# New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World

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### *About EQ Research*

EQ Research, LLC provides clean energy intelligence for clients in the nonprofit, business, and government sectors. Our analysts monitor energy policy and regulations in all fifty states, staying abreast of trends in distributed solar programs and policies, utility rate cases, energy storage, grid modernization, and other areas. We offer both monthly subscription services and specialized consulting, including policy analysis and expert testimony. EQ Research's staff is located nationwide, with a primary office in Cary, North Carolina.

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## ANOTHER PAPER ON UTILITY RATES?

They're back. No, not ghosts—rate cases: specifically, electric utility rate cases, and the cost of service studies that come with them. After a lull in the 1990s and early 2000s, the number of general rate cases began to escalate and continues to surge today. Aging infrastructure and the digital economy have put pressure on investor-owned utilities ("IOUs") and public power utilities to increase investments, particularly in their distribution systems and software. Concurrently, the growth in demand for electricity—for many utilities—has stagnated.

Increased investment and low or flat load growth is a common recipe for rate cases. What is new in this decade's rate cases is a rising interest in changing how residential and small commercial electricity users pay for utility services. Utilities are proposing, and regulators are grappling with, new rate designs, sometimes for the first time in decades. Frequently, utilities support their new pricing proposals by referencing a text written nearly 60 years ago: James Bonbright's 1961 *Principles of Public Utility Rates*.[1]

In 1961, many questions of regulatory economics remained unsettled across the United States, ranging from the proper treatment of acquisition adjustments to methods of calculating a rate of return. What is now almost universally called "revenue requirement" was called the "cost of service," and utility cost studies were high-level, if they were conducted at all. Most of Bonbright's work focused on complex revenue requirement and rate of return questions, in the process summarizing a robust conversation between economists that had spanned almost 50 years. Bonbright is best known, however, for developing a series of high-level criteria for regulators to use in determining if utility rate proposals met the abstract legal standards of being "just and reasonable" and preventing "undue discrimination." While acknowledging that rate design is an art, he argued that it could be an art that was at least practiced consistently, with a clearly articulated economic foundation.

In the three decades that followed Bonbright's book, the concept of the monopoly electric utility providing service at declining costs was flipped on its head, public utilities commission ("commission") proceedings expanded in scope and number of participants, and personal computers came into wider use. The designation "cost of service" came to be used to refer to the process of allocating costs to customer classes, whereas the funds the utility must collect are now called the "revenue requirement." In 1992, the National Association of Regulatory Utility Commissioners (NARUC) issued the *Electric Utility Cost Allocation Manual* (NARUC Manual), which catalogued a series of "generally accepted" methodologies regulators and their staffs should consider when deciding how to allocate an approved revenue requirement among broad classes of utility ratepayers.[2] The NARUC Manual catalogues the evolution of those aspects of utility cost studies that became at least somewhat settled in the years since Bonbright argued that their merits were "so dubious that they fully justify the skepticism with which utility cost analysis has been received by public utility companies and public service commissions."[3] These aspects were the methods for functionalizing, classifying, and then allocating costs among the various rate classes[4] or—if a rate class had more than one rate schedule—the various rate schedules.

We are now at another stage in the evolution of utility cost analysis. Utilities and regulators are grappling with complex questions about the future of the energy utility industry, arising from forces of technology, economy, demographics, and policy changes. With better and more detailed data now available, many regulatory participants have begun to advocate using results of the class cost of service study ("CCOSS") directly to set the level of various rate parts, such as fixed customer charges and demand charges. This is a break from tradition: in the past, CCOSSs were informational, but not dispositive -- useful as a framework for discussing class revenue requirements and rate relationships, but not for determining the direct prices that customers pay for selected parts of electricity service.

The CCOSS is a mathematical model packed with assumptions about how to allocate a utility's overall base revenue requirement among the various services it provides and the types of accounts it has for each of those services. **Appendix 1** outlines the key steps in the CCOSS. The model generally focuses on customer classes—the types of accounts whose usage profiles are assumed to be similar enough that the characteristics of their electricity use can be represented as a group—such as residential, commercial, and industrial. The CCOSS separates the revenue requirement into costs that correspond with these group characteristics.

You rarely, if ever, see a utility rate case without a CCOSS anymore. Frequently, the CCOSS is the basis for proposals to increase the fixed monthly charge for residential and small commercial customer accounts, or to add a demand charge to those rate schedules that for decades have not had one. A common rationale for using CCOSSs in rate cases is that such studies quantitatively answer three interrelated rate structure questions:

- Which utility customers have caused, and are causing, which utility costs?
- Which utility customers should pay those costs?
- What charges will ensure that the "right" customer accounts pay costs they "cause?"

In so believing, stakeholders often take the assumptions underlying a CCOSS for granted, arguing about inputs rather than purposes, and expertise rather than outcomes. But the questions include a leap of logic that the methodologies of CCOSS do not support. In this paper, we address why the CCOSS is ill-suited to the new demands being made of it -- specifically, why a CCOSS doesn't "answer" questions related to who causes which costs, who should pay, and how they should pay.

First, we explain the prominence of rate design questions and CCOSSs today, and illuminate the history that led to that prominence. Evolving economics, technology, demographics, and policies throughout utility service territories are pressuring old rate structure decisions that, in some cases, date back decades. Understanding the history and the context of cost of service and the CCOSS tool is critical to reflecting on its use and usefulness today.

Second, we describe how the modern CCOSS is poorly suited for answering the challenging rate design questions it is being given. In doing so, we look at both regulatory economic theory—with a focus on Bonbright's texts—and the tool itself. We highlight the many framing, data, and methodology choices and challenges facing those preparing and questioning the tool and its results.

In short, the regulatory arena is due for a conversation about how and why circumstances are changing, and what actions will create more desirable outcomes. Our suspicion is that the CCOSS as currently practiced will not enlighten that conversation. Rather, fueled by an abundance of data that is still not necessarily complete or useful, CCOSSs may be an electric industry version of the recently coined term "weapon of math destruction:" a tool that is opaque, scalable, and harmful.[5]

But if the CCOSS is not the focus of discussion about rate design, and if it cannot serve as justification for decisions about which households and small businesses should pay what for electricity service, what should stakeholders do? To address this, we offer recommendations on how to think about rate structure and the role of CCOSSs in the future. Old questions are new again: Which rate structures are fair? Which services does and should a public utility provide? Which services should have a price and who should pay? If your only tool is a hammer, every problem looks like a nail. Not every question can be answered with a CCOSS, so regulators and stakeholders need more than just a hammer in their toolbox. With an understanding of the history of cost of service and its expression in a CCOSS, we outline ways that regulators can put the CCOSS tool to good use in order to reach better outcomes over time.

# Rate Design Terminology

The subject of ratemaking is complicated and full of its own jargon. To ensure clarity, here are some definitions for the terms we use throughout this paper.

**Rate Structure**

Rate structure encompasses all of the actions and outcomes defined below: rate class, rate spread, and rate design. The tangible aspect of the rate structure is the tariff; the intangible aspect of the rate structure includes all of the philosophies, methodologies, data, assumptions, and calculations applied in its formation.

**Rate Class**

A rate class is a grouping of customers assumed to have similar characteristics with respect to (1) the utility facilities and services required to serve them, and (2) the patterns of their use of utility services. The most common broad groupings are residential, commercial, and industrial. Each rate class may have multiple rate schedules -- for example, rates may differ slightly for residential customers using electricity for winter space heating versus those using natural gas for this purpose.

**Rate Spread**

Rate spread is the allocation of a utility's approved revenue requirement among the rate classes. Regulators commonly look at each class's ratio of revenue produced at current rates compared to the revenue requirement allocated to that class in the CCOSS as a factor in deciding how much of any increase or decrease in revenue requirement to allocate to each class.

**Billing Determinant**

Billing determinants are the measurable dimensions of utility service for a given rate schedule, such as the amount of electricity taken over time (volume), the instantaneous use of electricity (demand), or the presence of particular facilities, such as a meter. These may be further differentiated by season or time of day.

**Rate Design**

Rate design is the process of identifying the billing determinants for a particular rate schedule and setting the levels for those billing determinants for a particular rate period. For example, a commercial rate schedule may include the following billing determinants: energy volume, energy demand (often based on the highest 15 minutes of use during the billing period), and presence of a meter and account. For a particular billing determinant, the rate may be the same at all times and billing periods, may differ by time or season, or may include two or more tiers such as an energy rate that increases with additional blocks of volume during the billing period.

**Rate Schedule**

A rate schedule is a table of rates applicable to either a customer class or a subset of a customer class (e.g., many utilities have one rate schedule for their entire residential class, but spread the commercial class over two or more rate schedules).

**Tariff**

The tariff (often called the tariff book) contains all of the utility's rate schedules as well as terms and conditions, rate riders, and any other matters affecting service to that utility's customers. Utilities must provide their tariff books publicly. Many do this at customer service centers in their service territories and on their websites.

## RATE DESIGN: PRESENT AND PAST

Rate design is a key issue for electric utilities across the U.S., and three big questions dominate today's debates:

- **Should a given utility change its residential or small commercial rate class segmentation?** This might appear as a question about whether the utility should create a new class for accounts with rooftop solar or for low-income customers. It has emerged out of an increasing knowledge about the characteristics and usage patterns within these mass-market classes. Regulators and practitioners, however, have rarely set parameters around what degree of difference justifies establishing a new rate class.

- **Should a given utility increase the customer charge applied to accounts on its residential and small commercial rate schedules?** Out of 126 general rate cases filed by investor-owned electric utilities that EQ Research has tracked since late 2014, 88 have sought increases in the monthly residential customer charge of 25% or more.[6] Generally, utilities request to increase customer charges for residential and commercial customers with the argument that a high level of costs for serving such accounts are embedded or "fixed." For example, Wisconsin Public Service Corporation recently claimed that the fixed, embedded cost to serve residential customers was $68.81 per month and proposed to increase their monthly charges from $19 to $25.[7] However, commissions have often rejected large fixed-charge increases, citing negative impacts on customer financial incentives to invest in energy efficiency.[8]

- **Should some or all of the accounts in the residential and small commercial classes have demand meters and pay a demand charge?** Around the middle of the 20th century, meters and pricing had generally settled into the pattern that prevails today except where utilities have invested in advanced metering infrastructure (AMI): residential and small commercial accounts have energy meters, and other accounts[9] have meters that are capable of measuring peak demand during the billing period, which is the basis of a demand charge for those accounts. For utilities with AMI, the only hurdle that remains before expanding the use of demand charges is political feasibility. While several utilities have proposed demand charges specifically for solar customers, Oklahoma Gas & Electric and Arizona Public Service Company proposed universal demand charges for residential customers.[10] Their stated justification is that a three-part rate "provides a more accurate price signal to customers, which helps to promote efficient use of energy."[11]

These questions have emerged because four important stakeholders in the utility regulatory arena—utilities, new market entrants, regulators, and mass-market customers—have reasons to be dissatisfied with current rate structures and rate design conversations.

