BEFORE THE

PUBLIC UTILITIES COMMISSION

OF NEW HAMPSHIRE

UNITIL ENERGY SYSTEMS, INC.	)	
REQUEST FOR CHANGE IN RATES	)	**Docket DE 21-030**

Direct Testimony of
Melissa Whited and Ben Havumaki

On Behalf of
The Office of Consumer Advocate

November 23, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A **Ms. Whited:** My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A **Mr. Havumaki:** My name is Ben Havumaki. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q Please summarize your professional and educational experience.

A **Ms. Whited:** I have 12 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models, performance incentive mechanisms, and rate design. In 2015, I was the lead author of a report for the Western Interstate Energy Board titled "Utility Performance Incentive Mechanisms: A Handbook for Regulators," and I have presented on performance incentive mechanisms to the National Association of Regulatory Utility Commissioners, National Governor's Association Learning Lab on New Utility Business Models, Midwest Governors' Association, and the Minnesota e21 Initiative working group.

I have sponsored testimony before the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Georgia Public Service Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Maryland, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Schedule MWBH-1.

A **Mr. Havumaki:** I have five years of experience in the energy field. At Synapse, I focus on ratemaking, rate design, performance-based regulation, and related regulatory issues. I am also regularly engaged in macroeconomic modeling and benefit-cost analysis (BCA). Prior to being hired by Synapse, I worked for the World Bank on a consulting team that authored a field manual on cost-benefit analysis for practitioners in the developing world.

I have sponsored testimony before the Georgia Public Service Commission and the Rhode Island Public Utilities Commission. I hold a Master of Arts in Applied Economics from the University of Massachusetts. My resume is attached as Schedule MWBH-2.

Q On whose behalf are you testifying in this case?

A We are testifying on behalf of the Office of the Consumer Advocate (OCA).

Q What is the purpose of your testimony?

A The purpose of our testimony is to address certain aspects of the rate application of Unitil Energy Systems, Inc. ("UES" or the "Company"). Specifically, our testimony addresses the Company's proposed multi-year rate plan, grid modernization proposal, overall rate increase for the residential class, allocation of costs among the rate classes, increase to the residential customer charge, and revenue decoupling mechanism. We do not address all aspects of the Company's proposal; silence on any issue should not necessarily be taken as acceptance of the Company's proposals.

Q What materials did you rely on to develop your testimony?

A The sources for our testimony and exhibits are public documents, responses to discovery requests, and our personal knowledge and experience.

Q Was your testimony prepared by you or under your direction?

A Yes. Our testimony was prepared by us or under our direct supervision and control.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your main conclusions.

A Our conclusions are as follows:

- The Company's proposal to increase residential distribution rates by 30 percent would result in rate shock and violates the principle of gradualism. This is particularly true considering the recent increase to supply rates.

- The Company's proposal for a multi-year rate plan with annual step adjustments based on net additions to rate base is devoid of any meaningful cost control incentives or performance commitments to ratepayers. The step adjustments could result in annual distribution rate increases of more than 10 percent on top of the Company's initial distribution rate increase of 30 percent for residential customers. Such increases are unreasonable.

- The Company should not rely on the minimum system method for cost allocation or as a guide for rate design. The minimum system method is deeply flawed in both theory and application and results in the overallocation of costs to the residential class and unreasonably high customer charges.

- The Company's proposal to increase the residential customer charge by nearly $5.00 fails to comport with widely accepted rate design principles, would adversely impact many low-income customers, and runs counter to state policy aims related to energy efficiency and conservation. Moreover, the proposal is based on the minimum system method, which should be rejected.

- The Company's proposed decoupling mechanism is generally sound but should be modified to provide greater customer protections.

- The Company's proposed grid modernization investments should first be addressed in the context of a Least Cost Integrated Resource Plan, consistent with RSA 378:38, and should not be approved in this docket.

Q Please summarize your recommendations.

A We offer the following recommendations:

1. The Commission should limit distribution rate increases for any one class to 125 percent of the total system rate increase.
2. The Commission should reject the Company's proposed annual step adjustments and return to traditional ratemaking. If the Company wishes for the Commission to consider alternative ratemaking, it should file a comprehensive performance-based regulation proposal that includes cost containment incentives, tracking metrics, and a commitment to improve performance in key areas through performance incentive mechanisms.
3. The Commission should reject the use of the minimum system method for cost allocation and rate design. Instead, the Company should be required to use the basic customer method for determining customer-related costs.
4. The customer charge for the domestic schedule should be maintained at its current level of $16.22 per month.
5. The Company's proposed decoupling mechanism should be approved, but with a cap on annual upward adjustments of 2.5 percent of distribution revenues, rather than total operating revenues, in order to guard against rate volatility for customers.

6. The Commission should not approve the Company's proposed grid modernization investments in this proceeding. These investments have not been adequately vetted in the context of the Company's Least Cost Integrated Resource Plan. Thus, approval of the Company's plan, and the recovery of such costs, is premature.

III. OVERVIEW OF TESTIMONY

Q Please describe the Company's proposal for revenue increases.

A The Company is proposing to increase total distribution revenues by approximately $12 million based on the calendar 2020 test year, followed by a series of step adjustments.[1] The $12 million revenue increase would represent a total distribution revenue increase of nearly 21 percent,[2] and the annual step adjustments could potentially result in year-over-year distribution revenue increases of another 10 percent or more each year.[3]

To implement this rate increase, the Company is proposing to allocate the majority of additional costs to the residential class. Specifically, the Company proposes to increase residential distribution rates by 145 percent of the system average increase,[4] yielding a 30

[1] Testimony of Robert B. Hevert, Docket No. DE 21-030, Exhibit RBH-1, April 2, 2021, p. 32.

[2] Response to OCA 3-01, Attachment 1 (Attachment MWBH-1).

[3] The Company proposes a cap on annual step adjustments of 2.5 percent of total electric operating revenue for the previous year. In 2020, the Company's total electric operating revenue was $188 million (Schedule CGDN-2, line 17), of which only $58 million was distribution revenue (Schedule RevReq-2, page 1). Thus, a 2.5 percent cap based on 2020 total revenues translates to an 8 percent increase in 2020 distribution revenues. However, default energy service rates have recently more than doubled, meaning that the Company's proposed cap based on total revenues would be higher still for future years.

[4] Schedule RJA-3, Page 1.

percent increase in residential distribution rates in the first year, followed by subsequent rate increases with each step adjustment.

Q What factors are driving the Company's overall revenue request and its proposal to increase residential distribution rates by 30 percent in the first year?

A There are several factors driving the Company's residential rate increase proposal, the primary ones being:

1) Substantial unrecovered capital investment costs;[5]
2) Future capital investments to maintain and modernize the electric distribution system;[6] and
3) The application of the minimum system method.

Q What steps should the Commission take to address these contributing factors?

A Rate cases provide the Commission with an opportunity to carefully review the reasonableness of the Company's test year revenue requirement, which is addressed by other witnesses in this proceeding. Even more importantly, rate cases provide an opportunity to assess how well the regulatory framework is operating, particularly with respect to how the incentives provided by the framework impact the Company's incentive to undertake capital investments, which is a primary focus of our testimony. In the sections below, we describe how the utility's proposed step adjustments are devoid of

[5] Testimony of Robert B. Hevert, Docket No. DE 21-030, Exhibit RBH-1, April 2, 2021, page 22.

[6] *Ibid*.

meaningful incentives to reduce costs and are therefore likely to result in over-investment and a continuation of rapidly rising rates.

In addition to addressing the overall regulatory framework, we also address inter-class equity in cost allocation. Because the minimum system method results in inequitable cost increases for the residential class, we recommend that the Commission require the Company to discontinue use of this method and instead adopt the basic customer method for classifying costs. This finding is also important in our conclusion that the proposed customer charge increase is unjustified, although there are also many policy grounds on which to reject the Company's proposed customer charge. Finally, we find the Company's decoupling proposal to be generally reasonable, as long as it is modified to provide greater customer protections against large bill swings.

IV. THE COMPANY'S REQUESTED REVENUE INCREASE WOULD RESULT IN RATE SHOCK

Q Is a 30 percent increase to residential distribution rates reasonable?

A No, the Company's proposal is flawed for numerous reasons,[7] but especially because a 30 percent distribution rate increase would contravene widely accepted ratemaking principles by subjecting residential ratepayers to rate shock. The rate shock would be

[7] As discussed below, we have numerous concerns with the Company's overall proposal, including its cost allocation study, which suggests that the residential class should be allocated an even greater rate increase. However, regardless of the results of any cost allocation studies, a 30 percent increase should be rejected on policy grounds.

particularly severe when coupled with the newly approved default energy service charges, which have more than doubled from $0.07/kWh to $0.18/kWh.[8]

Q What ratemaking principles should be considered when setting rates?

A We recommend that the core principles advanced by Professor James Bonbright be considered when setting rates. In his seminal work, Principles of Public Utility Rates, Professor Bonbright discusses the following eight key criteria:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    a. in the control of the total amounts of service supplied by the Company;
    b. in the control of the relative uses of alternative types of service.[9]

[8] UES Default Service Compliance Tariff, Redlined, filed on October 21, 2021, available at https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-041/LETTERS-MEMOS-TARIFFS/21-041_2021-10-20_UES_COMPLIANCE-TARIFF-REDLINE.PDF; and Public Utilities Commission, DE 21-041, Order Approving Default Service Rates, Order No. 26,532, October 8, 2021, available at https://www.puc.nh.gov/Regulatory/Orders/2021Orders/26-532.pdf.

[9] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

Q Are these principles widely recognized and used by commissions?

A Yes. The principles listed above have been recognized for many years as the standard for rate design by commissions across the country. The Company also acknowledges the central role of these principles when it refers to the Bonbright's "widely-referenced treatise on utility ratemaking."[10]

Q In what way would a 30 percent increase in residential distribution rates violate Bonbright's principles?

A Bonbright's principle regarding rate stability, or gradualism, means that customer rates should not change suddenly, particularly if this will cause harm to customers by significantly increasing a customer's bill. A 30 percent increase in distribution rates coupled with a 60 percent increase in supply rates clearly violates the principle of gradualism and would result in rate shock. Large increases in customer bills will impose financial hardship on many customers, particularly low-income customers.

Q How should the Company's cost allocation proposal be modified to be consistent with the principle of gradualism?

A To comport with the principle of gradualism, we recommend that no rate class be subject to a rate increase exceeding 125 percent of the system average increase. In addition, we recommend that the Commission seek to strengthen the utility's cost containment incentives so that the Company is encouraged to operate as efficiently as possible and future rate increases are more limited. The Company's proposed step adjustments do not provide such cost containment incentives, as discussed below.

[10] Direct Testimony of John D. Taylor, Docket No. DE 21-030, Exhibit JDT-1, April 2, 2021 at 4.

I. THE COMPANY'S MULTI-YEAR RATE PLAN PROVIDES INSUFFICIENT COST CONTAINMENT INCENTIVES

Q Please describe the Company's proposed multi-year rate plan.

A Company witnesses Messrs. Goulding and Nawazelski testify that the Company is proposing a "multi-year rate plan with annual step adjustments to recover the revenue requirement of capital additions to rate base."[11] Under this rate plan, the Company would make a filing in January of each year to account for the prior year's net change in non-growth plant additions, and rate adjustments would go into effect on April 1.[12]

Q Does the Company's proposal resemble a typical multi-year rate plan?

A Not at all. What the Company has proposed is essentially a series of annual rate cases that address rate base adjustments and associated revenue requirements. Unlike typical multi-year rate plans, the Company's proposal essentially removes regulatory lag from the traditional ratemaking process without introducing new cost containment incentives to encourage the utility to operate efficiently. This represents a significant departure from traditional ratemaking and shifts the balance of risk toward customers while undermining the utility's cost control incentives. In contrast, most multi-year rate plans seek to strengthen cost containment incentives by capping the utility's allowed revenues at a meaningful level and providing financial incentives for reducing costs below the cap.

[11] Testimony of Goulding and Nawazelski, Docket No. DE 21-030, Exhibit CGDN-1, April 2, 2021, page 37.

[12] Schedule CGDN-1, page 1 (Bates 000199).

Q What mechanisms do multi-year rate plans typically employ to provide cost containment incentives?

A Cost containment incentives in multi-year rate plans are the product of multiple factors. First, annual revenue adjustments are decoupled from the utility's actual costs. The revenue adjustments[13] provide "a utility an *allowance* for cost growth rather than reimbursement for its *actual* [cost] growth."[14] Thus, there is no true-up to actual costs during the rate plan.

Because there are no true-ups to actual costs during the rate plan, the utility must live within its revenue allowance. If the utility reduces its costs during the rate plan, it is frequently allowed to retain some or all of the savings. Conversely, if the utility exceeds its allowed revenue requirement, it must absorb some or all of these excess costs.[15] This shifts both the risk and reward associated with utility cost management to utility management and shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.[16]

[13] These revenue adjustments during the rate plan period may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. If utility cost forecasts are used, care must be taken to ensure that the forecasts are reasonable and in the public interest, increasing the need for regulatory oversight and information transparency.

[14] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

[15] Earnings sharing mechanisms are a common component of multi-year rate plans and determine the extent to which the utility can keep any savings. Earnings above a certain threshold are often shared with customers. In rare cases, utility under-earnings may also be shared with customers. Of 19 utilities in the United States with earnings sharing mechanisms, only one is reported to have a symmetrical earnings sharing mechanism. The others share over-earnings only. Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch. *Alternative Regulation for Emerging Utility Challenges: 2015 Update*. Edison Electric Institute. November 11, 2015, page 37-38.

[16] However, as discussed later, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

Finally, a multi-year rate plan institutes a "stay-out period" often lasting from three to five years. This stay-out period ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge, thereby strengthening the cost containment incentives associated with the revenue cap.

Q Does the Company's proposal provide greater cost containment incentives than traditional cost-of-service regulation?

A No. Traditional cost-of-service regulation creates an inherent cost containment incentive by setting rates based on a test year and then holding those rates fixed[17] until the utility files another rate case. Assuming that sales remain the same each year, the utility can increase profits by reducing costs during the period between rate cases, since the utility generally keeps any difference between revenues and costs. On the other hand, if costs increase under cost-of-service regulation, the utility's profits will decline until the higher costs are reflected in rates in a subsequent rate case. This delay in reflecting new costs in rates is referred to as "regulatory lag," and it helps incentivize efficient utility operations.[18]

The Company's rate plan removes most of the regulatory lag associated with cost-of-service regulation by introducing annual "step adjustments." Although technically these step adjustments are subject to a cap, the cap proposed by the Company is so high as to provide very little incentive to control costs. Further, the proposal would allow the

[17] With the exception of certain cost trackers that adjust rates as costs change.

[18] Of course, under cost-of-service regulation, the utility can always file a rate case when costs exceed revenues, thereby blunting its cost containment incentives.

