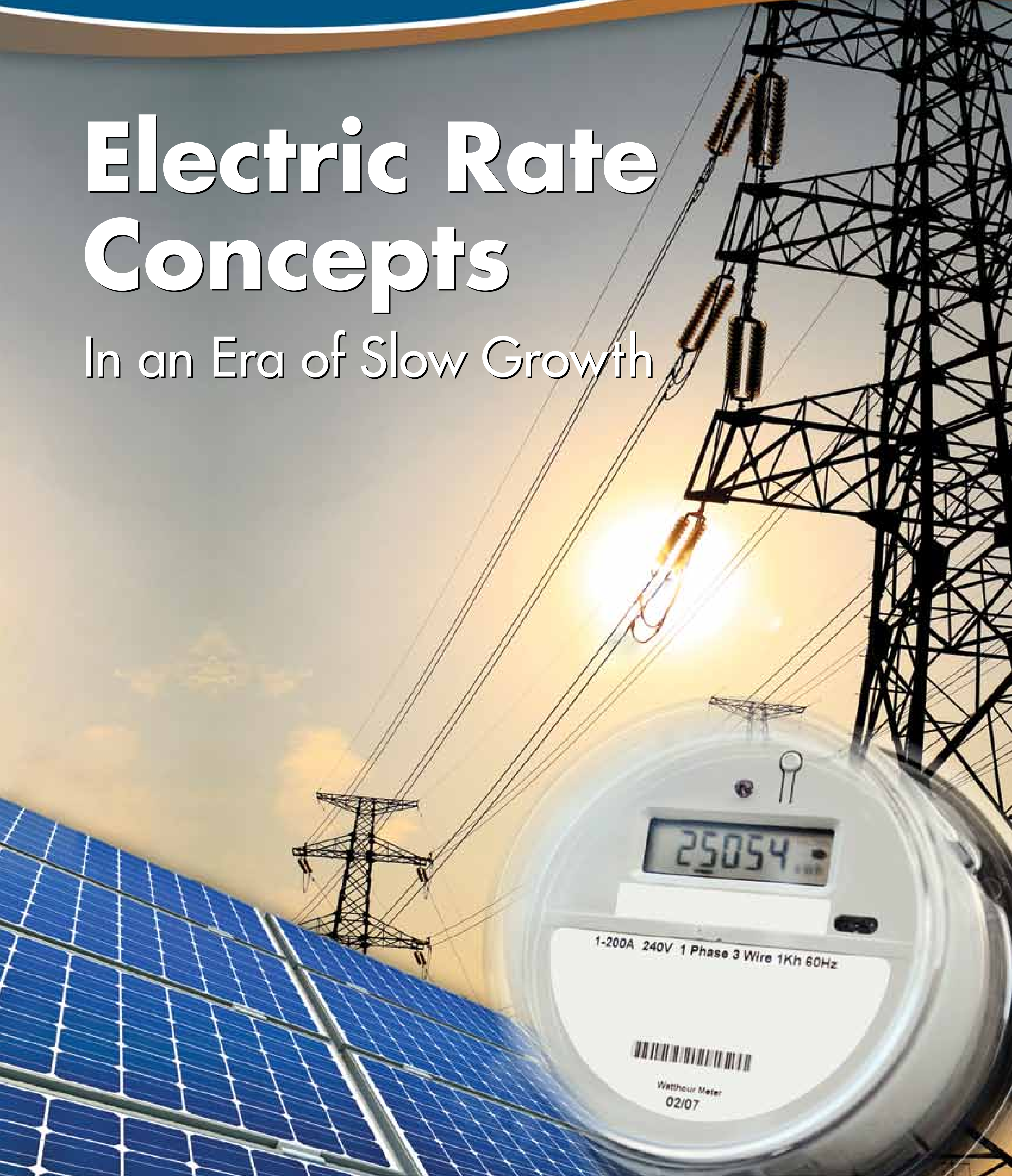
National Rural Utilities
Cooperative Finance Corporation

Created and Owned by America's Electric Cooperative Network

Electric Rate Concepts

In an Era of Slow Growth



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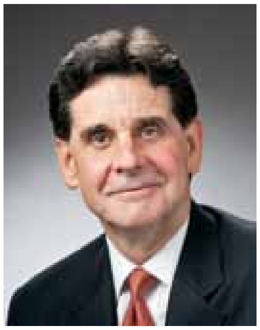
Foreword



Slowing electricity sales growth has been a reality in the electric utility industry for many years. Since the Great Recession, however, the growth rate has declined more sharply—and has even turned negative in recent years. Many electric systems also are being pressured by rising costs.

At the same time, the industry is faced with a number of challenges to its business model due to rapidly changing technology and government policy initiatives, many of which will affect how consumers use electricity in the years ahead. This could further cut electricity demand—especially grid-delivered power—and dampen utility revenue generated through traditional rate structures. These disruptive challenges include the spread of consumer-owned or leased distributed generation, such as solar photovoltaic systems; increased energy efficiency; renewable portfolio mandates and net metering requirements; and even the falling price of natural gas, which could further encourage consumer-owned generation.

Taken together, stagnant demand, rising costs and disruptive challenges can have a profound impact on the margins of electric cooperatives using traditional rate structures.

This publication presents some alternative rate-making approaches that could enable electric cooperatives to cope, even thrive, in the evolving environment. It presents a few of the key concepts described in the CFC and NRECA 2010 publication "Rate Strategies for 21st Century Challenges: A Guide to Rate Innovation for Cooperatives"—concepts that are even more relevant in today's slow-growth environment.

The following pages focus on a few of the key rate concepts included in the 2010 CFC and NRECA Rates Strategies publication that are particularly relevant in today's slow-growth environment, including:

1. Setting the fixed charge high enough to recover most of the cooperative's fixed costs, rather than collecting fixed costs through per-kilowatt-hour charges, and

2. Adopting a formulary rate plan, which decouples revenue from kilowatt-hour sales.

CFC is very much aware that each system is unique and faces different circumstances. But if cooperative managers and directors analyze their own situations and find it appropriate to consider alternative rate designs, we would be happy to provide further guidance.