- **Utilities are concerned about revenue erosion and lost investment opportunities.** Customers have new opportunities to meet at least some of their electricity needs without their electric utility, through energy efficiency, conservation, customer-sited generating resources, battery storage, energy management software, smart appliances, or a combination thereof. This threatens utilities' ability to collect enough revenue to cover increasing costs, and may curtail future investment opportunities considered by investors in valuing the company.

- **New entrants want opportunities.** Rate structure plays a significant role in the economic case that new entrants make to potential customers when they offer substitutes for utility services. Economics is not, of course, the only reason people may decide to invest in these substitutes, but it is a significant one.

- **Regulators are under pressure.** The growing number of rate case interveners means growing demands on regulators, including demands to lessen environmental impacts, reduce pressure on low-income ratepayers, or increase economic competitiveness. These demands typically focus and collide on rate structure changes.

- **Mass-market ratepayers may not want new rate structures.** Some customers would like different service attributes, such as more renewable electricity or incentives to use energy off-peak, and everyone wants more affordable bills, but few customers affirmatively want different rate structures.

As commissions grapple with these complex issues and mediate between these different stakeholders, CCOSSs have gained unprecedented importance. While commissions still tend to acknowledge that ratemaking is an art, many stakeholders argue that rates should come closer to the "ideal" as quantified in the CCOSS, and that view is gaining traction. Recent years have seen rate case testimony suggesting that the CCOSS should be the foundation for rate design because of three interrelated, foundational assumptions:

- Rates designed using CCOSS allocations are cost-based;
- Cost-based rates do not unduly discriminate; and
- Cost-based rates will send the best price signals.[12]

While these three high-level assumptions are not wholly wrong, they are also not precisely correct. To explain why, we first explore the confluence of electric industry trends that are creating such a heavy reliance on the CCOSS tool for deciding both rate spread and rate design questions.

"Q: If a . . . cost-of-service study is to assist with ratemaking and the adequacy of rates, should results from the study be used to help guide rate design?"

"A: Yes. The cost-of-service study will reveal the rate classes' revenue requirements and the unit costs for use in the design of each of the rates. By adhering as close as feasible to these costs, subsidies can be minimized and efficient price signals will be sent."

**Florida Public Service Commission, Docket No. 160186-El, Direct Testimony of Michael T. O'Sheasy, witness for Gulf Power Company, October 12, 2016, at pp. 5-6.**

## Legal Basis of the Utility Cost Study

States formed commissions to set prices or rates for critical services (including electricity) when their monopoly nature became clear and the monopoly propensity for price manipulation, such as that of Standard Oil, became known.[13] Early legal cases regarding economic regulation established a structure that balanced the tension between the state's police powers to ensure safety and public welfare under the Tenth Amendment with prohibitions on government takings of private property under the Fifth Amendment.[14] In the absence of sophisticated accounting software, early commission decisions and court reviews focused on establishing the overall cost of the utility's service and instituted ambiguous legal standards that prices be "just and reasonable," not "unduly discriminatory," and "in the public interest."

Identifying a rate structure that met those requirements was not a trivial task. Under conditions "when a company's earnings power is so high that any number of a variety of tariffs could be made to yield a fair return,"[15] commissions sought some rationale to select amongst possible rate structures, leading to the CCOSS. Prior to the 1980s, these studies were limited by the lack of electronic data and computer processing capability. Commissions did not blindly adhere to their results, and courts repeatedly acknowledged commission authority to engage in the "art" of utility regulation.[16] Moreover, some states explicitly required their commissions to consider objectives of rate structure other than reflecting the cost of service.

"By what basic standards . . . shall regulation pass judgment on a system of electric-utility rates which allows liberal discounts for incremental blocks of energy; or which levies higher charges, per kilowatt-hour, on residential consumers than on industrial consumers; or which concedes lower rates for off-peak consumption than for consumption at peak times or seasons?"

**Bonbright on the Commissioner's Conundrum, 1961, at p. 288.**

In recent years, however, the temptation to rely on a CCOSS has strengthened. If a utility's revenue requirement should be "cost-based," it seems only logical that "cost" should guide rate spread and rate design as well. The last several decades have seen changing cost and competition trends, increasing granularity of data and rates, and greater complexity of rate case proceedings. The next sections summarize these three key historical trends, which have combined to elevate the CCOSS to the key tool of modern electric rate design.

## Changing Trends on Cost and Competition

The *design* of rates—not just their overall *level*—becomes a key issue every time a new challenge to the electric industry's competitiveness emerges. This is because competition comes at the individual customer level, whether that customer is the energy manager of a manufacturing facility or the bill payer in a small townhouse. Electric bills are the basis upon which each customer will decide whether to change some aspect of the way they meet their electricity needs. Only rarely does this decision involve a complete alternative to electric utility service (i.e., going off the grid). Because of this, it is the variable or per-unit cost of utility electricity that becomes the point of comparison and choice. The specter of competition for individual customer energy choices has risen about every twenty years over the last several decades, with focal points in the 1970s, 1990s, and 2010s.

**The 1970s challenged natural monopoly assumptions.** In the aftermath of World War II, electric utilities by and large demonstrated the characteristics of a natural monopoly: declining per-unit costs. Demand soared, with annual growth rates for electricity consumption in the double digits.[17] The costs per unit of power delivered decreased as technology (particularly power generation) improved and costs were spread over more customers and more consumption. Utilities freely encouraged consumption through all-electric home displays and promotional rates.[18] The 1970s, however, turned the natural monopoly assumption on its head. New generation, including nuclear plants, became expensive. The Energy Crisis dramatically increased the cost of the oil still in widespread use for generating electricity. Inflation on labor and commodities and high interest rates caused rates to rise, often by triple-digit percentages. As higher rates depressed the amount of electricity demanded by spurring conservation and (sometimes) energy efficiency investments, the rate increases came faster.[19] Marginal costs exceeded the average costs on which rates were based, leading to revenue erosion. Utilities filed frequent rate cases and sought fuel and purchased power adjustment riders that allowed them to pass on some or all of their fuel risk to consumers. Hard-hit industrial consumers protested vehemently to rising rates, and some of the first rate structure fights were over rate spread: was the industrial class subsidizing the residential class or vice versa?

Regulators responded, often under extreme public outcry and utility financial pressure.[20] Disallowed nuclear and other new generating plant expenditures drove a few utilities to the brink of bankruptcy; interim rate increases saved others. With the passage of the Public Utilities Regulatory Policies Act of 1978 and the National Energy Conservation Policy Act of 1978, some utilities began testing time-of-use rates, including for mass-market customers; others guaranteed qualifying facilities high prices for supplying power to utilities, opening the supply of electricity commodity to outsiders for the first time since the early 20th century.

Almost all regulators, occasionally under state mandate, began requiring that utilities engage in providing basic energy efficiency programs. Several commissions opened proceedings to explore modifying rate designs to encourage conservation and peak demand reduction. Though dramatic rate design changes rarely ensued, this period saw the first inverted rate designs, under which greater use in a given billing period triggered higher rates and higher bills. In the process of these responses, commissions reviewed utility cost studies, but rarely considered them as conclusive in making rate structure—either allocation or design—decisions.

> "Practical considerations also militate against making cost of service the exclusive criterion in rate setting. Virtually every court considering the matter has rejected out of hand a rule that would reduce ratemaking to an exercise in cost accounting..."
>
> **The Florida Supreme Court in *International Chemical Corp. v. Mayo*, 336 So. 2d 548, 1976, at pp. 551-552.**

**The movement toward retail competition in the 1990s brought fears of significant load erosion.** The 1980s saw competition become a worldwide movement, with airlines, telecommunications, and then natural gas utilities all experiencing the partial or total loss of monopoly power. By the 1990s, several states were exploring retail electric competition, under the expectation that customers would experience both cost savings and innovation. The prospect of retail electric competition, however, raised fears among many stakeholders that new, unregulated market entrants would cherry-pick the choicest customers—particularly large, industrial customers with high load factors (i.e., fairly consistent electricity demand).

Following in the footsteps of natural gas utilities, most electric utilities during this decade revised their rate structures so that the larger commercial and industrial accounts, which were most attractive to competitors, paid rates much more aligned with their individual usage patterns. The energy component of electricity rates, billed per kilowatt-hour, increasingly included riders that passed through changes in variable costs, like fuel and purchased power cost fluctuations. Commissions instituted rate freezes to ensure that the choice of alternative electricity providers by some customers did not raise utility prices for all of those remaining. Economic development rates re-appeared as a favored tool to keep large loads in the utility's service territory and on its system, preserving large customers' contribution to fixed costs for the benefit of all ratepayers and often preserving local jobs.[21] Only mass-market customers did not receive a major rate-structure makeover. As computing power and the amount of computerized data increased, the CCOSS became more granular, but often took a backseat to more pressing political issues.

**The 2010s herald increasing capital investments but stagnant load.** Because equipment installed in the early to middle decades of the 1900s is now reaching its end of life and the need to ensure reliability is rising in an increasingly digital economy, utilities are steadily boosting their investments in the distribution system, including through roll-outs of multimillion-dollar

AMI and software upgrades.[22] While generation and transmission will likely remain the largest category of future capital investment, distribution investment is anticipated to rise significantly.[23] Inflation also remains a factor for most utility non-capital costs.[24] However, loads—and, thus, revenues—are not rising as quickly as inflation or, for some utilities, are flat or falling.[25] Energy efficiency, particularly that gained through building codes and federal equipment standards, continues to depress loads, along with changes in demographics and the economy. From a high of 9.8% annual growth from 1949 to 1959, according to the Energy Information Administration, national average annual load growth has been 0.5% from 2000 through 2015.[26]

The prospect of long-term load stagnation is causing a few commissions to renew interest in 1980s concepts of performance-based ratemaking and new alternative utility business models, but the overriding issue for the last few years has been the treatment of distributed energy resources ("DERs"), including solar energy and battery storage. As was the case with the competition from conservation in the 1970s and retail electric providers in the 1990s, the higher the rates for using electricity, the more attractive alternatives like DERs are to customers.

What is new is the availability and attractiveness of alternatives to mass-market customers. At a high level, some believe the existing utility regulatory model is flexible enough to promote increased customer choice and renewable energy; others believe the model will require a lesser or greater amount of adaptation. These opposing beliefs confront each other in complex general rate cases or revenue-neutral rate design proceedings that are ill suited to resolve them. Instead, experts put forward complex and competing CCOSS models as the basis for ensuring that rates directed toward these new market entrants are "fair" and serve the public interest.