Company to defer costs exceeding the cap to the next rate case at the Company's cost of capital, which compensates the utility for any delay in revenue recovery, thereby gutting any remaining cost containment incentives from the rate plan.[19]

While the Company's proposal provides the utility with virtually no downside for increasing spending, it also provides the utility with no upside for reducing spending, as the revenue increase in the annual step adjustments is based on actual costs. Thus, any cost efficiencies are returned to ratepayers, eliminating incentives for the utility to seek innovative solutions that would reduce costs below allowed revenue requirements.

Q Why do you assert that the Company's proposed cap on revenue adjustments does not provide adequate cost containment incentives?

A The Company proposes that adjustments be limited to 2.5 percent of the Company's prior year total electric operating revenue, with revenue for externally supplied customers being adjusted by imputing the Company's default energy service charges for that period.[20] In other words, the cap would be based on the Company's operating revenues including all supply costs, even for customers who take service from a retail supplier. In 2020, the Company calculated its total electric operating revenue for the purposes of the rate cap as $188 million.[21] Of this amount, only 31 percent ($58 million) was distribution revenue.[22] Thus, a 2.5 percent cap based on 2020 total revenues translates to an 8 percent increase in 2020 distribution revenues. However, default energy service rates have

[19] Schedule CGDN-1, page 2 (Bates 000200).

[20] Schedule CGDN-1, page 2 (Bates 000200).

[21] Schedule CGDN-2, line 17.

[22] Schedule RevReq-2, page 1.

recently more than doubled, meaning that the Company's proposed cap based on total revenues could be even higher still for future years. Thus, the Company's proposal could easily lead to distribution revenue increases of 10 percent or more each year, which would provide negligible incentives for the utility to control its spending and result in unreasonable rate increases for customers.

Q Would a lower cap on revenue adjustments mitigate your concerns?

A A cap set much lower based on distribution revenues only or a fixed amount (rather than fluctuating with supply costs) would represent an improvement over the Company's proposal. However, the plan would still suffer from serious design flaws in that the revenue adjustments would still be based on the Company's actual spending, which limits the Company's incentives to innovate to develop more efficient ways of providing service, since the Company will not benefit from such efficiencies.

Q Does the Company's stay-out provision provide an incentive for the Company to reduce costs?

A No. The Company has proposed a stay-out provision in which it would not come in for another rate case until the end of 2024, but because the rest of the rate plan lacks meaningful cost containment incentives, the stay-out provision is largely an empty gesture.

Q Are you proposing that the Commission adopt a multi-year rate plan that reflects the components you just described?

A For the purposes of this rate case, we recommend that the Commission reject the Company's proposed step adjustments and return to traditional cost-of-service regulation. If the Company wishes to pursue a multi-year rate plan in the future, the Company should do so in the context of a comprehensive performance-based regulation proposal, consisting of a multi-year rate plan with a meaningful cap on annual revenue adjustments (ideally set based on an external index),[23] an earnings sharing mechanism, and a stay-out period; as well as performance incentive mechanisms.

Q Please explain what you mean by a "comprehensive performance-based regulation framework."

A Performance-based regulation includes both performance incentive mechanisms and multi-year rate plans. Historically, performance incentive mechanisms were implemented primarily to ensure that the cost-cutting pressures from a multi-year rate plan did not result in degradation of utility service quality. Thus, traditional performance incentive mechanisms generally focused on reliability (SAIDI, SAIFI, and CAIDI) and customer service (e.g., call center responsiveness). More recently, performance incentive mechanisms have also been implemented to better align utility incentives with state energy policy goals, such as empowering customers and accommodating distributed energy resources.

A combination of performance incentive mechanisms and a well-designed multi-year rate plan would improve the likelihood that both the utility and customers will benefit from the modified regulatory framework. Without all of these elements, customers are better served under traditional cost-of-service regulation.

[23] Ideally, the annual revenue adjustments should be tied to an external inflation index, rather than based on utility cost forecasts. If forecasts are used, they should be tied directly to the investments contained in the utility's Least Cost Integrated Resource Plan and thoroughly vetted by stakeholders first.

II. THE COMPANY'S COST ALLOCATION METHODOLOGY IS FLAWED

Q Do you have any concerns regarding the Company's cost allocation method?

A Yes. Our primary concern hinges upon the use of the minimum system method for classifying costs as demand-related or customer-related. The minimum system method classifies costs by estimating the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs customer-related. This inevitably causes too great a portion of costs to be so classified, in a manner that is theoretically flawed and inequitable.

Q Why do you maintain that the minimum system method is flawed and inequitable?

A The shortcomings of this method have been widely documented. For example, multiple pages in the Regulatory Assistance Project's 2020 manual *Electric Cost Allocation for a New Era* are devoted to examining the flaws of the minimum system method. The relevant pages from the manual are included as Attachment MWBH-2, and key critiques of the minimum system method from the RAP manual are summarized below:[24]

1) The hypothetical "minimum system," used as the basis for this cost allocation method, still has the ability to serve some load—often a large portion of a typical residential customer's load. Without correcting for this, the minimum system overstates the customer-related costs.

[24] Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era: A Manual" (Regulatory Assistance Project, 2020), 145–49, https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

2) A large portion of the cost of the distribution system (e.g., the number of poles and length of conductors) is driven by the size of the territory served, rather than the number of customers.

3) The minimum system method generally uses commonly installed minimum sizes, rather than the smallest equipment ever used, currently in use, or that could be used. However, a key reason for using larger equipment is due to higher customer demands, and thus the minimum size currently in use does not represent the true minimum that would be required for a hypothetical minimum system.

4) The hypothetical minimum system is assumed to have the same number of units (number of poles, feet of conductors, etc.) as the actual system. In reality, both the size of equipment and the number of units is often driven in part by load.

5) Increasing the number of customers in an area without increasing demand can be accomplished with no additional poles or conductors.

The manual concludes that the "minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related."[25]

[25] Lazar, Chernick, and Marcus, 146.

Q Do you have any additional concerns with the minimum system method as applied by the Company?

A Yes. In addition to the numerous theoretical flaws inherent in the minimum system method, the Company did not apply the method in a manner consistent with the 1992 NARUC *Electric Utility Cost Allocation Manual*.[26] Instead of using the book cost associated with distribution system components, the Company escalated the costs of the hypothetical minimum system to 2020 dollars according to the Handy Whitman index. The Company then computed the share of customer-related costs as a percentage of the total revenue requirement for that portion of the distribution system. However, since the remainder of the revenue requirement was *not* escalated to 2020 dollars, the Company's method significantly overstates the portion of costs that should be classified as customer-related under the minimum system method.

Q Why is it problematic to escalate the minimum system costs without escalating the rest of the costs in the revenue requirement?

A The Company's approach is problematic because it does not compare cost categories on an apples-to-apples basis. Instead, costs classified as customer-related are escalated to 2020 dollars, while the remaining costs in the utility's revenue requirement are not.

Q How large of an impact does using 2020 dollars for minimum system costs have on the allocation of revenues to the residential class?

A We estimate that the costs allocated to the residential class are overstated by 32 percent due to escalating the minimum system costs to 2020 dollars. We calculated this by using

[26] NARUC, *Electric Utility Cost Allocation Manual* (Washington, DC: National Association of Regulatory Utility Commissioners, 1992).

the accumulated costs in the Company's minimum system workpaper,[27] rather than those same costs multiplied by the escalation factor from the Handy-Whitman index.[28] This resulted in a much smaller portion of costs in each distribution account being classified as customer-related. The difference in the proportion of costs classified as customer-related are summarized in the table below. For example, the portion of Account 364 (poles, towers, and fixtures) classified as customer-related falls from 45 percent to 13 percent for the primary system and from 46 percent to 13 percent for the secondary system.

Table 1. Portion of costs classified as customer-related using escalated and non-escalated costs

		Primary		Secondary	
Acct	**Description**	**Escalated to 2020$**	**No Escalation**	**Escalated to 2020$**	**No Escalation**
364	Poles, towers, & fixtures	45%	13%	46%	13%
365	Overhead conductors & devices	51%	12%	71%	12%
367	Underground conductors	69%	29%	36%	13%
368	Transformers	N/A	N/A	54%	18%

Q What method do you recommend using instead of the minimum system?

A We recommend using the basic customer method. Under this method, only the meter, service drop, and billing/collection costs would generally be classified as customer-related.

Q Why do you recommend the basic customer method instead of the minimum system method?

A The basic customer method adopts Bonbright's definition of customer-related costs as the "costs found to vary with the number of customers regardless, or almost regardless, of

[27] Provided in response to Staff 2-30, Attachment 4

[28] The accumulated costs are provided in the workpaper in sheet "Acct 364 to 368 vintage qty" column E.

power consumption."[29] As stated by the RAP manual, the "basic customer method for classification is by far the most equitable solution for the vast majority of utilities."[30] The manual notes that the basic customer method is currently used by jurisdictions across the country, including Arkansas, California, Colorado, Illinois, Iowa, Massachusetts, Texas, and Washington.[31]

III. THE COMPANY'S PROPOSAL TO INCREASE RESIDENTIAL CUSTOMER CHARGE SHOULD BE REJECTED

Q Please describe the Company's proposed increase to the residential customer charge.

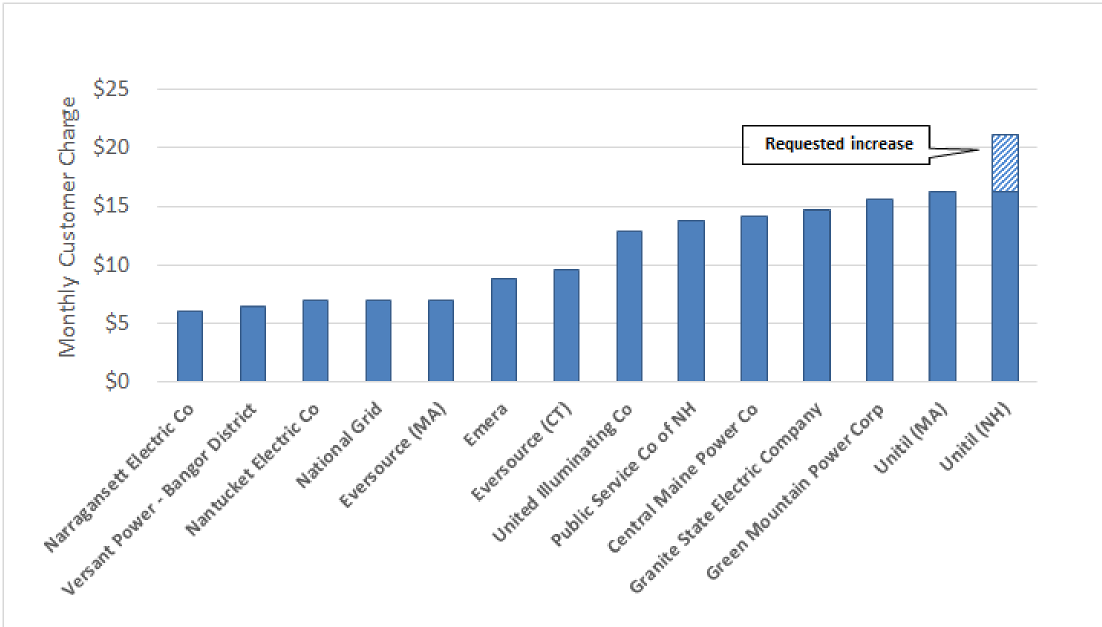
A The Company proposes to increase the residential customer charge by nearly $5.00—from $16.22 per month to $21.07 per month. We note that the Company's current customer charge of $16.22 is already the highest in New England. If the Company's proposed increase in the customer charge were to be granted, it would make its domestic rate a true outlier among its peers. We compare the Company's customer charge and the proposed increase to those of its peers in New England in Figure 1, below.

[29] James Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), 347.

[30] Lazar, Chernick, and Marcus, "Electric Cost Allocation for a New Era: A Manual," 145.

[31] Lazar, Chernick, and Marcus, 145.

Figure 1. Monthly Customer Charges for Investor-owned Utilities in New England[32]



Q Other than being out of step with other utilities in the region, is the proposed increase to the residential customer charge reasonable?

A No, for several reasons. First, the proposed increase to the customer charge is based on the flawed minimum system method, as discussed above. Second, the increase is inconsistent with the principle of gradualism. Third, the increase would undermine public policy goals.

Q Please explain how the Company's proposed increase to the customer charge would violate the principle of gradualism.

A If the currently proposed increase were to be granted, the result would be a customer charge that has increased by approximately 150 percent since 2011, from $8.40 per month to $20.07 per month. Moreover, the proposed increase in the customer charge

[32] Customer charge data for New England utilities sourced from utility tariffs.

would alter the rate structure of the domestic schedule by continuing the trend toward an increasingly fixed overall bill.

Q Is the proposed increase to the customer charge consistent with cost causation?

A No. Although the Company claims that the higher customer charge would bring it closer to the actual marginal customer cost,[33] this claim is based on the flawed minimum system method. Applying the basic customer method to the Company's cost allocation model results in a monthly residential customer charge of $17.79, which is closer to the current customer charge than the Company's proposal.[34] However, it is widely recognized that rate design should not blindly adhere to cost allocation results, and there are numerous other factors that should be considered when designing rates.

Q Why should cost allocation results not be applied directly to rate design?

A The results of a cost allocation study are just one factor among many that should be considered when designing rates. It appears that the Company recognizes this point, too, as it notes that rate design, "must necessarily include the exercise of judgement, as both quantitative and qualitative information must be evaluated before reaching a final rate design determination."[35] Thus, rate design is a product of both policy considerations and cost causation analyses.

[33] Direct Testimony of John D. Taylor, Docket No. DE 21-030, April 2, 2021 at 7.

[34] To perform this calculation, all secondary distribution system components were removed from the "customer" classification in the Company's cost of service model on worksheet "Input-Allocators."

[35] NH PUC. Docket No. DE 20-030. Direct Testimony of John D. Taylor, at 5.

Q Do you recommend increasing the customer charge to $17.79 per month, as indicated by the basic customer method?

A No. We recommend maintaining the customer charge at its current level of $16.22. As noted above, cost allocation results should not be binding on rate design. In the Company's case, the customer charge for residential customers is already very high. Moreover, we have several other concerns about the impacts of another increase to this customer charge—namely that the increase would adversely impact low-income customers and undermine state policy goals related to energy efficiency, distributed generation, and customer empowerment.

Q How will the Company's rate design unfairly impact low-use customers' bills?

A The Company's proposal would place a disproportionate strain on customers that use the least energy. Low-use customers will see disproportionately large average monthly bill increases, and their bills will becoming increasingly fixed. Simply put, the lower a customer's monthly consumption, the greater the relative bill increase. This impact is clearly shown in Schedule JDT-3, the key columns of which are reproduced below in Table 2.