Sheldon C. Petersen

Chief Executive Officer
National Rural Utilities Cooperative Finance Corporation

CHAPTER 1:
An Era of Slow Growth

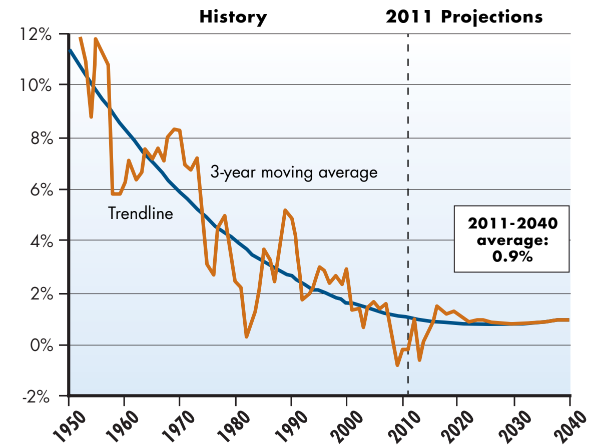
The rate of electricity demand growth generally has been falling since the 1950s, and the U.S. Energy Information Administration (EIA) predicts that demand growth will average less than 1 percent per year for the foreseeable future *(Chart 1)*.

This slowing demand growth has occurred for many reasons, including a shift in the economy toward less energy-intensive industries, slowing population growth and energy efficiency.

More recent changes appear to be largely a result of slower economic growth associated with the continuing effects of the 2007-2009 recession.

For example, apart from a weather-related spike in 2010, data from CFC's annual Key Ratio Trend Analysis (KRTA) show that electric cooperative kilowatt-hour sales growth has been on a steady downward trajectory since 2007 *(Chart 2)*. In fact, sales growth was negative in three of the past four years. It is nearly unprecedented to have sales decline. CFC believes that 2009 was the first year that ever happened.

Chart 1: *U.S. Electricity Demand Growth (1950-2040)*



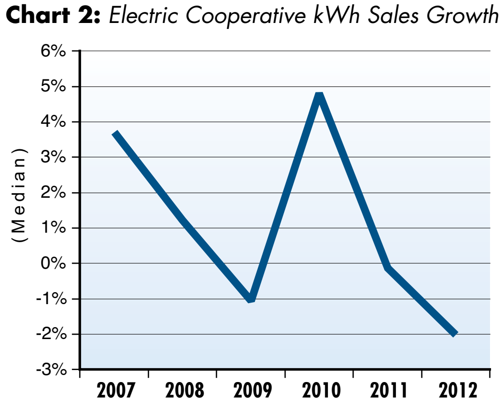
Source: U.S. Energy Information Administration, Annual Energy Outlook 2013

The weak economy also has affected consumer growth, which was less than 0.5 percent from 2009 through 2012 *(Chart 3)*. More "normal" year-over-year growth in recent years has been approximately 1.5 percent.

Looking to the future, there are several disruptive challenges spurred by evolving technologies and government policy that could further cut electricity demand (especially grid-delivered power) and affect utility revenue. These include the spread of consumer-owned distributed generation; increased energy efficiency mandates; the spread of energy-efficient lighting, appliances and "smart homes"; renewable portfolio mandates and net metering requirements; and even the falling price of natural gas—which could encourage consumer use of off-grid fuel cells and microturbines.

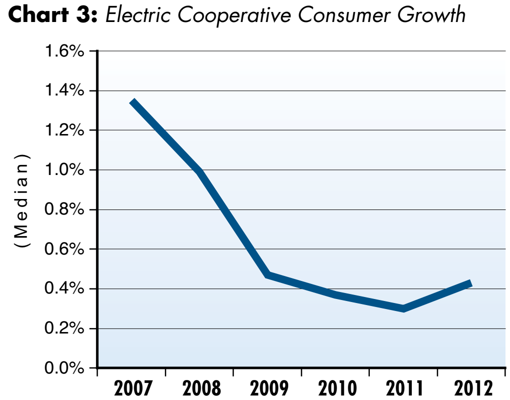
Forty-three states and the District of Columbia require electric utilities to pay residential customers who generate their own electricity using renewable technologies a rate credit for each kilowatt-hour produced in excess of their use—a policy known as net metering. An additional three states have voluntary programs.

Chart 2: *Electric Cooperative kWh Sales Growth*



Source: CFC KRTA data.

Chart 3: *Electric Cooperative Consumer Growth*



Source: CFC KRTA data.

KEY CONCEPT

Revenue Requirement

The amount of revenue needed for the cooperative to conduct its business and meet its financial goals. It includes the aggregate costs of service to be recovered each year from members, including power costs; depreciation; interest; operational, maintenance and other expenses; and capital costs, including margins less non-operating revenue.

KEY CONCEPT

Cost-Based Rates

Cost-based rates involve a pricing structure in which customers in each rate class pay their fair share of the utility's costs so there are minimal subsidies between classes of customers. To the extent possible, each individual customer within the class also should pay for the costs imposed on the system by that customer.

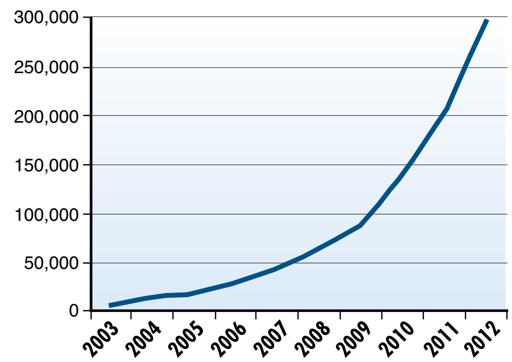
Based on preliminary 2012 data, the number of residential net metering customers has grown to approximately 300,000 nationwide—a 60-fold increase over the past 10 years *(see Chart 4)*.

That is still less than 1 percent of total residential customers, but it is a trend worth watching—especially since states' net metering policies increase the rate at which consumers invest in distributed generation while at the same time making it difficult for utilities to recover their fixed costs from consumers with distributed generation. [1]

As a result of these and other issues, it is unclear when, or if, more "normal" levels of demand growth will resume. As an industry, electric cooperatives may be moving to a sustained period of relatively flat sales growth, or even declining sales—a challenge the industry has never faced.

At the same time, many electric cooperatives are being pressured by rising costs, including increased expenditures for new plant, operations and maintenance, environmental and/or renewable energy requirements, staffing and other items.

