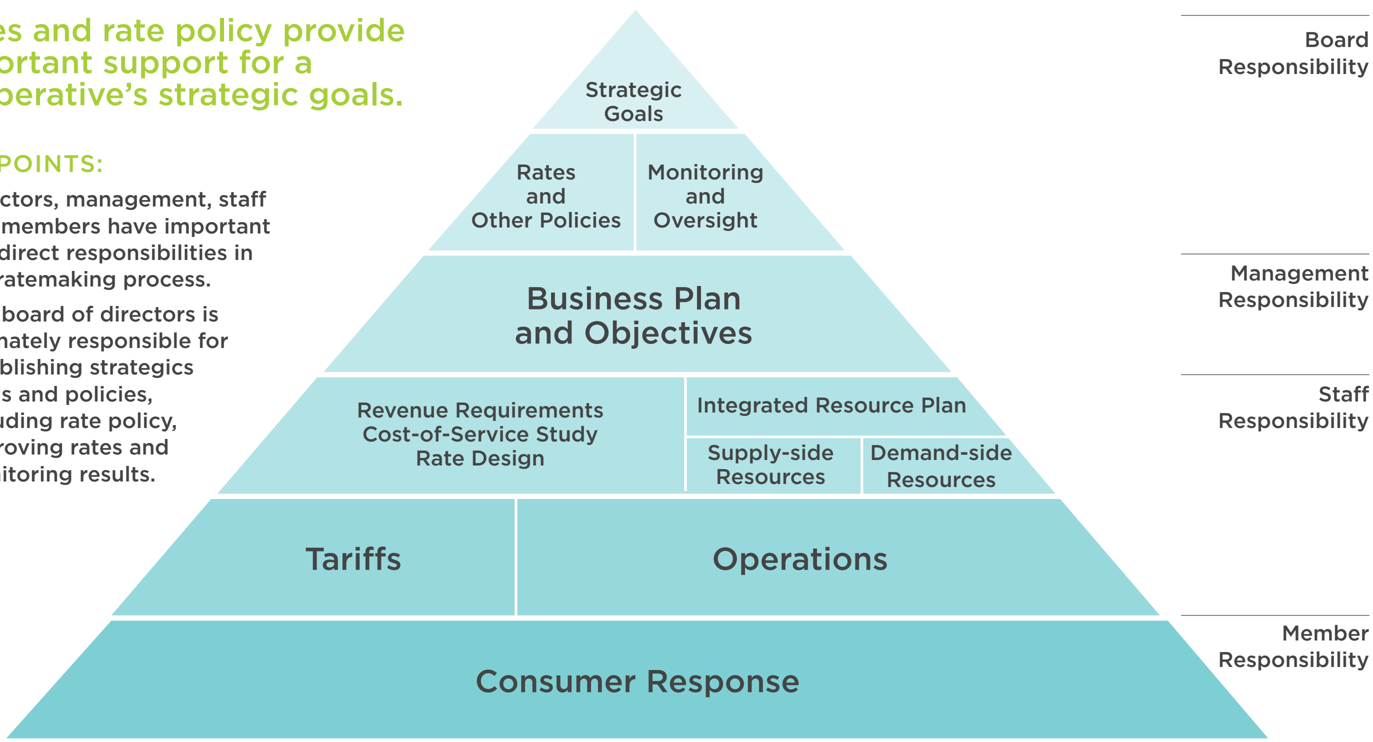
What policies should the Board have in place?

The determination of rates charged by the cooperative is one of the most important responsibilities of the Board. It is essential that the final rates approved by the Board are in line with the policies the cooperative has in place. The general areas of responsibility are shown below. [11]

Rates and rate policy provide important support for a cooperative's strategic goals.

KEY POINTS:

- Directors, management, staff and members have important but direct responsibilities in the ratemaking process.
- The board of directors is ultimately responsible for establishing strategics goals and policies, including rate policy, approving rates and monitoring results.



[11] NRECA 2011 Rate Strategies for 21st Century Challenges (A guide to rate innovation for cooperatives)

The Board needs to have in place three specific Board policies and the rates designed need to provide positive feedback and reinforcement of the policies. The three Board policies are:

- Financial Strategy or Equity Management Plan
- Rate Design Policy
- Distribution System Operator (DSO) Operating Policy

The cooperative should already have in place a Financial Strategy or Equity Management Plan and Rate Design Policy. The DSO Operating Policy likely does not yet exist because the role of the cooperative as a Consumer- Centric Utility (CCU) serving as a DSO has only recently been introduced.

1.1.1

WHAT ARE THE COOPERATIVE'S FINANCIAL STRATEGY OR EQUITY MANAGEMENT PLAN OBJECTIVES?

Alignment with the financial strategy policy is most important. The Board needs to have in place a strategy (a financial strategy plan, an equity management plan, etc.) which defines long-term income statement and balance sheet objectives for four basic metrics:

- Desired margin defined in terms of financial metrics such as TIER, DSC, ROR, MFI. (Times Interest Earnings Ratio, Debt Service Coverage, Margin For Interest, respectively).
- Desired equity levels
- Desired liquidity levels
- Desired capital credit retirement levels

The cooperative should have a policy defining guiding principles or criteria that the Board expects to be followed in the development of rates

These four objectives are all interrelated. The cooperative's revenue requirement is driven by the Board's target values for each of the four metrics as a result of the projected capital expenditures ("CAPEX") for the cooperative and interest rate on long-term debt. Volume II, Section 2.0 describes how the various values are interrelated and suggests tools that can assist the Board in developing target values. The Board should have defined the financial strategy and the key financial metrics prior to starting the rate analysis.

1.1.2

WHAT IS THE COOPERATIVE'S RATE DESIGN POLICY?

The cooperative should have a policy defining guiding principles or criteria that the Board expects to be followed in the development of rates. It is a three-step process in which the Board discusses and defines philosophy, states the philosophy in terms of a policy, and then defines specific criteria for the implementation.

Although the Board should begin with a discussion of rate philosophy, sometimes this can be a difficult discussion. One approach is to begin with a basic set of criteria and then allow the underlying philosophy to be defined in terms of how the Board believes the criteria should be applied.

The typical starting point is that rates:

- Are easily understood.
- Provide the required revenue.
- Provide revenue stability from year to year.
- Are cost-based and provide a fair apportionment of cost to member-consumers served.
- Send the proper pricing signals.
- Are not unduly discriminatory[12].

[12] James C. Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961), pages 291 – 292.

The wholesale power cost represents a disproportionate share of the cooperative's revenue requirement

However, the devil is always in the details, and the Board needs to decide its position on certain basic issues, and when possible, to provide some quantification of its position. Different Boards will have different views with regard to the following:

- What constitutes a fair apportionment of cost and what defines undue discrimination? This Rate Guide will provide a metric to evaluate discrimination between rate classifications using the relative rate of return (RROR).[13] However, this is not the only basis for evaluation. The Board should decide:
  - What is the appropriate metric for the cooperative?
  - What are allowable differences in relative margins between rate classes?
  - For rate classifications with a metric above or below the allowable difference, what is the plan to move to an acceptable level:
    - What are allowable maximum class rate increases relative to system average?
    - Should a rate class ever receive a rate decrease?
    - How should a rate class with minimum investment be evaluated?[14]
- To what extent should externalities, non-cost based and social factors be considered in the rate design and in the determination of the revenue requirement? Are these externalities a basis for a differential in the rates charged?
  - Do we need to consider the impact on low income member-consumers and do we equate low income with low energy usage?
- Do we want to discourage energy usage by putting in place inclining block rates even if there is no cost based justification in our wholesale rate?
- To what extent do we want to recover the full customer cost component in the customer or facility charge and what is the plan to reach the target goal?
- Do we consider the subsidy provided by government programs as sufficient to deal with social issues and should our rates be based only on the cooperative's cost of service?
- What are the externalities that need to be considered for my cooperative?
- Do we have specific goals in terms of renewable resources and what are the implications for rate design?
- Does our current rate structure accommodate member-consumers' use of rooftop solar, and does it do so in compliance with governing law and with fairness to non-users?
- To what extent do we want to encourage community solar as an alternative to roof-top solar?

The Rate Design Policy may differ if the cooperative's operating area is single or multiple certificated or if the cooperative operates under a state law that permits customer choice.

The wholesale power cost represents a disproportionate share of the cooperative revenue requirement. The wholesale power cost is defined by the wholesale power supplier's rates. This suggests the importance of alignment between the cooperative and wholesale power supplier's rate design. If service is from an

[13] See Section Volume II, Section 4.0.

[14] A large power customer may have minimum investment to serve and a RROR will not be an appropriate metric.

All these are functions of the DSO. The distribution cooperative is well positioned to be the entity for integration of the new technology and the development of rate and pricing for services that accommodate the member-consumer's requirements

Investor Owned Utility (IOU) or federal marketing entity, the ability to align rate design with wholesale power rates will be limited. However, wholesale service from a G&T should provide greater opportunity to coordinate the wholesale and retail rate designs. The distribution cooperative Board always has responsibility for the retail rates charged. However, even though a distribution cooperative and its G&T are separate legal entities and are not a joint venture or single enterprise, the Board should consider the alignment between wholesale and retail rates. The two-tier (sometimes three-tier) pricing scheme makes it difficult to align retail price and wholesale cost.[15]

1.1.3

WHAT IS THE COOPERATIVE'S DISTRIBUTION OPERATING POLICY?

Distribution cooperatives have always served as power supply aggregator and interface between the retail member-consumer and the wholesale supplier be it a G&T, an IOU, a federal marketing authority, etc. Historically, the boundaries were very clear with the power flow from the wholesale supplier through the distribution cooperative to the retail member-consumer.

However, to be successful the cooperative needs to understand the changes that are occurring, decide the role it wishes to play and translate that role into a policy

As wholesale markets have evolved, the wholesale supplier has adapted to changes in the interface between the distribution cooperative and wholesale market. The wholesale supplier navigated new rules dictated by FERC Order 888 (1996) and FERC Order 2000 (1999), the introduction of the "exempt wholesale generator," and the roles of the Regional Transmission Operator (RTO) and Independent System Operator (ISO) in the wholesale markets. Today, two-thirds of the electricity consumed in the United States is delivered in service areas with wholesale electric markets.[16]

The wholesale suppliers have had to adjust to the changes. The distribution cooperative needs to understand the changes that are occurring and decide the role they wish to play as the distribution system operator (DSO). One aspect involves the integration of the distributed energy resources and the associated operational and safety issues. Another aspect involves implementation of smart grid and micro grid applications and the possible transition from a radial system to an intelligent distribution system. Another is the utilization of AMI and the development of detailed data allowing the cooperative to provide improved service and reliability to the member-consumers. In order to fully integrate new technology the cooperative needs to evaluate interoperability and communication security issues. Given the changing role of the member-consumer as an active agent able to change a load profile and able to provide services to the distribution cooperative, the cooperative needs to consider the member-consumers expectations in terms of rates and pricing for service and how the cooperative will respond to these expectations.

All these are functions of the DSO. The distribution cooperative is well positioned to be the entity for integration of the new technology and the development of rates and pricing for services that accommodate the member-consumer's requirements. However, to be successful the cooperative needs to understand the changes that are occurring, decide the role it wishes to play and translate that role into a policy, i.e., the Distribution Operating Policy.

[15] Given the structure of the G&T and distribution cooperative, there will always be two tiers of pricing. G&T wholesale rate price to cooperative and cooperative retail rate to member consumer. In some instances, a G&T is serving transmission cooperatives who in turn serve the distribution cooperative, which creates the three tiers of pricing. This configuration provides great opportunities to distort the pricing signal to the ultimate retail member-consumer.

[16] NARUC Distributed Energy Resources Rate Design and Compensation, November 2016, page 38.

1.2

What steps should the Board expect in the development of a Rate Analysis?

At a minimum, the Board should have the Financial and Rate Design policies in place. The Board should have had discussions about future changes in the industry and the role they believe their cooperative should play in the implementation of new technology at the distribution level, as well as the extent they wish to be proactive in allowing their member-consumers opportunities to be active agents.

The Board should expect a process consisting of seven steps. Depending on the objectives established in Step #2, the focus and level of detail of the remaining steps will vary. If the cooperative is regulated, the Rate Analysis process will be influenced by the requirements of the regulator. The following are the specific steps involved in the development of a Rate Analysis:

1. Continually monitor the performance of the existing rates and identify when a rate change is required to maintain financial integrity.
2. Determine the Rate Analysis objectives, the criteria for evaluation and the expected deliverables.
3. Determine the revenue requirements for the test year.
4. Prepare the cost of service study (COSS) and identify the:
    a. Relative margins from each rate class
    b. Required increase in rate class revenue to realize revenue requirement objectives while reflecting rate policy criteria.
    c. Identify key cost drivers to be reflected in rates.
5. Identify rate options and, using data from the COSS, evaluate the options and develop proposed rates.
6. Review the implementation of the proposed rates in terms of impact on existing policies and programs.
7. Present final rates and communicate to member-consumers the reasons for the proposed changes.

A key responsibility of the Board is to maintain the financial integrity of the cooperative

The Board and management should be clear as to the reasons for the Rate Analysis

1.2.1

STEP 1: WHAT SHOULD THE BOARD MONITOR?

A key responsibility of the Board is to maintain the financial integrity of the cooperative. To do this, the Board needs to determine how the current rates are performing in terms of the financial objectives established by the Board and if and when rate revisions are required. The Board cannot rely on only current Form 7 data to make that decision. Management must provide and the Board must have in place data showing expected financial performance at least twelve months in the future and if regulated at least twenty-four months in the future.

The projected income statement metrics are typically in the form of a projected financial ratio such as TIER, OTIER, DSC, MFI or ROR. The projected balance sheet metrics are either equity as percent of assets or equity as percent of capitalization and liquidity. The relevant metric should be one that the Board references in the development of the Strategic Financial Plan or Equity Management Plan.

Each month the Board should have available the projected performance data. Volume I, Section 2.1 describes the tools available for development of the projections and Section 2.2 describes the factors to consider in determining the timing of the need for a rate adjustment.

1.2.2

STEP 2: WHAT IS THE REASON FOR THE RATE ANALYSIS AT THIS TIME?

The Board and management should be clear as to the reasons for the Rate Analysis. The typical reasons for a rate analysis include:

- The Board and management are monitoring the cooperative's revenue and margins and based on current trends the projected revenue and margins from current rates are not acceptable. The revenue level needs to be increased in order to meet the financial objectives as outlined in the cooperative's Strategic Financial Plan or Equity Management Plan.
- Based on previous rate analysis, the cooperative has identified earning differential issues either on an inter-class or intra-class basis that need to be corrected. The cooperative has committed to change rates to adjust rate class margin differentials.
- The current rates have been in place for years and during this time changes have occurred. The changes may include rate of load growth for the cooperative, member-consumer desire for new service and changes in the wholesale rate design and associated price signals and cost drivers. Changes in technology and in particular AMI allows the cooperative to more accurately track costs and increase inter/intra class fairness and equity. If regulated, there may be changed requirements related to application of specific rates or services.
- Member-consumers are requesting new services or applications that did not exist when the current rates were designed and rates need to be revised to accommodate the current member-consumer needs and application of new technology.

- The cooperative has used automatic adjustment provisions to recover increases in costs (typically the purchased power cost adjustment rider with all purchased power cost increase recovered on an energy adjustor) and it has become necessary to restate certain cost components in the rate charges in order to properly align cost causation with cost recovery.

The Board and management need to not only define the reasons for the analysis and the expected deliverables, but more importantly, be clear as to the criteria that will be applied. The policy guides are the Financial Objectives/Equity Management Plan, the Rate Design Policy and the DSO Policy.

1.2.3

STEP 3: WHAT IS THE TOTAL REVENUE REQUIREMENT AND HOW WAS IT DEVELOPED?

Determining the revenue requirement is the most fundamental element of the process and is linked to the financial objectives defined in the Strategic Financial Plan or Equity Management Plan. There are two components to the revenue requirement:

1. Total annual operating cost
2. Margin requirement

To determine the total annual operating cost the Board should consider:

1. What test year was selected to determine the revenue requirement? Reference Volume II, Section 1.2.
2. If a historic test year is being used, the Board then needs to understand the cost adjustments that were made and the extent to which the adjustments are forward looking. Reference Volume II, Sections 1.3 and 1.4.

To determine the margin component of the revenue requirement, the Board and management need to define four basic financial objectives:

1. The minimum acceptable financial coverage ratio. This value may be an accrual metric such as TIER, OTIER, MFI or a cash based metric such as DSC. Typically, both metrics are applicable and the determining factor will be the relationship between depreciation and principal payments for debt service. The minimum acceptable level should not be the defaults in the debt indenture. The minimum acceptable value should be some cushion above the debt requirements. Reference Volume II, Section 2.1.1.
2. The long term equity objective recognizing the balance between the cost of debt and impact on rates and the cost of capital credit program. Reference Volume II, Section 2.1.2.
3. The liquidity objectives. Reference Volume II, Section 2.1.3.
4. The capital credit retirement objectives. Reference Volume II, Section 2.1.4.

To determine the margin required to meet the financial objectives, management needs to provide to the Board the projected CAPEX over the forecast period. The forecast period is typically not less than three years or longer than ten years.

The objective is to determine the margins (typically defined by the coverage metric) needed to meet the equity, liquidity and capital credit retirement program given the projected CAPEX. If the resultant coverage ratios are equal to or greater than the minimum acceptable values in #1, then the resultant values are used. If the resultant values are less than the minimum acceptable values in #1, the coverage values in #1 should be used and the Board should determine the corresponding adjustment to be made in the equity, liquidity and capital credit program. Reference Volume II, Section 2.3.

The cost of service study (COSS) is the fundamental tool for the entire Rate Analysis process

The development of the COSS involves a number of steps that should involve cooperative staff from a number of different departments

1.2.4

STEP 4: WHY IS A COST OF SERVICE STUDY NECESSARY AND WHAT INFORMATION DOES IT PROVIDE?

The cost of service study (COSS) is the fundamental tool for the entire Rate Analysis process. The COSS provides information to allocate the total system revenue requirement to the individual rate classes. The data from the COSS is then used to allocate the class revenue requirement to individual member-consumers in the rate class, i.e., the rate design. The ability of the cooperative to realize the Rate Design Policy objectives is dependent on how the COSS is developed and utilized.

The development of the COSS involves a number of steps that should involve cooperative staff from a number of different departments. The steps include:

1. Define the retail rate classes that will be served. Reference Volume II, Section 3.1.
2. Define the functions of plant and operating expenses associated with providing service (functionalization of cost). At a minimum, the functionalization needs to be aligned with the expected unbundled rate components. Reference Volume II, Section 3.2.
3. Define the cost drivers for the plant investment and expenses associated with providing service (classification of cost). Reference Volume II, Section 3.3.
4. Determine the usage characteristics for each rate class and develop the associated allocation factors for each rate class. Reference Volume II, Section 3.4.
5. Allocate the revenue requirement to each rate class. Reference Volume II, Section 4.0.
6. Determine class revenue requirements recognizing rate impact issues and other factors that would affect the recommended revenue requirement for a rate class and that are reflected in the cooperative Rate Design Policy. Reference Volume II, Section 4.2.

The questions or considerations the Board should ask related to the COSS include:

1. To what extent are the existing rates cost based and what is the margin provided by each rate class relative to the system? Knowing the relative rate of return (or other metric defined in the Rate Design Policy) from each class will indicate to the Board margin differentials in the current rates.
2. What is the magnitude of rate change required for each rate class to realize the objectives defined in the Rate Design Policy?
3. Given the rate class revenue requirement from the COSS and the Rate Design Policy, the Board will then need to determine the allowable increase or decrease for each rate class. It is possible that the allowable increase will not provide sufficient revenue to meet the total revenue requirement target. If this is the case, the Board needs to revisit the total revenue requirement objective.
4. Based on the COSS, what are the appropriate customer or service charges for each rate class? What are the cost based energy charges for two part rates and the cost based demand and energy charges for three part and four part rates? Knowing the cost based components, the Board can evaluate rate options proposed by management and staff. Reference Volume II, Section 4.3.

The Board needs to clearly understand how the proposed rates and any changes in the rates are aligned with and will reinforce other cooperative programs

1.2.5

STEP 5: WHAT SHOULD THE BOARD CONSIDER WHEN A RATE CHANGE OR NEW RATE IS PROPOSED?

Step 5 merges the Board's Rate Design Policy and Financial Policy criteria and the Board's position related to adoption and integration of new technology into specific rates to the member-consumer. The determination of total system revenue requirement, the definition of applicable rate classifications, and the allocation of total system revenue requirement to a rate class have been addressed and the COSS has defined the basic cost drivers needed to align cost causation with cost recovery.

In step five, the revenue requirements are assigned to individual member-consumers as part of the rate design. In reviewing the recommendations, the primary questions asked by the Board should be:

1. Does the rate change or new rate properly address the issues identified in Step 2?
2. Have we addressed the need for any new rate classes based on requests from our member-consumers or because of the need to accommodate technology changes?
3. To what extent are the proposed individual components in the rate aligned with cost drivers defined in the cost of service? Stated another way, is the proposed rate sending the proper pricing signals and is there an alignment of cost causation and cost recovery? If costs are not fully recovered in a particular component, where are they recovered?
4. Will adoption of the changed or new rate result in any cost shifting between existing customer classifications?
5. What is the impact of the proposed rate change on customers at different usage levels? Are the impacts proposed consistent with the Rate Design Policy?
6. If competition is an issue, the Board will need a comparison of proposed cooperative rates and corresponding competitive rates.

1.2.6

STEP 6: HOW WILL THE PROPOSED RATES CHANGE IMPACT OTHER COOPERATIVE PROGRAMS?

The Board needs to clearly understand how the proposed rates and any changes in the rates are aligned with and will reinforce other cooperative programs. Examples include:

- Alignment of the line extension policy and required Contribution in Aid of Construction ("CIAC") given the capital cost recovered in the retail rate.
- Alignment with load management or energy conservation programs.
- Alignment with cooperative DSO Operating Policy.
- Implications related to the cooperative's position on DER and potential energy storage programs.

Ideally, the rates will reinforce other programs, or in the alternative, identify the changes that need to be made in other programs.

The communication of final rates is critical to a successful conclusion of the Rate Analysis process

1.2.7

STEP 7: WHAT IS THE PLAN FOR THE ROLL-OUT, IMPLEMENTATION AND COMMUNICATION OF THE PROPOSED RATE CHANGE?

The communication of final rates is critical to a successful conclusion of the Rate Analysis process. The management and staff need to outline to the Board the proposed steps to present, explain and implement the revised rates. For example:

1. Meetings with member-consumers to explain the reasons for the proposed changes, describe the new rates, and define the estimated impact on the individual rate classifications and member-consumers taking service under the rate classification.
2. Mailings to the member-consumers.
3. Articles in the cooperative's newsletter and local newspapers.
4. Information on the cooperative's website and social media.

1.3

Role of the Regulator

From the cooperative's perspective, the Board provides the balance between the interests of the member-consumer and the cooperative, and is the final authority for rates charged. For cooperatives operating in a regulated environment, the Board may not be the final decision maker, but rather the decision maker for the requested rates. Some states have very active regulation of all cooperative activities and others regulate only certain activities. For the regulated cooperative, the cooperative needs to consider the potential impact of a regulator in the process. The regulator can impact the process in a variety of ways including:

- The requirement to prepare specific documentation and analysis in support of any proposed rate change and associated rate filing. The required "Rate Filing Package" defined by the regulator may be very comprehensive.
- The time frame required to implement any rate adjustments.
- The cost of the rate change process including legal, audit and consulting services.
- The total revenue requirement that will be allowed for the cooperative.
- Test year cost adjustments that will be required or permitted.
- The magnitude of rate change that may be imposed on a particular customer class relative to the system average.
- The rate structure that may be reflected in a rate design.
- Recognition of statewide issues that the regulator may require to be addressed (value of solar, demand-side management, time-of-use rates, etc.).
- Notice requirement for rate change may include specific content, public meetings and notice period.

Management may find it beneficial to adopt certain typical regulatory requirements even if they are not regulated. Many of the recommendations related to the process described in the Rate Guide reflect typical regulatory requirements that a cooperative needs to consider even if not regulated.