## More Complex Models, Data, and Rates

Complicating the context for rate design issues now is the several-decade regulatory trend toward complex models fed by increasingly large amounts of data. Almost all utility data now exists in electronic form and new technologies, including AMI, dramatically increase the amount of data available. While this smart metering technology is far from new, the American Recovery and Reinvestment Act ("ARRA") kicked off waves of investment. Computing power has increased to the level where thousands of simulations can be run in minutes rather than days. The growing importance of computer models as significant if not determinative evidence for regulatory economic decisions led to a new term: "regulation by simulation."[27]

The CCOSS has participated fully in this trend. The calculation-intense nature of utility cost analyses proved challenging in pre-computer years, and full CCOSSs were uncommon even in the 1960s.[28] That changed in the 1990s: with the increasing power of desktop computers, least-cost planning (now called integrated resource planning) and other models and methodologies, including the CCOSS, began to add detail and scope to utility regulation. Business intelligence software now promises improvements to operations through better tracking of work orders, accounting, and distribution system reliability—all relying on more granular data that could be drawn on to populate the CCOSS. Utilities are still struggling to understand the full range of opportunities this presents.

Another source of increasing complexity for rate design issues is the nature of electric rates themselves. In past decades, the bill was the result of applying billing determinant rates to a particular customer account. The rates were set in general rate cases, so-called because the rate case comprehensively dealt with a utility's cost of service. This is no longer the case. The bills customers pay generally include not just a "base" rate, but also any number of adjustments that rise and fall on separate schedules. The fuel and purchased power automatic adjustment clauses approved in the 1970s were just the beginning. In recent years, commissions have approved pass-through adjustments for costs including generating plant retrofits for environmental compliance, vegetation management, smart grid investments, demand-side management costs, and rate case expenses.[29] Generally, automatic adjustments affect only the variable part of the rate, particularly for mass-market customers. Thus, the "price signal'" a customer's rates and bills send can no longer be comprehensively identified in the rate design context of a general rate case.

## Increasing Numbers and Complexity of Proceedings

On top of all this, the sheer number of electric utility regulatory proceedings has skyrocketed. So far, the 2010s have been the decade of the general rate case. The average number of rate cases filed in the 2010s exceeds the average number of those filed in prior decades for which we have concrete data—out of about 190 investor-owned utilities in the country, a fourth are filing rate cases each year (see **Figure 1**).[30] Data from Edison Electric Institute ("EEI") and EQ Research show an average of 38 rate cases filed per year since from 1990-2016. In 2016, more rate cases were filed than any other year on record. General rate cases are no longer the only source of changes to rate structure or individual rates, however. In addition to the adjustment clauses mentioned above, many states are addressing rate structure questions outside rate cases, in proceedings about "revenue neutral" cost allocation and rate design.

The frequency with which rate cases and other proceedings occur tax stakeholders' resources. While utilities can pass through the reasonable costs of their legal filings to their customers—often now exceeding $1 million[31]—other parties become resource-constrained. In addition, an unintended consequence of the overall paucity of general rate cases in the 1990s and early 2000s was the attrition of industry experts, an issue that continues to affect regulatory proceedings today.[32]

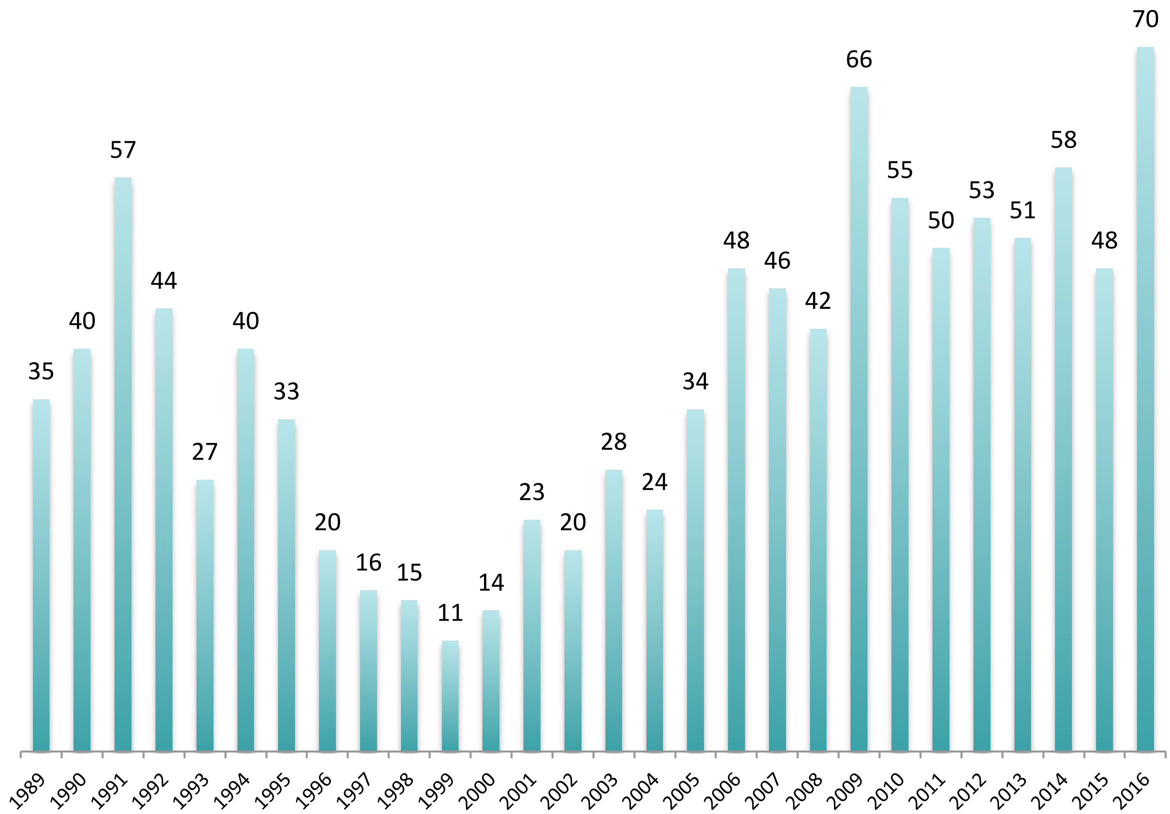


**Figure 1**: Number of rate cases filed by investor-owned utilities by year[33]

Meanwhile, ever more stakeholders are appearing in the increasing number of proceedings. In the first few decades of the 1900s, rate case participants might have included a utility's largest customers or the cities with which it had franchises, and those parties were primarily concerned with cost and reliability. In the 1970s, consumers' counsels emerged to represent the interests of residential and small business ratepayers in the face of steadily increasing costs.[34] Moreover, environmental nonprofits like the Environmental Defense Fund began to engage on issues such as the role of rate design in energy efficiency and conservation. The influx of retail competition and the emerging secondary market of energy services providers mean that more people want to be at the table, particularly in high-stakes proceedings like rate cases. By the early 2000s and continuing today, a rate case can have twenty or more interveners, representing a range of interests including small customers, multistate corporations, manufacturers, energy efficiency nonprofits, local governments, and developers of products competing for customers' attention.[35]

A settlement among the parties is a frequent result of numerous rate-related proceedings, many stakeholders with constrained resources, and a lack of experts to hire for help on the technical issues that often dominate. Indeed, settlements have resolved and ended a significant portion of rate cases in recent years. A consequence of this is that rate structure policy may be lost in black-box settlements that resolve competing interests. To the extent that commissions rely on their own prior decisions and the decisions made by commissions in other states, black-box settlements considerably narrow the tools available to regulatory participants in other jurisdictions or policymakers to help decide tough issues of economic regulation. Many such settlements also leave big parts of the decades-old rate structure untouched—such as the mass-market residential and small commercial rates—and consequently, there may be little recent guidance for the decisions commissions are making today.

## Where We Are Now

Past is prologue, and where we are now comes from where electric utility regulation has been. The increasing diversity of types of rates, and the increasing numbers of interveners engaged in the litigated process (each with different values and priorities) further encourages commissions to prioritize a tool that provides quantitative support for engaging in the art of ratemaking. Longstanding theoretical and practical flaws to using the CCOSS to design rates, however, make this quantitative support dubious. Whether a CCOSS supports decisions that a given rate structure is just and reasonable, in the public interest, and does not unduly discriminate is questionable.

## FLAWS IN THE CCOSS: THE THEORY

The CCOSS grew out of a history of robust economic debate on the nature of regulated monopolies and how to set prices for their services. Economists like Kahn, Pigou, and more modern thinkers like Borenstein explored regulation and competition issues in depth. But when utility rate case stakeholders argue that a CCOSS defines the costs that rates must recover, they most commonly invoke James Bonbright. Bonbright is best known for the "criteria of a sound rate structure" that he put forward as a summary of advice for regulators and the regulated as they crafted rates out of revenue requirements (we compare Bonbright's 1961 and 1988 rate criteria in **Appendix 2)**. Yet, Bonbright was also renowned because his work summarized then-current thinking about controversial issues that have since become more settled—ranging from the calculation of a return on equity to the calculation of rate base using original cost or replacement value.

The majority of electric rate cases filed in recent years either explicitly invoke Bonbright or reference one or more of his criteria. References to Bonbright typically start—and stop—with reference to rate structure, and assert that relying on his criteria will provide customers with "better" price signals. Yet even looking only at the residential rate class, the diversity of rate proposals that utilities claim meet Bonbright's guidelines is staggering. They include higher monthly customer charges,[36] tiered customer charges,[37] tiered "grid use charges" meant to recover distribution demand costs,[38] residential non-coincident demand charges,[39] and time-of-use charges.[40]

Bonbright's rate criteria are but one part of a broader work that explores the meaning and usefulness of cost of service as a regulatory concept. The two editions of Bonbright demonstrate a thoughtful approach to a constantly changing, inexact industry. We summarize the highlights below, quoting extensively from both editions.

There are four important theoretical concepts that are often overlooked or omitted when a stakeholder advocate invokes CCOSS as the best tool for designing rates:

- "Cost" may be better than "the public interest" as a standard, but it's still inexact;
- Utility costs send poor price signals;
- The more granular the rate, the more impractical is a "cost-based" rate; and
- A general rate case is not the real world.

"You keep using that word. I do not think it means what you think it means."
**Inigo Montoya, The Princess Bride**

## While Better Than "The Public Interest," Cost Remains an Inexact Standard

One of Bonbright's primary goals was to displace a public interest and social-welfare standard[41] for ratemaking, which he saw as the epitome of "extreme vagueness" and "not a real standard at all."[42] Rather, the public interest standard was "a mere form of words of highly emotional content, invoked as an instrument of persuasion by people who have at heart much more immediate interests in public utility tariffs—interests often, but not always, of a self-seeking nature." While attempting to add meat to a vague standard, Bonbright recognized that his recommendation that commissions set cost-based rates was no silver bullet. In the absence of a truly competitive market, costs must be constructed. What costs to include? What time or geographic selection to make? Should a commission consider only costs incurred, or hypothetical costs avoided, or both? Why are avoided costs and externalities considered for demand-side management program design but not for rate design? How can customer elasticity of use be effectively measured? While the term "public interest" is noticeably subjective, cost in the ratemaking sense is also a construction that depends on perspective.