Chart 4: *Residential Net Metered Customers*



Source: U.S. Energy Information Administration, Annual Electric Power Industry, August 2013

The combination of rising costs and stagnant or declining electricity sales has many systems wondering how to shore up their finances—short of drastic cost cuts. Because of these pressures, the credit rating agencies have suggested that utilities, regulatory commissions and governments need to work together to find solutions that will meet the needs of consumers, while also ensuring network reliability and the financial health of the utility.

In many cases, part of the answer may lie in reexamining rate design.

This guide discusses some alternative rate design concepts that electric cooperatives may wish to consider in order to mitigate the problem of flat sales and rising costs. It is not meant to address all potential circumstances a system may face. For example, a system may want to achieve certain goals such as reducing peak load, encouraging conservation and/or energy efficiency, supporting renewable energy resources or bringing new jobs to the local community. These goals are not specifically addressed in this guide, but they can be addressed, in part, through rates. For a more thorough discussion of these and other rate design issues, see the 2010 CFC/NRECA guide "Rate Strategies for 21st Century Challenges: A Guide to Rate Innovation for Cooperatives." [2]

Fundamental Concepts

A fundamental requirement of the rate design process is for a cooperative to determine its annual revenue requirements—or the minimum amount of revenue needed to conduct the cooperative's business and meet its financial goals. Revenue requirements must be sufficient to:

- Recover the cooperative's operating expenses, including power costs, interest on debt, operating and maintenance costs, administrative and general costs, and working capital expenses,
- Provide a return on capital sufficient to meet lender requirements and
- Achieve the cooperative's equity goals, including return of capital credits, and other financial targets.

1. For more information on net metering, see: www.cooperative.com/InterestAreas/Generation/DistributedGeneration/Pages/DistributedGenerationToolkit.aspx.

2. A PDF of the guide is posted on Cooperative.com and on CFC's Member Website under the Library tab: www.nrucfc.coop.

For electric cooperatives, another fundamental aspect of rate design is for rates to be cost-based. Cost-based rates involve a pricing structure whereby customers in each rate class—such as residential, commercial and industrial—pay their fair share of the cooperative's costs so there are minimal subsidies between classes of customers. To the extent possible, each individual customer within a class also should pay for the costs imposed on the system by that customer. That sends the right messages about costs to consumers and ensures cooperative values are upheld.

Sometimes cooperative directors and staff assume that because the cooperative recovers its costs and meets its financial goals, it has implemented cost-based rates. That is not necessarily true. While recovering costs and meeting financial goals are important objectives for any rate plan, the way in which costs are recovered determines whether the rates are, in fact, cost-based.

Traditional Electric Rate Design

There are three main categories of costs incurred by electric systems:

1. **Customer costs:** Consumer-related costs like a meter, meter pan, service drop and billing.
2. **Demand costs:** Investment in generation, transmission and distribution facilities of adequate size to meet peak customer demand.
3. **Energy costs:** Fuel costs and variable O&M costs based on energy usage.

Despite there being three categories of costs, most cooperatives use a two-part rate design for residential and other low-voltage (nonindustrial) customers consisting of a customer charge and an energy charge. This is because, historically, it has not been cost effective to meter the demand component of low-voltage customers. In most cases, the customer charge does not reflect the full amount of fixed costs involved in serving an individual consumer, while the energy charge contains a combination of fixed costs as well as variable energy-related costs.

A traditional rate design that recovers a significant portion of fixed costs and margins through the energy charge may result in higher-usage customers paying a disproportionate share of fixed costs. Additionally, if costs rise and/or kWh sales decline, the utility can lose money because an element of fixed costs goes unrecovered.

The traditional utility solution to this problem is to increase rates to reflect cost increases and/or to forego the collection of some fixed costs with the hope that kWh sales will bounce back in the near future. But this approach may require frequent rate increases to collect enough revenue to cover costs—and as noted earlier, it is possible demand will not bounce back as quickly as systems would like.

Two ways of addressing this problem, include:

1. Taking non-energy-related costs (i.e., fixed costs) and margins out of the energy charge and placing them in the customer charge.
2. Decoupling revenue from kilowatt-hour sales through a Formulary Rate Plan.

Alternative Ratemaking: A Look Back

Ratemaking has evolved over the decades in response to external events. In the 1960s and 1970s, for example, rising costs due to inflation, oil price shocks and stricter environmental standards led to increases in electric utility generating costs. But these cost increases could not be reflected in rates fast enough to keep utility margins from falling. At the same time, utilities' sales growth started to decline due to a slowdown in economic activity and consumers cutting their energy usage in response to rising electricity prices.

KEY CONCEPT
Three Categories of Costs

Customer Costs: Costs incurred to make service available to members. These are generally not related to electricity usage and include expenses such as the cost of meters, the service entrance and billing.

Demand Costs: Investment-related costs attributable to meeting peak demand, such as the cost of generation, substations, poles, wires and transformers.

Energy Costs: Costs incurred due to the member's use of electricity. The primary source for a distribution system is the variable portion of its wholesale power costs, including fuel.

In response, utilities adopted various mechanisms such as fuel adjustment clauses (FACs), future test years, putting Construction Work in Progress in the rate base and new rate designs (e.g., marginal-cost pricing) to combat the problem.

Since then, both electric and natural gas utilities have expanded their use of nontraditional ratemaking mechanisms, including multi-year price and revenue caps, cost trackers (like production cost adjustment or fuel cost adjustment riders), which allow current recovery of costs in specific categories, and revenue trackers (which compensate a utility for revenue losses between rate changes).

CHAPTER 2:
Alternative Rate Design

Recovering Fixed Costs Through Fixed Charges

When considering alternative rate design, it is important to recognize that the energy charge ideally should reflect only fuel and variable O&M costs. By using a rate design that addresses this point, cooperatives can help avoid diminished margins when kWh sales are stagnant or declining. This approach also allows a cooperative to promote conservation and energy efficiency without financially harming itself or its members.

To illustrate this point, first consider a "traditional" two-part rate design for distribution cooperatives. Chart 5 presents a typical rate design from a cost-of-service study that determined a total annual residential revenue requirement of $5,290,890.

In order to meet the revenue requirement while keeping the monthly customer charge at a modest level (in this case, $20), the energy charge must be $0.0977 per kWh. In this example, the demand component was measured, but—as is the case for most electric cooperatives—the member is not billed separately for this cost.