1.4

Risk Considerations

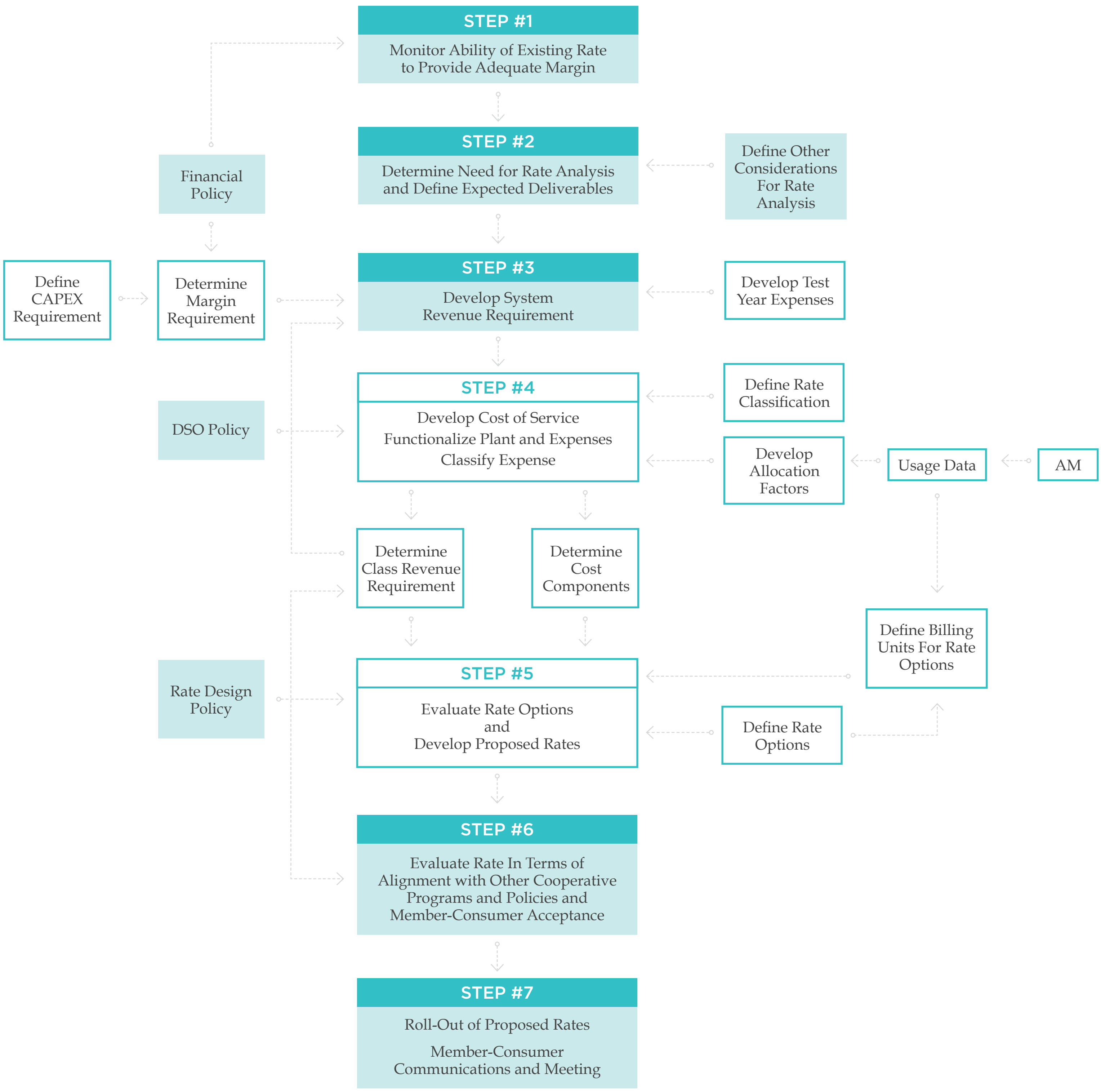
Risk is the underpinning consideration in any discussion of the processes and issues described above and the options to deal with those issues. The questions the Board should be considering in the discussion include:

1. What kind of processes do we have in place to identify risks, including new and changing risk to the cooperative?
2. Does Management's method of defining and quantifying risk seem reasonable?
3. Have we missed key risk areas in the past related to any of the activities described above? If yes, why?
4. What is our "risk appetite" and "risk tolerance" particularly in dealing with:
   a. Implementation of new technology?
   b. Seeking a balance between maintaining margins necessary to ensure financial integrity while at the same time minimizing cost to our member-consumers?
   c. Implementing new rates on a system wide basis or on a pilot basis?

1.5

Block Diagram of Process

The diagram on the following page is a summary of the Rate Analysis process. The specific functions in which the Board and management have direct involvement with have been highlighted.


STEP #1
Monitor Ability of Existing Rate to Provide Adequate Margin
STEP #2
Determine Need for Rate Analysis and Define Expected Deliverables
Define Other Considerations For Rate Analysis
Financial Policy
STEP #3
Develop System Revenue Requirement
Define CAPEX Requirement
Determine Margin Requirement
Develop Test Year Expenses
STEP #4
Develop Cost of Service
Functionalize Plant and Expenses
Classify Expense
DSO Policy
Define Rate Classification
Develop Allocation Factors
Usage Data
AM
Determine Class Revenue Requirement
Determine Cost Components
Define Billing Units For Rate Options
STEP #5
Evaluate Rate Options and Develop Proposed Rates
Rate Design Policy
Define Rate Options
STEP #6
Evaluate Rate In Terms of Alignment with Other Cooperative Programs and Policies and Member-Consumer Acceptance
STEP #7
Roll-Out of Proposed Rates
Member-Consumer Communications and Meeting

2.0

Defining the Need for Rate Analysis and Timing Considerations

Before the Rate Analysis begins, the Board will need to agree on the underlying issues to address and the expected deliverables. Section 1.2.2 identifies the most common issues as inadequate revenue and margins, rate class subsidies, distorted pricing signals, outdated rates, and mismatch between cost recovery and cost causation. While the trigger may be caused by any combination of these issues, the primary one is usually inadequate revenue and margins that will no longer achieve the metrics in the cooperative's Financial Strategic Plan or Equity Management Plan. The first step in the Rate Analysis process is actually an on-going process to determine when the existing rates are likely to no longer provide adequate margins to meet financial objectives. Section 2.1 outlines a monitoring process and Section 2.2 and 2.3 describe factors to consider in defining the appropriate "look-ahead" period for the cooperative.

The cooperative should not evaluate need by looking at current revenue and margins but instead consider forward-looking trends

2.1

Projecting the Need for Change in Revenue Requirement

The cooperative should not evaluate need by looking at current revenue and margins but instead consider forward-looking trends. If the cooperative waits until the margin adequacy tipping point has been reached to begin work on the Rate Analysis, it is too late. Section 2.2 discusses the schedule and the sequence of events required to implement a rate change. At least twelve months is likely required. If the cooperative is regulated the time frame will more likely be twenty four months. Each cooperative should identify the time line applicable to its specific situation and adjust its planning horizon accordingly.

The financial "look-ahead" should be prepared on a regular basis. Several monitoring tools are recommended. The first is to restate Form 7 historical financial data to reflect performance on a rolling twelve-month basis ("Financial Profile"). The Financial Profile should be prepared for at least the previous twenty-five periods in order to identify trends. At a minimum, the Financial Profile should include rolling twelve-month performance data for the following:

- Energy Sales (billing units)
- System margins with the emphasis on the metric(s) most meaningful to the cooperative:
  - Operating or net margin
  - Financial ratio (TIER, MFI, DSC, ROR)

Reference Appendix Schedules A-1.0 through A-5.0 for examples of selected Financial Profile reports and graphs.

The important point is that tools are in place to monitor trends in expected margins over the next twelve to twenty four months and this information is provided to the Board

A more comprehensive Financial Profile will report statistics by individual rate classes and by individual components of expenses. The latter provides more detailed information as to why the system is behaving the way that it is and may identify the specific component causing the erosion in earning. For a cooperative with power cost recovery clauses it is important to confirm the flow through provision is working properly. This means monitoring on a rolling twelve-month basis:

- The actual power cost incurred.
- The wholesale base power cost embedded in the rates.
- The difference between the actual wholesale power cost and the embedded or base wholesale power cost.
- A comparison of the calculated recoverable value with the actual power cost recovery.

The rolling twelve-month Financial Profile is an essential tool for monitoring the cooperative performance in order to evaluate the start date of a Rate Analysis.

The second tool is the budget which provides an indication of expected financial performance over the budget period. The trends resulting from the Financial Profile analysis can be compared with the budget values.

A third tool that provides a longer view is the Financial Forecast. Ideally, to better understand long- term financial trends, the cooperative should update their Financial Forecast every year with the first year being the budget data.

The Financial Profile, budget, and Financial Forecast are the three recommended reports to monitor trends in the cost and revenue and margins metrics. Keep in mind that the revenue stream used to compute the margins and associated financial metrics for these reports is the product of the existing rates times billing units. Therefore, it is also important to monitor trends in billing units for at least the major rate classes.[17] The Financial Profile analysis can provide trends in not only financial data but also usage data based on information reported in Part O of the RUS Form 7 and Part R of the CFC Form 7.

The review of trends in usage data (billing units) needs to be tempered with consideration of weather data. Some systems include as a part of the rolling twelve-month usage profile weather data such as heating and cooling degree days. This allows for normalization to reflect normal weather conditions. The tool available to the cooperative to normalize billing units over the long term is the power requirement study (PRS). The PRS forecasts usage data taking into account normalized weather and other trends reflecting econometric data for the cooperative's service area.

The important point is that tools are in place to monitor trends in expected margins over the next twelve to twenty four months and this information is provided to the Board. The expected margins should then be compared with target values established by the Board and management as a part of the Financial Strategy and any differences identified. Different Boards will have different views as to what conditions trigger a Rate Analysis and possible rate adjustment. Some Boards prefer to delay rate adjustments and are willing to seek larger adjustments made infrequently whereas others prefer smaller adjustments at more frequent intervals. The financial targets and implementation strategy should be defined by the Board well in advance of any detailed rate analysis work and communicated to management.

[17] Billing units include both demand and energy values applicable to individual rates and absent contract amounts will typically reflect member-consumer usage.

2.2

Time Frame Required to Develop Rates

The previous section suggested a look-ahead window of twelve to twenty-four months to conduct a Rate Analysis. To better define the look-ahead period, The Board and management should consider the events that must occur to implement any rate adjustment and then develop a schedule specific to the cooperative.

The following is a list of the typical events defining the time-frame:

- Select a test year (a twelve-month period)
- Gather test year data
- Prepare adjustments to the test year (expenses and revenue)
- Develop a pro-forma income statement defining margins earned under current rates given adjusted test year expenses and usage
- Develop the COSS
- Review the COSS to determine:
  - Revenue requirements by rate class
  - Rate design alternatives
  - Recommended rates
- Presentation of proposed rates for Board review
- Board approval of rates

The test year is the basis for the Rate Analysis. It can be any twelve-month period unless regulatory requirements define specific periods. The development of the Rate Analysis and the cost of service process in particular require a significant amount of detailed data. Because most cooperatives will typically prepare this data for various RUS/CFC annual reports, the calendar year twelve-month period is generally preferred. If a historic test year is selected, the data will generally not be available until the first quarter. (Test year options are discussed in detail in Volume II, Section 1.2.) Whereas it is desirable to use audited data (the audit report may not be available until the second quarter), it is acceptable to begin the analysis with unaudited data and update when audited data is available.

Much of the test year data will be readily available from standard reports such as the General Ledger or Trial Balance for accounting and monthly Sales Reports from rate billing (either in-house billing software or out sourced billing provider). Special queries of the billing system database may be required for some detailed usage and billing data. Engineering cost data may need to be compiled from recent work orders. The cooperative needs to discuss the availability of the required data when deciding on a test year since this can affect the selection. With a calendar year test year, the test year data will likely be available in the first quarter.

The next step is to review the test year and develop necessary adjustments for changes in revenues and expenses that are "known, measurable, and continuing in nature". (Test year adjustments are discussed in detail in Volume II, Section 1.2.) Ideally, the Management and Board have already identified the financial objectives so it is a matter of comparing the adjusted test year financial data given existing rates and the resultant margin with the strategic objectives to determine the initial estimate of the rate change. If Management and Board wait to define the margin objective, the schedule will need to be extended. The pro forma income statement with test year adjustments would typically be available within another thirty to sixty days.

The COSS assigns the plant and expenses to the rate classes. The development of the COSS is discussed in Volume II, Section 3. The COSS may require thirty to sixty days to complete.

The COSS results provide the data to determine the revenue requirements for each rate class and the cost data needed to design rates. Using this data, the next step involves defining and evaluating rate design alternatives and the development of rate design recommendations for the Board. This activity can take thirty to sixty days.

The Board has the responsibility of approving the overall class revenue requirements and the rate designs. If not rate regulated, the Board approved rates are the implemented rates. If rate regulated, the Board approves the rates that are requested from the regulatory authority. The Board should "own" the rates and that ownership will only come with a thorough understanding of the basis for the recommendations. The level and schedule for Board involvement needs to be determined early in the process to assure the project stays on schedule. Some Boards separate the process into three steps:

1. A meeting or Board retreat to review the procedure, discuss concepts, and seek input related to rate design options.
2. Followed by a second meeting to review results and discuss specific rate design options.
3. A third meeting to approve final rates.

Depending on the extent of Board involvement and the schedule for Board review, the final approval may not occur until the third quarter.

Rate implementation is dependent on Bylaw and/or other notice requirements. There may be a thirty to sixty day notice requirement (or longer) to member-consumers for any rate change. Working from the perspective of an effective date, this means that the final Board approval needs to take place at the October or November Board meeting for an effective date of January 1. The sequence described above should allow the Board to meet the January 1 effective date.

Given the tasks described above, this effectively forces at least a twelve-month planning horizon to revise rates. If regulated, the schedule will need to accommodate the regulatory process. This may mean another twelve months which stretches the planning horizon to twenty-four months.

Some jurisdictions allow an option of an abbreviated rate filing. While an abbreviated filing reduces the planning horizon, it may also limit the ability of the cooperative to adjust rates. In some states with abbreviated or accelerative rate filing options, the cooperative is limited to the manner in which rates can be adjusted.

2.3

Other Considerations

Other considerations may apply in deciding on the timeline and effective date of a rate change. For example, the power supplier may be planning to implement a rate change and the cooperative may want to schedule its change to be effective at the same time or to purposely delay implementation in order that the impact not be compounded. The cooperative may not want to put new rates in place that could adversely impact seasonal loads right before the beginning of the season (such as a June effective date with large irrigation systems or a January effective date if there is sensitivity to heating loads). Conversely, the opposite may be true if the cooperative is trying to capture the revenue associated with a rate change from seasonal loads. Events such as the cooperative's annual meeting or construction of a new headquarters building may affect the implementation of a rate change.

The Board needs to be aware of the activities required, the involvement of the Board, and the intended and possible unintended consequences of requested effective dates to identify how long it takes to implement an increase in rates. The point is to establish a mindset where the Board is always thinking in terms of expected revenue and margins twelve to twenty-four months in the future, not just the latest Form 7 report, and the management and staff is providing the information necessary for the Board to evaluate those future revenues and margins.

3.0

Developing Rate Options

The process for the development of the complete rate analysis is outlined in Volume I Section 1.0. In order to develop rates it is essential to identify the total revenue requirement, determine a fair and equitable allocation of the system revenue requirement to the rate class, and identify cost drivers that define the allocation of the class revenue requirement to individual member-consumers in that class in a manner that meets the cooperative Rate Design Policy objectives. The details of the activities involved in Steps 1 through 4 are described in Volume II.

Changes in volumetric billing units (kWh sales) whether caused by new technology, energy efficiency improvements or member-consumer behavior poses a very real concern regarding recovery of costs

Recognition of the membership's increasing concern for social and environment issues must also be considered

Some cooperatives may have already completed these activities and are interested in options available in meeting a series of evolving challenges, which include adapting to a cycle of evolving technology and changing member-consumer expectations. Changes in volumetric billing units (kWh sales) whether caused by new technology, energy efficiency improvements or member-consumer behavior poses a very real concern regarding recovery of costs. Recognition of the membership's increasing concern for social and environment issues must also be considered. Additionally, since the wholesale cost of power comprises such a significant component of the distribution cooperative's cost, the wholesale pricing signal and issues facing the wholesale provider should also be considered. These issues could include such factors as the costs of production capacity and transmission investments, the impact of distributed energy resources (DER) on the wholesale provider and the costs associated with environmental compliance.

This section focuses on Step 5 which involves defining various rate options and evaluating these options. This Section provides an overview of rate designs beginning with the common two-part rate design and extending to four-part rates, time-of-use rates and rates applicable for specific applications. There is also discussion of various proxies that can be applied. Specific examples are developed in this section to better understand how the option discussed translates to a specific rate design. The data for examples is from the cost of service discussion in Volume II. The results of the cost of service and the data used in the development of the rate options is shown in Schedules B-1.0 through B-5.0 and Schedules C-1.0 through 2.0 in the Appendix. In all examples, the rate design produces the same revenue requirement.

This list of rate options presented is certainly not a comprehensive listing of all possible options. The options listed should however, provide a sense of the alternatives to consider and provide a framework for determining options that could fit the cooperative's needs.

It is important for the Board and the Team to be on the same page in developing and implementing these criteria so all aspects of the rate design process work together

3.1

Rate Design Criteria

Each cooperative should develop rate design criteria that reflect its own goals and objectives. These rate design criteria serve as the guiding principles that inform how rates are developed. It is important for the Board and the Team[18] to be on the same page in developing and implementing these criteria so all aspects of the rate design process work together. The Board should work with the Team to determine the challenges it sees as outlined in Section 1 of this Volume and then to determine how it can address these challenges through its rate making procedure. Once it has established this "rate plan of work," it will become the cooperative Board's rate philosophy and a roadmap for specific rate designs.

Whether specifically written down or not, the Board in practice will have a philosophy of rate making. Part of the rate philosophy includes how specific criteria are prioritized and weighted. In general, all of the rate criteria are important, though Boards determine an appropriate balance of them as part of any rate change process. The following describes the core rate design criteria:

- Fair and non-discriminatory – Similarly situated member-consumers should be treated in a consistent manner. Each member-consumer should pay his or her share of the costs of providing service. The Board should move rates toward cost of service as a means of minimizing subsidies and maintaining fairness.
- Minimize impact on member-consumers – An important criteria for the Board to consider is the impact that rate changes have on individual member-consumers. In some cases the Board may decide that the benefit derived from the rate change is outweighed by negative member-consumer impact and seek an alternative rate design option. It is also important to understand that any time rate structures change, some member-consumers benefit and others do not. Communicating with member-consumers throughout the rate analysis process is one key to minimizing member-consumer distress.
- Send the proper pricing signals to member-consumers– It is important that rates are designed to reflect cost causation. The vast majority of the distribution cooperative's delivery costs are fixed; therefore, rates should be designed to reflect this. To the extent possible, retail rates should reflect the price signal sent by the wholesale cost of power.
- Understandable – Rates cannot be effectively used by member-consumers unless they are understood. As discussed later in this section, rates that provide the most precise pricing signal may be so complex that member-consumers cannot effectively use them. On the other hand, simple rate designs, such as traditional two-part rates, may be insufficient to achieve the cooperative's desired objectives.

CORE RATE DESIGN CRITERIA

- Fair and non-discriminatory
- Minimize impact on members-consumers
- Send the proper pricing signals
- Understandable
- Encourage efficient and responsible usage
- Other possible societal considerations
- Manage evolving member-consumer expectations
- Integrate new technologies

[18] The Team is discussed in detail in Volume II, Section 1.8. The Team includes staff from financial/accounting, billing and customer accounting, engineering and operations, member services, communications, information technology, and management.

One of the most important Board rate making roles is to consider each of these possible rate design criteria and then to weigh and balance their importance

- Encourage efficient and responsible usage – Conservation, energy efficiency and the use of renewables provide member-consumers the opportunity to lower their bill and also lower the cooperative's costs. Rates can be developed that permit the cooperative to achieve any desired objectives it identifies in this area.
- Other possible societal considerations – Some cooperatives have additional "societal" objectives, such as assisting low income member-consumers, retirees, military or injured member-consumers. Some jurisdictions mandate that member-consumers be permitted to "opt out" of certain cooperative programs such as AMI. Cooperatives might identify objectives to assist emergency services, schools, churches, parks, etc. Rates can be developed to achieve those objectives.
- Manage evolving member-consumer expectations – Technologically savvy member-consumers expect the cooperative to offer more sophisticated services. Real time pricing, three- or four-part rates, prepaid metering, critical peak pricing rates and others are just some possible member-consumer expectations that rates might need to provide. Many member-consumers today expect their service providers to provide them with choices and options.
- Integrate new technologies – Member-consumers are adopting a variety of new technologies to their homes and businesses. These technologies include, among a host of others, back-up generation, renewable energy and other DER technology; vehicle charging, energy efficiency and demand-side management (DSM); battery backup and storage; etc. In order to be able to take advantage of these technologies as a part of rate-making, the cooperative will require metering and billing technology that will permit it to do so. Most advanced metering infrastructure (AMI) meters provide at least some expanded ability for the cooperative to consider new rate options such as multi-part rates and real time pricing. While not within the scope of this Rate Guide, the cooperative should be sure that its long-term AMI plans will result in information technology (IT), AMI and other infrastructure that will allow it to implement any long-term rate objectives it may adopt as part of its rate criteria.

NOTE:

As a part of the rate discussion in this section, rates have been developed for a mythical "Standard Electric Cooperative." All of the rate options shown generate the same revenue from the rate class. The rates are shown unbundled so it is possible to determine, not only the total rate, but the major cost components of the rate and how different rate options recover the cost of providing service in different components with different billing units. While the rate designs for Standard are consistent with the Standard COSS, they are for illustration only.

One of the most important Board rate making roles is to consider each of these possible rate design criteria and then to weigh and balance their importance. For example, the Board may wish to increase the existing customer charge high enough that the full customer-related cost of providing service is recovered in the customer charge. But when it weighs this desired result against the member-consumer impact such a change would produce, may instead decide to apply the increase in phases over time. Or the Board may decide to encourage renewable energy, but when weighed against the need to continue to recover its fixed cost of providing distribution service, the Board may put member-consumer education as the short-term priority.

3.2

Traditional Versus Innovative Rate Design

Cooperatives should focus on rates that meet their needs

Much discussion around Board tables and at industry gatherings has focused on innovative rate designs. All too often this term encourages the cooperative to "chase technology" by designing rates focused on technological issues. For example, in the past cooperatives carved out groups of residential member-consumers with electric water heaters because their usage was different from other residential member-consumers. Today, cooperatives are carving out net metering, vehicle charging, and other specific rate class objectives. As a result, the cooperative ends up in the position of chasing (or hopefully anticipating) the newest technology as it is adopted by member-consumers.

Justification for the two-part rate remains strong

Each cooperative must determine for itself the objectives it desires to achieve and develop a rate philosophy to achieve those objectives. It must then determine criteria to weigh the relative importance of each possible rate option.

Cooperative Boards and regulatory bodies across the country have adopted a variety of effective and efficient rate design structures. Some are often labeled "traditional" while others are labeled today as "innovative." Regardless of label, cooperatives should focus on rates that meet their needs.

3.3

Traditional Residential Rate Designs: The Two-Part Rate

The Two-Part Rate (Customer Charge and Energy Charge) has been the "go-to" rate for most electric utilities almost since central station electric power began. While today many cooperatives are considering other designs, justification for the two-part rate remains strong.

- Minimal technological requirements – Two-part rates have minimal requirements for metering, meter reading and billing—only a standard mechanical meter registering energy usage and standard billing software. These meters were historically less costly and easy for individual residential member-consumers to read themselves each month – as was the case for many years.
- Easy to understand – Member-consumers are not required to understand complex issues related to time-based usage or demand. Electricity is priced based on volume, similar to water or other commodities. Of course, the trade-off of a simple -rate design is less flexibility and accuracy. Additionally, the emphasis is placed on selling a product rather than providing a service. On the plus side, when the cooperative has a traditional two-part rate and intends to maintain this rate structure, communication with member-consumers is relatively simple.
- Inertia and regulatory influence – The two-part rate is so common that some regulatory commissions are reluctant to consider anything else. And many Boards are cautious about moving to different rate structures, particularly if neighboring utilities maintain traditional rate structures.
- Minimum member-consumer impact – If the two-part rate is maintained, impact on individual member-consumers is mitigated.