Table 2. Increase in total bills for residential customers by usage

Monthly kWh	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Difference	% Difference
0-100	$22.71	$27.87	$5.17	22.7%
101-200	$42.79	$48.93	$6.14	14.3%
201-300	$59.78	$66.74	$6.96	11.6%
301-400	$76.89	$84.67	$7.78	10.1%
401-500	$94.06	$102.68	$8.62	9.2%
501-750	$122.87	$132.88	$10.01	8.1%
750-1,000	$165.67	$177.74	$12.08	7.3%
1,000-1,500	$223.98	$238.87	$14.90	6.7%
1,501-2,000	$311.56	$330.69	$19.13	6.1%
2,001-3,500	$439.52	$464.83	$25.32	5.8%
3,501-5,000	$711.82	$750.30	$38.48	5.4%
600	$120.00	$129.87	$9.87	8.2%

Source: Schedule JDT-3

As shown in the table above, the lowest-usage customers will see total bill increases of 14 percent or more, while the highest usage customers will see total bill increases in the range of 6 percent.

Q Who are the low-use customers that will be most impacted by the proposed rate design?

A Customers who consume less than average generally include low-income customers and customers who have taken steps to reduce their electricity consumption—often through investing personal financial resources in energy efficient technologies or distributed generation.

Q Why do you suggest that low-income customers would be hit hard by the increased basic service charge?

A Low-income customers tend to use less energy on average. This means that higher basic service charges will raise electricity bills most for those who can least afford it.

Q On what basis do you conclude that low-income customers tend to use less energy than average residential customers?

A Regional data from the Energy Information Administration's (EIA) 2015 Residential Energy Consumption Survey (RECS) for New England shows a clear positive relationship between income and annual electricity consumption, with usage generally increasing with income, and households in the two highest income tiers consuming more than double the amount of electricity as households in the lowest income tier.[36] The correlation between income and electricity consumption is also supported by data from the U.S. Department of Energy's (DOE) Low-Income Energy Affordability Data Tool (LEAD). While the LEAD tool reports spending on energy, this can be viewed as a proxy for energy consumption. For New Hampshire, LEAD shows a clear relationship between household income and total spending on both electricity and all energy, with households in the lowest income grouping (0 percent to 30 percent of state median income) reported to spend about 47 percent less on electricity per month than households at or above the median income level.[37]

Q Shouldn't the fact that lower-income households spend less on electricity alleviate concern about the impacts of increasing the customer charge?

A On the contrary, despite spending less in absolute dollars per annum on electricity, these low-income households use a far greater share of their available funds on electricity and other energy. In other words, they face far worse energy burdens (the percentage of household income spent on energy bills). Per the LEAD data, in New Hampshire,

[36] U.S. EIA. 2015 RECS Survey Data. https://www.eia.gov/consumption/residential/data/2015/.

[37] DOE. LEAD Tool. https://www.energy.gov/eere/slsc/maps/lead-tool.

households in the lowest income group have average electricity burdens of 10 percent, and average total energy burdens of about 19 percent—a strikingly high figure.[38] In contrast, households with incomes equal to at least the state median income level have average electricity burdens of 1 percent and average total energy burdens of 3 percent. The low-income customers with the highest energy burdens will be the ones experiencing the highest rate increases as a result of the increased customer charge.

Q Does New Hampshire's Low-Income Electric Assistance Program (EAP) mitigate against these negative effects?

A Only to a limited degree. First, it is important to recognize that the EAP program does not completely shield customers from the impacts of increases in the customer charge. In its present form, the program provides a discount of between 8 percent and 76 percent on the monthly customer charge, depending on household income.[39] More critically still, many eligible customers do not receive benefits from EAP.

Q How do you know that many eligible customers do not receive benefits from EAP?

A According to the Company's most recent EAP monthly report available, out of a total 67,125 residential accounts, only 7,719 accounts received assistance.[40] While we do not have access to household income data for the Company's residential customers, we are able to estimate the overall statewide eligibility share. With an income eligibility

[38] U.S. DOE. LEAD Tool. https://www.energy.gov/eere/slsc/maps/lead-tool.

[39] NH PUC. Docket No. DE 21-030. Hearing Exhibit 3 (Temporary Rates) at 3.

[40] NH PUC. Docket No. DE 20-123.Unitil Energy Systems, Inc. EAP Monthly Report, May 2021, at 5.

threshold set at 60 percent of state median income,[41] data from the American Consumer Survey suggests that at least 25 percent of all New Hampshire households should be eligible. For the Company's service territory, this finding would imply that there were greater than 9,000 households in the Company's service territory that were eligible, but not receiving EAP assistance. In other words, it would appear that most eligible households do not receive EAP assistance. These low-income households without assistance will be particularly hard hit by the Company's proposed customer charge increase.

Q What are the equity implications of your analysis?

A Our analysis shows that rate design has important equity implications by increasing bills for some types of customers more than others. Specifically, the proposed customer charge increase would have regressive impacts by increasing bills the most for customers who can least afford it.

Q Why do you contend that raising the customer charge would contravene Bonbright's principle of discouraging wasteful usage?

A By increasing the proportion of a customer's bill that is fixed and that cannot be offset by energy efficiency or other distributed resources, the Company's proposed rate design would reduce the incentive for customers to make such investments. This effect fails to meet Bonbright's eighth principle, which is discouraging wasteful use of service. It also

[41] NH Office of Strategic Initiatives. Income Eligibility Guidelines. https://www.nh.gov/osi/energy/programs/fuel-assistance/eligibility.htm.

runs counter to state policies that aim to enhance environmental protection and encourage energy efficiency. For example:

- In NH RSA 4-E:1 (the act that established the requirement for the state's 10-year energy strategy), the state articulated a commitment to "protecting natural, historic, and aesthetic resources" and specifically called for its energy strategy to consider energy efficiency and conservation.[42]
- In NH RSA 378:37, which established the Least Cost Integrated Resource Plan standard, the state enshrined both "protection of the safety and health of the citizens" and "[protection of] the physical environment of the state" as key energy policy considerations.[43]
- In NH RSA 374-F:3, X, which lists energy efficiency among the policy principles that guided the restructuring of the electric industry.[44]

Q Has the Commission addressed the relationship between customer charges and the incentive to conserve energy?

A Yes. In the Commission's Order No. 26,122 in DG 17-048, the Commission recognized the conservation benefits of revenue recovery through variable, rather than fixed charges, writing:

[42] NH RSA 4-E:1(II).

[43] NH RSA 378:37.

[44] NH RSA 374-F:3, X.

> Because decoupling reduces the risk that the utility will not receive its expected revenue, it allows fixed charges to be reduced. It also makes variable charges, based on usage, a larger part of a customer's bill and thus encourages conservation and efficient use.[45]

While DG 17-048 concerned decoupling for gas revenues, the principle articulated by the Commission applies here—the combination of lower fixed charges and higher variable charges, all else equal, promotes conservation.

Q Have other commissions recognized the detrimental impact of higher fixed customer charges?

A Yes, the negative effects of increasing basic service charges are well-recognized. One example comes from a 2016 rate case in Maryland. While the Potomac Electric Power Company requested to increase its basic service charge for residential customers from $7.39 per month to $12.00 per month, the Maryland Public Service Commission approved a much smaller increase to only $7.60 per month and explained that the proposed change would result in customers having less control over their bills and would be antithetical to energy conservation efforts.

> In arriving at this increase, we place emphasis on Maryland's public policy goals that intend to encourage energy conservation. Maintaining relatively low customer charges provides customers with greater control over their electric bills by increasing the value of volumetric charges. No matter how diligently customers might

[45] NH PUC. Docket No. DG 17-048. Order No. 26,122, at 54.

> attempt to conserve energy or respond to AMI-enabled peak pricing incentives, they cannot reduce fixed customer charges.[46]

In 2012, the Missouri Public Service Commission rejected a proposed increase in the basic service charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[47]

Q What do you recommend regarding the residential customer charge?

A For all of the reasons discussed above, we recommend that the Commission reject the Company's proposal and retain the existing residential customer charge.

[46] MD PSC. Case No. 9418. *In The Matter of the Application of Potomac Electric Power Company for Adjustment to its Retail Rates for the Distribution of Electric Energy*, Order No. 87884, at 110.

[47] MO PSC. File No. ER-2012-0166. *In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service*, Report and Order, at 110-11.

IV. THE COMPANY'S REVENUE DECOUPLING MECHANISM SHOULD BE APPROVED, WITH MODIFICATIONS

Q Please describe the Company's proposed revenue decoupling mechanism.

A In compliance with the Commission's Order No. 25,932, the Company is proposing a revenue decoupling mechanism (RDM) that reconciles monthly actual revenues per customer to authorized revenues per customer, by rate class. Any differences between actual and authorized revenues per customer would be aggregated over a 12-month period,[48] with revenue surpluses being refunded to customers, and revenue shortfalls recovered through a surcharge. Under the Company's proposal, the RDM would apply to all classes except the proposed electric vehicle and lighting classes.[49]

Q Does the Company propose to limit the amount of annual adjustments?

A Yes. The Company proposes to cap decoupling adjustments for revenue shortfalls to 2.5 percent of total revenues from delivered sales for the most recent 12-month period to "mitigate customer bill impacts."[50]

Q Do you support the Company's revenue decoupling proposal?

A In part. We wish to first acknowledge the important role that revenue decoupling plays in aligning utility incentives with the public interest. By ensuring that a utility recovers its revenue requirement even when sales decline, decoupling mitigates a utility's disincentive to support demand-side resources (including energy efficiency and other

[48] Monthly variances would be recorded in a deferred account with carrying costs accrued at the Prime rate.

[49] Direct Testimony of Timothy Lyons, Exhibit TSL-1, pages 5-6 (Bates 001459 – 001460).

[50] Lyons, Exhibit TSL-1, page 16 (Bates 001470).

distributed energy resources). Further, full decoupling is superior to a Lost Revenue Adjustment Mechanism (LRAM), since under full revenue decoupling the utility does not benefit from increasing sales, and revenue adjustments under full revenue decoupling are simpler and less contentious to calculate than under an LRAM.

In an era of declining sales per customer, revenue decoupling also reduces the need for a utility to adjust revenues through frequent rate cases, step adjustments, or multi-year rate plans. At the same time, decoupling offers a better means for addressing revenue volatility than increasing the customer charge.

Q Do you have any concerns with the Company's proposal?

A Yes. Our primary concern is that the Company's proposed cap on upward revenue decoupling adjustments is far too large to provide adequate protection for ratepayers against rate volatility.

Q Please explain your concern that the Company's cap on decoupling adjustments does not adequately protect ratepayers.

A The Company's proposed cap on revenue decoupling adjustments is set at the same level as the cap it is proposing for annual step adjustments—at 2.5 percent of the Company's operating revenues including all supply costs, even for customers who take service from a retail supplier.[51] Yet because only a small portion of the Company's total electric operating revenue is distribution revenue, a 2.5 percent cap based on 2020 total revenues translates to 8 percent of 2020 distribution revenues. Since the approved default energy service rates have

[51] Revenues for customers taking service from a competitive supplier would be calculated using the Company's default energy service charges, according to Lyons, Exhibit TSL-1, page 16 (Bates 001470).

more than doubled recently, the cap on revenue decoupling adjustments could far exceed 8 percent of distribution revenues in future years.

Q How do you recommend that the cap be set?

A As the recent adjustment to default energy service charges illustrates, supply rates can be extremely volatile. Thus, any cap on adjustments—whether for decoupling or annual step adjustments (should they be approved)—should be based on distribution revenues only, or a fixed value. Thus, we recommend that the cap on upward decoupling adjustments be set at 2.5 percent of distribution revenues.

V. THE COMPANY'S GRID MODERNIZATION PROPOSAL SHOULD FIRST BE VETTED THROUGH ITS LEAST COST INTEGRATED RESOURCE PLAN

Q What grid modernization investments are contained in the Company's proposal?

A During the years covered by the Company's proposed rate plan (2021–2023), the Company plans to undertake approximately $8.5 million in grid modernization investments, the costs of which would be recovered through annual step adjustments. However, the Company's grid modernization investments are expected to continue well into the future, with nearly $40 million being invested by 2030.[52] This spending plan is shown in the table below.

[52] Exhibit (KES-3), page 11. (Bates 000509).

Table 3. Grid Modernization Spending Plan[53]

	Project Costs (000's)										
Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Field Area Network	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ 4,622
ADMS and DERMS	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ 1,981
Volt/VAR Optimization	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 24,981
SCADA	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 7,140
Mobile Damage Assessment	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Total	$1,763	$2,437	$4,245	$4,612	$4,016	$3,575	$4,000	$4,647	$4,678	$5,756	$ 39,729

Q What are the objectives of the Company's grid modernization proposal?

A The Company's objectives for its grid modernization plan, as discussed in its proposal, can be summarized as follows:

- Deliver safe and reliable service for today's customers and the 21st Century economy;
- Enable adoption of new technologies and services to allow customers to better manage their energy needs;
- Reduce the environmental impact of electricity by integrating all types of generation and storage, improve efficiency, and optimize demand; and
- Encourage innovation by supporting the interconnection and business models of third parties.[54]

[53] Reproduced from Exhibit (KES-3), page 11, Table 1. (Bates 000509).

[54] Grid Modernization Plan, Exhibit (KES-3), March 2021, pages 16-17 (Bates 000514-000515).

Q Do you support the Company's grid modernization proposal?

A While we applaud the Company's vision to modernize the grid to achieve the objectives outlined above, the Company's rate application is not the appropriate venue for introducing such investments. Instead, these investments should first be vetted through the Company's Least Cost Integrated Resource Plan (LCIRP). The least-cost planning statute specifically requires that LCIRPs include "an assessment of the benefits and costs of 'smart grid' technologies, and the institution of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages."[55] The Company's 2020 LCIRP contained only a high-level discussion of planned grid modernization investments, primarily focusing on the activities being undertaken by its Massachusetts affiliate that it plans to also implement in its New Hampshire service territory.[56] However, the plan did not include specifics regarding the timing or costs of grid modernization investments in New Hampshire, as the Company stated that its roadmap and accompanying business plan were still under development.[57]

Q Why is it necessary to first review grid modernization proposals in the context of an LCIRP?

A There are several reasons why the LCIRP process is the appropriate place to address grid modernization proposals. First, as evidenced by a plain reading of the statute, the legislature intended for grid modernization proposals to be developed and presented in utilities' LCIRPs.

[55] RSA 378:38.

[56] UES, Docket DE 20-002, Report on Least Cost Integrated Resource Planning 2020, March 2020, pp. 22-24.

[57] *Id.*, p. 21.

Second, an LCIRP allows for grid modernization plans to be considered in the context of all of the utility's other distribution system investments. This allows for parties to better identify how the components interact, and how investments in grid modernization technologies may impact the need for investments in traditional distribution infrastructure. As the Commission stated in its 2020 Grid Modernization order, "[a] more granular and transparent approach to distribution system planning is necessary to ensure that investments are prioritized in a manner that accommodates an evolving electric system, while also maximizing ratepayer value."[58] Moreover, the Commission stated its expectation that "investments for which recovery is requested in rate cases are consistent with investments described in the LCIRP and related filings."[59]

Finally, the Commission has repeatedly observed that "constructive stakeholder processes can aid the Commission in its decision-making duties and allow parties to reach a result in line with their expectations."[60] In contrast to a litigated rate case, an LCIRP process provides greater opportunity for parties to interact constructively and enhances transparency. It also allows parties to potentially resolve issues prior to a litigated case.