Chart 5: *Traditional Two-Part Residential Rate Design: Compressing Fixed Costs into an Energy Charge and a Modest Customer Charge*

	Annual Revenue Requirement (based on actual cost)	**Billing Determinants**	**Proposed Rate**
Customer Component	$2,020,890	44,711[1]	**$20.00** (per bill)
Demand Component	$873,372	131,662[2]	**N/A** (per kW-Month)
Energy Component	$2,396,628	45,000,000[3]	**$0.0977** (per kWh)
Total Residential Revenue Required	**$5,290,890**		

1. Number of members (bills x 12). 2. Kilowatt demand. 3. Annual kilowatt-hour sales.

Most would consider this to be a reasonable rate design, and it is certainly typical of many electric cooperatives' residential rates. In reality, however, the proposed $20 customer charge reflects less than half of the actual customer-related costs. A more accurate customer-related charge would be $45.20 per month ($2,020,890 / 44,711 = $45.20).

The difference between $45.20 and $20 was added to the energy charge (along with all of the demand-related costs). As a result, the energy charge contains approximately 55 percent of the fixed customer-related charges plus 100 percent of the demand-related costs as well as all of the energy costs.

Because such a large percentage of fixed and demand costs is included in the energy charge, stagnant or declining sales will reduce the cooperative's margins and could threaten its ability to meet its financial targets.

Now consider a second situation. Chart 6 shows a two-part rate example using the same cooperative with the same annual residential revenue requirement, but in this case the customer charge ($64.73 per month) includes all service-related charges ($2,020,890) and demand-related charges ($873,372), while the energy charge reflects just fuel usage and variable O&M expenses. In other words, fixed costs are collected through the customer charge and variable costs are collected through the energy charge.

Chart 6: *Alternative Two-Part Residential Rate Design: Moving All Fixed Charges into the Customer Charge*

	Annual Revenue Requirement (based on actual cost)	**Billing Determinants**	**Proposed Rate**
Customer Component	$2,020,890	44,711[1]	**$64.73** (per bill)
Demand Component	$873,372	131,662[2]	**N/A** (per kW-Month)
Energy Component	$2,396,628	45,000,000[3]	**$0.05326** (per kWh)
Total Residential Revenue Required	**$5,290,890**		

1. Number of members (bills x 12). 2. Kilowatt demand. 3. Annual kilowatt-hour sales.

With this rate design, if sales are stagnant or decline, the cooperative's margins are not affected. For that reason, this method is recommended by some practitioners as the rate design of the future.

Because this design permits cooperatives to recover fixed costs regardless of the level of sales, cooperatives would be indifferent financially to the level of member investment in energy efficiency and distributed generation. Thus, distribution systems that actively support members interested in energy efficiency and distributed generation would not be financially impacted.

A rate design that collects fixed costs through fixed charges and variable costs through kWh charges also more accurately allocates costs to consumers within each rate class. For example, under traditional rate design, large electricity users tend to bear a larger proportion of the system's fixed costs than smaller users such as seasonal customers, or accounts serving stock tanks, fence chargers or barns, even though the fixed costs of serving all of the customers in the class may be similar. A cost-based rate reallocates the fixed costs within the customer class to ensure that smaller users pay a more equitable share.

This rate design also better informs consumers about the cooperative's cost structure. It helps the consumers to understand that—like cable television, mobile phone service and Internet service—most of the cost of providing service is based on the cost of the network and fixed infrastructure rather than the actual use of the service. For that reason, this rate design gives consumers a much more accurate and much lower incentive to invest in energy efficiency and distributed generation.

Unfortunately, each of the advantages of this rate design may also attract member and political opposition.

Proponents of energy efficiency and distributed generation have both strenuously opposed a move to a rate with higher fixed charges and lower per kWh charges because the shift reduces the incentive for consumers to invest in those resources. More traditional rates hide the incentive for energy efficiency and demand response in the rate design.

This rate design has also been opposed by those who use less electricity and advocates for low-income consumers. While not necessarily true in some cooperatives' service territories, there is a widely-held belief that low-income consumers use less electricity than higher-income consumers. By shifting to a more cost-based rate, those lower-use members and possibly the lower-income members would see higher bills.

The cost-based rate design also has an "optics" problem. Many cooperatives would find it challenging to gain member acceptance for an accurate fixed charge, which could run between $40 per month to over $80 per month depending on the cooperative, even though it is based on actual costs. This is especially true because most cooperatives' neighboring investor-owned utilities, to which they will be compared, are likely to have a much lower monthly charge. This may change in the future, as the investor-owned community has begun a major regulatory push to move toward more cost-based rates, but it will take time for that change to occur.

Most cooperatives contemplating a change toward higher and more cost-based fixed charges would seek to minimize the potential for any rate shock that could result from an abrupt movement to immediately align rate design with costs. Some may first engage in significant member and public education to pave the way. Others may increase the fixed charge slowly over time or may pair the increase in the fixed charge with a simultaneous decrease in the kWh charge.

Regardless of how well a particular rate design may reflect actual costs, it may be challenging for a cooperative to move all fixed costs into the customer charge. An alternative that may be more practical for some cooperatives would be to move as many fixed costs and margins as possible into fixed charges, while also introducing a separate adjustment mechanism to capture remaining fixed costs.

CASE STUDY

New Hampshire Electric Cooperative

Guiding Philosophies Encourage a Balanced Rate Structure

- Headquarters: Plymouth, N.H.
- Consumers served: 78,900
- Miles of line: 5,545
- Total MWh sales (2012): 745,649

Following a comprehensive cost-of-service study launched in November 2001, New Hampshire Electric Cooperative (NHEC) noticed an imbalance in its rate structure. Over time, members using electricity year-round were paying proportionately more than those members who had seasonal or low monthly usage. This resulted in the average member subsidizing the bills of seasonal members.

"About 36 percent of our 80,000 members are seasonal, and the low-usage members weren't paying their fair share of fixed costs since the majority of our fixed costs at that time were collected in the kilowatt-hour portion of sales," said NHEC CFO Dena DeLucca.

NHEC levies two charges to cover the fixed costs associated with maintaining the poles, wires and meters that provide members with access to electricity. The Member Service Charge, a set amount applicable to all members, covers part of the cost of providing distribution service. The Delivery Charge portion of members' bills, which is calculated on a per-kilowatt-hour basis, is the other charge NHEC levies to recover service costs. NHEC believes that using both charges helps keep rates as affordable and equitable as possible.