"[T]he very *meaning* to be attached to ambiguous, proposed measures such as those of 'cost' or 'value'—an ambiguity not completely removed by the addition of familiar adjuncts, such as 'out-of-pocket' costs, or 'marginal costs,' or 'average costs'—must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy."

**Bonbright 1961, at p. 290.**

"One of the reasons for the popularity of a cost-of-service standard of ratemaking no doubt lies in the flexibility of the standard itself. 'Cost,' like 'value' is a word of many meanings, with the result that people who disagree, not just on minor details but on major principles of ratemaking policy, all may subscribe to some version of the principle of service at cost."

**Bonbright 1988, at p. 109.**

## Utility Costs Send Poor Price Signals

Bonbright roughly categorized his rate design criteria into three functions that ratemaking should ideally accomplish[43]:

- **The Capital Attraction Function**, by which it provides sufficient monetary incentives for economic agents to devote their resources to providing services that people are willing and able to purchase;
- **The Efficiency Incentive Function**, by which it ensures that such services are provided at the lowest possible cost; and

- **The Consumer-Rationing Function**, by which it prevents waste, or more precisely, limits consumption to levels such that the incremental benefits received by each individual at the margin equal or exceed the incremental costs of providing the services.

He is clear in both editions that for rate structure questions (spread and design), the primary ratemaking function should be consumer rationing. This recommendation has two practical components. First, those setting utility prices should explore the likely consequences of those prices—how will the people paying them act in response and what will those actions mean for the utility's costs? Second, the rate-maker should determine whether the resulting behavioral changes and consequences for the utility are wasteful or economically justified, from a societal perspective.

**Discouraging wasteful use means establishing rates that will avoid wasteful utility costs.** Bonbright focused on the consequences of pricing that would reduce utility costs in the long run. He identifies the most important costs for the purpose of developing prices as those "anticipated costs that can still be escaped or minimized by a control of output."[44] In other words, rates should cause utilities to avoid costs that would be needlessly expended, rather than to recover costs that were already incurred. Yet CCOSSs rarely look at marginal—or avoidable—costs, and even less rarely look at long-run marginal costs, which economists generally prefer.[45] Bonbright acknowledges why ratemaking is rarely done on the basis of marginal costs: such rates would inevitably recover more or less than the utility's revenue requirement, setting the conditions for either utility extraction of monopoly profits or the confiscation of a utility's private property prohibited by the Constitution.

**Determining which costs resulting from the use of electricity are wasteful—as opposed to economically justified—requires taking a societal perspective.** Bonbright opined that when it comes to looking at efficiency from a consumer-rationing perspective, full costs and external costs matter. Both Bonbright editions assert that different concerns predominate when setting a revenue requirement versus establishing a rate structure. With respect to revenue requirement, "the relevant costs are enterpriser costs and not social costs [and] . . . the important equation is between total revenues and total costs rather than between the rate for any specific service and the cost of rendering this particular service..."[46] In contrast, with regard to rate structure, social costs matter greatly. Utility costs are inadequate unless they roughly internalize external costs.[47] This means that price signals based on a CCOSS that fail to account for externalities, such as carbon costs, are incomplete. Importantly, internalizing externalities is not the same as the social engineering that Bonbright opposed.

Bonbright suggests that the more important question is: how can rates be designed overall to prevent waste? To that, we would add: what else should and can economic regulation do to prevent "wasteful" utility costs, as Bonbright defines them? Decades after Bonbright's seminal thinking, it is apparent that utilities plan and build their systems of generation, transmission and distribution based on "representative" customers, particularly for the mass market. This is understandable: individual mass-market customers come and go, along with the electricity-usage affecting behaviors peculiar to them. Utilities cannot adjust the physical system in response to each and every such individual customer. They can only observe what is happening at a macro-scale, and put in motion the changes to the system that would reduce waste if those changes persist. Regulators can most effectively influence potentially wasteful utility costs by interjecting themselves firmly in these planning and building decision-making processes, not by hoping that electricity users pay attention to price signals that rates supposedly send and that utilities adjust their investments according to user response.

## The More Granular the Rate, the More Impractical a "Cost-Based" Rate

Bonbright recognized that the problems of designing rates based on sunk costs got larger as the rates at issue got more precise. In other words, general rate levels are easier to set than individual rate schedules or their billing determinant components.[48] Both editions agree on, and discuss at length, the difficulty—if not outright impossibility—of determining cost of service for individual rate schedules or, certainly, individual customers. His objection was partially philosophical, as the idea that "the rates charged to any single customer within that class should cover the costs of supplying this one customer" would reduce the "theory of rate structures to a mere theory of cost determination through the aid of modern techniques of cost accounting and cost analysis."[49] Indeed, "the problem of measuring the costs of separate classes and amounts of service is one of the most controversial problems in public utility rate theory."[50] Rates inherently create subsidies.[51] Even with better data and more powerful computing capabilities, this problem has not changed over the decades.[52]

> "In a very real sense, . . . the supply of any one type of service to thousands of ratepayers at different locations constitutes the supply of a different product to each customer. Similarly, service rendered at any one time is not the same product as an otherwise comparable service rendered at another time. But these millions of different service deliveries by a single public utility company are produced in combination and at total costs, most of which are joint or common either to the entire business or else to some major branch of the business. Under these circumstances, the attempt to estimate what part of the total cost of operating a utility business constitutes the cost of serving each individual ratepayer or class of ratepayer would involve a hopelessly elaborate and expensive type of cost analysis… the most that can be hoped for is the development of techniques of cost allocation that reflect only the major, more stable, and more predictable cost relationships."
>
> **Bonbright 1988, at pp. 391-392.**

## A General Rate Case is Not the Real World

Perhaps the most refreshing part of both editions of this seminal work on ratemaking is how Bonbright places economic regulation and ratemaking within the larger context. General rate case assumptions do not reflect the real world, and utility costs are not the only ones that matter for purposes of setting prices. Moreover, neither regulators reviewing rate filings nor utilities making them are unbiased, even when applying cost of service metrics. In this vein, Bonbright gave regulators three important pieces of guidance.

**First, use the right tool for the right task.** Utility prices do not operate on people's decisions involving electricity in a vacuum. Indeed, the stew of incentives, barriers, policies, and practices applicable to any given decision that might affect the cost of electricity supply or use is mind-boggling. Similarly, regulators do not make decisions in a vacuum. Applying principles and practices derived from historical situations that no longer apply will not serve modern utility ratepayers. The most important question to ask is: What are the objectives that a regulator wants to accomplish? Answering this question then prompts another: Given the larger context that the regulator cannot control, what tools of economic regulation are appropriate to influence the achievement of those objectives?

> "A mixed economy has at its disposal a variety of economic controls ancillary or alternative to that of the price system, with the result that, in the performance of any given function, price may merely assume some share in getting the desired result. What this share shall be is a question of policy that cannot be decided in the same way for all types of prices, or even for all public utility prices… On the contrary, we must assume responsibility for an attempt to resolves controversies as to how programs of ratemaking should cooperate with other policies of public utility operation and regulation in securing basic objectives of public policy."
>
> **Bonbright 1988, at p. 91.**

**Second, unintended consequences are probable.** It is rare to find any mention of potential unintended consequences in testimony proposing rate design changes. Yet, it would be equally rare for none to occur. Bonbright advised that the "administration of *any* standard or system of rate making has consequences, some of which are costly or otherwise harmful," and therefore might necessitate making less economically based choices.[53] Any rate design changes that commissions ultimately approve will land in a volatile mix of new technologies, demographic changes, and changes in values, beliefs, and feelings. New rate designs will almost certainly affect the economics and timing of end-user decisions to adopt or reject particular technologies. These choices, in turn, will likely affect the environmental outcomes of electricity use. Some may alter the role that electricity prices play in the economic vitality of a given service territory. Others may affect the relative burdens of electricity bills compared to other household needs. These difficult questions continue to proliferate.

**Finally, forget about perfect competition, optimums, or the ideal.** One of the words most frequently used in economic regulation—from resource planning to pricing—is "optimal."

Bonbright cautions against its use in connection with pricing: "*Satisfactory* results, not ideal or optimum results, are all that can be expected of the ablest group of rate makers."[54]

"[The] task of ratemaking or rate regulation is that of adapting utility rates to a larger economic environment, including a universe of nonutility prices and wages on which these rates have only a limited repercussion..."

**Bonbright 1988, at p. 71.**

## The Theory Informs the Tool

A CCOSS cannot answer what will create or defer a utility cost in the future; it attempts only to allocate costs the utility has incurred to serve its entire expected customer base at various times in the past. Thus, while some assert that a CCOSS can answer today's rate structure questions, Bonbright himself would likely disagree. But he would just as likely agree that a CCOSS can provide one perspective on these questions, along with other evidence and considerations. To do that well, however, it must be designed appropriately, with assumptions that are both reasonable and logically consistent. The next section looks at some of these specific methodological issues.

## FLAWS IN THE CCOSS: THE TOOL

Evoking the CCOSS as theoretical support for mass-market rate design is dubious. But the tool is also problematic in practice. In the process of assessing the cost causation of various rate classes and spreading a utility's revenue requirement to them, the CCOSS analyst makes many assumptions, including that:

- All of a utility's services have been identified, and each rate class's usage patterns are fully understood.
- In states using embedded CCOSS methodologies, the only costs that are relevant are those found in the utility's accounting system, because those are the costs that comprise the revenue requirement. In states applying marginal cost CCOSS methodologies, costs from the utility's most recent integrated resource plan and future costs for utility distribution equipment are relevant, although the resulting study must then be translated into embedded cost terms.
- The important effects of a given ratepayer using or not using utility services will appear in the utility's accounting system or other data it commonly tracks.
- Customer classes, as they are currently constructed, contain accounts with similar usage patterns, such that applying the same rate to everyone in the class does not unduly discriminate against any particular account.
- Costs that were jointly incurred—like distribution costs and software—can be precisely allocated to customers.

It is critical that these assumptions are explicit and that commissions structure processes that allow for questions about their accuracy and applicability. When Bonbright wrote *Principles of Public Utility Rates* (both editions), commissions considered CCOSSs informative, but not dispositive. He rightly criticized any model that attempted to allocate joint and common costs down to the last decimal and account as a means to decide rate spread and design. As utilities collect more data, the CCOSS is being tasked with doing precisely that. This section looks specifically at the flaws inherent in the tool itself, of which three are particularly important:

- The CCOSS as traditionally programmed is effectively a "black box" for which the utility is the only party with full access to data;
- The tool's assumptions for allocating joint and common costs may not sync with current electric industry practices, either as they are or as they may be; and
- The CCOSS, by itself, does not provide an effective framework to measure any metric of "success" besides whether a particular customer class has met its revenue requirement.

### The CCOSS is a Black Box

Utilities unquestionably provide a significant amount of data through the discovery process in a rate case. This does not necessarily mean, however, that all parties in the rate case have access to the information sufficient to evaluate the CCOSS and its support for any rate design proposals made in the rate case, by the utility or others. The development of rate classes from load research is a foundational step to every other aspect of each CCOSS developed for a rate case, but it can also be the step for which the least information is available. A CCOSS requires load data from individual customers at a daily, hourly, or sub-hourly basis. This data is frequently confidential, and it may be neither recent nor robust in terms of the variety of accounts within a given rate class that were included.