[58] Although this order was issued after the Company's 2020 LCIRP filing and is currently under suspension, it reflects substantial consensus among the parties on numerous issues. Public Utilities Commission, Order Guidance on Utility Distribution System Planning and Order Requiring Continued Investigation, Order No. 26, 358, Docket IR 15-296, May 22, 2020, at 5.

[59] Public Utilities Commission, Order Guidance on Utility Distribution System Planning and Order Requiring Continued Investigation, Order No. 26, 358, Docket IR 15-296, May 22, 2020, at 25.

[60] Public Utilities Commission, Order Approving Benefit Cost Working Group Recommendations, Order No. 26,322, Docket 17-136, December 30, 2019, at 8; and Public Utilities Commission, Order Guidance on Utility Distribution System Planning and Order Requiring Continued Investigation, Order No. 26, 358, Docket IR 15-296, May 22, 2020, at 24.

For these reasons, we recommend that the Commission decline to address the Company's grid modernization proposal in the instant proceeding and direct the Company to first introduce its proposal in the context of an LCIRP.

VI. CONCLUSION AND SUMMARY OF RECOMMENDATIONS

Q Please summarize your main conclusions and recommendations.

A Our conclusions and recommendations are as follows:

1. The Company's proposed increases to residential rates should be modified to no more than 125 percent of the system average increase in order to avoid rate shock.

2. The Company's proposal for a multi-year rate plan with annual step adjustments is devoid of any meaningful cost control incentives or performance commitments to ratepayers, and would result in unreasonable rate increases. It should thus be rejected in favor of a return to cost-of-service regulation. If the Company wishes for the Commission to consider alternative ratemaking, it should file a comprehensive performance-based regulation proposal.

3. The minimum system method is deeply flawed in both theory and application and results in the overallocation of costs to the residential class and unreasonably high customer charges. Therefore, the Commission should require the Company to use the basic customer method for determining customer-related costs.

4. The Company's proposal to increase the residential customer charge by nearly $5.00 fails to comport with widely accepted rate design principles, would adversely impact many low-income customers, and runs counter to energy

efficiency and conservation. Any increase in the customer charge should therefore be rejected.

5. The Company's proposed decoupling mechanism is generally sound but should be modified to provide greater customer protections by imposing a cap of 2.5 percent of *distribution* revenues, rather than total revenues.

6. The Company's proposed grid modernization investments should first be addressed in the context of a Least Cost Integrated Resource Plan, consistent with RSA 378:38, and should not be approved in this docket.

Q Does this conclude your testimony?

A Yes, it does.

VII. Schedules and Attachments

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Principal Associate,* 2017 – present*, Senior Associate,* 2015 – 2017*, Associate*, 2012 – 2015

Consult and provide analysis of rate design proposals, alternative regulation, and other topics including distributed energy resources and electric vehicles. Develop expert witness testimony in public utility commission proceedings. Author reports on topics at the intersection of utility regulation, customer protection, and environmental impacts.

University of Wisconsin - Madison, Department of Agricultural and Applied Economics, Madison, WI. *Teaching Assistant – Environmental Economics*, 2011 – 2012

Developed teaching materials and led discussions on cost-benefit analysis, carbon taxes and cap-and-trade programs, management of renewable and non-renewable resources, and other topics.

Public Service Commission of Wisconsin, Water Division, Madison, WI. *Program and Policy Analyst - Intern*, Summer 2009

Researched water conservation programs nationwide to develop a proposal for Wisconsin's state conservation program. Developed spreadsheet model to calculate avoided costs of water conservation in terms of energy savings and avoided emissions.

Synapse Energy Economics, Cambridge, MA. *Communications Manager*, 2005 – 2008

Developed technical proposals for state and federal agencies, environmental and public interest groups, and businesses. Edited reports on energy efficiency, integrated resource planning, greenhouse gas regulations, renewable resources, and other topics.

EDUCATION

University of Wisconsin, Madison, WI
Master of Arts in Agricultural and Applied Economics, 2012
Certificate in Energy Analysis and Policy
National Science Foundation Fellow

University of Wisconsin, Madison, WI
Master of Science in Environment and Resources, 2010
Certificate in Humans and the Global Environment
Nelson Distinguished Fellowship

Southwestern University, Georgetown, TX
Bachelor of Arts in International Studies, *Magna cum laude,* 2003.

ADDITIONAL SKILLS

- Econometric Modeling – Linear and nonlinear modeling including time-series, panel data, logit, probit, and discrete choice regression analysis
- Nonmarket Valuation Methods for Environmental Goods – Hedonic valuation, travel cost method, and contingent valuation
- Cost-Benefit Analysis
- Input-Output Modeling for Regional Economic Analysis

FELLOWSHIPS AND AWARDS

- Winner, M. Jarvin Emerson Student Paper Competition, Journal of Regional Analysis and Policy, 2010
- Fellowship, National Science Foundation Integrative Graduate Education and Research Traineeship (IGERT), University of Wisconsin – Madison, 2009
- Nelson Distinguished Fellowship, University of Wisconsin – Madison, 2008

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Colorado Public Utilities Commission (Proceeding No. 20AL-0432E): Answer testimony of Melissa Whited regarding inclining block rates. On behalf of Energy Outreach Colorado. March 8, 2021.

Maryland Public Service Commission (Case No. 9655): Direct and surrebuttal testimony of Melissa Whited regarding Pepco's proposed multi-year plan and performance incentive mechanisms. On behalf of Maryland Office of People's Counsel. March 3, 2021.

Nova Scotia Utility and Review Board (Matter No. M09777): Direct testimony of Melissa Whited regarding Nova Scotia Power Inc.'s proposed time-varying pricing tariff application. On behalf of Counsel to the Nova Scotia Utility and Review Board. February 24, 2021.

Georgia Public Service Commission (Docket No. 42516): Direct testimony of Melissa Whited and Ben Havumaki regarding Georgia Power's proposal to increase the customer charge for residential customers. On behalf of the Sierra Club. October 17, 2019.

Maine Public Utilities Commission (Docket No. 2018-00171): Direct testimony of Melissa Whited regarding utility incentives for non-wires alternatives. On behalf of Maine Office of the Public Advocate. December 17, 2018.

Rhode Island Public Utilities Commission (Docket No. 4780): Direct testimony of Tim Woolf and Melissa Whited regarding National Grid's Power Sector Transformation proposals. On behalf of the Rhode Island Division of Public Utilities and Carriers. April 28, 2018.

Rhode Island Public Utilities Commission (Docket No. 4770): Direct testimony of Tim Woolf and Melissa Whited regarding National Grid's proposed performance incentive mechanisms, benefit-cost analyses, and request for recovery of costs for its Advanced Metering Functionality study and distributed energy resources enablement investments. On behalf of the Rhode Island Division of Public Utilities and Carriers. April 6, 2018.

Rhode Island Public Utilities Commission (Docket No. 4783): Direct testimony of Tim Woolf and Melissa Whited regarding National Grid's Advanced Metering Functionality Pilot. On behalf of the Rhode Island Division of Public Utilities and Carriers. February 22, 2018.

Virginia State Corporation Commission (Case No. PUR-2017-00044): Direct testimony of Melissa Whited regarding Rappahannock Electric Cooperative's proposed increases to fixed charges for residential customers and small business customers. On behalf of Sierra Club. September 19, 2017.

California Public Utilities Commission (Application 17-01-020, 17-01-021, and 17-01-022): Joint opening testimony with Max Baumhefner and Katherine Stainken on fast charging infrastructure and rates; joint opening testimony with Max Baumhefner and Joel Espino on medium and heavy-duty and fleet charging infrastructure and commercial EV rates; joint opening testimony with Max Baumhefner and Chris King on residential charging infrastructure and rates. Rebuttal testimony on public fast charging rate design, commercial EV rate design, and residential EV rate design. On behalf of Natural Resources Defense Council, the Greenlining Institute, Plug In America, the Coalition of California Utility Employees, Sierra Club, and the Environmental Defense Fund. July 25, August 1, August 7, and September 5, 2017.

New York Public Service Commission (Case 17-E-0238): Direct and rebuttal testimony of Tim Woolf and Melissa Whited regarding Earnings Adjustment Mechanisms proposed by National Grid. On behalf of Advanced Energy Economy Institute. August 25 and September 15, 2017.

Utah Public Service Commission (Docket No. 14-035-114): Direct testimony of Melissa Whited regarding Pacificorp's proposed rates for customers with distributed generation. On behalf of Utah Clean Energy. June 8, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Cross-rebuttal testimony evaluating Southwestern Electric Power Company's proposed revisions to its

Distributed Renewable Generation tariff. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

Massachusetts Department of Public Utilities (Docket No. 17-05): Direct and surrebuttal testimony of Tim Woolf and Melissa Whited regarding performance-based regulation, the monthly minimum reliability contribution, storage pilots, and rate design in Eversource's petition for approval of rate increases and a performance-based ratemaking mechanism. On behalf of Sunrun and the Energy Freedom Coalition of America, LLC. April 28, 2017 and May 26, 2017.

Public Utilities Commission of Hawaii (Docket No. 2015-0170): Direct testimony regarding Hawaiian Electric Light Company's proposed performance incentive mechanisms. On behalf of the Division of Consumer Advocacy. April 28, 2017.

Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with T. Woolf regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

Federal Energy Regulatory Commission (Docket No. EC13-93-000): Affidavit regarding potential market power resulting from the acquisition of Ameren generation by Dynegy. On behalf of Sierra Club. August 16, 2013.

Wisconsin Senate Committee on Clean Energy: Joint testimony with M. Grabow regarding the importance of clean transportation to Wisconsin's public health and economy. February 2010.

TESTIMONY ASSISTANCE

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony of Tim Woolf regarding Public Service Company of Colorado's rate design proposal. On behalf of Energy Outreach Colorado. June 6, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Wisconsin Public Service Commission (Docket No. 05-UR-107): Direct and surrebuttal testimony of Rick Hornby regarding Wisconsin Electric Power Company rate case. On behalf of The Alliance for Solar Choice. August 28, 2014 and September 22, 2014.

Maine Public Utilities Commission (Docket No. 2013-00519): Direct testimony of Richard Hornby and Martin R. Cohen on GridSolar's smart grid coordinator petition. On behalf of the Maine Office of the Public Advocate. August 28, 2014.

Maine Public Utilities Commission (Docket No. 2013-00168): Direct and surrebuttal testimony of Tim Woolf regarding Central Maine Power's request for an alternative rate plan. December 12, 2013 and March 21, 2014.

Massachusetts Department of Public Utilities (Docket No. 14-04): Comments of Massachusetts Department of Energy Resources on investigation into time varying rates. On behalf of the Massachusetts Department of Energy Resources. March 10, 2014.

State of Nevada, Public Utilities Commission of Nevada (Docket No. 13-07021): Direct testimony of Frank Ackerman regarding the proposed merger of NV Energy, Inc. and MidAmerican Energy Holdings Company. On behalf of the Sierra Club. October 24, 2013.

PRESENTATIONS

Whited, M. 2021. "Evolution of Net Metering in Hawaii." Presentation to the NARUC Winter Policy Summit. February 4.

Biewald, B., M. Whited. "Evaluating and Shaping the Impacts of EVs on Customers: Tools for Consumer Advocates." Presentation at the NASUCA Mid-Year Meeting, June 19, 2019.

Whited, M. 2019. "Performance Incentive Mechanisms." Presentation to the 2019 Pennsylvania Public Utility Law Conference, Harrisburg, PA. May 31.

Whited, M. 2018. "Smart Non-Residential Rate Design: Designing for the Future." Presentation to the NARUC Annual Meeting, Orlando, FL. November 11.

Whited, M. 2016. "Energy Policy for the Future: Trends and Overview." Presentation to the National Conference of State Legislators' Capitol Forum, Washington, DC, December 8.

Whited, M. 2016. "Ratemaking for the Future: Trends and Considerations." Presentation to the Midwest Governors' Association, St. Paul, MN, July 14.

Whited, M. 2016. "Performance Based Regulation." Presentation to the NARUC Rate Design Subcommittee. September 12.

Whited, M. 2016. "Demand Charges: Impacts and Alternatives (A Skeptic's View)." EUCI 2nd Annual Residential Demand Charges Summit, Phoenix, AZ, June 7.

Whited, M. 2016. "Performance Incentive Mechanisms." Presentation to the National Governors Association, Wisconsin Workshop, Madison WI, March 29.

Whited, M., T. Woolf. 2016. "Caught in a Fix: The Problem with Fixed Charges for Electricity." Webinar presentation sponsored by Consumers Union, February.

Whited, M. 2015. "Performance Incentive Mechanisms." Presentation to the National Governors Association, Learning Lab on New Utility Business Models & the Electricity Market Structures of the Future, Boston, MA, July 28.

Whited, M. 2015. “Rate Design: Options for Addressing NEM Impacts.” Presentation to the Utah Net Energy Metering Workgroup, Workshop 4, Salt Lake City, UT, July 8.

Whited, M. 2015. “Performance Incentive Mechanisms.” Presentation to the e21 Initiative, St. Paul, MN, May 29.

Whited, M., F. Ackerman. 2013. “Water Constraints on Energy Production: Altering our Current Collision Course.” Webinar presentation sponsored by Civil Society Institute, September 12.

Whited, M., G. Brown, K. Charipar. 2011. “Electricity Demand Response Programs and Potential in Wisconsin.” Presentation to the Wisconsin Public Service Commission, April.

Whited, M. 2010. “Economic Impact of Irrigation Water Transfers in Uvalde County, Texas.” Presentation at the Mid-Continent Regional Science Association’s 41st Annual Conference/IMPLAN National User’s 8th Biennial Conference in St. Louis, MO, June

Whited, M., M. Grabow, M. Hahn.2009. “Valuing Bicycling’s Economic and Health Impacts in Wisconsin.” Presentation before the Governor’s Coordinating Council on Bicycling, December.

Whited, M., D. Sheard. 2009. “Water Conservation Initiatives in Wisconsin.” Presentation before the Waukesha County Water Conservation Coalition Municipal Water Conservation Subgroup, July.

Resume updated November 2021

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA*. Senior Associate,* June 2021 – Present; *Associate,* July 2018 – June 2021.

- Provides research, analysis, and consulting services, frequently in the context of regulated proceedings, with expertise in the following topic areas:
  - Rate design and performance-based regulation: Evaluates utility proposals and formulates new recommendations based on best practices and informed by innovative emerging models. Evaluates rate designs for consistency with policy goals using quantitative modeling and jurisdictional data. Provides expert testimony and other formal input in the context of regulated proceedings.
  - Benefit-cost analysis: Evaluates utility BCAs with reference to best practices, including emerging standards for grid modernization and distributed energy resources. Engaged in the development of new BCA practices in the arenas of grid modernization and resilience.
  - Macroeconomic analysis: Uses the IMPLAN model in conjunction with primary research and analysis and core economic principles to evaluate the GDP, job, and income implications of major grid changes.
- Contributing author to reports covering a range of topics including plant decommissioning, transportation electrification, energy storage and other new technologies, and growth in solar photovoltaic (PV) adoption.