To address the imbalance in its rate structure, in January 2004, NHEC increased its monthly Member Service Charge from $9.20 to $20. At the same time, the cooperative lowered the Delivery Charge component of members' bills from 4.219 cents per kWh to 2.567 cents per kWh.

NHEC also developed a series of "guiding philosophies" on rate design, including the philosophy that "cost causers should pay the costs they cause." Additionally, the cooperative sought to minimize inter- and intra-class subsidies and introduce any significant rate changes on a gradual basis to minimize the impact on members.

The initial changes, which were revenue neutral to NHEC, resulted in a small decrease in monthly bills for more than 75 percent of NHEC's members. Members using little or no electricity on a monthly basis saw a bill increase of approximately $9 per month.

"Regardless of whether a member uses thousands of kilowatt-hours per month or none, it costs the co-op the same amount of money to maintain service to both of those members," said NHEC CEO Fred Anderson. "The changes to the Member Service and Delivery charges were a significant step toward more closely aligning the co-op's fees, service charges and rates to the specific costs of providing its various services."

Member reaction was generally supportive. "Most people did respond positively when they understood we were trying to create a more balanced rate structure," DeLucca said. "For those members who were not so happy about the increase, we explained that electricity service is like a cable TV bill: Whether you use it or not, you still have to pay for the service."

NHEC has continued to adjust its charges in response to subsequent cost-of-service studies and shorter-term cost estimates. In 2013, the Member Service Charge was increased to $24.17, closer to the actual cost to serve each meter.

Through the rate changes, the proportion of fixed costs covered by fixed charges has doubled from about 30 percent to 60 percent.

"It's been great for us because we're now less reliant on kilowatt-hour sales," DeLucca said. "For the past few years, sales have been pretty flat, but the moves we've made have really helped us perform better financially. It's also meant that our support for energy efficiency doesn't undermine our business goals."

Adams-Columbia Electric Cooperative

A Gradual Move to Cost-Based Rates

- Headquarters: Friendship, Wis.
- Consumers served: 36,100
- Miles of line: 5,745
- Total MWh sales (2012): 491,088

About 12 years ago, Adams-Columbia Electric Cooperative (ACEC) decided the time was right to make its residential rates more cost-based.

"There was a general recognition that it was becoming important to be more cost-based than in the past," said ACEC CEO Marty Hillert. "At that time, there was also the potential for industry deregulation like we had seen in some other states, and we thought we should be prepared for it." Although the deregulation movement sputtered, ACEC kept moving in the direction of cost-based rates, and that has helped the cooperative over the past several years as sales have flattened in response to the slow economy.

A cost-of-service study had indicated the cooperative's monthly facility charge should be in the mid-$20 range—more than double its then-existing charges of $8 for full-time residential members and $10 for seasonal customers.

"We took the information from our cost-of-service study to an employee group and had breakout sessions with them and looked for ideas on how to implement what we wanted to achieve, and the group suggested doing it incrementally over time, thinking that would be more palatable for the members. So, that's what we did," Hillert said. "What also came out of that process was a really good communications plan to inform our members about what we were doing and why."

The member response was much better than ACEC had expected. "Because of the communication we'd done with them beforehand, more than 90 percent of our members accepted the higher facility charge. It didn't come as a surprise to them, and while they might not have liked it, they understood what was going on."

Perhaps the biggest challenge was to help the cooperative's nonresident, seasonal consumers accept the increase. About 40 percent of the cooperative's 36,000 members are seasonal consumers. Most of them live in metropolitan areas with municipal or investor-owned utilities as their home supplier—and they are used to a smaller facility charge.

About eight years ago, the cooperative began to apply the facility charge on a daily rather than a monthly basis, and that changed the attitude of seasonal members for the better. "They understand that we'll only bill for the days that service is made available," Hillert said.

The daily charge also is perceived as being cheaper than a monthly charge. "I'm not a psychologist, but for some reason it's more acceptable to our members to charge 92.88 cents per day rather than $28.25 per month. Right now, we're thinking about raising the charge by a nickel a day. In those terms, it sounds more reasonable than a $1.50-per-month increase, but it brings in the same revenue."

Roughly 95 percent of ACEC's fixed costs and margins are now recovered through the facility charge vs. about 40 percent prior to moving to cost-based rates. The rate change also has enabled the cooperative to stay financially healthy despite lower kilowatt-hour sales. "We're not quite as dependent on the energy side of our system to support what's going on in our operations," Hillert said. "We've had some variations in energy sales over the past few years but the negative variations have not caused us to need to implement any kind of a rate increase."

KEY CONCEPT

Decoupling Revenue from Sales

Cooperatives should consider moving toward recovering costs in the manner they are incurred, to the extent practicable. Under this approach, fixed costs and margins would be recovered through fixed charges, and variable costs through variable charges. If this cannot be fully achieved due to competitive pressures, cooperatives should consider adopting an adjustment mechanism that permits the recovery of fixed costs and appropriate margins regardless of the level of sales.

KEY CONCEPT

Formulary Rates

Formulary rate design is a method of decoupling revenue and sales. It involves adopting an adjustment mechanism (a per-kilowatt-hour charge) that provides for rates to automatically increase (or decrease) as kilowatt-hour sales rise or fall. This ensures cost recovery by maintaining margin, TIER, debt service coverage, equity or other identified financial indicators within predefined boundaries.

Formulary Rate Plan

"Revenue decoupling" is a generic term for a rate design that separates (decouples) an electric utility's fixed-cost recovery from the amount of energy it sells. The cost-based rates discussed above are one form of decoupling. Under another form of decoupling, an electric cooperative adopts an adjustment mechanism that ensures that it can collect revenue based on a revenue requirement approved by its board of directors or by a state regulatory commission in rate-regulated states.

Revenue is "trued-up" on a periodic basis using an automatic rate adjustment, or formula, with the result that a utility's financial performance should more closely track its target levels and should not increase or decrease with changes in sales. That means cooperatives are protected if their sales decline due to a weak economy, energy efficiency or conservation programs.