The original rate classes, still used by many utilities, were based on assumptions about the types of accounts that were "similarly situated." But who is similarly situated? Rate classes include within them accounts with different service, voltage, load, or other characteristics and the broader the rate class—such as the residential and small commercial—the more the differences and the wider their range. Are customers similarly situated with respect to their on-site equipment (electric heat or natural gas), or how their buildings or equipment relate to the utility systems of distribution, transmission, and generation (voltage, usage times)? Or what about an area that regulators have generally feared to tread in—the purposes for which customers use energy (dry cleaners or corner grocery, hospital or office building, renting or vacationing)? Some have proposed addressing only "obvious" exceptions to the notion that customers are similarly situated—such as whether the account has rooftop solar or not—but the question of what an obvious exception is has rarely been approached with methodological vigor.[55] These questions are particularly pertinent to the residential class, whose diversity in the how and when of using utility services can be large, let alone the cost implications of those differences. For example, residential accounts may include vacation homes, small studio apartments, mansions, and dwellings that heat with natural gas or oil (see **Figure 2**). [56]

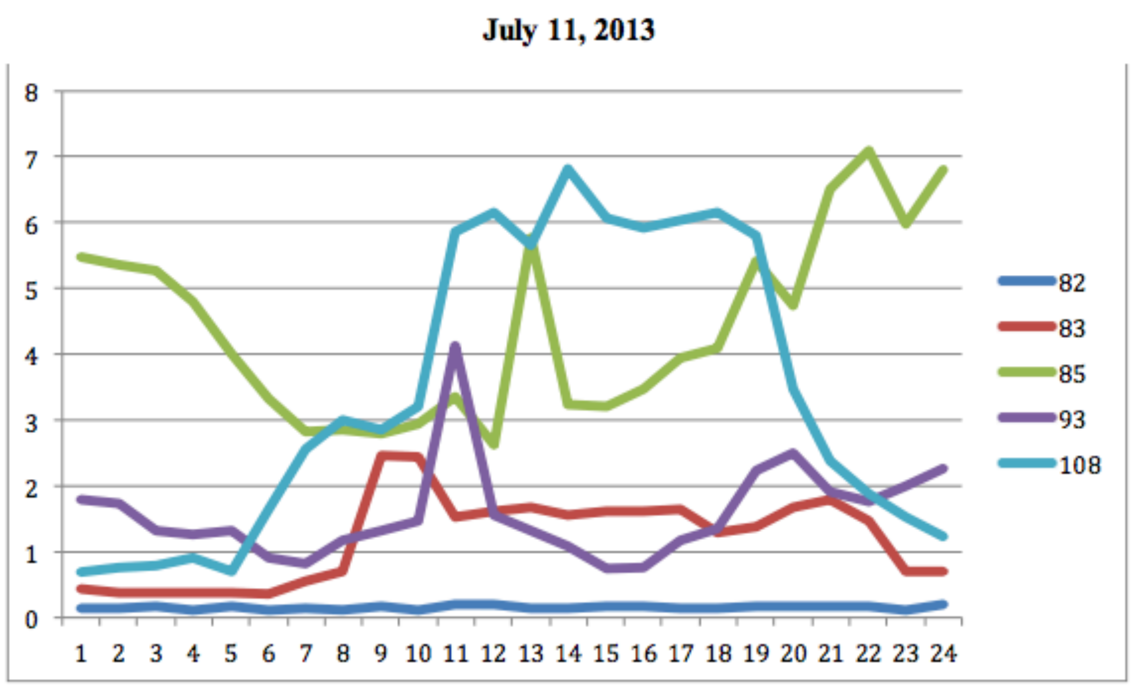


**Figure 2**: Variations in hourly demand across a single day for five residential customers in Colorado[57]

Historical load research compiled to show trends over time could provide significant insight as to the validity of rate class constructions, but this may not be available, either because it has been years since the last rate case or because load research is conducted infrequently or informally.[58] Many utilities are still in the process of installing AMI or have only recently completed its installation, meaning that for certain customers—and particularly those in the residential and small business classes—utilities may not even have a full test year's worth of hourly or sub-hourly data. Utilities that lack AMI may install special interval meters, but this is usually only on a small sample of customers.[59] Furthermore, the historical purpose of load research has been to update data about existing rate classes; the purpose has rarely been to examine whether customers within a given class remain "similarly situated" or explore the addition or subtraction of rate classes. Designing the load research to support the construction or de-construction of the traditional rate classes might require different load research.

An additional load research issue is that to varying degrees, all states consider individual electricity consumption data to be private and require that it be kept confidential. Sometimes rate case stakeholders can receive the data so long as account details are removed, but this can be time-consuming for utilities to produce and for stakeholders to evaluate. To avoid these problems, some utilities conduct statistical samples of different customers' electricity demand or consumption. Lacking the base data, stakeholders cannot assess whether the statistical elements of the data are complete or correct—an important concept given that data are often provided as averages, which can mask significant non-normal data distributions and create cross-subsidies between accounts that lie on either side of the average.[60] The gap between utilities and stakeholders will continue to widen as "big data" becomes more prominent in the electric industry.

## CCOSS Methodology Needs Refreshing

There are three core steps in a CCOSS: functionalization, classification, and allocation (and multistate utilities may also jurisdictionalize costs to the state's service territory their filing focuses on). **Appendix 1** provides more detail. Naturally, CCOSSs require many methodological choices, including the type, granularity, and vintage of data to use in constructing allocators. The NARUC Manual clarified which methodologies regulators and their staffs considered more valid (in 1992); however, it provides a series of alternatives rather than presenting a single, unified approach.[61] The decades since have brought, and continue to bring, upheavals in electric industry approaches to planning, engineering, and operations.

Ultimately, a significant chunk of the CCOSS is comprised of costs that are jointly and commonly incurred. Unlike a utility-owned streetlight, the costs associated with a substation, a transformer, a billing system, a transmission line, or a senior executive's salary may not be readily assigned to a particular customer class. Analysts are thus forced to create assumptions about how to divvy up those costs. Sometimes these assumptions are fully explained and argued in a rate case, and sometimes they are not. Among the assumptions an analyst might make:

- **Functionalizing administrative and general costs associated with office space**. A utility may own or lease and office building to centralize much of its staff. The NARUC Manual proposes that analysts functionalize the costs for an office building based on the square footage of space dedicated to the production, transmission, distribution, and customer service functions. However, a competing method is to functionalize these common costs in proportion to how much each comprises of the overall revenue requirement.[62]

- **Classifying the costs associated with the distribution system as customer-related**. The secondary distribution system includes the lower-voltage circuits, poles, wires, and service drops that connect to individual meters. Distribution costs are sometimes classified as a mix of "customer-related" costs and "demand-related" costs, and this designation can influence rate design. For example, a utility might use the "minimum system" approach to find that there is a bare-bones set of distribution equipment that is necessary to serve customers within that utility's service territory. Because this methodology classifies that bare-bones system as customer-related, its costs are allocated based on the number of customers—which tends to place more costs on the residential customer class, which is usually the largest customer class. See **Appendix 3** for more information on alternative approaches to classification.

- **Allocating the costs associated with meter reading and billing between customer classes**. Meter-reading expenses can include manual reads, the costs of sending trucks to collect meter reads, or the costs of establishing a software system to collect meter interval data. A utility may allocate the costs associated with reading customers' meters based on the cost of the meters used by each customer class, the proportion of metering costs as a share of the overall revenue requirement, or some other simplification. Often these weighting factors are applied across customer-related expenses, like the costs associated with maintaining call centers. For residential customers, these approaches might double the expenses allocated to those who have production meters for DERs, even as it averages out the higher costs required for manual meter reads with the lower costs required for meter-reading trucks.

New technologies like DERs are changing not only when, how, and why customers use electricity, but also how utilities design, build and maintain their systems. For example, the validity of methods used to allocate distribution costs depends on how distribution systems are planned—an area that is increasingly being reevaluated in states like California, New York, and Hawaii (and under discussion in Minnesota, Maryland, and New Hampshire, among others). Whereas distribution planners might have originally relied on historic customer usage data to assess new line extensions, they now may need to consider how to integrate microgrids and net-zero neighborhoods. Stakeholders considering the utility of the future also consider whether to unbundle, price, and provide choice around such utility services as reliability or voltage, and the more esoteric concepts of comfort or convenience.

Allocation methodologies that spread revenue requirements and design rates based on what the system *was* rather than on what it *could become* will hinder efforts to influence what regulators want the system to become. CCOSS methodologies must reflect conscious choices about the future of the system rather than past intended and unintended actions that produced what the system is today.

## The CCOSS Does Not Measure "Success"

After CCOSS analysts functionalize, classify, and allocate costs, they reconstitute the total into rate class-specific and schedule-specific revenue requirements.[63] Comparing these rate class or schedule revenue requirements to the actual revenues collected (or to be collected, in future test year jurisdictions) at current and proposed rates informs the analyst's overall rate spread and rate design recommendations. A final test is a demonstration that the proposed and approved rates produce the proposed and approved revenue requirements under the assumed levels of billing determinants.

The critical question rarely addressed in a rate case, however, concerns the effects of rate spread and rate design decisions. There is no precise way to measure whether rates that are adopted under the pretext that they are "just and reasonable" actually turn out to be the case. What first- and second-order effects arise from a particular rate design? What should commissions look for? How will they observe what happens? Many commissions have processes in place to observe the revenues and earnings the rates produce over time, checking to make sure they are not too high. Is this utility-centric measure the only measure of success needed? Or do we need more?

"Public utility counsel have sometimes argued that once a company's total revenue entitlements have been determined by a commission, the choice of a pattern of rates that will yield the allowed revenues should be left to the discretion of management, which will then be in an impartial position to make a fair apportionment of burdens among its different classes of customers. This is only a half-truth because, among other reasons, a utility company is concerned not just to secure rates that will presently yield the approved fair rate of return, but to develop a pattern of rates that will promote growth of earnings and that will protect these earnings against business depressions. The better the utility management, the greater are these concerns."

**Bonbright 1988, at p. 378.**

## An Inexact Tool Produces Inexact Results

Experienced modelers often say: “All models are wrong; some models are useful.” A CCOSS is no exception. Applying the methodologies that are used to allocate costs in the CCOSS to the design of rates creates distinctions down to the thousandth of a cent. The result is information, but it is not “true.” Even though the information on which the CCOSS is based is improving, fundamental flaws in the tool itself and its use remain. A CCOSS is often a black box. A litigated process may not be the most constructive way to identify all of the data and choices necessary to make a useful model and result. It is not usually possible to redo the CCOSS with choices its preparer discarded. Using the CCOSS model in a rate case produces a battle among a dwindling pool of experts, with complicated arguments that exclude some parties and almost all general stakeholders—nonprofits, trade associations, and local governments, who have neither the ability to hire outside experts nor long-lasting relationships with the experts who remain active. Members of the public can play virtually no role in advocating on CCOSS disputes or the recommendations based on them. In the final section, we’ll propose some possible solutions to the dilemmas regulators find themselves in when thinking about electric rates.