University of Massachusetts Boston, MA*. Graduate Teaching and Research Assistant,* 2017 – 2018

- Led ecosystem-valuation workshops for EPA-funded initiative to shape resilience policymaking in the Great Bay region of New Hampshire.
- Served as a teaching assistant in graduate econometrics course and undergraduate macroeconomics and urban economics courses.

Notre Dame Education Center and Jewish Vocational Service Boston, MA. *Math Instructor*, 2012 – 2017

- Taught foundational math to adult learners and standard high school math curriculum to students in non-traditional school program.

The City of New York New York, NY. *Senior Investigator*, 2007 – 2010

- Investigated complaints against officers of the New York City Police Department and issued disciplinary recommendations in formal reports to the agency board.

EDUCATION

University of Massachusetts, **Boston,** Boston, MA
Master of Arts in Applied Economics, 2018
Recipient of the Arthur MacEwan Award for Excellence in Political Economy

McGill University, Montreal, Quebec
Bachelor of Arts in History, 2007

PUBLICATIONS

Takahashi, K., T. Woolf, B. Havumaki, D. White, D. Goldberg, S. Kwok, A. Takasugi. 2021. *Missed Opportunities: The Impacts of Recent Policies on Energy Efficiency Programs in Midwestern States.* Synapse Energy Economics for the Midwest Energy Efficiency Alliance.

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Kallay, J., S. Letendre, T. Woolf, B. Havumaki, S. Kwok, A. Hopkins, R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021. *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments*. Synapse Energy Economics for Sandia National Laboratories.

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Woolf, T., D Bhandari, C. Lane, J. Frost, B. Havumaki, S. Letendre, C. Odom. 2021. *Benefit-Cost Analysis of the Rhode Island Community Remote Net Metering Program.* Synapse Energy Economics for the Rhode Island Division of Public Utilities and Carriers.

Woolf, T., B. Havumaki, S. Letendre, C. Odom, J. Hall. 2021. *Macroeconomic Impacts of the Rhode Island Community Remote Net Metering Program.* Synapse Energy Economics for the Rhode Island Division of Public Utilities and Carriers.

Kallay, J., A. Hopkins, A. Napoleon, B. Havumaki, J. Hall, M. Whited, M. Chang., R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021. *The Resilience Planning Landscape for Communities and Electric Utilities.* Synapse Energy Economics for Sandia National Laboratories.

Woolf, T., L. Schwartz, B. Havumaki, D. Bhandari, M. Whited. 2021. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations.* Prepared by Lawrence Berkeley National Laboratory and Synapse Energy Economics for the Grid Modernization Laboratory Consortium of the U.S. Department of Energy.

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Camp, E., B. Havumaki, T. Vitolo, M. Whited. 2020. *Future of Solar PV in the District of Columbia: Feasibility, Projections, and Rate Impacts of the District's Expanded RPS.* Synapse Energy Economics for the District of Columbia Office of the People's Counsel.

Whited, M., J. Frost, B. Havumaki. 2020. *Best Practices for Commercial and Industrial EV Rates*. A guide prepared by Synapse Energy Economics for Natural Resources Defense Council.

Knight, P., E. Camp, D. Bhandari, J. Hall, M. Whited, B. Havumaki, A. Allison, N. Peluso, T. Woolf. 2019. *Making Electric Vehicles Work for Utility Customers: A Policy Handbook for Consumer Advocates.* Synapse Energy Economics for the Energy Foundation.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Napoleon, A., B. Havumaki, D. Bhandari, T. Woolf. 2019. *Review of New Brunswick Power's Application for Approval of an Advanced Metering Infrastructure Capital Project: In the Matter of the New Brunswick Power Corporation and Section 107 of the Electricity Act; Matter No. 452.* Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Whited, M., B. Havumaki. 2019. *GD2019 04 M: DC DOEE Comments Responding to Notice of Inquiry.* Synapse Energy Economics for the District of Columbia Department of Energy and Environment.

Timmons, D., A.Z. Dhunny, K. Elahee, B. Havumaki, M. Howells, A. Khoodaruth, A.K. Lema-Driscoll, M.R. Lollchund, Y.K. Ramgolam, S.D.D.V. Rughooputh, D. Surroop. 2019. *Cost Minimization for Fully Renewable Electricity Systems: A Mauritius Case Study.* Energy Policy. 133, 110895.

Napoleon, A., T. Woolf, K. Takahashi, J. Kallay, B. Havumaki. 2019. *Comments in the New York Public Service Commission Case 18-M-0084: In the Matter of a Comprehensive Energy Efficiency Initiative.* Comments related to NY Utilities report regarding energy efficiency budgets and targets, collaboration, heat pump technology, and low- and moderate-income customers and requests for approval. Synapse Energy Economics on behalf of Natural Resources Defense Council.

Havumaki, B., E. Camp, B. Fagan, D. Bhandari. 2019. *Planning for the Future at the CTGS Site: Report on the Decommissioning Proposal of Maritime Electric*. Synapse Energy Economics for Carr, Stevenson, and MacKay.

Havumaki, B., J. Kallay, K. Takahashi, T. Woolf. 2019. *All-Electric Solid Oxide Fuel Cells as an Energy Efficiency Measure.* Synapse Energy Economics for Bloom Energy.

Takahashi, K., B. Havumaki, J. Kallay, T. Woolf. 2019. *Bloom Fuel Cells: A Cost-Effectiveness Brief.* Synapse Energy Economics for Bloom Energy.

Havumaki, B., T. Vitolo. 2019. *Comments to the Mississippi Public Service Commission: In response to the report of Acadian Consulting LLC.* Synapse Energy Economics for Gulf States Renewable Energy Industries Association, Sierra Club, and 25 x ’25.

Whited, M., J. Kallay, D. Bhandari, B. Havumaki. 2018. *Driving Transportation Electrification Forward in Pennsylvania: Considerations for Effective Transportation Electrification Ratemaking*. Synapse Energy Economics for Natural Resources Defense Council.

Havumaki, B. 2018. *Hydropower in the Decarbonized Mauritian Grid: A Prospective Study.* Master’s Thesis.

Havumaki, B., G. Mavrommati, C. Makriyannis. 2018. *World Bank Water Management, Sanitation, and Conservation Projects in Developing Countries: A Guide to Cost-Benefit Analysis.* Report for the World Bank.

TESTIMONY

Hawaii Public Utilities Commission (Docket No. 2018-0088): Panel testimony by Ben Havumaki regarding performance incentive mechanisms. On behalf of the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs. September 21, 2020.

Georgia Public Service Commission (Docket No. 42516): Direct Testimony of Melissa Whited and Ben Havumaki. On behalf of Sierra Club. October 17, 2019.

Resume updated August 2021

Attachment MWBH-1

State of New Hampshire
Public Utilities Commission
Concord

Report of Proposed Rate Changes
($000)

Unitil Energy Systems, Inc.
Tariff No. 3

Date Filed: April 2, 2021
Effective Date: May 2, 2021

(A) Class of Service	(B) Effect of Proposed Change	(C) Average Number of Customers	(D) Annual kWh Sales	(E) Annual kW / kVA Sales	(F) Annual Distribution Charge Revenue Under Present Rates	(G) Total Revenue Under Present Rates	(H) Proposed Distribution Change	(I) Annual Distribution Charge Revenue Under Proposed Rates	(J) % Change Distribution Only Revenue	(K) Change in Reconciling Mechanism Revenue	(L) Total Revenue Under Proposed Rates	(M) Proposed Change Revenue	(N) Percent Change Revenue
Domestic D	Increase	67,940	515,968,592		$31,582	$102,471	$9,445	$41,027	29.91%	-$1,175	$110,741	$8,270	8.1%
General Service - G2	Increase	10,559	312,134,498	1,234,532	$16,655	$57,627	$1,715	$18,371	10.30%	-$711	$58,631	$1,004	1.7%
G2 - kWh Meter	Increase	379	438,744		$87	$145	$9	$96	10.33%	-$1	$153	$8	5.5%
G2 - Quick Recovery Water Heat and/or Space Heat	Increase	257	4,483,579		$174	$763	$18	$192	10.33%	-$10	$771	$8	1.0%
Subtotal G2	Increase	11,195	317,056,821	1,234,532	$16,916	$58,535	$1,742	$18,659	10.30%	-$722	$59,555	$1,020	1.7%
Large General Service G1	Increase	168	319,767,459	1,000,283	$7,736	$49,323	$801	$8,537	10.35%	-$728	$49,395	$73	0.1%
Outdoor Lighting OL	Increase	1,549	7,625,729		$1,815	$2,816	$0	$1,815	0.02%	-$17	$2,799	($17)	(0.6%)
Total	Increase	80,852	1,160,418,601	2,234,816	$58,050	$213,145	$11,989	$70,038	20.65%	-$2,643	$222,491	$9,346	4.4%

(G) Present rates including delivery and default service rates effective December 1, 2020. Assumes all customers take default energy service.
G1 default service rate of $0.08581 (avg Dec '20 - Apr '21) used for G1.
(H) Total amount differs from revenue deficiency in RevReq-1 by $3k due to rounding.
(K) Class proportion of proposed changes in EDC and SBC.
(G) Column G + Column H + Column K.
(H) Column L - Column G
(I) Column M / Column G

Signed by: ___ /s/ Robert B Hevert
Title: Sr. Vice President

11.2 Distribution Classification

Newly evolving methods can fairly allocate a substantial portion of distribution costs on an energy basis.

The classification of distribution infrastructure has been one of the most controversial elements of utility cost allocation for more than a half-century. Bonbright devoted an entire section to a discussion of why none of the methods then commonly used was defensible (1961, pp. 347-368). In any case, traditional methods have divided up distribution costs as either demand-related or customer-related, but newly evolving methods can fairly allocate a substantial portion of these costs on an energy basis.

Distribution equipment can be usefully divided into three groups:

- Shared distribution plant, in which each item serves multiple customers, including substations and almost all spans of primary lines.
- Customer-related distribution plant that serves only one customer, particularly traditional meters used solely for billing.
- A group of equipment that may serve one customer in some cases or many customers in others, including transformers, secondary lines and service drops.

The basic customer method for classification counts only customer-specific plant as customer-related and the entire shared distribution network as demand- or energy-related. For relatively dense service territories, in cities and suburbs, this would be only the traditional meter and a portion of service drop costs.[140] For very thinly settled territories, particularly rural cooperatives, customer-specific plant may include some portion of transformer costs and the percentage of the primary system that consists of line extensions to individual customers. Many jurisdictions have mandated or accepted the basic customer classification approach, sometimes including a portion of transformers in the customer cost. These jurisdictions include Arkansas,[141] California,[142] Colorado,[143] Illinois,[144] Iowa,[145] Massachusetts,[146] Texas[147] and Washington.[148]

The basic customer method for classification is by far the most equitable solution for the vast majority of utilities.

140 Alternatively, all service drops may be treated as customer-related and the sharing of service drops can be reflected in the allocation factor. As discussed in Section 5.2, treating multifamily housing as a separate class facilitates crediting those customers with the savings from shared service drops, among other factors.

141 The Arkansas Public Service Commission found that "accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and … that [large industrial consumer parties] do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes" (2013, p. 126).

142 California classifies all lines (accounts 364 through 367) as demand-related for the calculation of marginal costs, while classifying transformers (Account 368) as customer-related with different costs per customer for each customer class, reflecting the demands of the various classes.

143 In 2018, the state utility commission affirmed a decision by an administrative law judge that rejected the **zero-intercept approach** and classified FERC accounts 364 through 368 as 100% demand-related (Colorado Public Utilities Commission, 2018, p. 16).

144 "As it has in the past, … the [Illinois Commerce] Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic" (Illinois Commerce Commission, 2008, p. 208).

145 According to 199 Iowa Administrative Code 20.10(2)e, "customer cost component estimates or allocations shall include only costs of the distribution system from and including transformers, meters and associated customer service expenses." This means that all of accounts 364 through 367 are demand-related. Under this provision, the Iowa Utilities Board classifies the cost of 10 kVA per transformer as customer-related but reduces the cost that is assigned to residential and small commercial customers to reflect the sharing of transformers by multiple customers.

146 "Plant items classified as customer costs included only meters, a portion of services, street lighting plant, and a portion of labor-related general plant" (La Capra, 1992, p. 15). See also Gorman, 2018, pp. 13-15.

147 Texas has explicitly adopted the basic customer approach for the purposes of rate design: "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service" (Public Utility Commission of Texas, 2000, pp. 5-6). But it has followed this rule in practice for cost allocation as well.

148 "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. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals" (Washington Utilities and Transportation Commission, 1993, p. 11).

For certain rural utilities, this may be reasonable under the conceptual view that the size of distribution components (e.g., the diameter of conductors or the capacity of transformers) is load-related, but the number and length of some types of equipment is customer-related. In some rural service territories, the basic customer cost may require nearly a mile of distribution line along the public way as essentially an extended service drop.

However, more general attempts by utilities to include a far greater portion of shared distribution system costs as customer-related are frequently unfair and wholly unjustified. These methods include straight fixed/variable approaches where all distribution costs are treated as customer-related (analogous to the misuse of the concept of fixed costs in classifying generation discussed in Section 9.1) and the more nuanced minimum system and zero-intercept approaches included in the 1992 NARUC cost allocation manual.

The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.

1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number.[149] Bonbright found that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system." He concluded that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems … clearly indefensible. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground" (1961, p. 348).
2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers.[150] Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage duration).

149 As noted above, for some rural utilities, particularly cooperatives that extend distribution without requiring that the extension be profitable, a portion of the distribution system may effectively be customer-specific.

150 Adding transformers also reduces the length of the secondary lines from the transformers to the customers, reducing losses, voltage drop or the required gauge of the secondary lines.

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.
4. The "minimum system" would still meet a large portion of the average residential customer's demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system (Sterzinger, 1981, pp. 30-32).
5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted.[151] However, the transformer industry could produce truly minimum-sized utility transformers, the size of those used for cellular telephone chargers, if there were a demand for these.
6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.
7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.
8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with **contributions in aid of construction**, as discussed in Section 15.2. Factoring in the entire length of the system, including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines.

Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid

151 For example, in many cases, utilities that make an allocation based on a minimum system use 10-kVA transformers, even though they installed 3-kVA or 5-kVA transformers in the past. Some utilities also have used conductor sizes and costs significantly higher than the actual minimum conductor size and cost on their systems.

overhead distribution equipment only under several unusual circumstances.[152] These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility, particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

The related zero-intercept method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load. The zero-intercept method usually involves statistical regression analysis to decompose the costs of distribution equipment into customer-related costs and costs that vary with load or size of the equipment, although some utilities use labor installation costs with no equipment. The idea is that this procedure identifies the amount of equipment required to connect existing customers that is not load-related (a zero-kVA transformer, a zero-**ampere** conductor or a pole that is zero feet high). The zero-intercept regression analysis is so abstract that it can produce a wide range of results, which vary depending on arcane statistical methods and the choice of types of equipment to include or exclude from an equation. As a result, the zero-intercept method is even less realistic than the minimum system method.