3.3.1

THE CUSTOMER CHARGE (OR SERVICE AVAILABILITY CHARGE)

The customer charge should reflect recovery of costs that are driven by just being a member-consumer, no matter how small

Many cooperatives discover, when changing rates and communicating with member-consumers, that no single issue causes more misunderstanding and unrest than changes to customer charges, also known as service availability charges. When considering the customer charge, the Team must carefully balance the same types of criteria it does with overall rate designs, including the length of time since the last change in the charge, the cooperative's customer charge compared to other utilities, the number of low and minimum use member-consumers it has and any other issues unique to its member-consumers.

CUSTOMER CHARGES:

- **Perhaps no issue has been of more general interest to and more widely considered by cooperative Boards than the Customer Charge.**
- **Cooperatives should consider either setting their fixed customer charges at the fixed customer-related cost of providing service or at minimum moving toward that ultimate goal as a part of any rate and cost of service analysis.**

Cost Recovery and Rate Design
Two Part Flat Rate

Cost Components	Allocation Factor	Retail Rate Design
Power Supply		
Demand	Power Supply CP	Energy
Energy	Energy	Energy
Power Supply Delivery		
Transmission	Transmission CP	Energy
Substation	Cooperative CP	Energy
Ancillary — Demand	Cooperative CP	Energy
Ancillary — Energy	Energy	Energy
Distribution Demand		
Sub-Transmission/Substation	Cooperative CP	Energy
Backbone Demand	Cooperative CP	Energy
Distribution Demand	Cooperative NCP	Energy
Distribution Customer		
Distribution Customer	Customers	Customer Charge
Customer Services	Customers	Customer Charge
Customer	Customers	Customer Charge
Ancillary	Customers	Customer Charge
Margin	Distribution Components	Distribution Components

The two-part rate recovers many fixed costs through energy charges, creating a mismatch between how costs are incurred and how costs are recovered from members-consumers.

Definitions of chart elements, descriptions of allocation factors and costs are how they are typically derived is described in Volume II, Section 3.

To the extent the cooperative does not fully recover its fixed customer-related costs in a monthly fixed charge, it is relying upon other billing units to recover those costs

A Cost of Service Study (COSS) should identify the customer-related cost of providing service. (See Volume II and Schedule F-2.0 in the Appendix.) The customer charge should reflect recovery of costs that are driven by just being a member-consumer, no matter how small. These costs would include items such as the cost of maintaining the minimum distribution system to serve the member-consumer, metering, meter reading, accounting, customer services and a share of required margins. Regulators and Boards sometimes find it difficult to recover the full customer-related cost of service through the monthly customer charge. The primary concern is often two-fold: member-consumer impact and comparisons to neighboring system customer charges.

Cooperatives, particularly those with more rural service areas, may find that their customer-related cost of providing service is far higher than for neighboring IOUs and municipal electric systems, primarily due to the lower line density of the cooperative's service territory. This disparity should be continually explained to member-consumers and regulators.

It is not uncommon for the Team to find their existing customer charge is so much lower than the actual customer-related cost of service, that it cannot implement the increase in a single rate adjustment without high levels of member-consumer impact. Many cooperatives have historically set customer charges below the full customer-related cost of service. To the extent the cooperative does not fully recover its fixed customer-related costs in a monthly fixed charge, it is relying upon other billing units to recover those costs. If those billing units are variable in nature, such as an energy charge, the cooperative risks under-recovering fixed costs from low consumption member-consumers and over-recovering from high consumption member-consumers. In addition, member-consumers have been provided with a pricing signal that inflates the value to the cooperative of member-consumers lowering their energy usage.

In some regulated environments, many regulators have deliberately required customer charges be kept low. They believe this is a "progressive" step of requiring high usage customer/member-consumers (assumed to be high income) to subsidize low usage customer/member-consumers (assumed to be low income). In fact, many low income member-consumers have quite high usage and the resulting shift in fixed cost recovery is actually regressive. As a part of any rate and cost of service study, the Team should consider either setting their fixed customer charges at the fixed customer-related cost of providing service or in any case moving toward that ultimate goal.

3.3.2

THE ENERGY CHARGE

In theory, the energy charge in the two-part rate should recover the purchased power cost and the distribution costs associated with the load size. In actual practice, the energy charge recovers these in addition to the customer costs not recovered in the customer charge.

This rate is simple to administer, easy to understand and less subject to error

It provides no signal that the price of energy purchased actually varies based on the time of the day or season

It may not even include recovery of the full customer-related cost of providing service in the monthly customer charge

3.3.2.1 TWO-PART FLAT RATE

The two-part flat rate has a monthly fixed or customer charge and a single energy or volumetric charge based on total kWh usage. As shown in the chart, and as explained in Volume II, Section 3, a distribution cooperative's own cost of providing wires service is fixed, and a two-part rate with all of its obvious benefits, is not the closest match to how costs are incurred.

This rate is simple to administer, easy to understand and less subject to error. If maintained, it results in less individual member-consumer impact than typically results from changes in basic rate structures. It does not provide a clear pricing signal that a sizable portion of the cooperative's own cost of maintaining its facilities (system wires cost) is fixed based on capacity (demand). In particular, it provides no signal that the price of energy purchased actually varies based on the time of the day or season. And it may not even include recovery of the full customer-related cost of providing service in the monthly customer charge.

Example of a two-part flat rate:

	Power Supply		Distribution			
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
Energy Charge	$0.03018	$0.03516	$0.00952	$0.02588	$0.00000	$0.10074

3.3.2.2 SEASONAL ENERGY RATES

The Seasonal rate provides a pricing signal that the cooperative's power cost varies by season, typically by weighting the energy charge for a season that drives costs year round or when the wholesale cost is higher in a particular season.

Example of a two-part seasonal rate:

	Power Supply		Distribution			
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
Energy Charge (June-Sept)	$0.04482	$0.03516	$0.01245	$0.02588	$0.00000	$0.11831
Energy Charge (Oct-May)	$0.01982	$0.03516	$0.00745	$0.02588	$0.00000	$0.08831

The increased cost of the "peak season" (in the case of the example, the summer months) signals that power cost is driven more by summer usage than is the case in other seasons and that lowering summer usage is more valuable to the cooperative. This rate is sometimes seen as encouraging electric heat usage during off-peak periods rather than discouraging usage during on-peak periods.

3.3.2.3 BLOCKED ENERGY RATES

When the cooperative has a customer charge set below its customer cost of providing service, the Team may want to recover the remaining unrecovered portion in the first block of energy used. This rate design has been referred to historically as a "declining block" rate because it once served the function of promoting electric sales for added devices such as electric heat, water heat, etc. Today, this rate structure is intended to recover fixed costs in early blocks. In some states, regulators and others object that this rate structure discourages energy efficiency and renewables by pricing the final blocks of energy at a lower rate.

Example of a two-part rate blocked rate:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$20.00	$20.00
First 100 kWh	$0.03018	$0.03516	$0.00952	$0.04822	$0.05702	$0.18010
Next 900 kWh	$0.03018	$0.03516	$0.00952	$0.02786	$0.00385	$0.10657
Next 1000 kWh	$0.03018	$0.03516	$0.00952	$0.01900	$0.00000	$0.09386

3.3.2.4 INCLINING OR INVERTED ENERGY RATES

Inclining or inverted rates are generally designed such that the final block(s) have higher charges than the first blocks. This rate design is generally used for two possible objectives:

- If the Team wants to move toward higher customer charges that are more reflective of actual customer-related costs of providing service, but is concerned about impact for the average member-consumer, this rate structure can be effective. Higher customer charges (which result in higher percentage increases for low usage member-consumers) coupled with an inverted rates (which result in higher percentage increases for high usage member-consumers), can help manage member-consumer impact.
- When the Team has an objective of encouraging energy efficiency and renewable energy, inverted rates provide the highest per kWh savings for reduced kWhs. This type of pricing signal is an example of the cooperative weighing the value of promoting reductions in power use ahead of recovering costs strictly based on cost of service.

Example of a two-part rate inverted blocked rate:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$20.00	$20.00
First 400 kWh	$0.03018	$0.03516	$0.00952	$0.02592	$0.00657	$0.10735
Next 400 kWh	$0.03018	$0.03516	$0.00952	$0.00000	$0.00000	$0.07486
Over 800 kWh	$0.03018	$0.03516	$0.00952	$0.03951	$0.01001	$0.12438

3.3.2.5 RAISED MINIMUM CHARGES

Some two-part rates include a monthly minimum charge higher than the monthly customer charge. This approach may be particularly helpful if the Team is not ready to move the customer charge to the full customer-related cost of providing service for low usage member-consumers, but there are large numbers of minimum-usage member-consumers within a rate class that the Team feels should see the full cost of providing service. It may also be helpful to ensure member-consumers with renewable or other distributed energy resources (DER), for example, return some minimum amount of billing to recover their fixed cost of service.

Example of a two-part rate raised minimum rate:

	Power Supply		Distribution			
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$20.00	$20.00
Energy Charge	$0.03018	$0.03516	$0.00952	$0.02588	$0.00584	$0.10658
Minimum Bill per Month	$0.00	$0.00	$0.00	$0.00	$32.50	$32.50

In this example, the member-consumer pays $32.50 until their consumption exceeds 117 kWh.

3.3.2.6 SUMMARY – TWO-PART RATES

Traditional two-part rates have been in place since the start of the electric utility industry and still have a place today. They should be considered as part of the rate balancing that is part of any rate design process.

PROS

- Easy to understand by member-consumers
- Easy to administer
- Historically popular – often what has always been used
- Often historically used by neighboring utility systems
- Often historically favored by regulators
- Advanced metering and bill processing not required
- Less new education required

CONS

- Not the strongest rate structure related to how costs are incurred
- Little pricing signal to control wires capacity costs
- Little pricing signal to control purchased power capacity costs
- Provides a pricing signal to lower energy without lowering capacity
- Not strongly time-based
- May result in margin instability during periods of reduction in energy sales for any reason(s)

Most billing systems can now adapt to somewhat more complex rates without expensive reprogramming

Member-consumers are familiar with complicated rates used by cell phone, cable television, internet and other service providers

3.4

Rate Designs Based on Capacity/Demand

Two-part rates have been used for many years. And many cooperatives continue to determine, after balancing the pros and cons for their system, that a two-part rate is meeting their individual needs.

But the Team should consider evolving changes in the industry. Most cooperatives have in place some type of AMI that permits more complex rates than in prior years for all member-consumers. Most billing systems can now adapt to somewhat more complex rates without expensive reprogramming. Also, member-consumers are familiar with complicated rates used by cell phone, cable television, internet and other service providers.

Some member-consumers are using power quite differently now, with increasing differences in average usage among member-consumers of rate classes. For example, residential member-consumers with electric car charging devices have quite different load curves, than residential member-consumers with distributed generation, or certain home-based businesses.

We will discuss common variations in rate designs, without claiming our list is all-encompassing.

PURPA DECOUPLING STANDARD

The PURPA decoupling standard requires utilities to consider recovery of fixed costs of providing service through fixed billing units rather than volumetric ones like kWh sales. The concept is that the utility should not have a financial disincentive to promote renewable energy efficiency and conservation.

There are a variety of means for a cooperative to accomplish this task. One is consider a factor similar to a power or fuel cost recovery factor.

A simpler solution is to move rates closer to the cost of service, recovering fixed costs through fixed billing units such as customer charges and demand charges. So a multi-part rate IS in effect a decoupling rate.

3.5

The Multi-Part Rate – Four-Part and Three-Part Rate Designs

A common rate design option offered for years to large power and large commercial member-consumers is the three-part rate (customer charge, demand charge and energy charge). These rates are sometimes called demand/energy rates or just demand rates. The fact that these rates have been used for many years is an indication that cooperatives have always understood demand rates provide a more accurate recovery of costs than the standard two-part rate. Modern metering technology, an increase in the number of member-consumers wanting billing options, and other reasons, has led to increased consideration of multi-part rates for all rate classes. The cooperative Team and Board should consider the pros and cons of this rate structure.

Cobb Electric Membership Corporation (Cobb) is a Georgia cooperative serving 180,000 meters spread over 432 square miles. Over a period of years, Cobb identified a trend of growth in plant and member-consumers coupled with reductions in revenues and kWh sales. In part to address this concern, Cobb has developed a three part rate consisting of customer charge, demand charge, and energy charge. Based on extensive discussions with focus groups Cobb decided to reflect the demand charge as a $/kwh/hour rate rather than a $/kW rate. Cobb carefully measured the impact of the new rate on member-consumers and set their capacity charges well below actual capacity costs as a balance of cost recovery versus individual impact. Cobb adopted special educational material and terminology to explain the entire process to member-consumers. Click here for more information.

Rates with a demand component provide a mechanism to communicate to member-consumers how costs are incurred so they can modify their usage and control their power cost

As explained in Volume II, Sections 3 and 4, a significant portion of BOTH the cooperative's purchased power capacity costs and own distribution wires cost are often driven by peak load (demand). Introducing a demand billing component to rates offers the cooperative the ability to recover costs in a manner that more closely tracks how those costs are incurred. Rates with a demand component provide a mechanism to communicate to member-consumers how costs are incurred so they can modify their usage and control their power cost.

With regard to purchased power capacity costs, the Team should consider how capacity or demand related costs are billed by the cooperative's power supplier. (See Volume II, Sections 3 and 4.) While not always the case, purchased power capacity cost is often billed based on the member's contribution to some measure of the wholesale supplier's peak demand. A retail rate which includes a Coincident Peak (CP) Demand rate component provides the member-consumer a pricing signal that can allow the member-consumer to lower the retail billing and also allow the cooperative to lower purchased power demand billing.

With regard to the distribution wires costs, the Team should consider that the majority of a cooperative's distribution capacity-related cost of providing service is based on the individual rate class and individual member-consumer's contribution to the distribution cooperative's non-coincident peak (NCP). A retail rate which includes an NCP demand rate component provides the member-consumer a pricing signal to lower peak usage across the month. When coupled with similar reductions from other member-consumers, the cooperative may be able to lower plant investment required to meet that peak load and thus reduce the distribution wires cost of providing service.

MULTI-PART RATE

Historically used quite commonly by cooperatives for billing large commercial and large power member-consumers, this rate structure provides a close alignment of how costs are incurred to the recovery of those costs in rates. The multi-part rate typically includes a customer charge, a volumetric variable energy charge and one or more demand or demand proxy charges such as connected horsepower, installed kVA, etc.

Cost Recovery and Rate Design
Four Part Flat Rate

Cost Components	Allocation Factor	Retail Rate Design
Power Supply Demand Energy	Power Supply CP Energy	CP Demand Energy
Power Supply Delivery Transmission Substation Ancillary—Demand Ancillary—Energy	Transmission CP Cooperative CP Cooperative CP Energy	CP Demand CP Demand CP Demand CP Demand
Distribution Demand Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	NCP Demand NCP Demand NCP Demand NCP Demand
Distribution Customer Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
Margin	Distribution Components	Distribution Components

The four-part rate closely aligns cost recovery with how costs are incurred, but requires four billing units and greater complexity.

3.5.1

VARIATIONS ON MULTI-PART RATE DESIGNS

3.5.1.1 FOUR-PART RATE

A four-part rate design typically includes an appropriate demand charge for recovery of wholesale capacity related costs, an NCP demand charge for recovery of distribution delivery costs, a customer charge to recover customer related costs and an energy charge to recover the variable cost components (power supply energy related costs).

This rate is sometimes called “partially unbundled” because it prices distribution wires cost recovery separately from the wholesale power cost recovery. A member-consumer can identify potential savings from reducing or eliminating peak usage at the time of the power supplier’s peak. A member-consumer wanting to reduce their contribution to distribution wires cost would need to reduce usage in all intervals. If the cooperative and/or its power supplier offers Demand Side management rates or credits, this rate structure permits the cooperative to offer self-directed savings achieved from changes in patterns of usage.

A primary disadvantage of a four-part rate is added complexity of metering and meter reading. Not all cooperative AMI systems provide the data needed and not all billing systems can bill it. In addition, the rate is more complex, making it prone to misunderstandings.

A rate with a demand charge is sensitive to load factor, whereas a two-part rate is not. Transitioning to a multi-part rate will affect two customers with identical monthly energy use quite differently, if the two customers have different load factors.

Example of a four-part rate:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
CP Demand Charge	$11.65	$0.00	$3.68	$0.00	$0.00	$15.33
NCP Demand Charge	$0.00	$0.00	$0.00	$3.38	$0.00	$3.38
Energy Charge	$0.00000	$0.03516	$0.00000	$0.00000	$0.00000	$0.03516

If the cooperative is not prepared to implement a four-part rate structure, the Team may wish to consider a three-part rate design.

3.5.1.2 THREE-PART RATE TO RECOVER FIXED DISTRIBUTION WIRES CAPACITY COST IN THE DEMAND CHARGE

One of the greatest concerns facing cooperatives with respect to rate design, is the recovery of its fixed distribution wires costs from member-consumers whose kWh energy sales have been reduced as a result of DER, energy efficiency or other measures. This rate structure is designed to recover only the fixed distribution wires cost in the demand charge. The capacity-related wholesale purchased power costs are recovered in the energy charge.

This rate design provides a clear price signal to member-consumers that fixed distribution wires costs are driven by the maximum load the distribution facilities must serve and cannot be avoided simply by shifting usage from one period of time to another. The primary advantage of this rate is that it helps ensure recovery of the cooperative's cost of providing wires service from all member-consumers fairly. The primary disadvantage of this type of rate is that it is difficult for a member-consumer to modify usage in such a way as to lower their retail billing. It is highly effective in allowing the cooperative recovery of its wires costs, even from member-consumers who dramatically lower usage because of DER, energy efficiency or conservation

Cost Recovery and Rate Design
Three Part Flat Rate - Wires Demand Only

Cost Components	Allocation Factor	Retail Rate Design
Power Supply Demand Energy	Power Supply CP Energy	Energy Energy
Power Supply Delivery Transmission Substation Ancillary — Demand Ancillary — Energy	Transmission CP Cooperative CP Cooperative CP Energy	Energy Energy Energy Energy
Distribution Demand Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	NCP Demand NCP Demand NCP Demand
Distribution Customer Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
Margin	Distribution Components	Distribution Components

Example of a three-part rate –demand charge is only wires demand:

	Power Supply		Distribution			
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
NCP Demand Charge	$0.00	$0.00	$0.00	$3.38	$0.00	$3.38
Energy Charge	$0.03018	$0.03516	$0.00952	$0.00000	$0.00000	$0.07486

There are many ways to design three-part rates

NCP Demand can be measured at the time of the member-consumer's monthly peak or the higher of the member-consumer's monthly peak, the highest measured peak in the previous 12 months or a contract amount.

3.5.1.3 THREE-PART RATE TO RECOVER WHOLESALE CAPACITY BILLING COST IN THE DEMAND CHARGE

There are many ways to design three-part rates. One of these is to align the retail rate with the wholesale cost drivers. This can be accomplished with a three-part rate design including a demand charge that recovers only the wholesale purchased power demand-related costs. The fixed distribution demand cost of providing service is typically recovered in the energy charge. A customer charge is also typically applicable.

This rate design does not focus on the recovery of the fixed distribution demand costs. With this rate design, a member-consumer reducing their energy consumption by installing DER will cause the cooperative's revenue to be reduced without a corresponding reduction to the cooperative's distribution demand cost of providing service.

The main advantage of this rate design is the price signal that allows member-consumers the ability to control their cost while at the same time reducing the cooperative's wholesale power costs

Cost Recovery and Rate Design
Three Part Rate—Purchased Power Demand

Cost Components	Allocation Factor	Retail Rate Design
Power Supply Demand Energy	Power Supply CP Energy	CP Demand Energy
Power Supply Delivery Transmission Substation Ancillary—Demand Ancillary—Energy	Transmission CP Cooperative CP Cooperative CP Energy	CP Demand CP Demand CP Demand Energy
Distribution Demand Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	Energy Energy Energy
Distribution Customer Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
Margin	Distribution Components	Distribution Components

The main advantage of this rate design is the price signal that allows member-consumers the ability to control their cost while at the same time reducing the cooperative's wholesale power costs.

Example of a three-part rate – purchased power demand charge only:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
CP Demand Charge	$11.65	$0.00	$3.68	$0.00	$0.00	$15.33
Energy Charge	$0.00000	$0.03516	$0.00000	$0.02588	$0.00000	$0.06104

This rate will provide a pricing signal to avoid power supplier peaks but is not effective at protecting recovery of the cooperative's own cost of providing wires service to the member-consumer.

3.5.1.4 THREE-PART HYBRID RATE

If the Board desires to move toward the four-part rate but believes two different demand charges are too complex for a residential rate, the three-part hybrid rate might be instituted. In this rate design, the retail demand charge is intended to recover all of the fixed distribution demand cost of providing service plus a base portion of the purchased power demand related cost through an NCP demand charge. Any remaining unrecovered purchased power demand cost is recovered in the energy charge.

An advantage of this rate structure is that it is simpler than a four-part rate and most AMI systems can capture the necessary data required for billing. Using the NCP demand as the billing unit provides a secure means of recovering costs. Conversely, the primary disadvantage of this rate is that member-consumers are not easily able to avoid or reduce the NCP demand billing units. As a result, this rate design does not lend itself to peak load management applications.

While not shown in the example, it is possible to design this rate with a CP demand charge that includes both recovery of purchased power capacity costs and all or a portion of distribution demand cost of service. However, including distribution demand costs in a CP demand charge introduces a significant measure of risk. To the extent that a member-consumer is able to avoid or reduce its CP demand billing units, the cooperative will not receive a full recovery of the distribution demand costs.

Example of a three-part hybrid rate— recover purchased power demand costs and capacity-related distribution wires costs in a demand charge:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
NCP Demand Charge	$2.37	$0.00	$0.75	$3.38	$0.00	$6.50
Energy Charge	$0.01205	$0.03516	$0.00379	$0.00000	$0.00000	$0.05100

Example of an hours-use three-part rate:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
NCP Demand Charge	$0.00	$0.00	$0.00	$3.38	$0.00	$3.38
First 200 kWh/NCP kW	$0.04191	$0.03516	$0.01323	$0.00000	$0.00000	$0.09030
Next 200 kWh/NCP kW	$0.02434	$0.03516	$0.00768	$0.00000	$0.00000	$0.06718
Over 200 kWh/NCP kW	$0.00000	$0.03516	$0.00000	$0.00000	$0.00000	$0.03516
Embedded Demand (if over 400 kWh/kW)	$13.25		$4.18			$17.43

When accompanied by a well-designed member-consumer education program, the multi-part rate can provide an effective method for recovery of costs and providing the member-consumer with the appropriate pricing signals

3.5.1.5 HOURS-OF USE THREE-PART RATE

Another means of moving toward a four-part rate without multiple demand charges is the hours-use rate. It is a variation of the three-part hybrid rate and has been used in large power and irrigation rates for years. The NCP demand charge in this rate recovers only the distribution demand cost of providing service. The rate recovers the purchased power capacity-related cost in energy rate blocks based on the monthly NCP demand. With the wholesale demand component embedded in the hours use energy blocks, the cost recovery is based on load factor. The assumption is that member-consumers with higher load factors are more likely to be operating at times of the purchased power peaks. Since the rate embeds demand within the blocks, member-consumers reaching the bottom block are paying a much higher equivalent demand charge. The rate does not impose a higher demand charge on member-consumers with poor load factors.

While the rate is less complex than the four-part rate, care should be taken to ensure that member-consumers understand how the rate works.

The Team should be generally aware that multi-part rates are possible and design them to meet their rate criteria.

3.5.1.6 SUMMARY – FOUR-PART AND THREE-PART RATES

Historically, multi-part rates were limited to large power and industrial member-consumers. The cost of demand meters and special meter reading requirements limited their widespread application. Reductions in AMI and meter reading costs, as well as the need to address concerns related to lost fixed cost recovery, are leading many cooperatives to consider application of these rate designs to other rate classes. Multi-part rates are somewhat more complex. However, when accompanied by a well-designed member-consumer education program, the multi-part rate can provide an effective method for recovery of costs and provide the member-consumer with the appropriate pricing signals.