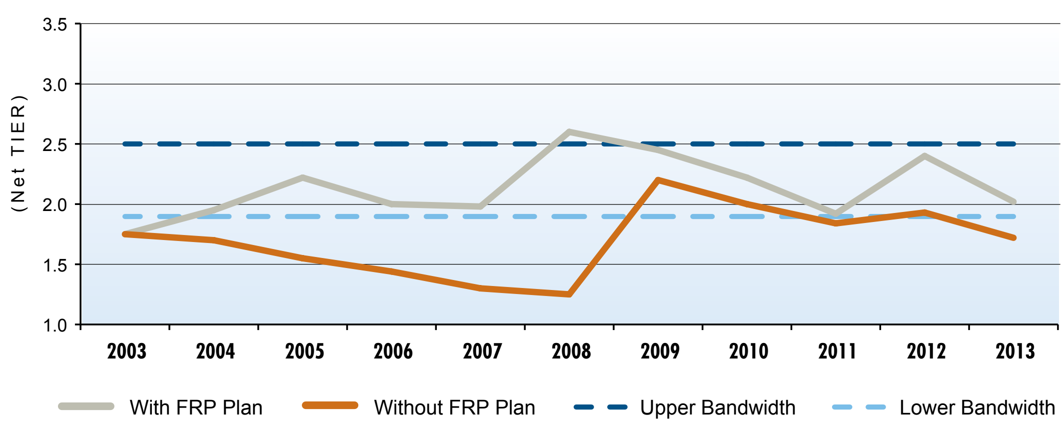
One such true-up mechanism is known as a Formulary Rate Plan (FRP). An FRP is a ratemaking method under which a cooperative's base rates are adjusted outside of a general change in rates. The adjustment usually occurs annually, although some systems make these adjustments more frequently. The adjustment is triggered if one or more financial metrics—e.g., times interest earned ratio (TIER), equity or modified debt service coverage (MDSC)—fall outside of a predefined range set by the cooperative's management and board. Typically, the midpoint of the range is the target authorized by the board of directors.

For example, assume a cooperative has identified a TIER of 2.20 as a target for its FRP with boundary points of 1.90 and 2.50. If the cooperative's actual TIER falls within the range of 1.90 and 2.50, no rate adjustment would be required. But if TIER falls outside of the band, then a per-kilowatt-hour rate adjustment (increase or decrease) would be triggered. The cooperative calculates the rate adjustment based on the required change in revenue needed to move TIER to the target level.

Chart 7 illustrates a cooperative under an FRP plan compared with the same cooperative under no FRP plan.

Compared with a cost or revenue tracker, an FRP is a more comprehensive ratemaking

Chart 7: *ABC Electric Cooperative: Net TIER with a Formulary Plan*



mechanism. A cost tracker (for example, a purchased power adjustment clause) allows a utility to recover its actual costs from customers for a specified function on a periodic basis outside of a rate case. A revenue tracker allows a utility to periodically adjust its rates outside of a rate case when the actual financial result (TIER, for example) deviates from the targeted range. So, whereas a cost tracker or revenue tracker addresses certain costs or revenue (and then, only those costs or revenue specified by the mechanism), an FRP accounts for all costs and revenue.

Benefits to the Cooperative. FRPs offer a practical means for systems to attain more consistent financial performance. Use of an FRP reflects an understanding that, for many electric cooperatives, it may be challenging to increase fixed charges to sufficiently cover all fixed costs and margins. Compared with traditional ratemaking, an FRP benefits cooperatives in several ways. First, it shortens the time between when a system incurs a cost and recovers it in rates. With less regulatory lag, a cooperative facing increasing costs is in a better financial position. Second, the cooperative has more certainty in recovering its costs and benefits from a clearly defined process of periodically reviewing costs and rates. Third, over time, it is likely a cooperative subject to rate regulation would need to file fewer general changes in rates. Changes in rates usually require additional costs and extra effort by staff and others (e.g., consultants) to do cost-of-service and rate design work.

Benefits to Cooperative's Member-Owners. FRPs can help moderate rate changes. For example, instead of a cooperative filing for a sudden, double-digit increase in rates, an FRP could achieve the same increase more gradually. Rate changes would tend to correspond to changes in the cooperative's expenses. As noted, an FRP can reduce the cost of general rate cases, which are ultimately passed through to members. They also establish an annual process for the board of directors to thoroughly review a cooperative's financial condition. An FRP can remove disincentives a cooperative may have regarding social goals (e.g., energy efficiency or assistance to low-income households) to the extent that an FRP allows quicker compensation to the cooperative for any drop in sales that might occur.

Limitations of FRPs

FRPs can be used in conjunction with efforts to increase fixed charges to narrow the gap between fixed charges and fixed costs, although they are not a substitute for setting fixed charges to cover fixed costs.

An FRP is a useful mechanism in assisting a cooperative with the timely collection of increases in expenses. However, if those expenses continue to increase and the FRP becomes an ever-growing portion of the charges to members, the portion of revenue collected based on kWh sales, as compared with fixed charges, will grow. Over time, this could lead to a greater imbalance between the manner in which costs are incurred and the way they are collected. Also, a growing per kWh charge will increase the relative competitiveness of distributed generation and, if such charges are not cost-based, send inappropriate price signals. For these reasons, FRPs are best used in conjunction with efforts to increase fixed charges to cover as great a portion of fixed costs as practical.

CASE STUDY

Pella Cooperative Electric Association

Moving to Formulary Rates in Iowa

- Headquarters: Pella, Iowa
- Consumers served: 2,800
- Miles of line: 632
- Total MWh sales (2012): 49,238

Pella Cooperative Electric
Your Touchstone Energy® Cooperative

In the years following the Great Recession, Pella Cooperative Electric Association, serving about 3,000 members in five central Iowa counties, has seen its kilowatt-hour sales decline due to various factors including general economic weakness, the encroachment of natural gas into its service territory from new housing developments, a ramp up in state-level energy efficiency goals, and temperature volatility that has caused some warmer-than-usual winters and cooler-than-usual summers. From the end of 2008 through 2012, Pella's total kilowatt-hour sales declined nearly 5 percent—a situation not unlike that of many other cooperatives.

The cooperative adopted a formulary rate plan (FRP) in 2011 that allows it to increase rates to recapture costs that have risen beyond the levels assumed in its last formal rate study. According to Pella CEO John Smith, the FRP—which also allows rates to decrease if costs go down—helps prevent large, infrequent rate increases in favor of smaller, more frequent adjustments. The FRP also requires the board to examine costs regularly (with an eye to keeping rates as low as possible), and helps ensure the financial stability of the cooperative.

"The FRP has really helped us in that we can't control the weather, we can't control the path of energy efficiency or alternative energy production and the effect that has on sales," Smith said. "But at least we have the ability to predict revenue, which helps ensure our financial stability, and we don't have a tremendous see-saw effect in rates. That makes my job much easier."