The best practice is to determine customer-related costs using the basic customer method, then use more advanced techniques to split the remainder of shared distribution system costs as energy-related and demand-related. Energy use, especially in high-load hours and in off-peak hours on high-load days, affects distribution investment and outage costs in the following ways:

- The fundamental reason for building distribution systems is to deliver energy to customers, not simply to connect them to the grid.
- The number and extent of overloads determines the life of the insulation on lines and in transformers (in both substations and line transformers) and hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.
- All energy in high-load hours, and even all hours on high-load days, adds to heat buildup and results in sagging overhead lines, which often defines the thermal limit on lines; aging of insulation in underground lines and transformers; and a reduction the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (marginal line losses due to another kWh of load greatly exceed the average loss percentage in that hour, and losses at peak loads dramatically exceed average losses).[153] To the extent that a utility converts a distribution line from single-phase to three-phase, selects a larger conductor or increases primary voltage to reduce losses, the costs are primarily energy-related.
- Customers with a remote need for power only a few hours per year, such as construction sites or temporary businesses like Christmas tree lots, will often find non-utility solutions to be more economical. But when those same types of loads are located along existing distribution lines, they typically connect to utility service if the utility's **connection charges** are reasonable.

A portion of distribution costs can thus be classified to energy, or the demand allocation factor can be modified to reflect energy effects.

The average-and-peak method, discussed in Section 9.1 in the context of generation classification, is commonly used by natural gas utilities to classify distribution mains and other shared distribution plant.[154] This approach recognizes that a portion of shared distribution would be needed even if all

152 These circumstances are: (1) if the customer would have been the farthest one from the transformer along a span of secondary conductor that is not a service drop; (2) if the customer is the only one served off the last pole at the end of a radial primary feeder, a pole and a span of secondary, or a span of primary and a transformer; and (3) if several poles are required solely for that customer.

153 For a detailed analysis of the measurement and valuation of marginal line losses, see Lazar and Baldwin (2011).

154 See *Gas Distribution Rate Design Manual* from the National Association of Regulatory Utility Commissioners (1989, pp. 27-28) as well as more recent orders from the Minnesota Public Utilities Commission describing the range of states that use basic customer and average-and-peak methods for natural gas cost allocation (2016, pp. 53-54) and the Michigan Public Service Commission affirming the usage of the average-and-peak method (2017, pp. 113-114).

customers used power at a 100% load factor, while other costs are incurred to upsize the system to meet local peak demands. The same approach may have a place in electric distribution system classification and allocation, with something over half the basic infrastructure (poles, conductors, conduit and transformers) classified to energy to reflect the importance of energy use in justifying system coverage and the remainder to demand to reflect the higher cost of sizing equipment to serve a load that isn't uniform.

Nearly every electric utility has a line extension policy that dictates the circumstances under which the utility or a new customer must pay for an extension of service. Most of these provide only a very small investment by the utility in shared facilities such as circuits, if expected customer usage is very small, but much larger utility investment for large added load. Various utilities compute the allowance for line extensions in different ways, which are usually a variant of one of the following approaches:

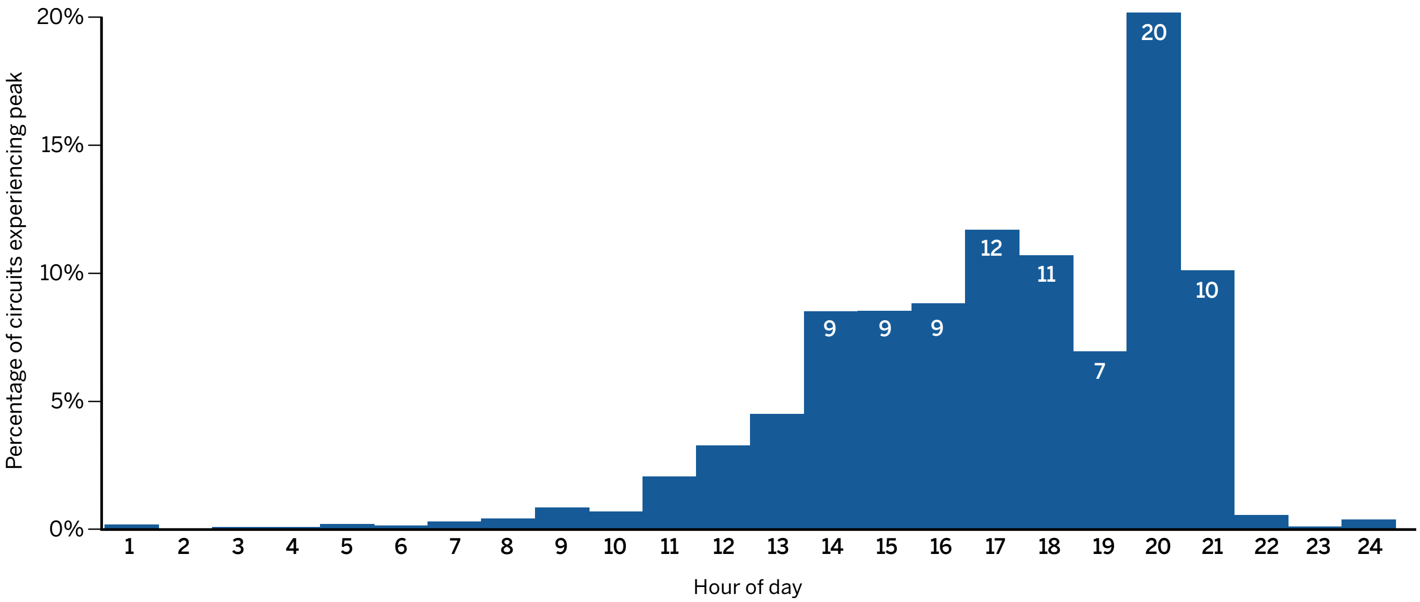
- The credit equals a multiple of revenue. For example, Otter Tail Power Co. in Minnesota will invest up to three times the expected annual revenue, with the customer bearing any excess (Otter Tail Power Co., 2017, Section 5.04). Xcel Energy's Minnesota subsidiary uses 3.5 times expected annual revenue for nonresidential customers (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Other utilities base their credits on expected nonfuel revenue or the distribution portion of the tariff; on different periods of revenue; and on either simple total revenue or present value of revenue.[155] These are clearly usage-related allowances that, in turn, determine how much cost for distribution circuits is reflected in the utility revenue requirement. Applying this logic, all shared distribution plant should thus be classified as usage-related, and none of the shared distribution system should be customer-related.
- The credit is the actual extension cost, capped at a fixed value. For example, Minnesota Power pays up to $850 for the cost of extending lines, charges $12 per foot for costs over $850 and charges actual costs for extensions over 1,000 feet (Minnesota Power, 2013, p. 6). Xcel Energy's Colorado subsidiary gives on-site construction allowances of $1,659 for residential customers, $2,486 for small commercial, $735 per kW for other secondary nonresidential and $680 per kW for primary customers (Public Service Company of Colorado, 2018, Sheet R226). The company describes these allowances as "based on two and three-quarters (2.75) times estimated annual non-fuel revenue" — a simplified version of the revenue approach.[156]
- The credit is determined by distance. Xcel Energy's Minnesota subsidiary includes the first 100 feet of line extension for a residential customer into rate base, with the customer bearing the cost for any excess length (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Green Mountain Power applies a credit equal to the cost of 100 feet of overhead service drop but no costs for poles or other equipment (Green Mountain Power, 2016, Sheet 148). The portion of the line extensions paid by the utility might be thought of as customer-related, with some caveats. First, the amount of the distribution system that was built out under this provision is almost certainly much less than 100 feet times the number of residential customers. Second, these allowances are often determined as a function of expected revenue, as in the Xcel Colorado example, and thus are usage-related.

If the line extension investment is tied to revenue (and most revenue is associated with usage-related costs, such as fuel, purchased power, generation, transmission and substations), then the resulting investment should be classified and allocated on a usage basis. The cost of service study should ensure that the costs customers prepay are netted out (including not just the costs but the footage of lines or excess costs of poles and transformers if a minimum system method is used) before classifying any distribution costs as customer-related.

155 California sets electric line extension allowances at expected net distribution revenue divided by a cost of service factor of roughly 16% (California Public Utilities Commission, 2007, pp. 8-9).

156 The company also has the option of applying the 2.75 multiple directly (Public Service Company of Colorado, 2018, Sheet R212).

Figure 40. San Diego Gas & Electric circuit peaks



Source: Fang, C. (2017, January 20). Direct testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 17-01-020

11.3 Distribution Demand Allocators

In any traditional study, a significant portion of distribution plant is classified as demand-related. A newer hourly allocation method may omit this step, assigning distribution costs to all hours when the asset (or a portion of the cost of the asset) is required for service.

For demand-related costs, class NCP is commonly, but often inappropriately, used for allocation. This allocator would be appropriate if each component overwhelmingly served a single class, if the equipment peaks occurred roughly at the time of the class peak, and if the sizing of distribution equipment were due solely to load in a single hour. But to the contrary, most substations and many feeders serve several tariffs, in different classes, and many tariff codes.[157]

11.3.1 Primary Distribution Allocators

Customers in a single class, in different areas and served by different substations and feeders, may experience peak loads at different times. Figure 40 shows the hours when each of San Diego Gas & Electric's distribution circuits experienced peak loads (Fang, 2017, p. 21). The peaks are clustered between the early afternoon (on circuits that are mostly commercial) and the early evening (mostly residential), while other circuits experience their peaks at a wide variety of hours.

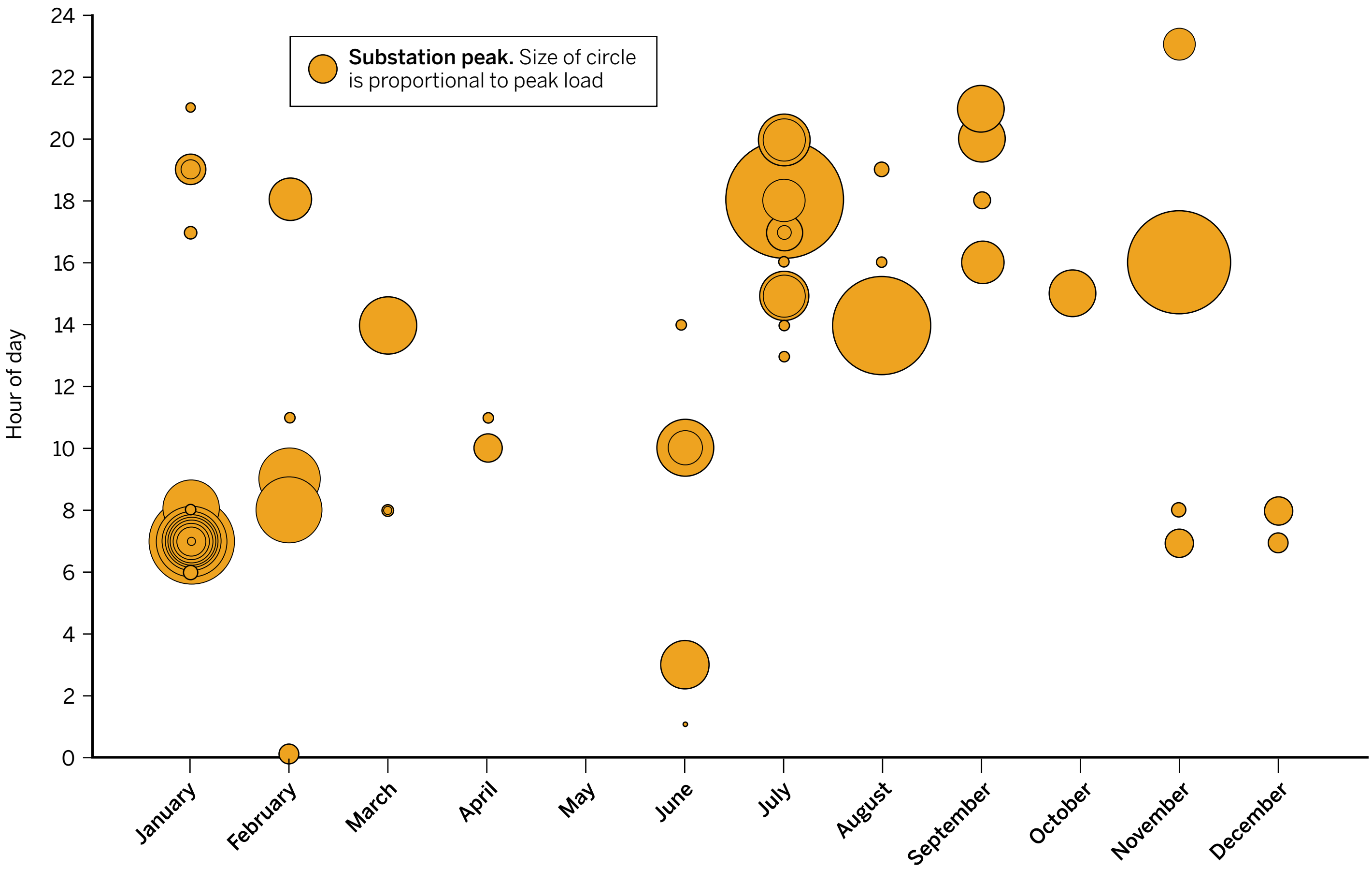
Figure 41 on the next page shows the distribution of substation peaks for Delmarva Power & Light over a period of one year (Delmarva Power & Light, 2016). The area of each bubble is proportional to the peak load on the station. Clearly, no one peak hour (or even a combination of monthly peaks) is representative of the class contribution to substation peaks.

The peaks for substations, lines and other distribution equipment do not necessarily align with the class NCPs. Indeed, even if all the major classes are summer peaking, some of the substations and feeders may be winter peaking, and vice versa. Even within a season, substation and feeder peaks will be distributed to many hours and days.

Although load levels drive distribution costs, the maximum load on each piece of equipment is not the only important load. As explained in Subsection 5.1.3, increased

157 Some utilities design their substations so that each feeder is fed by a single transformer, rather than all the feeders being served by all the transformers at the substation. In those cases, the relevant loads (for timing and class mix) are at the transformer level, rather than the entire substation.

Figure 41. Month and hour of Delmarva Power & Light substation peaks in 2014



Source: Delmarva Power & Light. (2016, August 15). Response to the Office of the People's Counsel data request 5-11, Attachment D. Maryland Public Service Commission Case No. 9424

energy use, especially at high-load hours and prior to those hours, can also affect the sizing and service life of transformers and underground lines, which is thus driven by the energy use on the equipment in high-load periods, not just the maximum demand hour. The peak hourly capacity of a line or transformer depends on how hot the equipment is prior to the peak load, which depends in turn on the load factor in the days leading up to the peak and how many high-load hours occur prior to the peak. More frequent events of load approaching the equipment capacity, longer peaks and hotter equipment going into the peak period all contribute to faster insulation deterioration and cumulative line sag, increasing the probability of failure and accelerating aging.