PROS	CONS
Decoupled rate structure strongly tied to how costs are incurred	More complex
Can provide a strong pricing signal for member-consumer to reduce overall peak demand and thus contribute to a reduction in distribution demand costs	More complicated to administer
Can provide a strong pricing signal for member-consumer to reduce demand contribution at the time of the purchased power capacity peak to reduce purchased power capacity costs	No strong historical background for residential and small commercial
History of use for large commercial and industrial member-consumers	Requires advanced metering and bill processing
Greater margin stability, particularly during periods of kWh reductions	Less likely to be used by neighboring utility systems
	Not always favored by regulators
	More education and communication required

3.6

Other Rate Designs

3.6.1

DEMAND PROXY

Three-part rates provide cooperatives a specific billing mechanism for recovery of demand costs of providing service. However, not all cooperatives desire to or are able to bill three-part rates for all rate classes. Some cooperatives do not have the necessary metering while others feel that using a proxy is easier to understand than an actual three-part rate. The proxy may include:

- **Transformer Size**—some cooperatives include either a monthly fixed or monthly kVA charge based on installed transformer size. This permits a demand related billing component without the requirement for monthly demand readings. A secondary advantage is that the member-consumer has a disincentive to request an over-sized transformer. A main disadvantage is the transformer must be sized to the member-consumer's load and a means must be developed to deal with situations where multiple meters are connected to a transformer bank.
- **Service Size**—the service entrance size (100 amp, 200 amp, etc.) is used to determine a customer or capacity charge. This can also discourage oversizing.
- **Demand-Based Customer Charges**—the utility measures the peak demand over some period of time for each member-consumer. The member-consumer is billed monthly based on the highest demand, but not with a demand charge. This could be a customer or fixed capacity charge.
- **Horsepower Charges**—the utility records the installed or operating horsepower for each member-consumer. The member-consumer is billed either monthly or seasonally based upon the installation's motor size. This could be a customer or fixed capacity charge.

DEMAND PROXY RATE

Used where a desired demand billing value is either not available or where the cooperative does not desire to implement a demand charge with revenue that may well vary by month across the year.

Some cooperatives find it easier to explain a capacity-related cost based on transformer size as opposed to explaining kW and the concept of capacity.

Example of a proxy demand charge – billed as a fixed monthly customer charge:

Amp Service	Customer Charge per month
100 Amp Service or Up to 10 kVA or Up to 10 kW	$10.00
200 Amp Service or 10 kVA – 25 kVA or 10 kW – 30 kW	$20.00
400 Amp Service or 25 kVA – 50 kVA or 30 kW – 60 kW	$35.00
Over	$50.00

Time-based rates provide the member-consumer the ability to control their own billing by reducing usage during peak periods or by shifting usage from peak periods to non-peak period

3.6.2

TIME-BASED RATE OPTIONS

The primary goal of a time-based rate design is to provide a pricing signal to member-consumers that reflects the relative cost of power from one time period as compared to another. Since the majority of the distribution cooperative's delivery costs are fixed, the focus of time-based rate designs is the time related cost differences in the wholesale purchased power cost. Time-based rates provide the member-consumer the ability to control their own billing by reducing usage during peak periods or by shifting usage from peak periods to non-peak periods.

TIME-BASED RATES

Rates used to identify differences in power cost related to time periods. They are most often offered as an optional rate, though some utilities offer only time-based rates.

The on and off peak periods can be based on a power supplier's peak periods or on periods of time when the utility is historically most likely to peak.

3.6.2.1 TIME OF USE (TOU) ENERGY RATE

A time of use energy rate is typically designed with pricing for energy consumption based on different time periods. Those time periods typically include an on-peak period and an off-peak period. Other periods can also be included to reflect critical peak, shoulder peak, or other relevant time periods.

The purpose of the rate is to reflect the relative underlying differences in costs associated with the different time periods. A time of use energy rate is typically applied to those rate classes where demand charges are not utilized.

Time of Use Energy rates are easiest to design when the wholesale power supplier has defined on- and off-peak periods with different energy charges during each time period. If this is the case, the distribution cooperative can mirror the wholesale time periods and differences in the retail rate.

Cost Recovery and Rate Design
Time of Use Energy

Cost Components	Allocation Factor	Retail Rate Design
Power Supply		
Demand	Power Supply CP	Energy – On peak
Energy	Energy	Energy
Power Supply Delivery		
Transmission	Transmission CP	Energy – On peak
Substation	Cooperative CP	Energy – On peak
Ancillary – Demand	Cooperative CP	Energy – On peak
Ancillary – Energy	Energy	Energy – On peak
Distribution Demand		
Sub-Transmission/Substation	Cooperative CP	Energy
Backbone Demand	Cooperative CP	Energy
Distribution Demand	Cooperative NCP	Energy
Distribution Customer		
Distribution Customer	Customers	Customer Charge
Customer Services	Customers	Customer Charge
Customer	Customers	Customer Charge
Ancillary	Customers	Customer Charge
Margin	Distribution Components	Distribution Components

A time-of-use rate design with long periods of on-peak pricing or that lack a meaningful pricing difference between the on and off peak periods might result in little to no participation

A more significant challenge is faced when the cooperative is determining how to best recover wholesale generation and delivery capacity-related costs through time-of-use energy rates. The distribution cooperative should carefully review the wholesale rate to identify, not just the magnitude of the capacity cost being billed, but how that cost is billed. The power supplier may be measuring billing demand units only during peak periods, which might only occur in a particular window of time or a particular season of the year. This will help the retail cooperative determine retail on- and off-peak windows for consideration.

The cooperative Team should also consider how the rate will be used by the member-consumer. Generally speaking, the greater the difference between the on- and off-peak energy charges, the more likely that member-consumers will respond by reducing peak consumption. A time-of-use rate design with long periods of on-peak pricing or that lack a meaningful pricing difference between the on and off peak periods might result in little to no participation. The cooperative in this case may wish to base the on-peak window on a narrower period of time in which peaks have historically most often occurred, even if this does not include all of the possible peak periods.

The Team should also consider whether the on and off peak time periods and charges should change based on season, and should include holidays and weekends. Changing member-consumer demographics and consumption patterns have caused the peaking periods for many cooperatives to change over time. The application of the time-based rate structure itself can result in a change in member-consumer consumption patterns and result in a change in peak loading patterns. Schedules C-1.0 and C-2.0 show example peak day load profiles for July and January, respectively.

Finally, it is important for the Team to understand that a strictly energy based TOU rate may have far less effect on reducing peak purchased power cost than some other rates, particularly those including demand charges. For example, a residential member-consumer responding to an energy-only TOU rate might reduce energy consumption significantly in summer months by modifying thermostat settings. However, at the same interval that determines the wholesale purchased power demand billing, the member-consumer's HVAC system could still be running. While the time-of-use energy rate provides a price signal, it is not as effective as a time-of-use demand based rate in recovery of capacity related costs.

In most cases, the on-peak ***energy charge is related to recovery of purchased power capacity*** costs. But this is not always the case. Note in the example below that in this case, the cooperative has identified its own capacity-related distribution wires cost of providing service. The cooperative Team determined that for it, the peak time periods for its internal needs match-up well with purchased power peak periods. So, in this particular case, in addition to weighting the on-peak energy charges, the Standard Electric Team have decided to recover its own capacity-related distribution wires cost through on-peak energy charges instead of all energy charges.

Example of a Time of Use Energy Rate:

	Power Supply		Distribution			
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
kWH On-Peak	$0.10059	$0.03516	$0.03175	$0.04960	$0.00000	$0.21710
kWH Off-Peak	$0.00000	$0.03516	$0.00000	$0.01571	$0.00000	$0.05087

Energy only time-of-use rates are widely used and provide a mechanism by which the cooperative can provide its member-consumers a price signal that certain costs vary based on the time period of consumption.

Mid-Carolina Electric Cooperative (MCEC) is a South Carolina cooperative serving 45,000 meters spread over 4,100 square miles. MCEC developed and implemented a three part rate with on-peak capacity charges to ensure collection of fixed costs through non-volumetric billing units. The cooperative balanced establishing a peak window wide enough to reflect peak periods versus the need to keep windows narrow enough that member-consumers would participate in the program. In addition, MCEC measured the impact of the rates on each individual within each rate class and determined some within each rate class had greater negative impact from the rate change—resulting in modifications in rates to mitigate those impacts. Education was key, both in advance of implementation of the rates and continuing over time. Click here or more information.

PROS

- Provides a price signal that power costs vary in different time periods
- Allows member-consumers the ability to actively engage in controlling their bill
- Easy to understand
- Common rate design that is widely used by many utilities
- Track record of regulatory approval

CONS

- Design of an effective energy only TOU rate is dependent on price signal in the wholesale rate to the cooperative
- Recovery of wholesale peak demand costs less certain than a demand-based TOU rate
- Depending on the cooperative’s AMI technology, changes in on- and off-peak periods may require programming changes to meters

3.6.2.2 TIME-OF-USE DEMAND RATE

A TOU demand rate is a standard three- or four-part rate with on- and off-peak energy charges and a demand charge for the recovery of demand related costs. The demand charge may be either based on an NCP demand billing unit or on a CP demand billing unit. A CP demand charge would provide an additional time-based price signal for the recovery of power supply capacity costs.

For more discussion on the differences between CP and NCP demand, see Volume II, Sections 3 and 4.

Time-of-use demand rates provide stronger pricing signals related to the recovery of demand related costs than do energy only TOU rates

The time-of-use demand rate with an NCP demand billing unit recovers the fixed distribution demand costs in the demand charge. The time based cost differences in the wholesale purchased power cost are reflected in the on and off peak energy charges. This provides greater stability for the recovery of distribution demand costs. The on and off peak energy charges should provide some measure of the price signal in the wholesale power supplier’s rate. With this rate option, member-consumers have the ability to reduce their billing by managing their consumption while also reducing the cooperative’s costs.

Example of a three-part time of use rate—with NCP demand billing:

	Power Supply		Distribution			
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
NCP Demand Charge	$0.00	$0.00	$0.00	$3.38	$0.00	$3.38
kWH On-Peak	$0.10059	$0.03516	$0.03175	$0.00000	$0.00000	$0.16750
kWH Off-Peak	$0.00000	$0.03516	$0.00000	$0.00000	$0.00000	$0.03516

A time-of-use rate with a NCP demand billing unit is not intended to provide recovery of the wholesale demand related costs in the demand charge. The NCP demand billing unit is intended to reflect the member-consumer’s contribution to distribution wires demand cost. The purchased power demand costs are recovered through the on peak energy charge and, to the extent the member-consumer can avoid energy usage during the time period in which the wholesale power supply demand costs are determined, the member-consumer will reduce their billing.

As is the case with all TOU rates, this rate must be structured reflecting the embedded cost and structure of the wholesale purchased power rates. TOU rates can also be designed with CP demand billing units included—but this is essentially either the four-part rate or the three-part rate with CP demand.

Member-consumers have high potential for savings if they can respond to market pricing signals but are assuming far more market risk given that the power cost might vary enormously based on the market price at any given time

3.6.2.3 REAL-TIME PRICING AND PARTIAL REAL-TIME PRICING

Real-Time Pricing provides member-consumers pricing during intervals or blocks of time during the year. It can be simply a rate that bills the market prices, or a program that allows member-consumers access to the market in some way. Or it may be a more complex version of a TOU rate, recognizing likely market prices for time intervals across the year. Member-consumers have high potential for savings if they can respond to market pricing signals but are assuming far more market risk given that the power cost might vary enormously based on the market price at any given time. Before considering this approach, the cooperative Team should fully understand the capabilities of their AMI system.

The cooperative also needs to know whether it has the ability to give member-consumers access to the market in this way. Some cooperative power supply contracts obligate them to purchase power for all of their member-consumers under a single wholesale rate. Other contracts permit the retail member-consumer to have access to market prices, but the power supplier must make the market purchase on behalf of the member-consumer system and end-use member-consumer.

The technological, billing and contractual requirements are the reasons why real-time pricing, even when offered, is often limited to large power or industrial member-consumers. The cost of administering the program has been generally prohibitive to offer to smaller member-consumers. But modern technology is breaking down this barrier and more and more cooperatives are considering offering customer choice on a “sell through” or “virtual” customer choice option.

REAL-TIME PRICING RATES

Rates that allow access in some manner to potential market pricing savings and to the risk of potential market costs.

Can be direct access or the cooperative may simply offer a more complex TOU rate based on anticipated market pricing at different time intervals

If the cooperative Team is considering offering real-time pricing to residential member-consumers, it should be sure that it has all facilities and technology in place now.

One approach would be for the Team to consider a hybrid of real-time pricing and TOU. This approach requires the cooperative to review the average costs of market purchases at different intervals during the year. A more complex version of the TOU rate can then be developed with a variety of peak blocks that serve as a proxy for real-time pricing. This type of dynamic pricing must be continually monitored to ensure that the components of the rate are reflective of the market prices.

Example of a hybrid TOU-RTP rate:

	Power Supply			Distribution		
	Demand	Energy	Delivery	Demand	Customer	TOTAL
Customer Charge	$0.00	$0.00	$0.00	$0.00	$27.72	$27.72
Energy Charge-Summer (June-Sept)						
kWH Critical Peak	$0.53472	$0.03516	$0.16877	$0.02588	$0.00000	$0.76453
kWH High Peak	$0.07130	$0.03516	$0.02250	$0.02588	$0.00000	$0.15484
kWH Medium Peak	$0.00713	$0.03516	$0.00225	$0.02588	$0.00000	$0.07042
kWH Off Peak	$0.00000	$0.03516	$0.00000	$0.02588	$0.00000	$0.06104
Energy Charge Shoulder (April, May, Oct)						
kWH High Peak	$0.07130	$0.03516	$0.02250	$0.02588	$0.00000	$0.15484
kWH Off Peak	$0.00000	$0.03516	$0.00000	$0.02588	$0.00000	$0.06104
Energy Charge-Winter (November-March)						
kWH Critical Peak	$0.26736	$0.03516	$0.08438	$0.02588	$0.00000	$0.41278
kWH High Peak	$0.07130	$0.03516	$0.02250	$0.02588	$0.00000	$0.15484
kWH Medium Peak	$0.00713	$0.03516	$0.00225	$0.02588	$0.00000	$0.07042
kWH Off Peak	$0.00000	$0.03516	$0.00000	$0.02588	$0.00000	$0.06104

Real-time pricing rate programs offer member-consumers access to market pricing. The member-consumer is provided a greater degree of choice and information with regard to price, but also assumes more risk.

PROS	CONS
More accurate tracking of wholesale power costs	Complex structure to administer
Provides significant opportunity for savings by the member-consumer	May not be permitted by regulators and by wholesale power purchase agreements
Minimum risk to the cooperative, allowing lower rates	Requires advanced AMI, communications and billing systems
Likely large power member-consumers requesting this rate will be well versed in its application	Member-consumers must be highly educated in how market prices work

3.6.2.4 LOAD CONTROL / DEMAND SIDE MANAGEMENT (DSM)

For purposes of this document, renewable programs will be treated separately in Section 3.

While DSM and TOU are sometimes thought of as similar rates, they are quite different. Traditional TOU rates, even those with demand components, are based on peak blocks of time during which power is more costly. This is often reflected in wholesale market pricing. Typically, load control or DSM rates are a response to wholesale rate structures or market prices and must be individually tailored.

For example, the cooperative may have a CP demand or other capacity pricing signals in their wholesale rate encouraging them to reduce or shift usage, at a single interval of time. Or the wholesale rate may be focused on the individual member-consumer system peak. The general approach to this rate will be to avoid individual peak usage at peak times.

For years, some cooperatives have offered a demand side management (DSM) rate for many rate classes. The purpose of this rate is typically to provide an incentive to encourage reductions in peak demand or to directly control member-consumer load in order to reduce demand during peak periods. A sample of these programs include:

RESIDENTIAL

- Air Conditioning Control
- Water Heater Control
- Three or Four-part Rates
- Incentives to Control Pool Pumps
- Peak Shaver Rates/ Notice

COMMERCIAL

- Irrigation Control
- Industrial Curtailable Rates
- Dairy/Commercial Curtailable/DER Rates
- Unbundled/RTP Rates
- Buy-Through/Market Rates

Programs of this type may be divided into two categories. There are programs organized and administered by the power supplier and programs organized and administered by the distribution cooperative. In both cases the intent is to reduce load. The customer removes load either to reduce capacity during all peak periods or only when requested to do so to avoid critical peaks, to provide system security, and/or at times of high market or system pricing.

A reduction in capacity load should ideally result in corresponding reductions in wholesale costs of operations or in the cost of future capacity additions.

When the program is administered by the power supplier, the distribution system receives either a benefit related to reductions in billing under a standard wholesale rate, credits, or other benefits provided by the power supplier for program participation. These credits might reflect the total benefit to be derived by the power supplier or a portion of the benefit, with the remainder of the benefits flowing through to all member-consumer systems. The distribution cooperative can themselves offer some type of DSM program or rate that transfers this benefit to participating member-consumers.

The alternative is for the distribution cooperative to offer a DSM program on its own, basing its program on the wholesale rate for purchased power, or looking through the wholesale rate to wholesale cost.

The value of DSM to the wholesale supplier is not always perfectly aligned with the value of DSM communicated through the wholesale rate structure. This can result in potential issues with distribution load control rates that are not administered by the wholesale supplier. One wholesale customer could devise a DSM rate that, while fully reflecting wholesale costs, shifts a portion of their cost recovery to the other wholesale customers.

LOAD CONTROL & DSM

Rates that pass through power cost savings to member-consumers willing and able to either replace peak load with self-generation, reduce peak load with conservation, or relocate peak load to other non-peak time periods.

It should be noted again that these issues are strongly related to the structure of the wholesale rate and billing units. The DSM program being considered by any distribution cooperative will be individually tailored by the Team to reflect how the cooperative incurs generation capacity costs.

Some cooperatives and regulators include consideration of the member-consumer's investment to participate in any program. When the investment is high, some would consider that the program is regressive. The cooperative must use care that its DSM does not result in cost recovery being shifted to other of its own member-consumers without corresponding reductions in costs. It is important for the Team to determine the rate criteria result it desires from any TOU or DSM rate.

Does it wish to encourage reductions of peak demand usage only during peak intervals based on a wholesale rate? If so, a DSM rate is more likely to accomplish this task.

Does it wish to encourage generally lower usage across a block of time, reflecting market pricing and/or their wholesale rate? If so, a TOU rate might be better.

Does it wish to simply provide information related to costs and allow member-consumers to select how they can participate? If so, a Four-part rate with on- and off-peak energy charges might be highly effective assuming member-consumers understand the rate.

To illustrate how different rate designs affect member-consumers with different usage characteristics, seven of the rate designs were compared. The following graph shows how the billing is similar for the class average member-consumer. All of the rate designs being shown generate the same total billing for the Standard Electric residential rate class as a whole. But the impact on individual member-consumers can be quite different, depending on individual usage. Please note, however, that for member-consumers with class average usage, the impact is similar under all rate options.

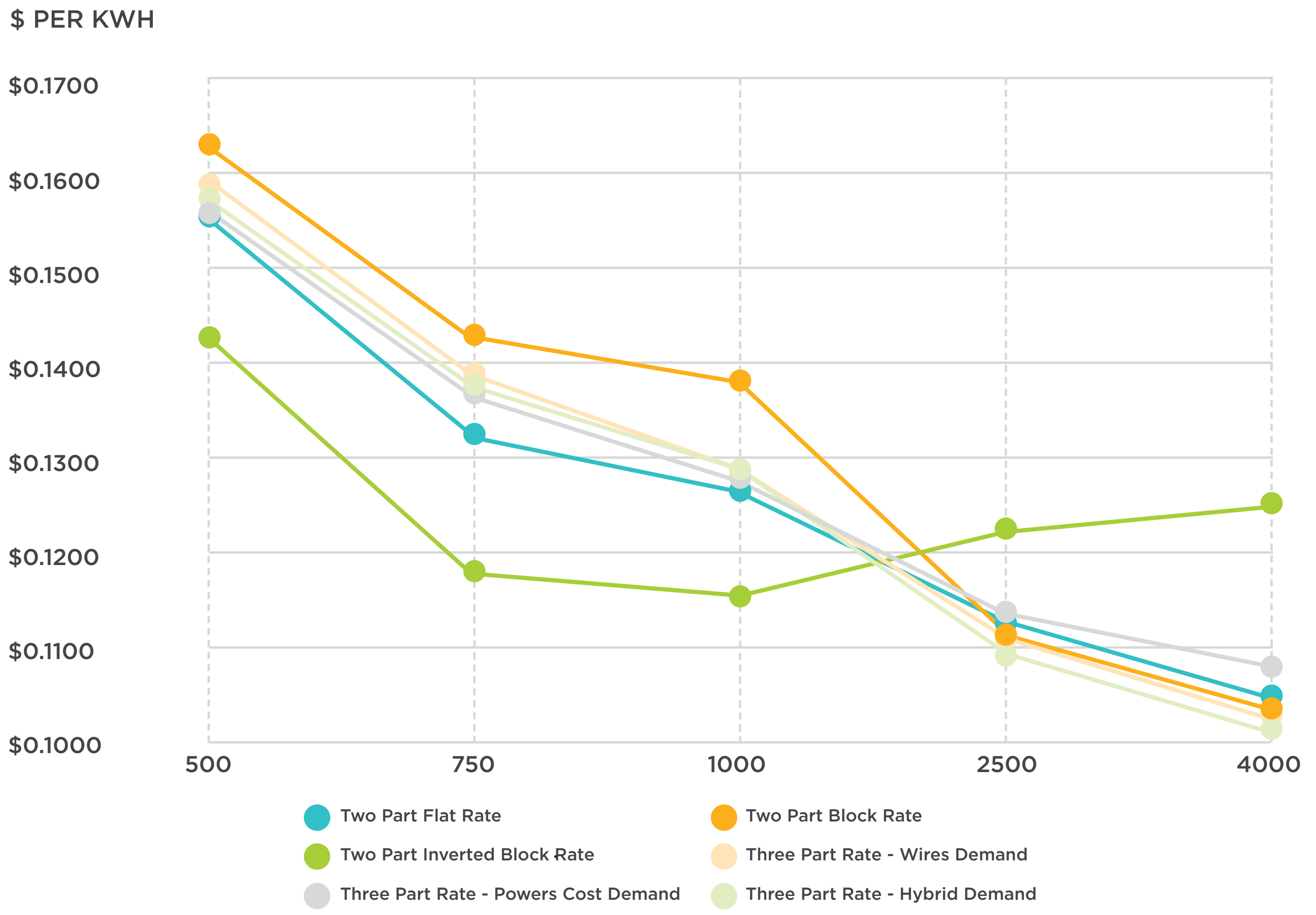
OFFERING OPTIONAL RATES

One of the key rate philosophies for the Board to consider is related to providing member-consumers with choices. Many cooperatives have done so for years, offering for example a standard two-part rate, a TOU rate, and a three-part rate. The member-consumer is permitted to select the option they prefer.

The Team must be careful any time it offers multiple rates and allows member-consumer choice. They must assume over time that member-consumers will migrate toward the cheapest and best option. The cooperative might consider calculating billing under each rate option for each member-consumer in order to determine the impact on cooperative revenues as member-consumers ultimately make this choice. Rates may need to be tweaked to ensure the cooperative will receive its revenue requirement once member-consumers have migrated to their best billing option.

The cooperative will also want to ensure that member-consumers understand who is responsible for making the rate choice. Is the cooperative responsible? If so, what happens if at the end of the year, the choice was not the lowest cost option?

The cooperative must also establish how long the customer is obligated to the choice, as well as penalties for changing the choice outside the offered term.



3.6.2.5 THERMAL STORAGE RATES

Thermal storage rate offerings are a subset of TOU rates. They are designed to work with member-owned devices that store heat or cold. When coupled with a TOU-type rate, the member-consumer can realize cost savings by storing heat or cold during off-peak periods and using it during peak periods. Cooperative margins are not reduced because the rate passes peak capacity savings to the member-consumer.

This program may be operated with credits provided to member-consumers who participate. However, a highly effective means is to simply offer a TOU rate coupled with the program. This works when wholesale rates provide a demand or energy based on- and off-peak pricing signal and when the cooperative's on-peak windows are narrow enough to permit the member-consumer to have sufficient thermal storage to last through the on-peak periods.

3.7

Large Power and Industrial Rates

The majority of distribution cooperative member-consumers are residential and small commercial. As a result, the majority of this document has been focused on residential rates. For many cooperatives, rates for large power member-consumers have historically been based on three-part rate structures. Other rate design options for unique industrial loads should also be considered.