## LOOKING TO THE FUTURE: REPAIR OR REPLACE?

Whether the CCOSS tool provides *an answer* depends on the question one is asking. Whether the CCOSS provides a *good answer* depends on questions and considerations outside the capabilities of the tool. Whether the CCOSS produces *a desirable outcome*, with as few unintended and adverse consequences as possible, depends on several factors:

- Have decision-makers clearly articulated the desirable outcome and ways that it can be observed and measured?
- Do those using the CCOSS understand the factors that would contribute to a desirable outcome?
- Are decision-makers ready and able to take action if that outcome does not appear, or if unintended, adverse consequences do appear?

Considering the flaws inherent to the concept of the CCOSS and its execution, the question emerges: is this the tool we want to use to define desirable outcomes? Is this the tool that will help regulators make decisions that keep utilities whole while allowing competitive energy markets to thrive? Is this the tool that will lead to cleaner energy and reduce carbon emissions? Is this the tool that will help more customers make good energy choices, or will it eliminate choices? The answers depend on which questions a regulatory body is wrestling with.

The CCOSS, as it is currently used, is tethered to the past. Projections of electricity sales rely on past experience and identifiable relationships (e.g., construction, gross domestic product) to estimate the future. Accounting data is based on costs that have been incurred. Even CCOSSs that apply marginal cost principles may shift between short- or long-term marginal cost, and be vague about the assumptions made to calculate the next unit's cost. Because the industry is in the middle of a shift, not all of these past experiences or data will be relevant in ten or even five years.

Rate design is an important dimension of the environment in which utilities and their customers and competitors interface. To navigate through this environment, rate-setters must focus on what is happening now and what they think will happen soon, adjusting as reality differs from what was expected. Looking backwards, to the past, hinders rather than helps the navigation. If the CCOSS is to have a place in this evolution, stakeholders—including regulators, utilities, and interveners—will need to refresh both the theory and the practices behind it. We have four suggestions for these stakeholders, but particularly for regulators:

- Be specific about the role of pricing in the questions you're trying to answer;
- Prioritize load research;
- Make sure a CCOSS is transparent and usable; and
- Refresh the methodologies in the CCOSS to reflect current—and possibly future—practices.

**Regulators should be specific about the role of pricing in the questions they're trying to answer.** Regulators are again being asked to set the lines of interaction between electric utilities and new market entrants. In the future—and currently in states like Hawaii—they may be asked to define or oversee new electric utility services, like voltage control or enhanced reliability. These questions have implications for rate structure, and certain rate designs may reduce competition in or even demand for new or existing services. Outcomes of rate setting could be less customer choice and fewer opportunities for third parties or utilities to innovate and electricity users to obtain desired services. As in the 1970s and 1980s, regulators may look to economists for advice on what sorts of rate structures are appropriate to prevent waste (and how to measure that outcome). They may also want to examine whether other tools that they already use are relevant to rate structure. Integrated resource planning (IRP), for example, offers insight in the form of its long-term perspective. IRPs may contain granular assumptions, but they are fundamentally about making choices that could meet multiple different alternative futures, a benefit that is increasingly as relevant to distribution planning as it is to power supply planning.

Ultimately, it is important to consider what is and is not within the purview of utilities and regulators. Bonbright urged regulators to use the right tools for the right job. Sometimes, that involves setting prices, and other times, it involves stepping back to allow other policymakers and the market to take a leading role. Utility rate design is a blunt tool, and other tools may offer much better precision and the ability to control unintended consequences. For example, if utilities are experiencing revenue erosion—a question of fact—then there are multiple policy alternatives to consider, including well-designed revenue decoupling adjustments[64] that allow for more stable revenue collection regardless of electricity sales.

**Load research should be a priority.** If patterns of electricity use and their relationships to key indicators like gross domestic product are changing, then traditional forecasting methods may not effectively predict the future. Identifying these patterns requires new load research, and that takes time. Utilities report on the same data and metrics that they did decades ago, despite the increasing availability of tools that can measure and record how electricity is used. We need to ask broader, deeper, better questions about load if we hope to influence how the production and application of electricity unfolds over the next decades. This research should inform not only pricing but also planning across the generation, transmission, and distribution systems. Ideally, the questions and sources for this research would be developed collaboratively, in a regulatory proceeding that invited as many different perspectives as possible.

**The CCOSS should be transparent and usable.** Traditionally, the utility prepares and files the CCOSS, and then interveners critique it. The underlying data may not be available, because it is not in a format that makes review practical, has not been asked for correctly, or is confidential. The Arizona Corporation Commission took steps to address this by requiring Arizona Public Service Company to provide a transparent cost of service model as part of its rate case filing, although parties could debate how well this worked.[65] We recommend taking this a step further by having a third party oversee the creation of the CCOSS. This third party would transparently document all data and methodologies. Having a third party whose role is to independently oversee the CCOSS would help in multiple ways. Because they would have responsibility for the calibration of the model, they could create multiple alternative scenarios and identify which assumptions are sensitive to the outcomes. They could ensure that data is statistically meaningful and logically consistent throughout the model. They could also identify data gaps. We believe that a collaborative process could provide a better framework for asking questions and exploring different opportunities.

**CCOSS methodologies need refreshing.** The NARUC Manual has been adopted in most, but not all, states—but it was last updated in 1992. Just as the NARUC Manual refined concepts that were not fully settled in Bonbright's time, it is time to refine concepts that were appropriate in 1992, but might not be today. This means reexamining utility practices and assumptions around system planning and operations to see if the CCOSS correctly reflects them in their current form or how they may change in the near- or longer-term, based on new utility software and related process changes. For example, as battery storage and advanced inverters improve the load factor of rooftop solar in the near term, CCOSS load assumptions and methodology choices may need to shift to reflect that change.

## Questions Regulators Can Ask to Make Rate Structure Proposals Useful

What current reality of how utility customers use the system is the rate structure proposal attempting to change?

What is the proposer's hypothesis regarding why the rate structure proposal will cause this change? What may be necessary in addition to the rate change to accomplish this? What might act as barriers to the rate structure accomplishing this?

Will the rate structure change have any effect on the utility's decision-making and, if so, how?

What other consequences -- intended or unintended -- might occur as a result of the rate structure change?

Do better means outside of rate structure, and possibly outside of the regulatory arena, exist to bring about this change?

## Conclusion

The growing complexity of energy markets and utility regulation has fueled a desire to rely more and more on the CCOSS as a tool not just to construct class revenue requirements, but also to design rates. This is not the first time that rate structure has been front and central—it occurs every time there is a challenge to the electric utility industry's competitiveness. Boosting the CCOSS into its new role are two trends: big data, and the hope for quantitative and objective decision-making support. But the CCOSS is not innately objective, and parties' reliance on it calls into question not just whether the assumptions and methodologies within the CCOSS are valid, but also whether the CCOSS is still the correct tool to be using to make the difficult decisions that regulators face.

Ultimately, there is no innately "good" or "bad" rate structure. There are only rate structures that, over time, move you closer to your goals and those that move you further away from them. Regulators should ask the questions described below to help ensure they understand the objectives and realities of rate decisions. The desire to make rate structure, and particularly the design of certain rate schedules, a problem that is solved by applying the CCOSS is, in fact, part of the problem.

## APPENDIX 1: Steps in the Cost of Service Study (Actual Study Steps in Blue)

The amount of money that that a utility must collect from its customers to pay for capital costs, manage expenses like salaries, and provide a return to its investors is called a revenue requirement (and more specifically, a "base" revenue requirement, which is distinct from costs collected through riders or adjustments). A CCOSS mathematically derives the "cost to serve" particular types of customers—it uses engineering, load, and accounting data to allocate the utility's revenue requirement between customers based on how they use the utility's system and services. This concept is known as "cost causation." Importantly, this is not the cost to serve any one unique individual, but a simplified (typically average) result based on how that *type* of customer *tends* to use the utility's overall system. A CCOSS has four key steps—functionalizing, classifying, allocating, and constructing class revenue requirements—but there are eight overall steps in the life cycle, from creating underlying data to verifying that the proposed rates will lead to the right amount of revenue.

### Conduct Load Research

Many of the important steps in the CCOSS require load data (generally for a twelve-month period) and at a daily, hourly, or sub-hourly basis. Utilities may need to install special interval meters on customers' premises if their meters do not ordinarily provide this level of granularity. Load research generally samples a cross-section of established customer classes. This load data may be normalized, or "smoothed", to remove anomalous weather in a particular year.

### Set the Revenue Requirement

The revenue requirement (which may be "jurisdictionalized" to a utility's state service territory) is the amount of funding a utility needs to cover its capital and operating expenses. Utilities and regulators make numerous key decisions in setting the revenue requirement, including establishing the historic or forecast "test year" used to check whether cost estimates are valid. Some states treat rate cases in phases, starting with the setting of the revenue requirement, followed by a second phase for regulatory approval of rate structure. A utility may prepare a CCOSS for either phase, or both. After the revenue requirement has been set, the subsequent steps of the CCOSS, as well as the rate design process, become a zero-sum game: costs that are not allocated to some customers must be allocated to others.

### Functionalize Costs

Functionalization is the first step in breaking down the approved revenue requirement into its component parts to draw conclusions about cost causation. In general, functionalization follows the categories set in the Federal Energy Regulatory Commission's Uniform System of Accounts.[66] This means that capital and operating costs are categorized based on whether they relate to the power generation ("production"), transmission, distribution, customer service, or administrative and general ("A&G") functions.

### Classify Costs

Next, a CCOSS analyst must analyze each functionalized set of costs and decide whether the cost was created because customers used electricity, needed electric capacity, or simply connected to the electric system. These costs are then classified as "energy-related," "demand-related," or "customer-related." This step informs how those costs are allocated in the next step—for example, by kWh, kW, or number of customers. Note that A&G does not obviously fit into any of these classifications.

### Develop Allocators

In the allocation step, the analyst uses load research and historic billing determinants (and sometimes projections) to develop customer class-specific mathematical "allocators" based on the functionalized and classified costs.

### Spread Costs to Classes

After costs are functionalized, classified, and allocated, they are reconstituted into customer class- and schedule-specific revenue requirements. These customer class revenue requirements are compared to actual revenues collected from the customer class at current and proposed rates in order to provide perspectives on how to allocate changes in the overall revenue requirement. If a given rate schedule does not generate enough revenue to cover what the CCOSS shows to be its allocated revenue requirement, and another rate schedule generates more than what it should have, parties may propose that a rate decrease be assigned to the rate schedule recovering more and a rate increase be assigned to the rate schedule recovering less.