Ideally, the allocators for each distribution plant type should reflect the contribution of each class to the hours when load on the substation, feeder or transformer contributes to the potential for overloads. That allocation could be constructed by assigning costs to hours or by constructing a special demand allocator for each category of distribution equipment. If a detailed allocation is too complex, the allocators for costs should still reflect the underlying reality that distribution costs are driven by load in many hours.

The resulting allocator should reflect the variety of seasons and times at which the load on this type of equipment experiences peaks. In addition, the allocator should reflect the near-peak and prepeak loads that contribute to overheating and aging of equipment. Selecting the important hours for distribution loads and the weight to be given to the prepeak loads may require some judgments. Class NCP allocators do not serve this function.

Rocky Mountain Power allocates primary distribution on monthly coincident distribution peak, weighted by the percentage of substations peaking in each month (Steward, 2014, p. 7). Under this weighting scheme, for example:

- A small substation has as much effect on a month's weighting factor as a large substation. The month with the largest number of large substations seriously overloaded could be the highest-cost month yet may not receive the highest weight since each substation is weighted equally.
- The month's contribution to distribution demand costs is assumed to occur entirely at the hour of the monthly distribution peak, even though most of the substation capacity that peaks in the month may have peaked in a variety of different hours.
- A month would receive a weight of 100% whether each substation's maximum load was only 1 kVA more than its maximum in every other month or four times its maximum in every other month.

This approach could be improved by reflecting the capacity of the substations, the actual timing of the peak hours and the number of near-peak hours of each substation in each month. The hourly loads might be weighted by the square or some other power of load or by using a peak capacity allocation factor for the substation, to reflect the fact that the contribution to line losses and equipment life falls rapidly as load falls below peak.

Many utilities will need to develop additional information on system loads for cost allocation, as well as for planning, operational and rate design purposes. Specifically, utilities should aim to understand when each feeder and substation reaches its maximum loads and the mix of rate classes on each feeder and distribution substation.

In the absence of detailed data on the loads on line transformers, feeders and substations, utilities will be limited to cruder aggregate load data. For primary equipment, the best available proxy may be the class energy usage in the expected high-load period for the equipment, the class contribution to coincident peak or possibly class NCP, but only if that NCP is computed with respect to the peak load of the customers sharing the equipment. Although most substations and feeders serving industrial and commercial customers will also serve some residential customers, and most residential substations and feeders will have some commercial load, some percentage of distribution facilities serve a single class.

The NCP approximation is not a reasonable approximation for finer disaggregation of class loads. For example, there are many residential areas that contain a mix of single-family and multifamily housing and homes with and without electric space heating, electric water heating and solar panels. The primary distribution plant in those areas must be sized for the combined load in coincident peak periods, which may be the late afternoon summer cooling peak, the evening winter heating and lighting peak or some other time — but it will be the same time for all the customers in the area.[158]

Many utilities have multiple tariffs or tariff codes for residential customers (e.g., heating, water heating, all-electric and solar; single-family, multifamily and public housing; low-income and standard), for commercial customers (small, medium and large; primary and secondary voltage; schools, dormitories, churches and other customer types) and for various types of industrial customers, in addition to street lighting and other services. In most cases, those subclasses will be mixed together, resulting in customers with gas and electric space heat, gas and electric water heat, and with and without solar in the same block, along with street lights. The substation and feeder will be sized for the combined load, not for the combined peak load of just the electric heat customers or the combined peak of the customers with solar panels[159] or the street lighting peak.

Unless there is strong geographical differentiation of the subclasses, any NCP allocator should be computed for the

158 Distribution conductors and transformers have greater capacity in winter (when heat is removed quickly) than in summer; even if winter peak loads are higher, the sizing of some facilities may be driven by summer loads.

159 The division of the residential class into subclasses for calculation of the class NCP has been an issue in several recent Texas cases. In Docket No. 43695, at the recommendation of the Office of Public Utility Counsel, the Public Utility Commission of Texas reversed its former method for Southwestern Public Service to use the NCP for a single residential class (instead of separate subclasses for residential customers with and without electric heat), which reduced the costs allocated to residential customers as a whole (Public Utility Commission of Texas, 2015, pp. 12-13 and findings of fact 277A, 277B and 339A). The issue was also raised in dockets 44941 and 46831 involving El Paso Electric Co. El Paso Electric proposed separate NCP allocations for residential customers with and without solar generation, which the Office of Public Utility Counsel and solar generator representatives opposed. Both of these cases were settled and did not create a precedent.

combined load of the customer classes, with the customer class NCP assigned to rate tariffs in proportion to their estimated contribution to the customer class peak.

11.3.2 Relationship Between Line Losses and Conductor Capacity

In some situations, conductor size is determined by the economics of line losses rather than by thermal overloads or voltage drop. Even at load levels that do not threaten reliability, larger conductors may cost-effectively reduce line losses, especially in new construction.[160] The incremental cost of larger capacity can be entirely justified by loss reduction (which is mostly an energy-related benefit), with higher load-carrying capability as a free additional benefit.

11.3.3 Secondary Distribution Allocators

Each piece of secondary distribution equipment generally serves a smaller number of customers than a single piece of primary distribution equipment. On a radial system, a line transformer may serve a single customer (a large commercial customer or an isolated rural residence) or 100 apartments; a secondary line may serve a few customers or a dozen, depending on the density of load and construction. Older urban neighborhoods often have secondary lines that are connected to several transformers, and some older large cities such as Baltimore have full secondary networks in city centers.[161] In contrast, a primary distribution feeder may serve thousands of customers, and a substation can serve several feeders.

Thus, loads on secondary equipment are less diversified than loads on primary equipment. Hence, cost of service studies frequently allocate secondary equipment on load measures that reflect customer loads diversified for the number of customers on each component. Utilities often use assumed diversity factors to determine the capacity required for secondary lines and transformers, for various numbers of customers. Figure 42 on the next page provides an example of the diversity curve from El Paso Electric Co. (2015, p. 24).

Even identical houses with identical equipment may routinely peak at different times, depending on household composition, work and school schedules and building orientation. The actual peak load for any particular house may occur not at typical peak conditions but because of events not correlated with loads in other houses. For example, one house may experience its maximum load when the family returns from vacation to a hot house in the summer or a very cold one in the winter, even if neither temperatures nor time of day would otherwise be consistent with an annual maximum load. The house next door may experience its maximum load after a water leak or interior painting, when the windows are open and fans, dehumidifiers and the heating or cooling system are all in use.

Accounting for diversity among different types of residential customers, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat, peaking in the winter, and some with fossil fuel heat, peaking in the summer.

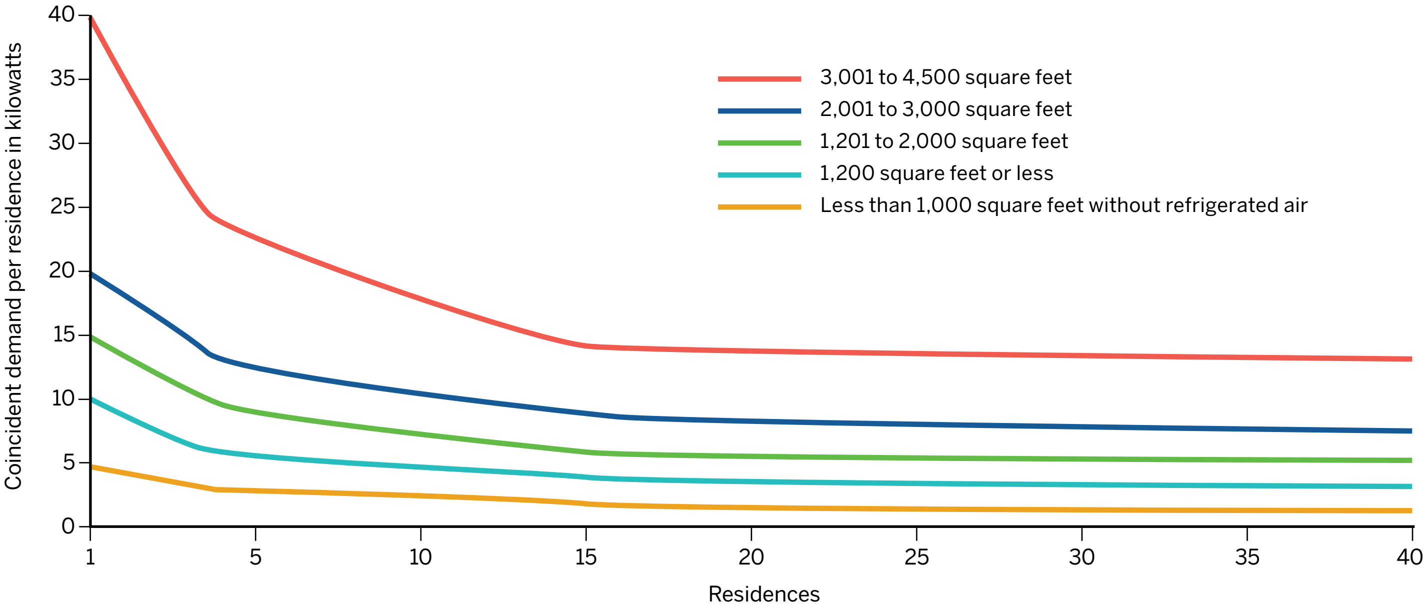
The average transformer serving residential customers may serve a dozen customers, depending on the density of the service territory and the average customer NCP, which for the example in Figure 42 suggests that the customers' average contribution to the transformer peak load would be about 40% of the customers' undiversified load. Thus, the residential allocator for transformer demand would be the class NCP times 40%. Larger commercial customers generally have very little diversity at the transformer level, since each transformer (or bank of transformers) typically serves only one or a few customers.

The same factors (household composition, work and

160 The same is true for increased distribution voltage. Seattle City Light upgraded its residential distribution system from 4 kV to 26 kV in the early 1980s based on analysis done in the Energy 1990 study, prepared in 1976, which focused on avoiding new baseload generation. The line losses justified the expenditure, but the result was also a dramatic increase in distribution system circuit capacity. The Energy 1990 study was discussed in detail in a meeting of the City Council Utilities Committee (Seattle Municipal Archives, 1977).

161 In high-load areas, such as city centers, utilities often operate secondary distribution networks, in which multiple primary feeders serve multiple transformers, which then feed a network of interconnected secondary lines that feed all the customers on the network (See Behnke et al., 2005, p. 11, Figure 8). In secondary networks, the number of transformers and the investment in secondary lines are driven by the aggregate load of the entire network or large parts of the network. The loss of any one feeder and one transformer, or any one run of secondary line, will not disconnect any customer. The existence of the network, the number of transformers and the number and length of primary and secondary lines are entirely load-related. Similar arrangements, called spot networks, are used to serve individual large customers with high reliability requirements. A single spot network customer may thus have multiple transformers, providing redundant capacity.

Figure 42. Typical utility estimates of diversity in residential loads



Source: El Paso Electric Co. (2015, October 29). *El Paso Electric Company's Response to Office of Public Utility Counsel's Fifth Request for Information.* Public Utility Commission of Texas Docket No. 44941

school schedules, unit-specific events) apply in multifamily housing as well as in single-family housing. But the effects of orientation are probably even stronger in multifamily housing than in single-family homes. For example, units on the east side of a building are likely to have summer peak loads in the morning, while those on the west side are likely to experience maximum loads in the evening and those on the south in the middle of the day.

Importantly, Figure 42 represents the diversity of similar neighboring single-family houses. Diversity is likely to be still higher for other applications, such as different types and vintages of neighboring homes, or the great variety of customers who may be served from the shared transformers and lines of a secondary network.

Until 2001, the major U.S. electric utilities were required to provide the number and capacity of transformers in service on their FERC Form 1 reports. Assuming an average of one transformer per commercial and industrial customer, these reports typically suggest a ratio ranging from 3 to more than 20 residential customers per transformer, with the lower ratios for the most rural IOUs and the highest for utilities with dense urban service territories and many multifamily consumers.[162] Only about a dozen electric co-ops filed a FERC Form 1 with the transformer data in 2001, and their ratios vary from about 1 transformer per residential customer for a few very rural co-ops to about 8 residential customers per transformer for Chugach Electric, which serves part of Anchorage as well as rural areas.

Utilities can often provide detailed current data from their geographic information systems. Table 30 on the next page shows Puget Sound Energy's summary of the number of transformers serving a single residential customer and the number serving multiple customers (Levin, 2017, pp. 8-9). More than 95% of customers are served by shared transformers, and those transformers serve an average of 5.3 customers. Using the method described in the previous paragraph, an estimated average of 4.9 Puget Sound Energy residential customers would share a transformer, which is close to the actual average of 4.5 customers per transformer shown in Table 30 (Levin, 2017, and additional calculations by the authors).

The customers who have their own transformer may be too far from their neighbors to share a transformer, or local load growth may have required that the utility add a transformer. In many cases, residential customers with

162 Ratios computed using Form 1, p. 429, transformer data (Federal Energy Regulatory Commission, n.d.) and 2001 numbers from utilities' federal Form 861 (U.S. Energy Information Administration, n.d.-a, file 2).

Table 30. Residential shared transformer example

	With multiple residences per transformer	With single residence per transformer	Total
Number of transformers	197,503	47,699	245,202
Number of customers	1,054,296	47,699	1,101,995
Customers per transformer	5.3	1	4.5

Sources: Levin, A. (2017, June 30). Prefiled response testimony on behalf of NW Energy Coalition, Renewable Northwest and Natural Resources Defense Council. Washington Utilities and Transportation Commission Docket No. UE-170033; additional calculations by the authors

individual transformers may need to pay to obtain service that is more expensive than their line extension allowances (see Section 11.2 or Section 15.2).

Small customers will have similar, but lower, diversity on secondary conductors, which generally serve multiple customers but not as many as a transformer. A transformer that serves a dozen customers may serve two of them directly without secondary lines, four customers from one stretch of secondary line and six from another stretch of secondary line running in the opposite direction or across the street.

Where no detailed data are available on the number of customers per transformer in each class, a reasonable approximation might be to allocate transformer demand costs on a simple average of class NCP and customer NCP for residential and small commercial customers and just customer NCP for larger nonresidential customers.

11.3.4 Distribution Operations and Maintenance Allocators

Distribution O&M accounts associated with a single type of equipment (FERC accounts 582, 591 and 592 for substations and Account 595 for transformers) should be classified and allocated in the same manner as associated equipment. Other accounts serve both primary and secondary lines and service drops (accounts 583, 584, 593 and 594) or include services to a range of equipment (accounts 580 and 590). These costs normally should be classified and allocated in proportion to the plant in service, for the plant accounts they support, subfunctionalized as appropriate. For example, typical utility tree-trimming activities are almost entirely related to primary overhead lines, with very little cost driven by secondary distribution and no costs for protecting service lines (see, for example, Entergy Corp., n.d.).