3.7.1

COST-BASED INDUSTRIAL RATES

Cooperatives often address large Industrial rates on a case-by-case basis. This is in part because the typical rural distribution cooperative serves few of these member-consumers. Large loads may, however, contribute a disproportionate share of total revenue to the cooperative. Since their service delivery level may be at substation or even transmission level, they also require individual consideration when allocating costs.

During the development of the COSS, the Team should carefully consider each industrial member-consumer to determine that they are accurately identifying all the costs associated with providing service. This is important to ensure the cooperative is correctly allocating costs. In many cases, there might be relatively little in the way of distribution cooperative facilities in place to serve these member-consumers. But the industrial member-consumer may incur a substantial percentage of total purchased power cost for the cooperative. In any case, the particulars of any one industrial member-consumer might be quite different and help explain why the cooperative Team might individually allocate costs, determine a desired margin and design individual retail rates for each such member-consumer. Only when the cooperative is fortunate enough to have multiple industrial member-consumers at different service levels is there a need for the development of traditional tariff-based rates for an industrial rate class.

The Team should consider designing their retail rates in such a way that they are certain to recover the full cost of providing service from the industrial member-consumer. This is generally accomplished by designing a "cost plus" retail rate. Specific costs including any wholesale ratchets, demand roll-ins and facilities costs recovered over time should be included in the rate.

In particular, with new and potential loads, the cooperative Team must consider how much risk it wishes to assume in providing service. Utilities are often looked to by economic development groups to provide incentives when recruiting large industrial entities. Any cost not fully passed on by the cooperative to the industrial member-consumer, such as an incentive or a facilities allowance in excess of what rates will support, should be considered as an investment made by the cooperative and its member-owners in the business. The Team might ask itself if it would make a similar investment in some other venture with similar risks using member-consumer resources should the opportunity arise. In the event of a large industrial member-consumer bankruptcy, the impact on the cooperative could be substantial due to unrecoverable power cost billing alone. The retail rate developed should either include a margin component for risk or be structured in such a way that the cooperative has little risk from the project. Some cooperatives manage risk by requiring deposits, payment by electronic fund transfer, immediate due date, surety bond, or letter of credit.

An alternative for providing new service to a large industrial member-consumer, and in particular one requiring significant investment by either the wholesale supplier or the distribution cooperative, is to require a Contribution in Aid of Construction ("CIAC"). The monthly rate would then consist of a flow through of wholesale power cost, O&M, taxes, allocated A&G, and a margin component. Because there is no investment, the margin component would not be based on ROR, TIER or DSC. An alternative is to mirror the manner in which capital credits are allocated. If a CIAC is not possible, the other alternative is to have a capital cost component on an accrual basis (depreciation + interest) or cash basis (debt service) and to match the amortization of the debt to the contract term. With either approach it will be necessary to make certain there is an agreement on how renewals and replacements will be financed, particularly if there should be a major failure.

3.7.2

SEASONAL RESIDENTIAL AND SEASONAL AGRICULTURAL

Creating rates for these loads can be particularly challenging

Some cooperatives serve seasonal loads related to the agricultural industry. These loads might include irrigation, dairy facilities, grain dryers or elevators, seasonal agricultural processing, catfish or chicken operations, and cotton gins. For these member-consumers, the Team must consider that the cooperative maintained distribution facilities are in place year round, though the member-consumer may only use the facilities for a portion of the year. Another similar type of load is related to resort homes, hunting cabins or winter homes or other seasonal residences. Again, cooperative facilities are in place for the full year though usage is only intermittent or seasonal.

Creating rates for these loads can be particularly challenging. This is especially true when the period of time in which the load operates is likely to occur when the cooperative establishes a peak demand which the power supplier applies year-round. In these cases, depending on the structure of the wholesale rate, the cooperative may be incurring monthly demand charges all year while the seasonal member-consumer is only purchasing power for a portion of the year.

There are three main areas of consideration for the Team with rate structures of this type:

- Recovering the wires cost of serving the member-consumer.
- Recovering the purchased power capacity cost.
- Recognizing the seasonal benefits of some member-consumers.

For residential member-consumers, the cooperative needs to ensure that its rates and terms and conditions of service do not encourage them to disconnect then reconnect a single service from year-to-year in order to avoid monthly charges. Since the member-consumer has facilities in place all year but is only paying for those facilities for a portion of the year, the cooperative Team may elect to recover its year-round cost of serving the member-consumer in an annual charge based on demand, installed horsepower, installed transformer kVA or another demand-based factor or with a demand ratchet. The customer charge may also be included or converted into an annual charge.

If the cooperative's power supplier includes a demand charge in all months affected by the member-consumer, the cooperative might consider adding to the horsepower or other aforementioned charges a sufficient amount to permit recovery of ratcheted power supply capacity-related costs created by the member-consumer.

Some member-consumers may benefit the cooperative due to their seasonal nature. For example, if the cooperative serves seasonal cotton gin loads whose usage generally occurs outside of the cooperative's power supply capacity window, this might benefit the cooperative. Or, if agricultural processing load occurs following the crop irrigation season and outside of the power supplier's peak window, it would be a complementary load. The cooperative Team must be careful to allocate costs based on an understanding of how this type of load functions in the cooperative's region.

3.8

Lighting Rates

Lighting rates vary by cooperative. Some cooperatives do not offer lighting to member-consumers while others offer metered lighting, non-metered lighting or both. Street lighting, signal lighting, sign lighting, decorative lighting and many, many other lighting types are designed to meet the particular needs of individual cooperative systems. Today, most cooperatives are offering LED lighting of various types and sizes. They may continue to offer legacy mercury vapor, high pressure sodium or metal halide lighting fixtures. Some cooperatives have implemented plans to completely replace legacy lighting with comparable LED lighting.

3.8.1

RECOVERING POWER COST FROM LIGHTING

The cooperative Team should consider both the wholesale energy and capacity costs when allocating power cost to lighting equipment. Energy for lighting can either be metered or estimated based on average lighting consumption for unmetered fixtures of a given size. Purchased power capacity cost can be determined effectively if the Team identifies the time of the power supplier's peak for each month of the year to determine if the peak period occurs during daylight or night hours.

It is crucially important to understand the structure of the wholesale rate design. If the power supplier has little to no capacity-related component in the wholesale rate design, lighting is no more or less costly to obtain power supply for than any other load. If, on the other hand, the power supplier provides a strong seasonal pricing signal based on peak summer load, and if the summer power supply peak occurs during daylight hours, the lighting power supply cost is mostly wholesale energy with little or no added capacity related costs.

Some cooperatives charge lighting member-consumers for changes in power/fuel cost while others do not. The safest and fairest approach is to charge lighting member-consumers for changes in power/fuel cost in the same manner as all other rate classes.

3.8.2

DETERMINING THE WIRES COST OF PROVIDING SERVICE FOR LIGHTING

Cooperative records show the cost of providing service for lighting member-consumers. Many cooperatives have found, however, that their costs may be understated. This is generally due to maintenance and operations costs not separately recorded by service crews. This should be considered by the cooperative Team when evaluating the performance of the lighting rate class as shown in the COSS (see Volume II, Appendix Schedule F-1.0) and in determining an ultimate retail rate.

For new lighting types and sizes, the Team can determine costs based on a number of factors including the initial cost of the equipment, estimated on-going maintenance costs, and average usage compared to other lights producing the same lumens.

3.8.3

DETERMINING LIGHTING RATES

The cooperative Team needs to determine an appropriate margin from lighting service. While lighting member-consumers should be treated fairly and equitably as all other member-consumers, it should be noted that outdoor lights are more of an optional service. In the early days of cooperative history, many promoted outdoor lighting to increase electric sales. Today, most lighting service is offered to provide security.

3.9

Service Charge Revenue and Adjustment Revenue

In this context, the term "Service Charge" refers to charges for services and not the monthly fixed charge sometimes labeled "Service Charge" by some cooperative tariffs.

While the focus of the Rate Guide has been on retail rate design, many cooperatives derive material revenue from service charges such as late fees, collection fees, connect and disconnect fees, meter reading fees, and service call fees. Revenue collected from these and other fees to recover associated costs do not have to be collected through retail rates being charged to member-consumers. There are several items for the Team to consider during the retail rate proceeding.

Even in states where retail rates are not regulated by the state, there may be regulatory requirements related to service charges. For example, the percentage late fee may be limited by law or regulation. Service conditions during which disconnects can occur may also be regulated. The Team should consider these issues during consideration of service charge changes.

AMI systems with remote connect and disconnect capabilities may affect the service charge revenues. The cooperative might consider differences in connect or account initiation fees between member-consumers who may be remotely connected and those who cannot.

Prepaid metering may significantly affect revenues associated with late fees and disconnect/reconnect fees. Collection of fee revenue and security deposits may be mostly eliminated. Of course, costs will be reduced in both cases as well.

"OTHER" REVENUE

The focus of much of the rate design is the base rate and base rate revenue. But another portion of the potential charges to member-consumers and the potential revenue for the cooperative is "Other Revenue." There can be any number of sources of this type of revenue, but the most common are based on two types: Service charges and adjustment revenue.

Service charges are things like returned check charges, collections fees, connection fees, late payment charges, wheeling revenue, etc.

Adjustment revenue is based on revenue from a number of different types of factors the cooperative could employ to maintain its revenue stability. Examples of this would be power cost adjustment, debt cost adjustment, margin stabilization, renewable energy adjustment, etc.

As part of the COSS, the team should consider each of these adjustment factors and determine 1) should the rate "re-set" the factors close to zero, 2) are any of the historical factors no longer meeting needs and 3) should the Team consider adding new factors.

3.9.1

ADJUSTMENT REVENUE

In addition to the base tariff charges many cooperatives apply a factor or factors to recover costs that change frequently. For example, a distribution cooperative might obtain its power cost from a wholesale power supplier whose wholesale rate includes fuel cost components which may change monthly. Some cooperatives have factors to recover costs associated with renewable energy or energy efficiency programs. Some have a debt cost adjustment factor, property tax adjustment factor, storm hardening cost recovery factors, or a margin stabilization factor, among many other possible programs.

Most factors recover costs through energy charges. Calculating and implementing demand factors is more complex. While energy factors predominate, they may cause an issue over time.

For example, a power cost recovery factor based on total cost of power recovers changes in both energy and demand charges. Assuming base rates were perfectly aligned with costs at a point in time, as the factor grows, increasing wholesale demand charges will be recovered through the energy adjustment being applied.

The cooperative may consider a maximum level it will allow any factor to reach before revising rate designs. Otherwise, rates will become increasingly less tied to costs over time.

3.9.2

FUEL AND PURCHASED POWER COST ADJUSTMENTS

The most common type of adjustment factor is intended to recover changes in the cost of purchased power. In some states, this factor is prohibited or not implemented by all cooperatives. In others, cost recovery is limited to either changes in fuel cost or changes in volumetric charges. In others, the factor recovers changes in the total cost of purchased power.

Depending on the cooperative and state, the factor may be called Fuel Cost Adjustment, Purchased Power Cost Recovery, Power Cost Adjustment, Power Cost Recovery Factor, Wholesale Power Cost Recovery, or any number of similar titles. It is typically calculated in one of two ways. The cost of purchased power is divided by the kWh sold, and a base cost of purchased power per kWh sold is subtracted from the resulting cost of power per kWh sold to produce a factor. Or the cost of purchased power is divided by the kWh purchased and a base cost of purchased power per kWh purchased is subtracted from the resulting cost of power per kWh purchased, and the resulting factor is corrected for losses to bring it to the sales level. The Team must be careful to understand how their factor works to avoid over- or under-collection related to incorrectly applying losses to the factor calculation.

RE-BASING ADJUSTMENTS

Adjustment factors over time tend to recover costs through energy charges. For this reason, as the factors become larger, stated rates become increasingly distant from total cost the member-consumer pays.

Many cooperatives consider (or are required to do so by regulation) "re-basing" rates. This involves moving the current factor amount into the base rates and "resetting" all factors closer to zero.

At the time of any COSS and rate analysis, the Team and Board should consider this and carefully communicate these changes to members-consumers. Without correct communication, members-consumers may perceive that a given rate change is greater than will be the case. The member-consumer may focus on the amount that the BASE rate changes and not realize there is at the same time an off-setting change in the charges recovered from the factors.

Re-basing adjustments are more and more important as rates move closer and closer to being cost based. Regardless of the changes in cost that a particular factor is intended to recover, most are driven at least in part by capacity-related costs, and yet most factors are entirely recovered through energy charges.

The cooperative should consider a maximum level it will allow any factor to reach before revising rate designs. Otherwise, rates will become increasingly less tied to costs over time.

If industrial rates have direct power cost billing, industrial power cost and kWh sold or purchased, as applicable, are excluded when calculating factors for the remaining member-consumers.

When the cooperative has large industrial member-consumers, with load factors different from the remainder of the system, the Team should consider calculating the factor for industrial member-consumers separately from the remainder of the system. The system losses contributed by these member-consumers are potentially quite different from the remainder of the system.

When the cooperative has a PCA based on their total cost of power, a situation can even develop with an industrial member-consumer receiving the benefit of load control or management directly from the cooperative, and then because this action lowers the average total cost of purchased power, the cooperative may see the same demand savings passed through a second time to all remaining member-consumers through the power cost adjustment factor.

In fact, this same issue should be considered by the cooperative as part of any load control program initiated by the cooperative. If the program is successful, cooperatives typically pass through to participating member-consumers the benefits of reducing wholesale demand costs, but if the cooperative has a power cost recovery factor, reductions in the average total cost of power are potentially passed through to all member-consumers a second time through their power cost factor. To address this issue, the cooperative could choose to manage their factor through changes in the base cost as the programs become more effective. Where permitted by regulation, the cooperative may consider adding back the load control demand savings they are giving to the DSM member-consumers when calculating the power cost adjustment factor.

Cooperatives offering avoided cost purchases from member-consumers with DER may include power purchased from those member-consumers along with power purchased from other power suppliers in the calculation of the power cost adjustment factor.

The Team will also want to consider means of managing their power cost recovery factor. Some cooperatives adopt a rolling twelve month or annual change where permitted so as to avoid monthly swings in the factor. Many cooperatives track any over or under recovery of power cost on a monthly basis for recovery in future power cost adjustment factors.

3.9.3

MARGIN STABILIZATION ADJUSTMENT

A margin stabilization adjustment is a separate rate rider mechanism whose purpose is to maintain the cooperative's margins at a certain level. The factor is typically calculated based on TIER, Rate of Return or DSC. This type of adjustment, if permitted by regulation, can be an effective tool for cooperatives to provide secure financial cost recovery. It can also help avoid years with high or low margins caused by unseasonal weather or economic impacts. The factor can lower the cooperative margins during periods of high sales as well as raise them during opposite periods.

The Team and Board, however, should consider the added responsibility they take on with this type of margin factor. Any added expenses incurred by the cooperative may well cause automatic increases in rates through increases in the factor. To minimize this process, some cooperatives adopt procedures for the Board to carefully audit and review the factor, to approve any change to the factor, or to cap the size of the factor – changes above that point might trigger a new COSS or detailed Team review.

3.9.4

RENEWABLE ENERGY, ENERGY EFFICIENCY AND DSM ADDERS/ADJUSTMENTS

In some states, particularly where cooperatives have state renewable, energy efficiency or DSM standards, cooperatives may consider a factor to recover the cost of these programs.

Care should be taken when considering multiple factors. For example, when the cooperative is offering both energy efficiency and renewable programs, each analysis will assume average usage per member-consumer and average savings from the program when calculating costs and benefits. For example, if the DER member-consumer is offsetting all or most of his or her usage through renewable net metering, permitting the same member-consumer to participate in a rebate program to purchase high efficiency HVAC equipment is unlikely to produce the savings contemplated by each program.

3.9.5

EVALUATING THE RATE IMPACT ON INDIVIDUAL MEMBER-CONSUMERS

The team must carefully consider the impact of their proposed rate designs on individual member-consumers. Even rate design options that have very small impact on total revenue for an entire rate class can have extreme impact on individual member-consumers, particularly with usage at the margins.

For example, when considering a three part rate, the Team will likely discover that the impact on individual member-consumers with high demand usage is quite different from member-consumers with lower demand usage for the same monthly kWh usage. Or the Team may find that increasing the customer charge results in a greater percentage increase on low use member-consumers than on high usage member-consumers.

Most cooperatives develop comparisons of billing under existing and proposed rate options at representative usage levels. An example of this is shown on Schedule B-5.0 and indicates the percentage increase for usage at different levels and for the class average member-consumers. In addition, the Standard Electric Team has included the number of member-consumers within each of the billing strata so the board can determine the number of member-consumers impacted. In some cases, a review of the member-consumer impacts may result in the Team going back and redesigning the rates to minimize that impact.

Not only is this information important for the Team when designing the rates, it may be even more important when communicating rate impact to member-consumers at the time of implementation.

4.0

Other Considerations in Evaluating Rate Options

There are other factors that need to be considered in the evaluation of rate options and selection of the proposed rate. Some of them include:

1. *Using AMI to implement innovative rate structures*
2. *Coordination with Line Extension Investment*
3. *Implications for Net Metering, Renewables and Pre-Paid Metering*

4.1

Implication of Technology on Rate Design Options

Cooperatives desire to provide member-consumers with rate options that closely relate to how costs are incurred, including three part rates, time differentiated rates, DSM rates, etc. In order to offer rate design options that track cost, every cooperative Team should review IN ADVANCE their existing billing, communications and meter data management systems to ensure that data will be available to implement a rate option the cooperative Team and board may determine is appropriate.

NOT ALL AMI IS EQUAL

AMI capability is an important factor in developing a COSS and innovative rate designs.

At the beginning of a Rate Analysis Study, the Team will want to evaluate the features of their AMI system to determine the potential rate designs their AMI technology can support.

Advanced Metering Infrastructure (AMI) has swept the country in recent years. AMI offers a broad range of configuration capabilities. At one extreme are AMI systems that measure monthly energy usage remotely. At the other extreme are AMI systems that provide two-way communication and control. The cooperative can read demand and energy usage by time interval, remotely connect and reconnect all or some of their meters and remotely manage load, as well as provide usage and other information to member-consumers, record outages and other important functions.

Most cooperatives today have AMI somewhere between these two extremes. Initial AMI installations may reveal unexpected deficiencies which block the effectiveness of the planned rate design. For example, existing back office systems may not be capable of processing, interpreting, and storing the massive amounts of usage data generated by AMI meters. Choke points along the communication pathways may limit data flows through a particular substation serving a high number of meters. Data management packages or billing packages acquired as components of the initial AMI system design may not interface with existing software. In short, the cooperative's system may well not include Interoperability of Multi-Speak® Specification (the ability for different cooperative computer systems to "talk with" one another—an NRECA objective for many years). Such limitations may restrict not only desired operational efficiencies and cost savings but also the ability to offer new rate designs such as real-time pricing.

Examples (not all-inclusive) of the types of cooperative systems that should be reviewed no later than the start of a COSS process are as follows:

- AMI meter system.
    - If the cooperative desires to modify existing on peak and off peak periods, can this be done remotely, or must the meters be reprogrammed manually?
    - Can the meter be programmed to record usage in multiple time periods to permit on peak, off peak and critical peak or similar rate design options?
    - Does the meter include multiple registers to record flow in both directions for net metering or a single register rolling both directions?
    - Does the meter report usage for each meter at each interval? If not, can the cooperative obtain demands that occur on any given interval (CP peak demands) or does the meter only record peak demand for the month (NCP peak demand)?
- Communications system
    - Does the system used to report meter readings back to the office have sufficient capacity to provide daily demand readings or only monthly demand readings?
    - Does the system allow two-way communication so the cooperative can communicate peak periods, manage member-consumer equipment, and/or remotely connect, disconnect and offer prepaid service?
    - Does the communications system interface with the cooperative website so member-consumers may see information about daily, weekly or monthly usage and manage consumption?
- Billing system
    - Does the billing system interface with the meter system to permit the cooperative to adopt more complex rate structures such as three part rates, DSM rates, TOU rates, etc., without crippling increases of staff time?
    - If so, will the cooperative need to activate typically unused portions of the billing system? Will the system incur costs to implement the processes from their IT provider(s)?
    - Does the billing system interface with the cooperative website so member-consumers may see in addition to their daily, weekly and monthly usage, similar information about their billing? Does the interface allow member-consumers to gather information about their rates and cost and receive signals about peaks and DSM to allow them to manage cost?
    - Have the billing staff been trained in the operation of new and potentially complex requirements of their billing system and rates?
- Are all of these systems secure to help provide that no confidential member-consumer data will be exposed and none of its systems compromised?

The preceding examples are not all inclusive. But they do indicate the problems that many cooperative Teams and boards experience as they prepare to implement new and innovative rate designs structures. They discover only at the very end of the process that, no matter how desirable they feel a given rate structure might be, their existing system will simply not permit it. Cooperatives should consider this carefully when they select, implement and operate their IT systems, particularly with regard to AMI, communications and billing.

AMI systems provide a flood of potential rate data at the cooperative

Retail consumer backlash to AMI has sometimes been a problem. Concerns expressed by consumers include the potential loss of privacy due to two-way communication and negative health impacts caused by AMI meter technology. As a result of this backlash, some member-consumers insist and some regulators require cooperatives to provide consumers the ability to "opt out" of AMI meters. This option dilutes the effectiveness of the AMI system on all levels. As AMI systems continue to develop and expand; however, a point will be reached where the AMI infrastructure is no longer an "extra" feature of the system and becomes the standard offer.

In any case, AMI systems provide a flood of potential rate data at the cooperative. The data helpful in developing engineering analysis and COSS analysis might be used only every three to five years. It is a challenge to invest time and data processing and storage every year for data that is not required monthly for billing member-consumers.

AMI can expand the rate design options and in some cases, provide communication with member-consumers

The cooperative can make use of AMI data available in a variety of ways in their COSS analysis and rate designs. For example, AMI may provide for each member-consumer and in total for each rate class the contribution to any peak period the cooperative desires. If that data is available, and used by the Team, the COSS will be far more reflective of actual costs and provide far more accurate data to use in designing rates.

Beyond the cost of service allocations and determination, AMI can expand the rate design options and in some cases, provide communication with member-consumers. For example, if the cooperative has full two-way communications with its meter systems, it is possible to coordinate meter reading, time of use rates and thermostat control. Also, AMI may offer the ability to remotely control irrigation or commercial processing motors. When coordinated with remote connect and disconnect collars, the AMI system can permit prepaid metering—certainly one of the most popular applications of AMI technology through rates.

The Team may consider not only the rates it has in place today but possible future rate structures. If the Team desires to adopt rates that cannot be implemented with current technology, it should begin gathering, processing and storing the data TODAY that will permit it to ultimately move to desired rate designs. The primary purpose of the COSS analysis is to determine the cost to serve each rate class and provide the data necessary to develop rates. The COSS can also provide information to coordinate rates with other cooperative programs.

4.2

Developing the Allowable Line Extension Investment

The COSS will identify the plant investment associated with providing service to the member-consumer. The rates will include a capital cost and O&M component reflecting the average investment to serve the average member-consumer. The cooperative will have in place a line extension policy that identifies the investment the cooperative will make to provide service to a member-consumer and the additional amounts the member-consumer will be required to pay for service. Clearly the line extension requirements need to be coordinated with investment assumptions reflected in the retail rates charged.

The application of a line extension allowance varies from cooperative to cooperative. Some cooperatives have a policy of providing a predetermined allowance to each new member-consumer in a rate class. Others perform an individual analysis for each connecting load. Some do not provide an allowance at all while others will extend facilities up to a certain distance before requiring the connecting party to pay for additional facilities. The type of load (residential, commercial, industrial, etc.), may also determine the approach taken by each cooperative.

The Team can use the COSS to determine the embedded cost to serve the current member-consumer. The Team then can determine the cost functions that the line extension policy is intended to reflect. Some line extension policies consider only the costs associated with the line extension, transformers, meters, and services required to provide service. Other line extension policies will go further and consider average embedded backbone facilities associated with providing service. For many cooperatives that are competing for new loads in dual certificated areas, the allowable line extension will be defined by what is required to be competitive in the dual service area.

ALLOWABLE LINE EXTENSION INVESTMENT

Different rate designs will support different levels of line extension. When rates are changed, it is important to evaluate the line extension policy to determine if it needs to be modified to correspond with the new rate and allowable investment.