### Design Rates

Given the revenue requirement allocated to each rate class, the question then turns to the type of charges by which those customers should pay for the service they take. The most common types, shown below, are called "billing determinants":

#### Customer or Account Charge

A fixed dollar amount paid every billing period.

#### Demand Charge

A rate charged for the kilowatts ("kW") of demand that the customer needs to use electricity. The charge is generally based on the customer's demand at either their individual peak ("non-coincident") or the system's overall peak ("coincident"). The price for a kW may differ depending on the time of day or season in which the peak occurs.

#### Energy Charge

A rate per kWh for the electricity used during the billing period. The rate may differ depending on the time of day or the season in which it was used, or both. It may also increase the more electricity the account uses in a given billing period (inclining block rates) or decrease the more electricity is used (declining block rates).

### Prove the Revenue

The approved rates multiplied by billing determinants must roughly equal the approved revenue requirement. Billing determinants must be something the utility can count (such as accounts on a given rate schedule) or measure (such as kWh or kW) and either keep a record of (if the rate case is being done on a historic test year basis) or forecast (if a future test year is being used)—in other words, they have to be able to demonstrate that the billing determinants they are using are appropriate.

## Appendix 2:

# Principles of Public Utility Rates

| | 1961 Bonbright Criteria | 1988 Bonbright Criteria (Differences Italicized) |
|---|---|---|
| 1 | The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application. | The related "practical" attributes of simplicity, *certainty, convenience of payment, economy in collection*, understandability, public acceptability, and feasibility of application. |
| 2 | Freedom from controversies as to proper interpretation. | Freedom from controversies as to proper interpretation. |
| 3 | Effectiveness in yielding total revenue requirements under the fair-return standard. | Effectiveness in yielding total revenue requirements under the fair-return standard *without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.* |
| 4 | Revenue stability from year to year. | Revenue stability from year to year *with a minimum of unexpected changes seriously adverse to utility companies.* |
| 5 | Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.") | Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers *and with a sense of historical continuity.* (Compare "The best tax is an old tax.) |
| 6 | Fairness of the specific rates in the apportionment of total costs of service among the different consumers. | Fairness of the specific rates in the apportionment of total costs of service among the different *ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e ., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).* |
| 7 | Avoidance of "undue discrimination" in rate relationship. | Avoidance of "undue discrimination" in rate relationship *so as to be, if possible, compensatory (i.e ., subsidy free with no intercustomer burdens).* |
| 8 | Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:<br>(a) in the control of the total amounts of service supplied by the company;<br>(b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.). | *Static* efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:<br>(a) in the control of the total amounts of service supplied by the company;<br>(b) in the control of the relative uses of alternative types of service (on-peak versus off-peak *service or higher quality versus lower quality service).* |
| 9 | | *Reflection of all the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities.)* |
| 10 | | *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply programs.* |

## APPENDIX 3: The Three Classification Methodologies

The classification of customer-related costs is particularly controversial, as utilities may be tempted to recover those costs through uniform fixed charges that are applied to each customer in a class. The NARUC Manual explains considerations related to selecting between certain methodologies, but it does not take a position on the use of one over another.[67]

**Minimum-Size Method ("Minimum System")**
An analyst applying this method attempts to construct a bare-bones version of the electric system based on the number and location of utility customers, and says that the costs of that minimum system are customer-related rather than demand-related.

**Zero-Intercept Method**
An analyst applying this statistical methodology interpolates the size of the system where there is zero customer load, and calls the costs associated with that size of system customer-related.

**Basic Customer Method**
An analyst applying this method asserts that the only costs directly attributable to customers are those on the basic service line, and that all other costs relate to demand or energy use.[68] (This approach was not put forward in the NARUC Manual, but has been accepted in some states.)

There is no national consensus on the "best" classification methodology to use, and the approved methodologies may vary by state:

**Kentucky (2000)**
"As it has stated in numerous orders over the last decade, the Commission believes that the zero-intercept methodology is the more acceptable way to divide distribution main costs into demand-related and customer-related components."[69]

**Minnesota (2016)**
"The Commission is persuaded, on valid theoretical grounds, that the minimum-system studies over-allocate distribution costs to the customer component."[70]

**Oregon (1998)**
"The zero-intercept approach can be used in limited circumstances, but is not sufficiently robust to be used for all distribution cost calculations."[71]

**Indiana (2011)**
"In addition, we find the minimum distribution system calculation to be less subjective than Mr. Heid's zero-intercept method."[72]

## END NOTES

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[1] James C. Bonbright, Principles of Public Utility Rates (1961) ["Bonbright 1961"]; James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, Principles of Public Utility Rates (1988) ["Bonbright 1988"].

[2] Out of its 198 pages, the NARUC Manual includes only one paragraph addressing the use of cost of service studies in designing rates. See page 13. That paragraph states "Regulators design rates, the prices charged to customer classes, using the cost incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance."

[3] Bonbright 1961 at p. 367.

[4] The commonly referenced customer classes are residential, small commercial, large commercial, and industrial. The latter two, in particular, generally have more than one rate schedule associated with them. What characterizes residential and small commercial rate designs more than any other feature is the absence of a demand charge.

[5] *See generally* Cathy O'Neil, Weapons of Math Destruction (2016).

[6] Based on EQ Research general rate case data accessed February 9, 2017.

[7] Public Service Commission of Wisconsin, 6690-UR-124, Direct Testimony of Ronda L. Ferguson (May 15, 2015) at pp. 8-11, available at: http://psc.wi.gov/apps40/dockets/content/detail.aspx?dockt_id=6690-UR-124 [cites Bonbright at p. 2] (WPSC "installs standard size facilities for residential customers… [and] has no control over equipment that customers choose to install…").

[8] This trade-off has long kept some commissions from approving customer charge increases. See, e.g., Washington Utilities and Transportation Commission, Docket UE-140762 consolidated, Order 08, March 25, 2015, p. 91 ("The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals").

[9] Large commercial and industrial, but generally not street lighting accounts.

[10] Oklahoma Gas & Electric, Docket No. PUD 201500273 (December 18, 2015); Arizona Public Service Company, Docket No. E-01345A-16-0036 (June 1, 2016).

[11] Oklahoma Corporation Commission, PUD 201500273, Direct Testimony of Ahmad Faruqui (December 18, 2015) at p. 4, available at: http://imaging.occeweb.com/AP/CaseFiles/occ5248973.pdf.

[12] See, e.g., Direct Testimony of H. Edwin Overcast on behalf of Tucson Electric Power Company and UNS Electric, Inc., Docket No. E-00000J-14-0023.

[13] This section is drawn from Kahn (The Economics of Regulation: Principles and Institutions); Charles F. Phillips, Jr., The Regulation of Public Utilities (1988); and Paul J. Garfield and Wallace F. Lovejoy, Public Utility Economics (1964).

[14] *See* Smyth v. Ames, 169 U.S. 466 (1898); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

[15] Bonbright 1961 at p. 287.

[16] See 1st District Appellate Court of IL, Chicago v. Illinois Commerce Com, 133 Ill. App. 3d 435, 5/13/85, at p. 444 ("Moreover, although class cost of service is the prime criterion the Commission looks at in determining the proper allocation among customer classes, it is not the only criterion the Commission may consider. Section 32 of the Public Utilities Act allows the Commission to consider 'other relevant factors.' (Ill. Rev. Stat. 1983, ch. 111 2/3, par. 32.) Our supreme court has held that those other relevant factors are not exclusively related to cost factors… Considerations of rate continuity or the desirability of making changes gradually can properly limit changes in rate design."); see also International Minerals & Chemical Corp. v. Mayo, 336 So. 2d 548 (1976 Fla. LEXIS 4463) at p. 551-552 ("Practical considerations also militate against making cost of service the exclusive criterion in rate setting. Virtually every court considering the matter has rejected out of hand a rule that would reduce ratemaking to an exercise in cost accounting… Factors like those testified to by TECO's expert, *viz.*, 'rate history and experience of the utility, the consumption and load characteristics of the various classes of customers, value of service, public acceptance of rate structures which have been in effect in the past without serious dissatisfaction, and conservation of energy' were all properly considered by the PSC, even though these factors are not specified by statute"); 1975 Mich. PSC LEXIS 3, Nov. 24, 1975, U-4698 & U-4718 ("The Commission has repeatedly stated that cost of service is not the sole criterion for the structuring of rates… Such rigid and doctrinaire adherence to cost of service does not provide a reasonable basis for the Commission to design rates."); 1976 Wash. UTC LEXIS 4, Sept. 27, 1976, U-76-1 ("Insofar as required reliance on a cost of service, a recent decision by the Florida Supreme Court, International Minerals v. Florida Commission, decided June 4, 1976, P.U.R. No. 22,351, page 50, 933, stated that practical considerations militate against making cost of service an exclusive criterion in setting rates; that most every court considering the matter has rejected out of hand the rule that would reduce ratemaking to an exercise in cost accounting.").

[17] Richard Hirsh, Technology and Transformation in the American Electric Utility Industry (2003) at p. 56.

[18] See, e.g., James E. Suelflow, Public Utility Accounting: Theory and Application (1973) at p. 59-62; Bonbright.

[19] Joseph Eto, The Past, Present, and Future of U.S. Utility Demand-Side Management Programs (1996) LBNL-39931, available at: https://emp.lbl.gov/sites/all/files/39931_0.pdf.

[20] Richard Hirsch. Energy Crisis of the 1970s (2002) Smithsonian Institution, available at: http://americanhistory.si.edu/powering/past/history3.htm.

[21] See, e.g., Richard L. Carlson and Donald J. Sipe, Guidelines for Granting Industrial "Distress" Rate Discounts, Public Utilities Fortnightly (January 15, 1995) at p. 18 ("Increasingly we see electric utilities offering discounted rates to targeted customers or classes to offset rising competition."); Discounts Defined, Public Utilities Fortnightly (July 15, 1996) at p. 29 ("To date, at least 41 states have allowed economic development rates, 34 states have allowed load retention rates, 4 states have established flexrates, and 5 have ok'd some form of broad-based PBR [performance-based rates].").

[22] See, e.g., American Society of Civil Engineers, 2013 Report Card for America's Infrastructure, http://www.infrastructurereportcard.org/a/#p/energy/overview, and U.S. Energy Information Administration, Electricity distribution investments rose over the past two decades (2014), available at: http://www.eia.gov/todayinenergy/detail.cfm?id=18531.

[23] EEI, Electric Utility Industry Financial Data and Trend Analysis, available at: http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx; and EEI, Electric Power Industry Capital Investment Expected to Remain at Record Level, available at: http://www.eei.org/resourcesandmedia/energynews/Pages/Electric%20Power%20Industry%20Capital%20Investment%20Expected%20to%20Remain%20at%20Record%20Level.aspx

[24] Non-capital costs are largely operating and maintenance expenditures and administrative and general expenditures. The fuel/purchased power component of these is usually separately handled under and automatic adjustment clause.