Pella's formulary rate design includes an Energy Cost Adjustment (ECA) and a Distribution Cost Adjustment (DCA). Both charges are based on kilowatt-hour usage, and apply to all rate classes (residential, commercial and agricultural).

The ECA is a traditional wholesale power cost adjustment, in which a base rate is established and then trued up each month based on Pella's actual wholesale power costs. The DCA is the mechanism used to ensure the cooperative meets its financial goals.

The Pella board selected modified debt service coverage (MDSC) and equity as a percent of assets as the drivers of their financial policy. The DCA is set to generate sufficient revenue to achieve the MDSC and equity targets but can be adjusted if necessary.

"Our board looks at the DCA on a yearly basis as part of the budget process," Smith said. "We calculate it based on the known inputs of the past year and anticipated costs, but we also have the ability to raise or lower the rate based on the true costs of volatile inputs like transportation fuel, transformers, substations, wire, copper or labor. Ultimately, what it allows us to do is to meet our financial goals, which are set by policy, and meet our financial responsibilities as set out in our loan covenants. And our board feels they have even greater ability to watch and control the costs that set the rates."

"Formulary rates don't eliminate the need for rate studies, but we don't have to do them as frequently, so long as our main assumptions remain consistent," Smith added. "The FRP also has helped us streamline the rate-setting process and mitigate the risks of falling demand. The traditional rate-setting model didn't allow us to make decisions quickly enough to fit our end-of-the-year financials that would affect financial covenants."

The response from members has been "benign," Smith said. "The members who have called up to ask about it have had a positive response. They truly believe the board is looking at the amount of revenue and only charging what is needed. I think that's been positive."

CASE STUDY

Florida Keys Electric Cooperative

Restructuring Rates (Twice) in the Florida Keys

- Headquarters: Tavernier, Fla.
- Consumers served: 31,500
- Miles of line: 820
- Total MWh sales (2012): 640,872

As a result of the Great Recession, Florida Keys Electric Cooperative (FKEC) began to experience falling revenue and margins. Overall demand among FKEC's 31,000 members was down as commercial businesses lost customers and the vacation homes of nonresident members sat unused. To meet its equity targets, the FKEC board had already extended the capital credits retirement period from 15 years to 18 years, and the board did not want to extend the period again. FKEC launched two rate redesign initiatives over three years.

In 2008, FKEC introduced a formulary rate design with a new per-kilowatt-hour Equity Charge for all members. The formula used to calculate the charge is based on FKEC's desired return on equity (ROE) using inputs for plant growth and the cooperative's capital credit retirement cycle. The rate is set each year, and if actual ROE comes in above or below a specified range, the charge is adjusted up or down.

"That ability to automatically adjust the Equity Charge is a big benefit to us," said FKEC CFO Cris Beaty. "Our rates aren't regulated by the public service commission, but our rate structure is. Once the formula was approved by the commission, we only have to notify them if we change the kilowatt-hour rate. We don't have to go through a full-blown rate tariff change each year."

The formulary rate design helped FKEC, but as the cooperative's sales continued to decline, FKEC was forced to keep increasing the Equity Charge to meet its goals. And since the Equity Charge is volumetric (based on kilowatt-hour sales), that meant high-usage members were bearing more of the burden than low-usage members.

In late 2009, FKEC worked with CFC on a new cost-of-service study, analyzing costs by consumer class, and found that high-usage residential members were subsidizing low-usage members, many of whom were non-residents with vacation homes. The cooperative had been including a flat $10-per-month Customer Charge on member bills, but the study found that in order to ensure all members were contributing equally to covering the cooperative's fixed costs, a $35 to $50 service fee would be required.

The FKEC board voted to replace the Customer Charge with a Daily System Access Charge of 80 cents per day, or roughly $24 per month. At the same time, the cooperative was able to initially reduce the Equity Charge to zero because the new daily charge compensated for some of the revenue that had been collected in the Equity Charge. The Equity Charge has since been increased to 0.065 cents per kWh. This 2011 rate restructuring enabled FKEC to collect more system-wide fixed costs through the fixed daily charge, narrow the subsidization of low-usage members and restructure rates in a way that was revenue neutral.

FKEC estimated that members using between 1,400 and 1,500 kWh per month were at the break-even point and would see no change in their overall monthly bill; higher users would see savings, and lower users would pay more. The highest increase would be roughly $14 to those members using little or no electricity in a month.

Taken together, the two rate actions allowed FKEC to meet its financial goals while moving toward a more balanced rate structure, and without overwhelming members with a big one-time jump in rates. "Rate restructuring did exactly what we wanted it to," Beaty said. "Our sales have been flat the past two years, but our margins have stabilized."

Member reaction to the rate restructuring was minimal. "Members didn't really respond to the formulary rate change," Beaty said. "Prior to the second restructuring we did a very good job on the public relations side, stressing that it was a revenue-neutral adjustment. Seasonal members were the ones primarily affected, while resident members' bills went down."

CHAPTER 3:
Recommendations and Conclusion

Key Items for Consideration

Customer Charge

Cooperatives are encouraged to consider moving toward rates that recover fixed costs through fixed charges and variable costs through variable charges.

Formulary Rates

Consider adopting formulary rate design. Compared with traditional ratemaking, a formulary rate plan can benefit cooperatives and their members in several ways.

With an FRP, cooperatives have more certainty in recovering costs and margins in an increasing-cost or decreasing-sales environment. Those costs are also able to be recovered more quickly. Systems subject to rate regulation can generally save on regulatory compliance costs because fewer general changes in rates need to be filed.

For members, an FRP can help ensure the cooperative's financial strength, thereby helping to reduce its cost of capital, helping to keep rates low. It also can allow the system to more quickly share with its members a portion of the benefits from any cost decreases.

Member Communication

Regardless of the approach to rate design that a cooperative may take, changes that result in higher bills for members are never popular. But a cost-based design that is fair and equitable to all members is usually the easiest to justify—and to explain through proactive member communication. Ideally, the cooperative should create a specific rate implementation communications plan.

The goal of a communications plan is to achieve member acceptance of rate changes, and to support continued member satisfaction with the cooperative. It should foster member understanding of the cooperative's objectives and how they will lead to reliable supply and acceptable costs for members on a long-term basis.