Of importance in the effective design of rates is to ensure that the proper investment is made by the cooperative to serve the load. This is particularly true for large power or industrial member-consumers. The assumption in developing rates for residential or small commercial classes is that the investment made will be used and useful over the life of the investment. This may not be the case with large power or industrial member-consumers with a significantly shorter project life. It is important in these instances that the capital cost required to provide service either be contributed by the member-consumer directly as CIAC or the cost recovery component of the rate be aligned with the contract period for service. Even then the cooperative may also require a letter of credit or some other instrument that will assure the cooperative that it receives payment for the capital component of cost of service.

4.3

Issues Related to Net Metering, Renewables and Pre-paid Metering

4.3.1 NET METERING

Net metering, in general, and solar applications, in particular, are of special interest to many cooperatives.

Net metering has been in place for many years across the country. But the falling cost of renewable energy and the maturity of the solar industry in particular are causing explosive growth in some states. While net metering is beyond the scope of this Guide, because it impacts rates and cost recovery, it will be discussed here as an example of coordinating policies with rates. Of course, as is the case with all rate designs, the Board must weigh multiple equally important criteria when considering rates. Recovering costs from the member-consumers who cause costs to be incurred is important, as is promoting energy efficiency and renewable energy, as is following PURPA guidelines related to decoupling.

St. Croix Electric Cooperative (SCEC) serves 10,500 meters in rural Wisconsin. In the course of implementing their net metering program, they learned valuable lessons that are important to cooperatives implementing all kinds of rate changes, not just net metering. They were concerned about recovering the fixed cost of providing service more fully from fixed billing units. Once fixed costs were recovered, the cooperative, felt it could provide more flexibility in the design of the remaining elements in their rate. In addition, to mitigate individual impact, they grandfathered member-consumers, only to discover this decision was difficult for their billing system to implement. As a result they found it to be important to carefully establish that the cooperative's systems are able to implement innovative rate structures. Click here for more information.

Net metering rules vary throughout the United States. In most states, regulatory commissions have established the rules for net metering, though not all of these rules apply to cooperatives. In states where cooperatives are not under regulated jurisdiction, the practice even among cooperatives may vary.

This situation can be a significant issue when there are large numbers of net metering member-consumers and the cooperative bills under a two-part rate

There is little doubt that opinions vary widely with regard to the correct approach for net metering especially between the utility sector and other parties. Factoring in stakeholder positions and regulatory commission requirements increases the complexity.

The practice of net metering is not universally defined across states. Some cooperatives are moving away from net metering as a means of compensating renewable DER and are instead considering retail member-consumers as partial-requirements member-consumers. There are generally three concepts involved in net metering rates and they are defined differently in different states. The basic concept is that a member-consumer has installed a renewable resource generator of some type behind the retail meter and is now being billed the net of what is consumed less what is generated.

1. **Avoiding usage that occurs at the same time as generation**

   While some cooperatives do not permit this, requiring instead that the member-consumer send all energy generated onto the grid and purchase all usage required for the load, most permit the member-consumer to offset any usage that happens at the time of generation. This situation can be a significant issue when there are large numbers of net metering member-consumers and the cooperative bills under a two-part rate, particularly if the cooperative has set its customer charge well below its customer-related cost of providing service. The member-consumer may offset all or a portion of the cooperative's ability to recover its own full fixed wires cost of providing service. Historically, the numbers of net metering member-consumers were small and the desire to subsidize the renewable industry great enough that these issues were not considered as material. This is not the case in many places today.

Banking is of particular concern to most distribution utilities because the member-consumer is being compensated at the full retail rate, potentially for the entire output of the generator

2. **Banking excess generation to be used at another time period by the member-consumer or at another site by the member**

   If the member-consumer never generates at any time during the month more energy than used, banking is not an issue. But if the member-consumer ever generates in excess of usage, most net metering programs require that the utility "bank" this excess generation and allow the member-consumer to use it to offset load during later periods. Some states only permit the banked excess generation to offset load in the same month, others in the same year, and in others the banked excess generation is evergreen.

   In a few states, banking is not permitted and the member-consumer can only "net" energy that is generated at the time of consumption against retail usage. In some states, a net metering member-consumer is permitted to use excess energy generated to offset load both at the location where the generation is installed and at any other site the member-consumer may have.

   Banking is of particular concern to most distribution utilities because the member-consumer is being compensated at the full retail rate, potentially for the entire output of the generator. The full retail rate includes a number of costs that would typically not be eliminated by renewable DER, including distribution wires cost and a portion of purchased power demand costs. Banking may also provide an incentive to over size renewable generation. In some states this is addressed by limiting the maximum size requirement for residential and/or commercial generation that can be considered under net metering.

Washington Electric Cooperative (WEC) is a fully regulated cooperative serving 10,500 meters in Vermont spread over 2,728 square miles. The case study reviews a net metering rate change instituted by the cooperative. Part of the rate developed included a grid access fee to recover fixed cost of providing service from net metering customers through a fixed billing unit. Since the cooperative determined that the value of solar number it developed would not be of general application, perhaps of more general interest were challenges the cooperative experienced in implementing their new rate as part of their own billing system. For a time, net metering member-consumers had to be billed by hand until these issues were resolved. In addition, the cooperative determined education was key and based its program on a message of fairness and equity for all member-consumers. Click here for more information.

3. **Avoided Cost**

   Generation in excess of banked usage is not purchased by the cooperative in some states. In others, the excess generation is purchased at "avoided cost." For a distribution cooperative, this is typically either the avoided cost of purchased power or the power supplier's avoided cost of power.

   To the extent that cooperatives can build their own cost of providing distribution wires service into fixed billing rate, any change in kWh sales, whether from renewable net metering or any other cause, is far less of a potential problem. Over time, the issue is often not one between the cooperative and its member-consumers, because lost margins (reductions in revenues that are greater than reductions in costs) ultimately will trigger a rate increase paid by other member-consumers, or decrease the patronage capital allocated to all member-consumers or both. The issue is between member-consumers with renewable generation and other, often lower income, member-consumers.

4.3.2

SOLAR PROGRAMS

Solar programs present a unique challenge for distribution cooperatives. Unlike many other types of renewable DER, solar installations have the real potential to reduce some portion of the purchased power peak demand cost. The amount of savings depends on factors included in the wholesale rate structure, the location of the cooperative, and the orientation of the solar facilities. Individual rooftop solar systems are typically oriented to produce maximum kWh as opposed to maximum wholesale capacity reductions.

For solar in particular, some advocates push for a wide range of additional adders to use in developing the value of solar. The adders are generally related both to potential peak reductions (purchased power peak and even some distribution capacity peak costs) and societal benefits related to environmental improvements. Others would include savings from avoided capacity realized many years in the future, though most regulated cooperatives are limited by commissions in their ability to include future costs in setting their rates.

4.3.3

COMMUNITY SOLAR PROGRAMS

Community solar programs provide an opportunity for member-consumers and the cooperative to participate together in a DER option. Community solar allows member-consumers who are renters or who cannot afford the large up-front capital investment of individual rooftop solar the opportunity to participate in the program. Community solar programs are regulated in many jurisdictions and may also be limited by the provisions for each distribution cooperative's power purchase contracts.

A major advantage to a community solar program is the ability of the cooperative to orient solar DER to maximize capacity production instead of energy production in parts of the country where these two orientations are materially different.

Cooperatives with community solar may offer a variety of approaches:

- Sell a share in the project and allow "virtual net metering" with the member-consumer receiving a prorated share of the generation from the unit.
- Purchase a share in the output with a fixed charge or credit for the member-consumer each month based on investment and operation costs and cost of generation over time
- Value of DER and compensation
- Offer rate design options to retail member-consumers.

Some cooperatives have sought to offer additional rate offerings to member-consumers. In some cases, the motive is simply a desire to provide a choice to member-consumers. In other cases, additional rate options provide an opportunity for member-consumers to save based upon their load characteristics and consumption patterns. In states with laws providing consumer choice, additional rate options are generally intended to appeal to desirable consumers or to simply give options to existing member-consumers.

Regardless of the intent, cooperatives must always make one assumption when considering offering multiple rate options to member-consumers. Cooperatives must assume for ratemaking purposes that over time, member-consumers will migrate to the lowest rate option. This assumption helps with the establishment of rates and the expectation they will produce the intended revenue.

4.4

Alignment of Proposed Rate Design with Implementation of Pre-Pay Programs

Many cooperatives throughout all regions of the U.S. offer prepaid programs. In the past, pre-pay rate offerings sometimes included additional charges aimed to recover additional costs associated with specialized metering, remote connect and disconnect equipment, and payment processing such as online and kiosk related fees. Today, most pre-pay rates are indistinguishable from standard rate offerings for other member-consumers with the exception of the application of a daily rate. For rate making purposes, the primary impact of prepaid metering is related to changes in service charge revenue and expenses related to collection of late fees and benefits from the time value of money. As data is gathered, some cooperatives believe that effectively run prepaid programs have the impact of reducing load as member-consumers watch, understand and adjust peak usage.

5.0

Implementation of Proposed Rates

Few decisions have the immediate impact on cooperative member-consumers as changes in retail rates. Communicating rate changes to member-consumers and providing notice in a prescribed manner is generally required in states where cooperatives are rate regulated. However, notice requirements only address the mechanics of communicating a rate change. There is much more involved in providing meaningful member-consumer communication regarding rates.

5.1

Primary Goal in Implementing a Rate Change

A rate implementation plan developed alongside the COSS will help the cooperative achieve member-consumer acceptance of the rate changes and continued satisfaction with the cooperative

Experience shows that some member-consumers will react negatively to rate changes. This may be true even when there is an economic benefit to them as a result of the rate change. A rate implementation plan developed alongside the COSS will help the cooperative achieve member-consumer acceptance of the rate changes and continued satisfaction with the cooperative. The rate implementation plan ensures that an appropriate message is developed regarding the proposed rate change and is communicated through each of the cooperative's communication channels. At a high level, the plan should reinforce the message to member-consumers that the pending rate change supports the Cooperative's goals and objectives to provide reliable electric service at an affordable cost on a long-term basis.

Sioux Valley Electric Energy (SV) is a merged cooperative serving 23,000 meters in South Dakota and Minnesota. They had the challenge of unifying rate structures and implementing basic service charges into rates that did not include these fixed billing units previously. The cooperative elected to implement rate changes and fixed charges over a period of years to reduce the impact on member-consumers. At the same time, the educational process of communicating with member-consumers did not end with the initial rate implementation. An on-going process and willingness to reconsider the initial rate change plan maximized member-consumer understanding and minimized member-consumer complaints. Click here for more information.

An educated staff person is perhaps the best communication tool for the cooperative

5.2

Developing the Implementation Plan

Developing an effective Implementation Plan requires the input of cooperative management and senior staff and expertise of member services and communications personnel. A cooperative's manager or other senior staff will typically take the lead in talking with member-consumers and the public about rate changes. While member services and communications staff may take this role in some settings, they will certainly be involved in developing the materials used to educate member-consumers about rates and other issues of interest.

A successful implementation plan will include two primary target audiences. They may be considered an internal audience and an external audience. The internal audience includes cooperative staff and directors. The external audience includes member-consumers and may be thought of as individual member-consumers, local organizations such as civic groups or trade organizations who include cooperative member-consumers and the general public.

5.2.1 INTERNAL AUDIENCE

It may not be critical for all cooperative staff to understand all aspects of the cost of service and rate analysis. However, at a minimum, all employees should be able to communicate the general process the cooperative undertook to analyze and modify rates. Cooperative staff should be well informed prior to communicating a proposed rate change. Cooperative staff are commonly in contact with member-consumers outside the workplace through business, social, community and school activities. An educated staff person is perhaps the best communication tool for the cooperative.

Beyond a general understanding of the process and outcome, cooperative managers and senior staff should consider how staff interact with member-consumers and the general public and ensure there is an appropriate level of communication and understanding of the cost of service, rate analysis and rate change. Managers, senior staff and any other staff responsible for communicating with member-consumer groups, civic organizations or key accounts should be well versed in all aspects of the cost of service process, rate change and member-consumer impact. Member services and those staff who respond to member-consumer billing questions and concerns should be intimately familiar with the existing and proposed rates and member-consumer impact. Staking engineers should be able to communicate any associated changes in the cooperatives line extension policy which may have changed as a result of the cost of service and rate analysis.

What is important to remember is member-consumers should be informed about an upcoming rate change well in advance so that they may be prepared

Directors should also understand the process undertaken by the cooperative. They should understand the cooperative's regulatory ratemaking requirements and process. In some cases, the cooperative is regulated by a public utility commission. In others, the public utility commission is no longer the cooperative's ratemaking authority. In such cases, communicating with member-consumers that the cooperative's cost of service and rate study was developed in accordance with generally accepted regulatory standards and practices is important.

Many cooperatives provide training sessions conducted by internal staff or a rate consultant to ensure staff and directors are able to communicate the key issues and are able to answer questions from member-consumers in a positive way. They should be able to direct member-consumers to additional resources offered by the cooperative or others to help them manage energy usage. They also should be trained to direct member-consumers of the media or other interested parties to the appropriate cooperative spokesperson.

5.2.2 EXTERNAL AUDIENCE

Communicating rate changes to member-consumers may require at a minimum notice requirements stemming from public utility commission regulatory rules. Cooperatives should be familiar with these requirements and the regulatory approved method of fulfilling them. Cooperatives who are no longer jurisdictional to their states public utility commission should consider what was once required of them when providing notice of rate changes. Many cooperatives still follow these notice requirements.

All cooperatives, as part of their implementation plan, should consider the many other communication channels available to them to educate member-consumers on when a rate change will occur and how much their bill will change. The timing for each communication channel message may vary based upon the cooperative's notice requirements and implementation plan. Some cooperatives will begin communication with member-consumers the need for a potential rate change upon commencement of a cost of service and rate study. Others will begin communicating key issues well before rates are scheduled for implementation. What is important to remember is member-consumers should be informed about an upcoming rate change well in advance so that they may be prepared.

COMMUNICATION METHOD	AUDIENCE	TIMELINE
Internal education about rates, costs of doing business	Directors, employees	Directors, employees
Director Training	Directors	Directors
Employee Training	Employees	Employees
Frequently Asked Questions (Talking Points)	All Audience	All Audience
Managers Column	Member-consumers	Member-consumers
Formal Notice of Rate Change	All Audience	All Audience
Website Announcement	All Audience	All Audience
Online Video	All Audience	All Audience
Letter to Member-Consumers	Member-consumers	Member-consumers
Newsletter article(s)	Member-consumers	Member-consumers
Bill Stuffer	Member-consumers	Member-consumers
News Release	Member-consumers	Member-consumers
Presentations	Member-consumers	Member-consumers

Cost is the bottom line for most cooperative member-consumers

Generally speaking, member-consumers want to know the answers to these questions:

Why is a rate change needed? Many member-consumers understand there are cost pressures which affect the cooperative just like other utility services. They see periodic rate increases in their cable TV, natural gas, telephone, cell phone and other similar services. They may also be aware of industry matters such as such as climate change and renewable resources, but they may not understand how these issues affect the cooperative's costs. They may not be familiar with complex issues affecting the cooperative's power supply costs. A rate adjustment provides an opportunity to educate member-consumers about the key issues that affect the cooperative's costs and to assure member-consumers the cooperative is working hard to manage costs both in the present and for the future.

How will rates be adjusted, and how will the change be implemented? Cost is the bottom line for most cooperative member-consumers. Member-consumers should know which rates will change and how much they will increase (or decrease). If there are important changes in the rate design, member-consumers should have the opportunity to understand them. For example, if establishing a higher customer charge is an important component of the proposed rates, member-consumer communication regarding the recovery of fixed costs might be a focal point.

The cooperative needs to demonstrate in every way it can that it is being prudent with member-consumers' money

Significant structural changes to rates or the introduction of new rate designs requires much more thought, effort and time to communicate as opposed to the routine rate change. The need for thorough communication lies in the fact that many member-consumers may be affected in any number of ways when rates are structurally changed. Even the slightest change in structure can result in one member-consumer seeing no increase, another seeing a large increase, and a third seeing a rate reduction. The cooperative must be clear as to the rate change at different levels and not reference only average values.

What is the cooperative doing to manage its costs, ensure reliability and provide for the member-consumers' future needs? Member-consumers need to know the cooperative is actively working on their behalf. The cooperative needs to demonstrate in every way it can that it is being prudent with member-consumers' money. Appearances also are important. For example, one cooperative received a member-consumer complaint about a bucket-truck that had been left running unattended. It turned out that there was a legitimate reason, and in this case, the cooperative had the opportunity to explain this to the concerned member-consumer. This story illustrates that member-consumers do pay attention to a cooperative's actions as well as its words.

How can member-consumers manage their use of electricity to manage their bills? Communicating how member-consumer consumption will determine their billing is critical, especially when introducing rates with components such as time-of-use or demand billing. This enables member-consumers to pay careful attention to their consumption patterns in order to take advantage of potential cost saving. The cooperative can provide critical information on how member-consumers can manage their energy costs in order to mitigate the impact of the proposed rate change. Member-consumers need to understand how they can change their usage patterns in response to rate signals to lower their bills. It is important that member-consumers understand the billing determinants by which rates will be calculated and how billing determinants are derived. This is especially true when introducing new concepts such as demand kW and other complex issues.

Most cooperatives have a variety of programs to help member-consumers conserve and use energy more efficiently, but some member-consumers may not be aware of them. Cooperatives also can serve as a clearinghouse for information on other resources, particularly for lower income member-consumers.

Member-consumer meetings may be a regulatory requirement for some cooperatives implementing a rate change. Even if not required, the meetings provide an opportunity to educate member-consumers on the ratemaking process and proposed rate changes and provide a forum for member-consumers to ask questions.

Cooperatives should begin to prepare member-consumers for a rate change as soon as it becomes clear one is needed.

The primary intent of implementing rates in phases is to reduce member-consumer impact

5.3

When is the best time to implement new rates?

Cooperatives should begin to prepare member-consumers for a rate change as soon as it becomes clear one is needed. If a cooperative foresees a need for annual adjustments or a future large adjustment, it should be discussing this with member-consumers through as many channels as possible.

It is desirable to implement new rates when it will have the least impact on member-consumers' bills and in a way that is revenue neutral, if possible. The optimal timing depends on the nature and level of the change. If the cooperative does not need a significant amount of additional revenue, changes are likely to have a neutral effect on member-consumer bills. For example, for many cooperatives, a shift to cost-based rates will result in higher customer and demand charges and lower energy charges. Implementing that type of change during a high usage period such as a summer or winter month will spread changes in customer and demand costs over the most kilowatt-hours, and member-consumers will benefit most from lower energy charges. Ideally, rates reflecting a large increase in revenue requirements should be implemented in months with lower usage to minimize the impact on member-consumers.

Cooperatives that decide to delay increases to improve timing should analyze the financial impact on the cooperative. Minimizing the impact on cooperative member-consumers also delays the income to the cooperative. It is important to consider whether the income lost is worth the potential gain in goodwill from member-consumers.

For many years, cooperative rate philosophy emphasized stability of rates and infrequent changes. Although stability is important, an overdue rate increase can lead to large or unexpected changes that can have an adverse effect on the member-consumer. It is best for member-consumers to perceive changes in cost as relatively small. More frequent, smaller rate increases protect the cooperative's financial integrity while avoiding rate shock and negative member-consumer reaction. Many cooperative boards and managers have adopted this philosophy and revisit the cost of service and rate study process every three to five years.

5.4

Should the cooperative consider implementing new rates in stages over a period of time?

Some cooperatives choose to implement rate changes over time. The primary intent of implementing rates in phases is to reduce member-consumer impact. There are instances when a phased approach may be beneficial. If the cooperative's overall rate increase is significant and adversely affects one or more rate classes, a phased implementation will be beneficial by helping mitigate member-consumer impact.

If a proposed rate design represents a significant departure from the existing rate already in place, the cooperative may wish to implement gradual changes over a period of time. Even though the overall rate change may have little or no impact on a rate class, the rate change may have a significant impact on individual member-consumers within that class, both positive and negative. If such circumstances exist, the cooperative can implement the rate in annual increases to minimize member-consumer impact. Implementing substantial changes in rate levels or differences in rates in stages may help to improve member-consumer acceptance. For example, if a cooperative's customer charge is $17.50 per month but the actual customer-related costs are $35 per month, the cooperative might choose to implement a customer charge of $22.50 per month for a year before further increasing the customer charge. Again, cooperatives should analyze the financial impact that any delay will have on its income.

In rare cases, proposed rate design changes may warrant implementation for certain member-consumers within a rate class but not all of them at the same time. This has historically occurred when there was a significant departure in the retail rate which negatively impacted a group of member-consumers. For example, a cooperative who has experienced growth due to urban sprawl may find it impractical to continue offering a separate irrigation rate. However, the transition for the few remaining irrigation services may result in significant rate increases for those member-consumers. In such cases, the tariff can be closed to new services while existing member-consumers will be transitioned to a new rate over a period of time. Similarly, a cooperative may adopt a similar approach for implementing a new rate for a large group of member-consumers. Implementing a three-part rate for a residential rate class requires a measured approach. A cooperative may choose to transition existing member-consumers to the new three-part rate over a period of time while immediately placing new connects directly on the new rate. In the meantime, the cooperative can use the transition period to provide education, implement parallel billing and offer member-consumers the ability to move to the new rate under their own direction.

It is important to consider a phased approach from the member's perspective. A phased approach mitigates member-consumer impact. However, a phased approach when the cooperative implements a rate change over several phases may appear differently to a member-consumer. If a cooperative sets rates and forecasts the need for additional revenue in year five of its financial forecast, then implements rates over three or more phases only to change rates again, it may appear to member-consumers that the cooperative is perpetually changing rates.

5.5

Monitoring rates is an ongoing process

Cooperatives continually monitor their financial performance. It is also a good practice to continually monitor rates. This is especially important following a rate change. Upon modifying rates, cooperatives staff should sample monthly bill calculations for each affected rate class.

Rates can also be monitored to gauge whether or not the pricing signal(s) is affecting member-consumer behavior. This is especially important for rates such as time-of- use rates. Time based rates may require adjustments to achieve the desired member-consumer response.

Rates should also be revised when the cooperative financial ratios begin to approach board defined thresholds, when there is a significant change in cost of service such as a change in wholesale power costs; or when the rate design is not achieving the desired member-consumer response.