11.3.5 Multifamily Housing and Distribution Allocation

One common error in distribution cost allocation is treating the residential class as if all customers were in single-family structures, with one service drop per customer and a relatively small number of customers on each transformer.[163] For multifamily customers, one or a few transformers may serve 100 or more customers through a single service line.[164] Treating multifamily customers as if they were single-family customers would overstate their contribution to distribution costs, particularly line transformers and secondary service lines.[165]

This problem can be resolved in either of two ways. The broadest solution is to separate residential customers into two allocation classes: single-family residential and multifamily residential, as we discuss in Section 5.2.[166] Alternatively, the allocation of transformer and service costs to a combined residential class (as well as residential rate design) should take into account the percentage of customers who are in multifamily buildings, and only components that are not shared should be considered customer-related.

163 One large service drop is much less expensive than the multiple drops needed to serve the same number of customers in single-customer buildings. Small commercial customers may also share service drops, although probably to a more limited extent than residential customers.

164 Similarly, if the cost of service study includes any classification of shared distribution plant as customer-related (such as from a minimum system), each multifamily building should be treated as a single location, rather than a large number of dispersed customers. For utilities without remote meter reading, the labor cost for that activity per multifamily customer will be lower than for single-family customers.

165 Allocating transformer costs on demand eliminates the bias for that cost category.

166 If any sort of NCP allocator is used in the cost of service study, the multifamily class load generally should be combined with the load of the type of customers that tend to surround the multifamily buildings in the particular service territory, which may be single-family residential or medium commercial customers.

11.3.6 Direct Assignment of Distribution Plant

Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop.

Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.

11.4 Allocation Factors for Service Drops

The cost of a service drop clearly varies with a number of factors that vary by class: customer load (which affects the capacity of the service line), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer) and whether customers require three-phase service.

Some utilities, including Baltimore Gas & Electric, attempt to track service line costs by class over time (Chernick, 2010, p. 7). This approach is ideal but complicated. Although assigning the costs of new and replacement service lines just requires careful cost accounting, determining the costs of services that are retired and tracking changes in the class or classes in a building (which may change over time from manufacturing to office space to mixed residential and retail) is much more complex. Other utilities allocate service lines on the sum of customer maximum demands in each class. This has the advantage of reflecting the fact that larger customers require larger (and often longer) service lines, without requiring a detailed analysis of the specific lines in use for each class.

Many utilities have performed bottom-up analyses, selecting a typical customer or an arguably representative sample of customers in each class, pricing out those customers' service lines and extrapolating to the class. Since the costs are estimated in today's dollars, the result of these studies is the ratio of each class's cost of services to the total cost, or a set of weights for service costs per customer. Either approach should reflect the sharing of services in multifamily buildings.

11.5 Classification and Allocation for Advanced Metering and Smart Grid Costs

Traditional meters are often discussed as part of the distribution system but are primarily used for billing purposes.[167] These meters typically record energy and, for some classes, customer NCP demand for periodic manual or remote reading and generally are classified as customer-related. Meter costs are then typically allocated on a basis that reflects the higher costs of meters for customers who take power at higher voltage or three phases, for demand-recording meters, for TOU meters and for hourly-recording energy meters. The weights may be developed from the current costs of installing the various types of meters, but as technology changes, those costs may not be representative of the costs of equipment in rates.

In many parts of the country, this traditional metering has been replaced with advanced metering infrastructure. AMI investments were funded in many cases by the American Recovery and Reinvestment Act of 2009, the economic stimulus passed during the Great Recession, but in other cases ratepayers are paying for them in full in the traditional method. In many jurisdictions, AMI has been accompanied by other complementary "smart grid"

167 Some customers who are small or have extremely consistent load patterns are not metered; instead, their bills are estimated based on known load parameters. The largest group of these customers is street lighting customers, but some utilities allow unmetered loads for various small loads that can be easily estimated or nearly flat loads with very high load factors (such as traffic signals). An example of an unmetered customer from the past was a phone booth. Unmetered customers should not be allocated costs of traditional metering and meter reading.

Table 31. Smart grid cost classification

Smart grid element	Legacy approach: Equivalent cost	Legacy approach: FERC account	Legacy approach: Classification	Smart grid classification
Smart meters	Meters	370	Customer	Demand, energy and customer
Distribution control devices	Station equipment and devices	362, 365, 367	Demand	Demand and energy
Data collection system	Meter readers	902	Customer	Demand, energy and customer
Meter data management system	Customer accounting and general plant	903, 905, 391	Customer and overhead	Demand, energy and customer

investments. On the whole, these investments include:

- Smart meters, which are usually defined to include the ability to record and remotely report granular load data, measure voltage and power factor, and allow for remote connection and disconnection of the customer.
- Distribution system improvements, such as equipment to remotely monitor power flow on feeders and substations, open and close switches and breakers and otherwise control the distribution system.
- Voltage control equipment on substations to allow modulation of input voltage in response to measured voltage at the end of each feeder.
- Power factor control equipment to respond to signals from the meters.
- Data collection networks for the meters and line monitors.
- Advanced data processing hardware and software to handle the additional flood of data.
- Supporting overhead costs to make the new system work.

The potential benefits of the smart grid, depending on how it is designed and used, include reduced costs for generation, transmission, distribution and customer service, as described in Subsection 7.1.1. A smart meter is much more than a device to measure customer usage to assure an accurate bill — it is the foundation of a system that may provide some or all of the following:

- Benefits at every level of system capacity, by enabling peak load management since the communication system can be used to control compatible end uses, and because customer response to calls for load reduction can be measured and rewarded.
- Distribution line loss savings from improved power factor and phase balancing.
- Reduced energy costs due to load shifting.
- Reliability benefits, saving time and money on service restoration after outages, since the utility can determine which meters do not have power and can determine whether a customer's loss of service is due to a problem inside the premises or on the distribution system.
- Allowing utilities to determine maximum loads on individual transformers.
- Retail service benefits, by reducing meter reading costs compared with manual meter reads and even automated meter reading and by reducing the cost of disconnecting and reconnecting customers.[168]

The installations have also been very expensive, running into the hundreds of millions of dollars for some utilities, and the cost-effectiveness of the AMI projects has been a matter of dispute in many jurisdictions. Since these new systems are much more expensive than the older metering systems and are largely justified by services other than billing, their costs must be allocated over a wider range of activities, either by functionalizing part of the costs to generation, distribution and so on or reflecting those functions in classification or the allocation factor.

Special attention must be given to matching costs and benefits associated with smart grid deployment. The expected benefits spread across the entire spectrum of utility costs, from lower labor costs for meter reading to lower energy

168 The data systems can also be configured to provide systemwide Wi-Fi internet access, although they usually are not. See Burbank Water and Power (n.d.).

Table 32. Summary of distribution allocation approaches

Element	Method	Comments	Hourly allocation
Substations	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy ALLOCATOR: Loads on substations in hours at or near peaks	Reflect effect of energy near peak and preceding peak on sizing and aging	Allocate by substation cost or capacity, then to hours that stress that substation with peak and heating
Poles	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Pole costs driven by revenue expectation	As primary lines
Primary conductors	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	• Distribution network is installed due to revenue potential • Sizing determined by loads in and near peak hours	• Cost associated with revenue-driven line extension to all hours • Cost associated with peak loads and overloads on distribution of line peaks and high-load hours
Line transformers	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Secondary energy DEMAND ALLOCATOR: Diversified secondary loads in peak and near-peak hours	Reflect diversity	Distribution of transformer peaks and high-load hours
Secondary conductors	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Energy is more important for underground than overhead	Distribution of line peaks and high-load hours
Meters	FUNCTIONALIZATION: Advanced metering infrastructure to generation, transmission and distribution, as well as metering ALLOCATOR FOR CUSTOMER-RELATED COSTS: Weighted customer	Allocation of generation, transmission and distribution components depends on use of advanced metering infrastructure	N/A

* Except some to customer, where a significant portion of plant serves only one customer

costs due to load shifting and line loss reduction. Legacy methods for allocating metering costs as primarily customer-related would place the vast majority of these costs onto the residential rate class, but many of the benefits are typically shared across all rate classes. In other words, the legacy method would give commercial and industrial rate classes substantial benefits but none of the costs.

Table 31 identifies some of the key elements of smart grid cost and how these would be appropriately treated in an embedded cost of service study. These approaches match smart grid cost savings to the enabling expenditures.

11.6 Summary of Distribution Classification and Allocation Methods and Illustrative Examples

The preceding discussion identifies a variety of methods used to functionalize, classify and allocate distribution plant. Table 32 summarizes the application of some of those methods, including the hourly allocations that may be applicable for modern distribution systems with:

- A mix of centralized and distributed resources, conventional and renewable, as well as storage.
- The ability to measure hourly usage on the substations and feeders.
- The ability to estimate hourly load patterns on transformers and secondary lines.

Table 33. Illustrative allocation of distribution substation costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: substation (legacy)	$9,730,000	$9,730,000	$7,297,000	$3,243,000	$30,000,000
Average and peak	$10,056,000	$10,056,000	$8,100,000	$1,788,000	$30,000,000
Hourly	$9,939,000	$10,533,000	$9,009,000	$519,000	$30,000,000

Note: Numbers may not add up to total because of rounding.

Where the available data or analytical resources will not support more sophisticated analyses of distribution cost causation, the following simple rules of thumb may be helpful.

- The only costs that should be classified as customer-related are those specific to individual customers:
  - Basic metering costs, not including the additional costs of advanced meters incurred for system benefits.
  - Service lines, adjusting for shared services in buildings with multiple tenants.
  - For very rural systems, where most transformers and large stretches of primary line serve only a single customer (and those costs are not recovered from contributions in aid of construction), a portion of transformer and primary costs.
- Other costs should be classified as a mix of energy and demand, such as using the average-and-peak allocator.
- The peak demand allocation factor should reflect the distribution of hours in which various portions of distribution system equipment experience peak or heavy loads. If the utility has data only on the time of substation peaks, the load-weighted peaks can be used to distribute the demand-related distribution costs to hours and hence to classes.

11.6.1 Illustrative Methods and Results

The following discussion and tables show illustrative methods and results for several of the key distribution accounts, focused only on the capital costs. The same principles should be applied to O&M costs and depreciation expense. These examples use inputs from tables 5, 6, 7 and 27.

Substations

Table 33 shows three methods for allocating costs of distribution substations. The first of these is a legacy method, relying solely on the class NCP at the substation level.[169] The second is an average-and-peak method, a weighted average between class NCP and energy usage. The third uses the hourly composite allocator, which includes higher costs for hours in which substations are highly loaded.

Primary Circuits

Distribution circuits are built where there is an expectation of significant electricity usage and must be sized to meet peak demands, including the peak hour and other high-load hours that contribute to heating of the relevant elements of the system. Table 34 on the next page illustrates the effect of four alternative methods. The first, based on the class NCP at the circuit level, again produces unreasonable results for the street lighting class. The second, the legacy minimum system method, is not recommended, as discussed above. The third and fourth use a simple (average-and-peak) and more sophisticated (hourly) approach to assigning costs based on how much each class uses the lines and how that usage correlates with high-load hours.

Transformers

Line transformers are needed to serve all secondary voltage customers, typically all residential, small general

169 The street lighting class NCP occurs in the night, and street lighting is a small portion of load on any substation, so the street lighting class NCP load rarely contributes to the sizing of summer-peaking substations. The NCP method treats off-peak class loads as being as important as those that are on-peak. This is particularly inequitable for street lighting, which is nearly always a load caused by the presence of other customers who collectively justify the construction of a circuit.

Table 34. Illustrative allocation of primary distribution circuit costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: circuit (legacy)	$69,565,000	$69,565,000	$43,478,000	$17,391,000	$200,000,000
Minimum system (legacy)	$113,783,000	$51,783,000	$24,739,000	$9,696,000	$200,000,000
Average and peak	$67,041,000	$67,041,000	$53,997,000	$11,921,000	$200,000,000
Hourly	$66,258,000	$70,221,000	$60,059,000	$3,462,000	$200,000,000

Note: Numbers may not add up to total because of rounding.

service and street lighting customers and often other customer classes as well. We present four methods in Table 35: two archaic and two more reflective of dynamic systems and more granular data. All of these apportion no cost to the primary voltage class, which does not use distribution transformers supplied by the utility.

The first method is to apportion transformers in proportion to the class sum of customer noncoincident peaks. This method is not recommended because it fails to recognize that there is great diversity between customers at the transformer level; as noted in Subsection 11.3.3, each transformer in an urban or suburban system may serve anywhere from five to more than 50 customers. The second is the minimum system method, also not recommended because it fails to recognize the drivers of circuit construction, as discussed in Section 11.2. The third is the weighted transformers allocation factor we derive in Section 5.3 (Table 7), weighting the number of transformers by class at 20% and the class sum of customer NCP (recognizing that the diversity is not perfect) at 80%. The last is an hourly energy method but excluding the primary voltage class of customers.

Customer-Related Costs

The final illustration shows two techniques for the apportionment of customer-related costs, based on a traditional customer count and a weighted customer count. Even for simple meters used solely for billing purposes, larger customers require different and more expensive meters. There are fewer of them per customer class, but the billing system programming costs do not vary by number of customers. In addition, a weighted customer account is also relevant to customer service, discussed in the next chapter, because the larger use customers typically have access to superior customer service through "key accounts" specialists who are trained for their needs.

Table 35. Illustrative allocation of distribution line transformer costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Customer NCP (legacy)	$32,258,000	$16,129,000	$0	$1,613,000	$50,000,000
Minimum system (legacy)	$32,461,000	$14,773,000	$0	$2,766,000	$50,000,000
Weighted transformers factor	$29,806,000	$14,903,000	$0	$5,290,000	$50,000,000
Hourly	$23,810,000	$23,810,000	$0	$2,381,000	$50,000,000

Note: Numbers may not add up to total because of rounding.

Table 36. Illustrative allocation of customer-related costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Unweighted					
Customer count	100,000	20,000	2,000	50,000	172,000
Customer factor	58%	12%	1%	29%	100%
Customer costs	$58,140,000	$11,628,000	$1,163,000	$29,070,000	$100,000,000
Weighted					
Weighting factor	1	3	20	0.05	
Customer count	100,000	60,000	40,000	2,500	202,500
Customer factor	49%	30%	20%	1%	100%
Customer costs	$49,383,000	$29,630,000	$19,753,000	$1,235,000	$100,000,000

Note: Numbers may not add up to total because of rounding.

Table 36 first shows a traditional calculation based on the actual number of customers. Then it shows an illustrative customer weighting and a simple allocation of customer-related costs based on that weighting. Each street light is treated as a tiny fraction of one customer; although there are tens of thousands of individual lights, the bills typically include hundreds or thousands of individual lights, billed to a city, homeowners association or other responsible party.[170]

170 In some locales, street lighting is treated as a franchise obligation of the utility and is not billed. In this situation, there are no customer service or billing and collection expenses.