[25] Department of Energy, Large Power Transformers and the U.S. Electric Grid (2012) at p. 28, available at: https://energy.gov/sites/prod/files/Large%20Power%20Transformer%20Study%20-%20June%202012_0.pdf; ASCE, Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure (2011) at p. 37, available at: http://www.asce.org/uploadedFiles/Issues_and_Advocacy/Our_Initiatives/Infrastructure/Content_Pieces/failure-to-act-electricity-report.pdf; EIA, Investment in electricity transmission infrastructure shows steady increase (2014), available at: http://www.eia.gov/todayinenergy/detail.php?id=17711; EIA, Electricity distribution investments rose over the past two decades (2014), available at: http://www.eia.gov/todayinenergy/detail.php?id=18531.

[26]EIA, Annual Energy Outlook 2015 with projects to 2040 (2015), at p. 8, available at: https://www.nrc.gov/docs/ML1617/ML16172A121.pdf.

[27] E. Kahn, Regulation by Simulation: The Role of Production Cost Models in Electricity Planning and Pricing, Operations Research, Vol. 43 No. 3 (May-June 1995), at pp. 388-398.

[28] Bonbright 1961 at p. 339 ("[b]ut comprehensive apportionments have been presented officially in only a tiny fraction of the rate cases.").

[29] National Regulatory Research Institute, Alternative Rate Mechanisms (March 1, 2014) available at: http://nrri.org/download/nrri-14-03-alternative-rate-mechanisms/; AARP, Inc., Increasing Use of Surcharges on Consumer Utility Bills (May 2012) available at: http://www.aarp.org/content/dam/aarp/aarp_foundation/2012-06/increasing-use-of-surcharges-on-consumer-utility-bills-aarp.pdf.

[30] EEI Q4 2016 Financial Update [EEI Q4 2016], available at http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx; American Public Power Association, U.S. Electric Utility Industry Statistics (2015-2016), available at: http://www.publicpower.org/files/PDFs/USElectricUtilityIndustryStatistics.pdf.

[31] News articles state that Florida Power & Light will spend $4.9 million on its 2016 rate case, e.g., Palm Beach Post, FPL customers paying $4.9 million for rate case (August 23, 2016), available at: http://www.mypalmbeachpost.com/news/business/fpl-customers-paying-49-million-for-rate-case-cost/nsK4B/. In its final order, the Public Utilities Commission of Texas approved over $3 million in rate case expenses for El Paso Electric and its municipalities, minus $600,000. Docket No. 44941, Order (August 25, 2016) at p. 8-9.

[32] Hethie Parmesano and Jeff D. Makholm, The Electricity Journal, The Thaw: The End of the Ice Age for American Utility Rate Cases – Are You Ready? (2004), available at: http://www.nera.com/content/dam/nera/publications/archive1/The%20Thaw%20End%20of%20Ice%20Age%20July%202004.pdf; Energy Times, Crafting your Next Rate Case (January 1, 2005) available at: http://tdworld.com/business/crafting-your-next-rate-case.

[33] EEI Q4 2016.

[34] National Association of State Utility Consumer Advocates, available at: http://nasuca.org/about-us/.

[35] For example, the service list for PG&E's 2017 rate case (A.15-09-001) includes a certificate of service with 29 named parties.

[36] See, e.g., monthly residential fixed charge increase proposals from Alliant Energy in Wisconsin ($7.67 to $18.00 in 660-UR-120); Delmarva Power in Delaware ($11.70 to $17.47 in 16-0649); Unitil in New Hampshire ($10.27 to $15.00 in DE 16-384); and Penelec in Pennsylvania ($9.99 to $17.10 in R-2016-2537352), among many others.

[37] See, e.g., National Grid's filings in Rhode Island (Docket 4568, filed July 1, 2015) and Massachusetts (Docket 15-155, filed November 6, 2015).

[38] Colorado Public Utilities Commission, Proceeding No. 16AL-0048E (Public Service Company of Colorado, filed January 25, 2016).

[39] See, e.g., Tucson Electric Power (Arizona, E-01933A-15-0322); El Paso Electric (Texas, 44941); and Montana-Dakota Utilities (Montana, D2015.6.51), among others.

[40] See, e.g., Unisource Energy Services (Arizona, E-04204A-15-0142), among others.

[41] Other foundations monopolies and quasi-monopolies used to price service in the first half of the 20th century included value of service and promotion of the service.

[42] Bonbright 1961 at pp. 27-28.

[43] A fourth function, "compensatory income transfer from buyer to seller," is usually subsumed within the capital attraction function.

[44] Bonbright 1961 at p. 301.

[45] Even CCOSSs performed on a marginal cost basis tend to assume the system, and usage patterns, as they are, rather than how they could be.

[46] Bonbright 1961 at pp. 80-81.

[47] Id.; Bonbright 1988 at p.114.

[48] The first edition adds this, reflecting one of the major arguments of the 1950s with respect to ratemaking: "I do not believe that the arguments on behalf of replacement-cost pricing of utility services are well taken. On the contrary, I am convinced that some version of an actual-cost basis of rate making, with its frank acceptance of a sunk-cost price philosophy, is preferable for practical reasons and is by no means inferior for reasons of price theory. But the deficiencies of a sunk-cost standard of rate making should be recognized; and they are especially serious in the determination of the individual rate schedules as distinct from the general rate levels." Bonbright 1961, at p. 76.

[49] Bonbright 1961 at pp. 295-296.

[50] Bonbright 1988 at p. 116.

[51] Sean Casten and Joshua Meyer, Public Utilities Fortnightly, Cross-Subsidies: Getting the Signals Right (2004) available at: http://www.fortnightly.com/fortnightly/2004/12/cross-subsidies-getting-signals-right.

[52] See, e.g., Direct Testimony of Scott J. Rubin on behalf of Arizona Utility Ratepayer Alliance (February 3, 2017) Docket No. E-01345A-16-0123.

[53] Bonbright 1961 at pp. 37-38 (emphasis in original); Bonbright 1988 at p. 79.

[54] Bonbright 1961 at p. 35 (emphasis in original).

[55] As another example, if non-coincident peak demand is important for customers at the circuit level—and many utilities argue that it is—should rates consider geographic diversity, instead of being assessed like postage stamps? See, e.g., Colorado PUC, Proceeding No. 16AL-0048E, Direct Testimony of Dolores R. Basquez at pp. 30-32 (January 25, 2015) (discussing load diversity). In contrast, some Alaskan utilities have geographically diverse rates, such as Alaska Power Company (see, e.g., Docket TA857-2).

[56] Rhode Island PUC Docket 4568, Workpaper NG-3, at p. 3; Oklahoma Corporation Commission, PUD 201100087, Direct Testimony of Greg Tillman (July 28, 2011) at p. 21; P. Chernick et al., Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers (2016).

[57] P. Chernick et al., Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers (2016) at p. 19.

[58] Hethie Parmesano and Jeff D. Makholm, The Electricity Journal, The Thaw: The End of the Ice Age for American Utility Rate Cases – Are You Ready? (2004) available at: http://www.nera.com/content/dam/nera/publications/archive1/The%20Thaw%20End%20of%20Ice%20Age%20July%202004.pdf

[59] See, e.g., Direct Testimony of George Novela on behalf of El Paso Electric (May 11, 2015) Docket No. NMPRC 15-00127-UT, at pp. 8-10.

[60] See, e.g., Direct Testimony of William A. Monsen on behalf of the Alliance for Solar Choice (October 27, 2015) Docket No. 15-07041, at p. 10, available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/6655.pdf.

[61] NARUC, Electric Utility Cost Allocation Manual (1992) at p. 67 ["NARUC Manual"] ("no method is prescribed by regulators to be followed exactly" and "The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives.").

[62] NARUC Manual at p. 105.

[63] The sum of these rate class/schedule revenue requirements may not be the utility's total revenue requirement, particularly if the Commission has adopted a policy of basing rate spread and design on marginal cost of service rather than embedded cost of service.

[64] Decoupling is defined as "a rate adjustment mechanism that breaks the link between the amount of energy a utility sells and the revenue it collects to recover the fixed costs of providing service to customers… decoupling allows automatic or semi-automatic price adjustments, which ensures recovery of the allowed revenue amount as prices are adjusted so that the allowed revenue is recovered… and this removes the incentive for utilities to increase sales as a means of increasing revenue and profits…" National Renewable Energy Laboratory, Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities (December 2009) at p. 1, available at: http://www.nrel.gov/docs/fy10osti/46606.pdf.

[65] Arizona Corporation Commission, Docket No. E-00000J-14-0023, Decision No. 75859 (January 3, 2017), at pp. 21-22, 143-145.

[66] Because many, if not most, utilities maintain books that conform with the Federal Energy Regulatory Commission's Uniform System of Accounts, functionalization can rely on questions of accounting interpretation rather than modeling or engineering data.

[67] NARUC Manual at pp. 90-95.

[68] See, e.g., 1993 Wash. UTC LEXIS 65 at pp. 16-17 ("The company proposed to classify distribution costs using the Basic Customer method, which treats substations, poles, towers, fixtures, conduit, and transformers as demand-related. Service drops and meters are classified as customer-related… The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past."). Alaska appears to generally prohibit any classification methodology other than basic customer, according to 3 A.A.C. 48.540 on Cost of Service Methods ("Customer costs may include (A) carrying costs associated with service lines from the transformer to the meter, meters, and installation on customer premises; and (B) meter-reading expense, customer installation expense, meter maintenance, and customer accounting and billing expense. (2) Customer costs may not include (A) any portion of the distribution system costs, which will be considered and classified as demand-related costs; (B) any portion of the transmission system; or (C) any portion of the generation system."); 2016 Minn. PUC LEXIS 254, pp. 71-72, 80 (finding for a natural gas utility that "The Basic Customer method reflects the premise that the distribution system is a shared asset designed and built to provide the capacity to serve customers during periods of peak demand, and thus should generally be regarded as capacity cost. Only costs that can be traced back to a specific customer --such as the costs of service lines, meters, billing, and collection--are classified as customer costs… In addition, the Commission will also direct Great Plains to file in its next rate case an alternative CCOSS using the Basic Customer method. Having both studies will better illuminate how the choice of analytical method influences the costs assigned to each customer class.").

[69] Kentucky Public Service Commission, Case No. 2000-080 on Louisville Gas & Electric's natural gas rate case (2000 Ky. PUC LEXIS 1356, at pp. 92-93).

[70] Minnesota Public Utilities Commission, G-008/GR-15-424 on CenterPoint Energy's natural gas rate case (2016 Minn. PUC LEXIS 163, at p. 127).

[71] Oregon Public Utilities Commission, UM 827 on marginal cost methodologies for electric utilities (1998 Ore. PUC LEXIS 246, at p. 8).

[72] Indiana Utilities Regulatory Commission, Cause No. 43839 on Southern Indiana Gas & Electric's electric rate case (2011 Ind. PUC LEXIS 115, at pp. 200-201).