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Schedule A-1.0

FINANCIAL PROFILE EXAMPLE—KEY OPERATING RATIOS AND STATISTICS

	12-Months Ended	Rate Base	Return	Interest on LT Debt	Net Margins	Rate of Return	Oper. TIER	Net TIER	Mod. Net TIER	DSC	Equity as Percent of		Avg. Debt Cost	Return on Equity	Plant Growth Rate	General Funds Ratio
											Assets	Capitalz.				
		$	$	$	$	%	X	X	X		%	%	%	%	%	%
1	12/31/Year -2	210,565,322	17,502,614	6,862,012	12,495,860	8.31	2.53	2.82	2.71	3.39	42.71	46.83	5.44	11.58	9.47	4.37
2	1/31/Year -1	212,865,187	17,283,177	6,986,821	12,174,117	8.12	2.45	2.74	2.63	3.31	42.66	46.82	5.54	11.05	9.43	4.98
3	2/28/Year -1	213,968,841	17,894,591	7,101,529	12,433,232	8.36	2.50	2.75	2.68	3.32	43.12	47.11	5.64	11.42	9.34	3.86
4	3/31/Year -1	218,074,141	18,482,664	7,197,394	13,159,988	8.48	2.56	2.83	2.72	3.37	42.18	47.42	5.75	11.50	10.05	3.13
5	4/30/Year -1	217,122,747	18,972,641	7,267,113	13,605,291	8.74	2.60	2.87	2.77	3.41	42.14	46.20	5.76	12.21	9.03	3.65
6	5/31/Year -1	218,273,255	19,510,215	7,386,629	13,971,344	8.94	2.64	2.89	2.79	3.38	42.31	46.86	5.84	12.45	8.70	3.23
7	6/30/Year -1	220,893,338	19,896,183	7,606,685	14,129,715	9.01	2.61	2.86	2.76	3.30	41.60	45.97	5.98	12.57	8.85	4.43
8	7/31/Year -1	223,734,093	20,062,793	7,738,219	14,306,525	8.97	2.59	2.85	2.74	3.27	41.28	45.93	6.05	12.40	9.28	4.38
9	8/31/Year -1	226,298,646	19,928,601	7,833,149	14,130,362	8.81	2.54	2.80	2.69	3.18	41.42	46.19	6.11	11.95	9.93	3.09
10	9/30/Year -1	227,649,688	19,885,806	7,908,878	13,752,258	8.74	2.51	2.74	2.63	3.11	40.94	45.57	6.13	11.85	10.11	5.20
11	10/31/Year -1	228,293,597	20,369,232	7,949,809	14,176,909	8.92	2.56	2.78	2.67	3.15	41.16	45.58	6.12	12.27	9.67	5.35
12	11/30/Year -1	229,531,520	19,980,662	8,197,049	13,334,486	8.70	2.43	2.63	2.53	2.99	42.36	46.44	6.27	11.51	9.66	4.91
13	12/31/Year -1	230,727,204	17,643,015	7,883,854	11,375,176	7.65	2.22	2.44	2.32	2.78	42.39	46.36	5.99	9.57	9.58	5.80
14	1/31/Year -0	233,875,396	18,012,785	7,851,841	11,719,424	7.70	2.28	2.49	2.37	2.84	42.73	46.43	5.92	9.76	9.87	6.15
15	2/28/Year -0	235,226,024	17,502,015	7,834,848	10,991,464	7.44	2.22	2.40	2.30	2.75	42.78	46.21	5.85	9.29	9.93	5.51
16	3/31/Year -0	236,802,112	17,686,945	7,743,232	11,142,737	7.47	2.25	2.44	2.35	2.75	42.25	45.98	5.73	9.51	8.59	4.45
17	4/30/Year -0	237,730,555	17,377,682	7,721,626	10,768,045	7.31	2.21	2.39	2.30	2.72	42.59	46.02	5.68	9.22	9.49	3.59
18	5/31/Year -0	238,203,536	17,442,369	7,570,914	10,705,166	7.32	2.26	2.41	2.32	2.78	42.43	45.96	5.53	9.43	9.13	2.62
19	6/30/Year -0	239,467,198	16,831,325	7,348,353	10,341,972	7.03	2.25	2.41	2.30	2.77	42.27	45.94	5.35	9.01	8.41	2.00
20	7/31/Year -0	241,520,952	16,822,967	7,213,323	10,284,049	6.97	2.29	2.43	2.33	2.82	41.36	45.01	5.21	9.11	7.95	3.36
21	8/31/Year -0	243,325,587	16,676,196	7,128,261	10,235,594	6.85	2.29	2.44	2.34	2.83	41.48	45.26	5.11	8.96	7.52	2.55
22	9/30/Year -0	245,390,168	15,528,840	7,043,307	9,173,614	6.33	2.16	2.30	2.20	2.72	40.86	44.74	5.02	7.94	7.79	3.49
23	10/31/Year -0	246,952,628	15,269,137	6,957,989	9,038,201	6.18	2.14	2.30	2.19	2.72	41.17	45.13	4.94	7.69	8.17	3.61
24	11/30/Year -0	249,150,250	13,956,973	6,894,537	7,765,974	5.60	1.97	2.13	2.02	2.61	41.76	45.71	4.87	6.47	8.55	2.87
25	12/31/Year -0	251,567,301	14,579,520	6,979,640	8,376,468	5.80	2.05	2.20	2.09	2.67	41.26	45.01	4.90	6.89	9.03	3.79

Schedule A-2.0
FINANCIAL PROFILE EXAMPLE—USAGE STATISTICS

							kWh Sold % Increase			Consumer % Increase			Miles % Increase		
	12-Months Ended	kWh Sold	Office Use	kWh Purchased	Losses	Percent Losses	Period	Annual	Cons	Period	Annual	Total Miles Line	Period	Annual	Cons. Density
						%	%	%		%	%		%	%	
1	12/31/Year -2	1,480,456,720	1,971,818	1,596,566,299	114,137,761	7.15	0.91	8.31	100,593	0.32	1.11	12,647	11.58	1.31	7.95
2	1/31/Year -1	1,496,019,405	1,959,491	1,603,343,465	105,364,569	6.57	1.05	8.36	102,709	2.10	3.48	12,663	0.13	1.71	8.11
3	2/28/Year -1	1,518,023,112	1,968,395	1,641,259,142	121,267,635	7.39	1.47	8.56	102,166	(0.53)	3.34	12,678	0.12	1.77	8.06
4	3/31/Year -1	1,540,026,805	1,986,000	1,681,676,716	139,663,911	8.31	1.45	8.74	102,708	0.53	4.33	12,718	0.32	1.73	8.08
5	4/30/Year -1	1,572,914,958	1,976,567	1,718,513,107	143,621,582	8.36	2.14	9.08	103,276	0.55	4.53	12,729	0.09	1.64	8.11
6	5/31/Year -1	1,585,131,259	1,969,274	1,724,802,867	137,702,334	7.98	0.78	9.10	103,559	0.27	4.47	12,743	0.11	1.63	8.13
7	6/30/Year -1	1,593,495,176	1,937,102	1,728,771,797	133,339,519	7.71	0.53	9.09	103,922	0.35	4.48	12,752	0.07	1.61	8.15
8	7/31/Year -1	1,603,752,568	1,945,410	1,734,448,619	128,750,641	7.42	0.64	9.10	103,764	(0.15)	3.98	12,759	0.05	1.46	8.13
9	8/31/Year -1	1,607,164,627	1,904,179	1,728,858,711	119,789,905	6.93	0.21	9.09	103,369	(0.38)	3.25	12,767	0.06	1.40	8.10
10	9/30/Year -1	1,602,396,445	1,915,662	1,743,968,856	139,656,749	8.01	(0.30)	9.13	103,671	0.29	3.22	12,780	0.10	1.43	8.11
11	10/31/Year -1	1,610,183,603	1,932,912	1,748,407,736	136,291,221	7.80	0.49	9.11	103,967	0.29	3.17	12,796	0.13	1.43	8.12
12	11/30/Year -1	1,635,042,744	1,937,528	1,810,879,376	173,899,104	9.60	1.54	9.20	104,183	0.21	3.06	12,805	0.07	1.31	8.14
13	12/31/Year -1	1,619,685,665	1,887,428	1,787,978,297	166,405,204	9.31	(0.94)	9.40	104,489	0.29	3.87	12,812	0.05	1.30	8.16
14	1/31/Year -0	1,606,632,983	1,864,222	1,789,479,753	180,982,548	10.11	(0.81)	7.39	104,976	0.47	2.21	12,834	0.17	1.35	8.18
15	2/28/Year -0	1,607,457,816	1,895,437	1,769,799,457	160,446,204	9.07	0.05	5.89	106,023	1.00	3.78	12,848	0.11	1.34	8.25
16	3/31/Year -0	1,599,189,670	1,921,664	1,756,707,070	155,595,736	8.86	(0.51)	3.84	106,873	0.80	4.06	12,896	0.37	1.40	8.29
17	4/30/Year -0	1,589,314,331	2,015,039	1,745,976,082	154,646,712	8.86	(0.62)	1.04	107,673	0.75	4.26	12,903	0.05	1.37	8.34
18	5/31/Year -0	1,594,253,086	2,072,393	1,750,474,329	154,148,850	8.81	0.31	0.58	108,116	0.41	4.40	12,913	0.08	1.33	8.37
19	6/30/Year -0	1,600,702,690	2,098,890	1,774,088,339	171,286,759	9.65	0.40	0.45	108,476	0.33	4.38	12,917	0.03	1.29	8.40
20	7/31/Year -0	1,609,559,898	2,114,108	1,789,298,279	177,624,273	9.93	0.55	0.36	108,329	(0.14)	4.40	12,922	0.04	1.28	8.38
21	8/31/Year -0	1,636,226,159	2,159,325	1,814,472,267	176,086,783	9.70	1.66	1.81	108,061	(0.25)	4.54	12,947	0.19	1.41	8.35
22	9/30/Year -0	1,641,380,648	2,151,724	1,818,613,695	175,081,323	9.63	0.32	2.43	108,448	0.36	4.61	12,972	0.19	1.50	8.36
23	10/31/Year -0	1,652,127,323	2,142,938	1,834,129,585	179,859,324	9.81	0.65	2.60	108,873	0.39	4.72	12,987	0.12	1.49	8.38
24	11/30/Year -0	1,652,408,549	2,158,449	1,801,397,665	146,830,667	8.15	0.02	1.06	109,284	0.38	4.90	12,998	0.08	1.51	8.41
25	12/31/Year -0	1,674,108,209	2,198,330	1,824,474,167	148,167,628	8.12	1.31	3.36	109,960	0.62	5.24	13,017	0.15	1.60	8.45

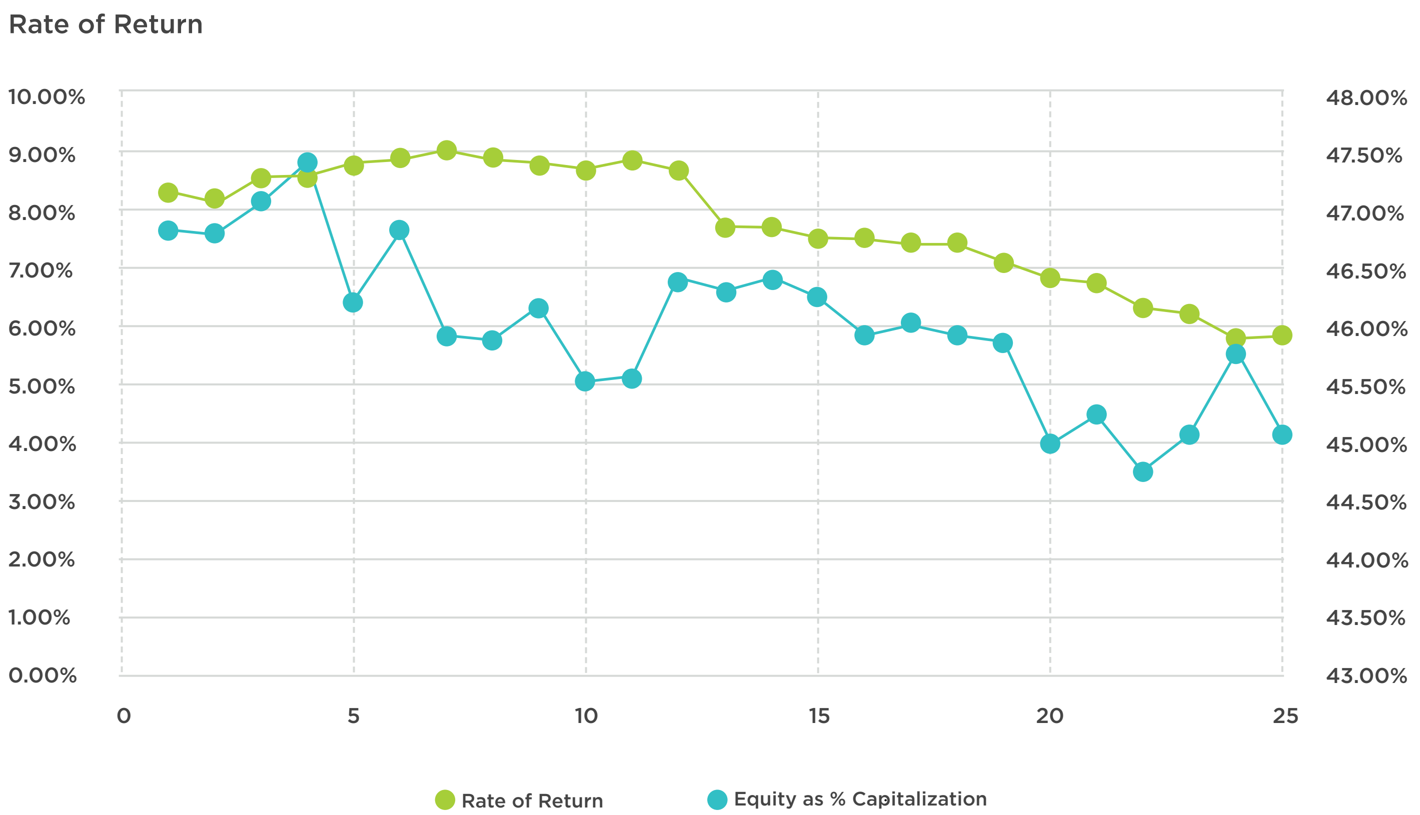
Schedule A-3.0

FINANCIAL PROFILE EXAMPLE—STATEMENT OF OPERATIONS

	12-Months Ended	Operating Revenue	Power Cost	Revenue Less Power Cost	Trans. + Distrib. O&M	Cons Acct.	Admin. & General	Deprec.	Taxes	Other Interest & Deduct.	Total Exp. w/o Pur. Pwr.	Interest on LT Debt	Operating Margin
		$	$	$	$	$	$	$	$	$	$	$	$
1	12/31/Year -2	122,312,752	75,329,067	46,983,685	9,745,756	5,964,730	6,135,296	7,142,599	492,691	173,059	29,654,130	6,862,012	10,467,543
2	1/31/Year -1	124,929,294	77,898,339	47,030,955	9,858,031	6,004,453	6,193,341	7,188,766	503,188	170,459	29,918,237	6,986,821	10,125,896
3	2/28/Year -1	129,277,588	81,250,992	48,026,596	10,122,544	5,962,989	6,306,698	7,237,887	501,887	167,161	30,299,166	7,101,529	10,625,901
4	3/31/Year -1	133,674,086	85,049,405	48,624,681	10,341,281	6,082,819	5,917,005	7,285,721	515,191	84,240	30,226,257	7,197,394	11,201,030
5	4/30/Year -1	137,652,747	88,245,786	49,406,961	10,338,095	6,184,636	6,045,099	7,332,841	533,649	43,894	30,478,214	7,267,113	11,661,633
6	5/31/Year -1	141,786,823	91,576,138	50,210,684	10,571,913	6,200,945	6,005,560	7,381,585	540,467	38,405	30,738,875	7,386,629	12,085,181
7	6/30/Year -1	145,628,052	94,515,146	51,112,906	10,910,750	6,289,646	6,038,319	7,431,358	546,650	40,496	31,257,219	7,606,685	12,249,002
8	7/31/Year -1	148,216,060	96,790,530	51,425,530	10,821,078	6,345,159	6,156,693	7,482,196	557,612	35,090	31,397,827	7,738,219	12,289,485
9	8/31/Year -1	150,824,467	99,055,433	51,769,035	11,150,270	6,401,808	6,206,395	7,533,920	548,041	23,285	31,863,719	7,833,149	12,072,167
10	9/30/Year -1	152,371,220	100,908,587	51,462,633	10,923,432	6,430,640	6,143,402	7,580,522	498,832	52,559	31,629,387	7,908,878	11,924,368
11	10/31/Year -1	154,612,204	102,501,146	52,111,058	10,819,084	6,459,738	6,346,006	7,627,026	489,973	46,037	31,787,863	7,949,809	12,373,386
12	11/30/Year -1	154,783,198	102,901,371	51,881,827	10,867,270	6,521,698	6,362,097	7,668,427	481,673	51,822	31,952,987	8,197,049	11,731,792
13	12/31/Year -1	149,733,071	99,661,330	50,071,741	11,170,329	6,622,985	6,438,854	7,709,758	486,800	125,590	32,554,316	7,883,854	9,633,570
14	1/31/Year -0	146,571,803	95,662,524	50,909,279	11,432,524	6,768,513	6,465,829	7,756,303	473,326	125,001	33,021,496	7,851,841	10,035,942
15	2/28/Year -0	143,587,489	92,467,190	51,120,299	11,787,172	7,110,341	6,461,038	7,800,094	459,637	128,018	33,746,301	7,834,848	9,539,150
16	3/31/Year -0	140,470,316	89,004,903	51,465,413	11,772,841	7,190,882	6,467,270	7,869,476	478,000	269,722	34,048,190	7,743,232	9,673,991
17	4/30/Year -0	137,489,326	86,067,957	51,421,369	11,936,062	7,279,823	6,448,426	7,920,306	459,069	321,430	34,365,117	7,721,626	9,334,626
18	5/31/Year -0	134,452,484	82,538,924	51,913,560	11,911,118	7,390,181	6,764,474	7,964,697	440,722	319,549	34,790,740	7,570,914	9,551,906
19	6/30/Year -0	131,502,243	79,852,923	51,649,320	12,188,884	7,566,486	6,619,388	8,009,089	434,146	325,750	35,143,744	7,348,353	9,157,223
20	7/31/Year -0	129,594,194	77,238,482	52,355,712	12,696,146	7,683,004	6,677,195	8,054,215	422,185	330,867	35,863,612	7,213,323	9,278,777
21	8/31/Year -0	127,132,041	74,394,097	52,737,944	12,913,115	7,990,957	6,633,605	8,100,802	423,269	340,986	36,402,734	7,128,261	9,206,949
22	9/30/Year -0	124,435,913	72,143,413	52,292,500	13,249,022	8,226,470	6,674,211	8,147,128	466,830	342,736	37,106,396	7,043,307	8,142,797
23	10/31/Year -0	122,243,431	69,729,196	52,514,234	13,573,416	8,328,558	6,680,258	8,193,741	469,125	345,947	37,591,045	6,957,989	7,965,201
24	11/30/Year -0	119,836,150	67,898,419	51,937,730	13,806,144	8,725,175	6,745,925	8,239,310	464,202	342,096	38,322,853	6,894,537	6,720,341
25	12/31/Year -0	121,391,407	68,984,238	52,407,169	13,875,526	8,455,102	6,748,321	8,287,869	460,831	270,401	38,098,050	6,979,640	7,329,479
Form 7, Part A Lines:		1	2, 3		4, 5, 6, 7	8, 9, 10	11	13	14, 15	17, 18, 19		16	21

Schedule A-4.0

FINANCIAL PROFILE EXAMPLE—RATE OF RETURN

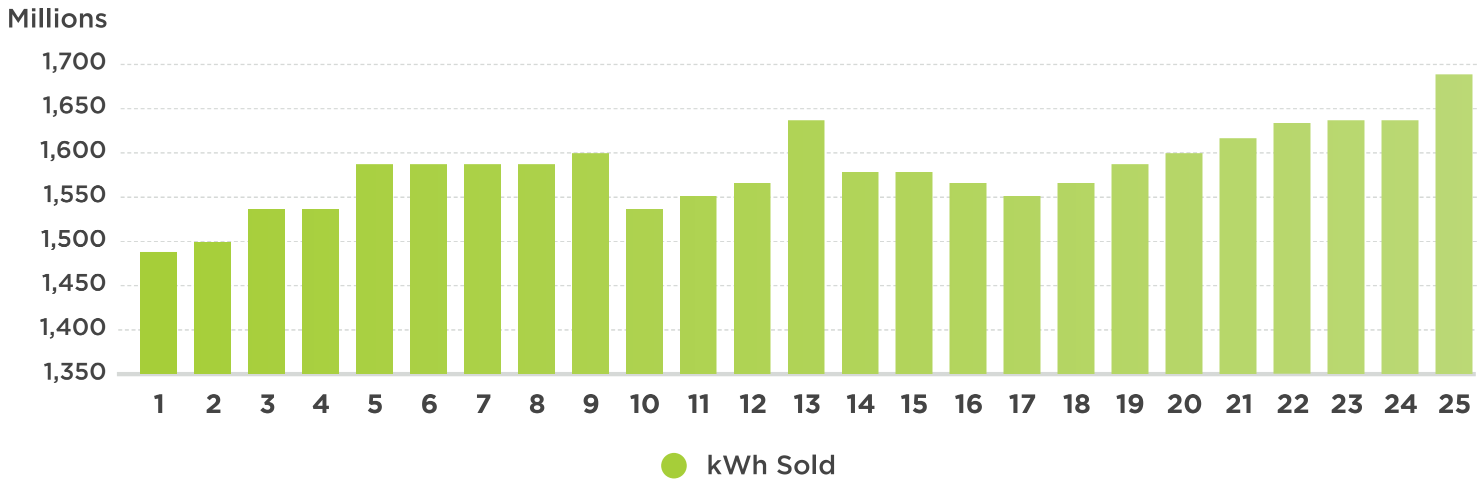


Schedule A-5.0

FINANCIAL PROFILE EXAMPLE—KWH SOLD

Standard Electric Cooperative, Inc.

Rolling 12-Month Periods Ended 12/31/Year -2 through 12/31/Year -0



Schedule B-1.0

COST ALLOCATION SUMMARY

Account	Total	Residential	COMMERCIAL	IRRIGATION	LARGE POWER	Industrial	Security Lts	Street Lts
Rate Base	303,617,690	238,774,960	19,151,645	13,674,683	17,019,325	3,752,276	9,160,685	2,084,116
Operating Revenue	192,813,464	135,223,989	11,283,884	6,514,689	17,718,979	17,460,065	4,149,868	461,990
Operating Expenses	181,684,293	129,395,245	10,214,652	6,600,828	15,118,981	16,283,710	3,732,473	338,404
Return	11,129,171	5,828,744	1,069,232	(86,139)	2,599,998	1,176,355	417,395	123,586
Rate of Return	3.666%	2.441%	5.583%	-0.630%	15.277%	31.350%	4.556%	5.930%
Relative ROR	1.000	0.666	1.523	(0.172)	4.168	8.553	1.243	1.618
Interest	10,086,256	7,959,881	634,810	448,569	555,281	120,849	298,416	68,450
Operating Margins	1,042,915	(2,131,137)	434,422	(534,708)	2,044,717	1,055,506	118,979	55,136
Margin % Revenue	0.541%	-1.576%	3.850%	-8.208%	11.540%	6.045%	2.867%	11.934%
Operating TIER	1.103	0.732	1.684	(0.192)	4.682	9.734	1.399	1.805
Revenue Deficiencies								
Uniform ROR = 7.927%	12,937,430	13,098,024	448,845	1,170,078	(1,250,942)	(878,927)	308,737	41,614
Deficiency as % of Revenue	6.710%	9.686%	3.978%	17.961%	-7.060%	-5.034%	7.440%	9.008%
Uniform % Margin = 6.795%	12,937,430	12,144,520	356,519	1,048,619	(902,041)	140,410	174,879	(25,476)
Deficiency as % of Revenue	6.710%	8.981%	3.160%	16.096%	-5.091%	0.804%	4.214%	-5.514%

Schedule B-2.0

SUMMARY OF COMPONENTS OF EXPENSES

Accounts	Total	Residential	COMMERCIAL	IRRIGATION	LARGE POWER	Industrial	Security Lts	Street Lts
Average Consumers	88,163	81,525	4,827	1,244	565	2	47,504	4,664
kWh Sold	1,830,775,494	1,151,165,422	97,806,128	55,350,845	189,686,899	299,314,241	34,581,451	2,870,508
NCP kW	10,775,573	8,804,700	521,316	285,952	580,553	469,043	105,271	8,738
CP kW	4,225,034	2,980,736	231,492	144,811	400,332	420,159	43,863	3,641
PUR PWR DEMAND	**64,248,682**	**45,701,556**	**3,517,154**	**2,302,715**	**6,020,746**	**6,054,182**	**602,464**	**49,865**
Monthly Cost per Cons	60.73	46.72	60.72	154.25	888.02	252,257.58	1.06	0.89
Average Cost per kWh	0.035094	0.039700	0.035960	0.041602	0.031740	0.020227	0.017422	0.017371
Cost per NCP kW	5.96	5.19	6.75	8.05	10.37	12.91	5.72	5.71
Cost per CP kW	15.21	15.33	15.19	15.90	15.04	14.41	13.74	13.70
PUR PWR ENERGY	**63,473,630**	**40,472,271**	**3,438,634**	**1,946,006**	**6,597,534**	**9,702,462**	**1,215,803**	**100,920**
Monthly Cost per Cons	60.00	41.37	59.36	130.36	973.09	404,269.25	2.13	1.80
Average Cost per kWh	0.034670	0.035158	0.035158	0.035158	0.034781	0.032416	0.035158	0.035158
Cost per NCP kW	5.89	4.60	6.60	6.81	11.36	20.69	11.55	11.55
Cost per CP kW	15.02	13.58	14.85	13.44	16.48	23.09	27.72	27.72
WIRES DEMAND	**41,944,804**	**33,056,114**	**2,770,133**	**1,891,473**	**3,118,892**	**744,254**	**328,699**	**35,239**
Monthly Cost per Cons	39.65	33.79	47.82	126.71	460.01	31,010.58	0.58	0.63
Average Cost per kWh	0.022911	0.028715	0.028323	0.034172	0.016442	0.002487	0.009505	0.012276
Cost per NCP kW	3.89	3.75	5.31	6.61	5.37	1.59	3.12	4.03
Cost per CP kW	9.93	11.09	11.97	13.06	7.79	1.77	7.49	9.68
TOTAL CUSTOMER	**36,083,787**	**29,092,073**	**2,006,810**	**1,544,575**	**730,866**	**80,242**	**2,311,641**	**317,580**
Monthly Cost per Cons	34.11	29.74	34.65	103.47	107.80	3,343.42	4.06	5.67
Average Cost per kWh	0.019710	0.025272	0.020518	0.027905	0.003853	0.000268	0.066846	0.110635
Cost per NCP kW	3.35	3.30	3.85	5.40	1.26	0.17	21.96	36.34
Cost per CP kW	8.54	9.76	8.67	10.67	1.83	0.19	52.70	87.22
Total Expenses	**205,750,903**	**148,322,014**	**11,732,731**	**7,684,769**	**16,468,038**	**16,581,140**	**4,458,607**	**503,604**
Monthly Cost per Cons	**194.48**	**151.61**	**202.55**	**514.79**	**2,428.91**	**690,880.83**	**7.82**	**9.00**
Average Cost per kWh	**0.112385**	**0.128845**	**0.119959**	**0.138837**	**0.086817**	**0.055397**	**0.128931**	**0.175441**
Cost per NCP kW	**19.09**	**16.85**	**22.51**	**26.87**	**28.37**	**35.35**	**42.35**	**57.63**
Cost per CP kW	**48.70**	**49.76**	**50.68**	**53.07**	**41.14**	**39.46**	**101.65**	**138.31**