Being proactive in presenting the changes to members in an informative and positive way increases the likelihood of member buy-in. To that end, the rate message should be consistent across the cooperative's communications channels, including its newsletter, website and community activities.

Items For Further Consideration

Three-Part Rates

In providing electric service to comparatively low-voltage residential and small commercial customers, two-part rates—which squeeze the three categories of costs (customer, demand and energy) into two parts (customer and energy)—have been the standard for many decades. This practice originated because of the additional costs associated with metering the demand component.

Today, however, with the use of technologies like automated meter reading (AMR), advanced metering infrastructure (AMI) and smart meters, the effective cost of metering has fallen. As a result, it is becoming feasible to bill all customers on a three-part rate, which more accurately reflects the reality of incurred costs.

Chart 5 depicted an example of a traditional two-rate design, and Chart 6 is an example of an alternative two-part design in which fixed costs, including demand costs, were moved into the customer charge. Neither example is an ideal solution to the problem of falling sales.

Using the same cooperative, now let's look at how a three-part rate might work, where costs are spread over their respective billing units (customer, kW and kWh charges) *(Chart 8)*.

Chart 8: *Three-Part Residential Rate Design: Recovering the Same Revenue Requirement*

	Annual Revenue Requirement (based on actual cost)	**Billing Determinants**	**Proposed Rate**
Customer Component	$2,020,890	44,711[1]	**$45.20** (per bill)
Demand Component	$873,372	131,662[2]	**$6.63** (per kW-Month)
Energy Component	$2,396,628	45,000,000[3]	**$0.05326** (per kWh)
Total Residential Revenue Required	**$5,290,890**		

1. Number of members (bills x 12). 2. Kilowatt demand. 3. Annual kilowatt-hour sales.

The resulting customer charge is $45.20 per month, the separate demand charge is $6.63 per kW-month, and the energy charge is $0.05326 per kWh.

The three-part rate has several of the advantages of the two-part cost-based rate. It recovers costs in a manner that more accurately reflects the way in which the cooperative incurs costs. That means that the distribution system is indifferent to the level of sales and cannot be financially harmed by increased energy efficiency and distributed generation. It frees up the distribution system to be much more supportive of members interested in energy efficiency and distributed generation. It also means that costs are more equitably allocated between members within each customer class, while members receive a more accurate incentive to invest in energy efficiency and distributed generation. The three-part rate has the additional advantage of being less likely to attract opposition from low-income advocates, as it is less likely to shift costs to low-income members who use little power.

On the other hand, the three-part rate shares several of the political disadvantages of the two-part cost-based rate. It may still attract opposition from energy efficiency and demand response advocates, and it does have an "optics" problem. Although the monthly customer charge is now considerably less than the $64.73 given in the previous example, many managers may find it challenging to impose a $45.20 customer charge (not to mention a demand charge applied to a residential consumer). The three-part rate has the added challenge of being difficult to explain accurately to the average consumer. It is important to recognize, however, that this cost-based three-part rate design collects the same amount of revenue for the cooperative as the two-part rate, although it affects consumers differently.

As noted earlier, it is also important to realize that two-part rates, as currently used by the industry, have an overreliance on the energy charge for collecting revenue. If the energy component is set correctly in this three-part rate (i.e., if it collects only fuel and variable O&M costs) then if kWh sales fall, there would be no revenue shortfall for the cooperative, since fuel is not burned or variable O&M expended. Therefore, margins remain unchanged.

Essentially, three-part rates provide for an efficient—and more accurate—means of billing for electric service.

Time-of-Use Rates

Member demand and consumption of electricity varies during the day, month and year, and the cost to generate or purchase electricity varies during the day, month and year as well. Time-varying rates charge different prices for electricity at different times of the year or day to better track those variations.

The simplest option, which many cooperatives employ, is a seasonal tariff under which consumers are charged a different price during peak season than during the off-peak season. The price in each season is fixed in advance and made known to consumers.

Some cooperatives also offer time-of-day (TOD) rates, which give members the ability to pay a different price during peak hours of the day than during off-peak hours. Those prices also are fixed in advance and made known to consumers. Both rates provide members an incentive to shift energy use to off-peak periods.

The purpose of TOD rates is to give consumers price signals that encourage them to make economically efficient choices about the level and pattern of their electricity use.

The effectiveness of TOD rates is proportional to the peak to off-peak differential. Lower differentials (e.g. 1.5:1) will have small benefits but will grow over time. Larger differentials will provide greater benefit, but will likely cause additional member unrest.

Generation costs stated on a time-of-day basis are an excellent way for the cooperative to signal its cost structure in such a way as to provide an opportunity for consumers to evaluate their ability to reduce peak load.

In practice, time-of-use rates have tended to be less effective than they could be because the peak period was often set for 12 hours—too long to realistically cause load shifting—and because the differential between the cost of peak and off-peak power was too small to make load shifting worthwhile for members. The more effective programs established a much higher price differential and shortened peak periods to no more than four hours per day.

Conclusion

In years ahead, it is likely that rate design will become increasingly important as electric cooperatives face a number of challenges caused by a potentially extended period of historically weak sales growth, combined with rapidly changing technology, government policy initiatives favoring renewable generation and related pressures.

Alternative rate-making approaches can enable electric cooperatives to cope, even thrive. In today's slow-growth environment, electric cooperatives may wish to consider:

1. Setting the fixed charge high enough to recover most of the cooperative's fixed costs, rather than collecting fixed costs through per kilowatt-hour charges.
2. Adopting a formulary rate plan, which decouples revenue from kilowatt-hour sales and provides a measure of financial certainty in cases where fixed charges are insufficient to cover fixed costs and needed margins.

Cooperatives seeking a broad discussion of several rate strategies for the years ahead may wish to refer to the CFC and NRECA 2010 publication "Rate Strategies for 21st Century Challenges: A Guide to Rate Innovation for Cooperatives."

No one (or two, or three) of the alternative rate design concepts described in this report is necessarily the "correct" one for all cooperatives to adopt. Every system is unique and faces different circumstances. In some cases, a combination of different rate elements may be most appropriate.

It is our hope that this publication will assist electric cooperatives as they consider the most appropriate rate strategies for their unique situations and challenges.

KEY CONCEPT

Time-of-Use (TOU) Rate

Rates that vary the price of electricity to reflect the cooperative's cost of providing electricity at different times. TOU rates may vary with seasons, day of week or time of day. Both demand and energy charges may vary.

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