Schedule B-3.0
COMPONENTS OF EXPENSE WITH CLASS RETURN - RESIDENTIAL

		Unit Cost			
	Required Revenue	kWh	CP kW	NCP kW	Customer
Components of Expenses - Detailed					
Power Supply-Demand	34,737,661	0.03018	11.65	3.95	35.51
Power Supply-Energy	40,472,271	0.03516	13.58	4.60	41.37
Power Supply-Delivery	10,963,895	0.00952	3.68	1.25	11.21
Sub-Transmission	1,190,070	0.00103	0.40	0.14	1.22
Distribution Substation	3,425,880	0.00298	1.15	0.39	3.50
Distribution Backbone	13,163,611	0.01144	4.42	1.50	13.46
Distribution Demand	12,011,816	0.01043	4.03	1.36	12.28
Distribution Customer	19,339,696	0.01680	6.49	2.20	19.77
Customer Services	1,398,862	0.00122	0.47	0.16	1.43
Customer	6,375,502	0.00554	2.14	0.72	6.52
Total	143,079,264	0.12430	48.01	16.27	146.27
Components of Expenses - Consolidated for Rate Design					
Power Supply Demand	34,737,661	0.03018	11.65	3.95	35.51
Power Supply Energy	40,472,271	0.03516	13.58	4.60	41.37
Power Supply-Delivery	10,963,895	0.00952	3.68	1.25	11.21
Distribution Demand	29,791,377	0.02588	9.99	3.38	30.45
Distribution Customer	27,114,060	0.02355	9.10	3.08	27.72
Total	143,079,264	0.12429	48.00	16.26	146.26
Billing Units					
12-Month Sum		1,151,165,422	2,980,736	8,804,700	978,300

Schedule B-4.0
SUMMARY OF RATE CHANGE

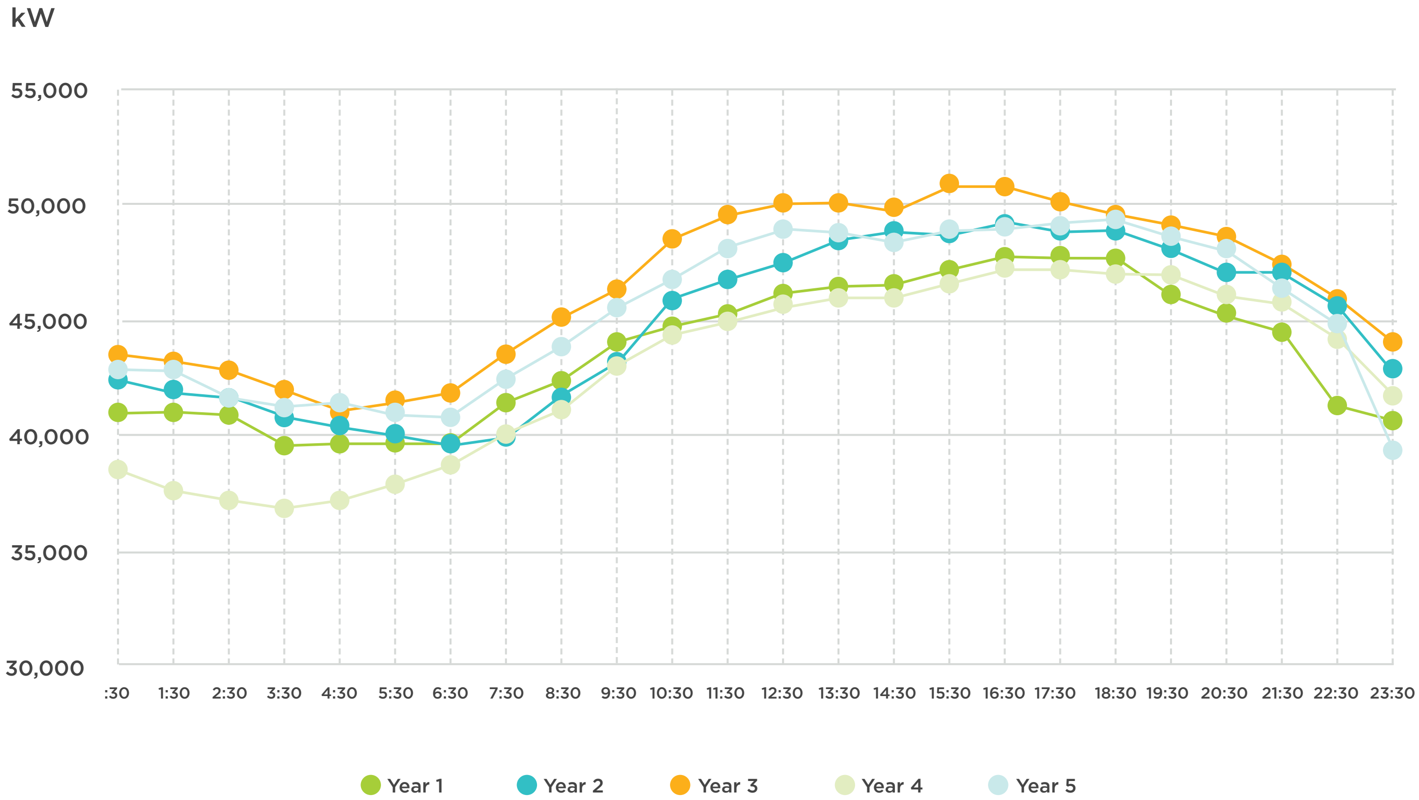
	Consumers	kWh Sold	Adjusted Test Year Revenue	Proposed Revenue	Change	Percent Change
Residential	81,525	1,151,165,422	$132,083,016	$143,079,264	$10,996,248	8.33%
Commercial 1-Phase	3,776	59,350,895	6,754,550	7,284,321	529,771	7.84%
Commercial 3-Phase	1,051	38,455,233	4,330,657	4,584,036	253,379	5.85%
Commercial Total	4,827	97,806,128	11,085,207	11,868,357	783,150	7.06%
Irrigation	722	34,212,927	4,197,549	4,716,824	519,275	12.37%
Irrigation-Load Control	522	21,137,918	2,250,478	2,537,229	286,751	12.74%
Irrigation Total	1,244	55,350,845	6,448,027	7,254,053	806,026	12.50%
Large Power-Secondary	546	125,027,857	12,627,210	12,806,597	179,387	1.42%
Large Power-Primary	19	64,659,042	5,034,489	4,855,079	-179,410	-3.56%
Large Power Total	565	189,686,899	17,661,699	17,661,676	-23	0.00%
Industrial	2	299,314,241	17,460,066	17,460,066	0	0.00%
Security Lights	47,504	34,581,451	4,138,049	4,448,356	310,307	7.50%
Street Lights	73	2,870,508	459,304	501,034	41,730	9.09%
Total Energy Sales	**88,236**	**1,830,775,494**	**189,335,368**	**202,272,806**	**12,937,438**	**6.83%**
Other Revenue			**3,478,100**	**3,478,100**	**0**	**0.00%**
Total			**192,813,468**	**205,750,906**	**12,937,438**	**6.71%**

Schedule B-5.0

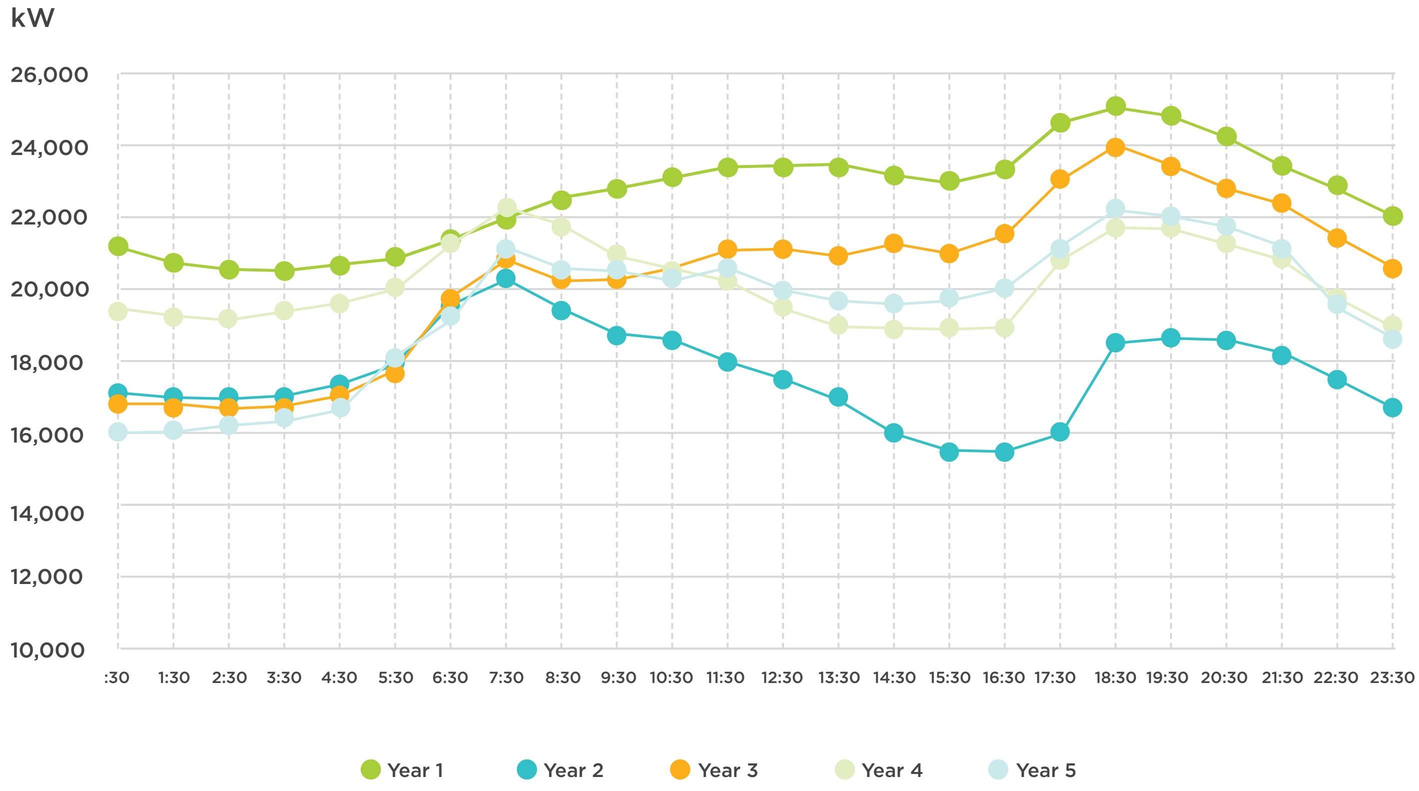
COMPARISON OF EXISTING AND PROPOSED RATES - RESIDENTIAL

	kWh Usage	Monthly Bills w/ kWh Ending in Block	Exisitng Rate	Proposed Rate	Change	Percent Change
Customer Charge			$14.50	$27.72	$13.22	91.17%
Energy Charge, per kWh			$0.08950	$0.10074	$0.01124	12.56%
PCA Factor, per kWh			$0.01311	$0.00000	($0.01311)	-100.00%
Total Energy, per kWh			$0.10261	$0.10074	($0.00187)	-1.82%
	0	1,359	$14.50	$27.72	$13.22	91.17%
	50	4,006	$19.63	$32.76	$13.13	66.89%
	100	2,304	$24.76	$37.79	$13.03	52.63%
	250	6,522	$40.15	$52.91	$12.76	31.78%
	500	7,228	$65.81	$78.09	$12.28	18.66%
	750	13,025	$91.46	$103.28	$11.82	12.92%
	1,000	8,567	$117.11	$128.46	$11.35	9.69%
	3,000	38,167	$322.33	$329.94	$7.61	2.36%
	5,000	2,642	$527.55	$531.42	$3.87	0.73%
	Over 5,000 kWh	229				
1,177		Class Average	$135.27	$146.29	$11.02	8.15%

Schedule C-1.0
JULY - PEAK DAY



Schedule C-2.0
JANUARY - PEAK DAY



APPENDIX

GLOSSARY OF TERMS

Annual Growth in Total Utility Plant (KRTA Ratio #116): Measures the percent change in total utility plant (TUP) from the previous year. Plant Growth Rate = change in TUP from the previous year ÷ TUP balance, previous year.

Annualized / Annualization: The process of taking an event (such as an increase in cost) that occurred sometime during an accounting period (such as June of a year) and restating the impact as if the event had been in place for the full accounting period (a total of twelve months).

Average Debt Cost: Measures the average cost of borrowed funds. As calculated on Appendix Schedule A-1.0:

$$\text{Average Debt Cost} = \frac{\text{Form 7 Part A, Line 16}}{\text{CFC Form 7 Part B, (Line 38 EOY + Line 38 BOY)} \times 0.5}$$

$$\text{Average Debt Cost} = \frac{\text{Form 7 Part A, Line 16}}{\text{RUS Form 7 Part B, (Line 43 EOY + Line 43 BOY)} \times 0.5}$$

EOY = End of Year
BOY = Beginning of Year

Billing Units: Quantities (meter, kWh, demand, etc.) to which rate components are applied to determine the monthly bill.

Capital Expenditure (CAPEX): Annual capital requirement for plant additions including general plant less plant financed with contributions in aid of construction.

Classification of Cost: Process of defining cost in terms of usage characteristic that drives the cost, i.e., energy, customer, demand.

Coincidental Demand: The sum of two or more demands that occur in the same time interval.

Coincidental Peak Load: The maximum value in an accounting period of the coincident demand.

Contribution in Aid of Construction (CIAC): Payment made by a member-consumer for the facilities to provide service.

Consumer Density (KRTA Ratio #125, Average Consumers Per Mile of Line): Measures the density of the utility system in terms of the number of consumers per mile of line constructed and in service. Consumer density = Average Total Consumers Served (KRTA Ratio #1) ÷ Total Miles of Line (KRTA Ratio #5) The average number of members-consumers per mile of line. As calculated on Appendix Schedule A-2.0:

$$\text{Consumer Density} = \frac{\text{Average Consumers}}{\text{Miles of Line}}$$

Consumers = CFC Form 7, Part R, Line 10 and RUS Form 7, Part O, Line 10

Miles of Line = Form 7, Part B, Line 5

Debt Service: The annual principal and interest payments on long-term debt. Note: The annual amount billed as opposed to the amount paid is used in KRTA ratio calculations.

Distributed Energy Resource (DER): The DER may be located behind the wholesale meter or behind the retail meter. DER may include renewables such as solar or wind generation or any type of fossil-fired generation.

Debt Service Coverage Ratio (DSC) (KRTA Ratio #12): A metric that reflects the ability of the cooperative to pay annual debt service. DSC = (Margin + Depreciation + Interest LTD) ÷ Debt Service. Note: Additional items may be required if the cooperative has capital leases. The long-term lease calculation is intentionally left out to simplify the DSC equation and should be included if long-term leases are large enough to trigger the calculation.

$$\text{DSC} = \frac{\text{Part A, Line 29 + Line 16 + Line 13}}{\text{Billed Debt Service}}$$

$$\text{ODSC} = \frac{\text{Part A, Line 21 + Line 16 + Line 13 + Line 22 +} \\ \text{Cash Patronage Capital Retirements Received}}{\text{Billed Debt Service}}$$

G&T and Lender Cash Patronage Capital Retirements Received reported on CFC Form 7, Part J and on RUS Form 7, Part I.

Distribution System Operator (DSO): The entity responsible for developing, operating, and maintaining the electric distribution system including interconnections with other systems.

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Equity Level as a Percentage of Assets (KRTA Ratio #16): Measures the percent of total assets owned by cooperative members.

RUS Form 7, Part C Balance Sheet. Line 36 ÷ Line 29.

CFC Form 7, Part C Balance Sheet. Line 35 ÷ Line 28.

Equity Level as a Percentage of Total Capitalization (KRTA Ratio #18): Measures the percent of total capitalization (debt and equity) owned by cooperative members.

RUS Form 7, Part C Balance Sheet. Line 36 ÷ (Line 36 + Line 43).

CFC Form 7, Part C Balance Sheet. Line 35 ÷ (Lines 35 + Line 38).

Equity Management Plan: A financial strategy established by the Board of Directors that identifies the key financial objectives for the cooperative. May also be referenced as a Financial Strategy Plan. The plan has four key metrics that can be adjusted to meet particular objectives of the system: equity (either % of assets or % of capitalization), coverage ratios (TIER, DSC, OTIER), liquidity (combination of general fund cash and line of credit) and the capital credit retirement program.

Financial Forecast: Ten-year financial forecast for the cooperative.

Financial Profile: A summary of operating expenses, margin, coverage ratios, rate of return or usage data on a rolling 12-month basis. The purpose is to identify a rolling 12-month income statement that identifies trends in cost, revenue, usage, and margin.

Financial Strategy: See Equity Management Plan above.

Forecasted Test Year: Any future 12-month period showing revenue, expenses, usage data and margins for the cooperative.

Formula Rate Proceeding: Used in many FERC proceedings. The FERC approves a formula rather than a specific rate. Each year the formula is populated with data consistent with the protocols the FERC approved. The result is an updated rate or revenue requirement.

Form 7: Either RUS or CFC statistical report. The analysis reflects RUS Revision Date 2014 and CFC Version 1.05 (1/2016).

Functionalization: The assignment of costs associated with a major function such as Production, Transmission, Distribution, Administrative and General Cost.

General Funds Ratio: The general fund cash balance divided by total utility plant. As calculated on Appendix Schedule A-1.0:

$$\text{General Funds Ratio} = \frac{\text{Part B, Lines } 9 + 12 + 13 + 15 \text{ thru } 18}{\text{Line } 3}$$

Generation and Transmission Cooperative (G&T): This analysis references two types of G&Ts. The first type provides wholesale service to a member distribution cooperative. The second provides service to a member transmission cooperative, and the transmission cooperative then provides service to a member distribution cooperative.

Historic Test Year: Any actual historic 12-month period.

Interest on Long-Term Debt (LTD): Reported on RUS/CFC Form 7, Statement of Operations, Part A, Line 16.

Independent System Operator (ISO): The entity coordinating, controlling, and monitoring the electrical power system within a state or states.

Investor-Owned Utility (IOU): A public utility owned by a corporation or private company.

Key Ratio Trend Analysis (KRTA): The KRTA is a set of 145 financial and operating ratios used by staff and board members of distribution systems to better understand how their cooperative has trended over time and compares with other cooperatives nationally and within four other peer groups.

Line Loss (KRTA Ratio #139): Measures the difference between electricity sold and accounted for and electricity purchased. As calculated on Appendix Schedule A 2.0:

$$\text{Percent Losses} = \frac{\text{kWh Purchased \& Generated-(kWh Sold + Own Use)}}{\text{kWh Purchased and Generated}}$$

CFC Form 7, Part R and RUS Form 7, Part O:

kWh Purchased & Generated = Line 16 + Line 17
kWh Sold = Line 11
Own Use = Line 15

Liquidity: Consists of general fund cash plus lines of credit available to the cooperative and reflects working capital available to the cooperative to meet operating cash flow requirements.

Long-Term Debt (LTD): Loans or financial obligations with a term greater than one year.

Long-Term Lease Calculation: Used in KRTA coverage Ratios #6 through #15 when long-term leases are greater than 2% of total margins or equities. Please refer to the KRTA formula guide on the CFC Member Website for the specific calculation.

Margin for Interest (MFI): A metric of margin and interest found in some long-term debt indentures.

Net Margin: Patronage capital or margins as reported on RUS/CFC Form 7, Statement of Operations, Part A, Line 29.

Non-Coincidental Peak Load: The maximum rate of energy usage over a defined period (60 minutes, 30 minutes, 15 minutes, etc.) determined over an accounting period (monthly, seasonal, annual, etc.).

Normalized / Normalization: The process of restating usage, revenue, and associated expenses to "normal" weather conditions or to recognize changes in usage for a very large customer or a rate class.

Operating Margin: Patronage capital and operating margins as reported on RUS/CFC Form 7, Statement of Operations, Part A, Line 21.

Operating Times Interest Earned Ratio (OTIER): See Times Interest Earned Ratio (TIER) below.

Plant Growth Rate: The annual percent change in net utility plant. As calculated on Appendix Schedule A-1.0:

$$\text{Plant Growth Rate} = \frac{\text{Form 7 Part B, Line 5}}{\text{Line 5 (12 months ago)}} - 1$$

Pro-forma Income Statement: An income statement restated to reflect an accounting period restated for revenue and expense adjustments.

Public Utility Regulatory Policies Act (PURPA): The Public Utility Regulatory Policies Act (PURPA, Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978) is a United States Act passed as part of the National Energy Act. It was meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply).

Purchased Power Adjustment/Power Cost Adjustment (PPA): A clause in a rate schedule that provides for adjustments to the bill when total power cost billed from the wholesale supplier varies from a specified base amount reflected in the rate design. The adjustment is typically reflected in a $/kWh adjustment to the member-consumer. However, some adjustors track changes in the demand and energy component separately.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA).

Rate Base: The capital investment associated with providing service. For this Rate Guide, estimated as net utility plant × historical ratio of Rate Base to Net Utility Plant.

Rate of Return (ROR): A value equal to the Return divided by the Rate Base.

Return: Interest and Other Deductions plus Margin. Form 7 Part A, Line 21 + Lines 16 thru 19.

Return on Equity: As calculated on Appendix Schedule A-1.0:

$$\text{Return on Equity} = \frac{\text{Rate of Return - (1 - Equity \% Capitalization) x Average Debt}}{\text{CostEquity \% Capitalization}}$$

Revenue Requirement: The total revenue that the rates charged to member-consumers must produce in order to pay all of the operating expenses associated with providing service and the capital cost associated with meeting the financial objectives.

Regional Transmission Organization (RTO): The entity coordinating, controlling, and monitoring a multi-state electric grid.

Test Year: A 12-month period that is used for the determination of the cost components for the cost of service analysis and margin component necessary to meet the cooperative's financial objectives.

Times Interest Earned Ratio (TIER): Measures the cooperative's ability to generate sufficient earnings from net margins to pay interest on long-term debt.

$$\text{Net TIER } \textbf{(KRTA Ratio \#6)} = \frac{\text{Part A, Line 29 + Line 16}}{\text{Line 16}}$$

$$\text{Modified TIER} = \frac{\text{Part A, Line 29 - Line 26 - Line 27 + Line 16}}{\text{Line 16}}$$

$$\text{OTIER } \textbf{(KRTA Ratio \#8)} = \frac{\text{Part A, Line 21 + Line 16 + Patronage Cash Received}}{\text{Line 16}}$$

Cash Patronage Capital Retirements Received reported on CFC Form 7, Part J and on RUS Form 7, Part I.

Note: The long-term lease calculation is intentionally left out to simplify the TIER equation and should be included if long-term leases are large enough to trigger the calculation. Please reference the long-term lease calculation in the glossary.

Unbundling: The separating of the total process of providing electric power service from generation to metering into its component parts for the purpose of identifying the separate pricing components.