BEFORE THE
PUBLIC UTILITIES COMMISSION
OF NEW HAMPSHIRE

NORTHERN UTILITIES, INC **REQUEST FOR CHANGE IN RATES**	)))))	**Docket DG 21-104**

Direct Testimony of
Courtney Lane and Ben Havumaki

On Behalf of
The Office of Consumer Advocate

April 1, 2022

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A **Ms. Lane:** My name is Courtney Lane. I am a Senior Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue #3, 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 #3, 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, the U.S. Department of Energy, the 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. Lane:** I have 17 years of experience in energy policy and regulation. At Synapse, I work on issues related to utility regulatory models and performance incentive mechanisms. Prior to working at Synapse, I was employed by National Grid as the Growth Management Lead for New England where I oversaw the development of customer products, services, and business models for Massachusetts and Rhode Island such as performance-based regulation. In previous roles at National Grid, I worked on the deployment of non-wires alternatives and grid modernization efforts and led the development of the Rhode Island electric and natural gas energy efficiency plans. Prior to joining National Grid, I worked on regulatory and state policy issues pertaining to energy conservation, retail competition, net metering, and the Alternative Energy Portfolio Standard for Citizens for Pennsylvania's Future (PennFuture). Prior to that, I worked for Northeast Energy Efficiency Partnerships, Inc. where I promoted energy efficiency throughout the Northeast.

I have sponsored testimony before the Maryland Public Service Commission, the Pennsylvania Public Service Commission, the Public Service Commission of the District of Columbia, and the Rhode Island Public Utilities Commission.

I hold a Master of Arts in Environmental Policy and Planning from Tufts University and a Bachelor of Arts in Environmental Geography from Colgate University. My resume is attached as Schedule CLBH-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 Public Utilities Commission of New Hampshire, 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 CLBH-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 Northern Utilities, Inc. ("Northern" or the "Company"). Specifically, our testimony addresses the Company's proposed multi-year rate plan, the proposed increase to the residential customer charge, and the Company's reliance on the minimum-system method for classifying distribution mains costs and its implications for rate design and class cost allocation. 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 for a multi-year rate plan (MRP) with annual step adjustments that track to the Company's actual costs lacks any meaningful cost control incentives or performance commitments to ratepayers.

- The Company's proposal to increase the residential customer charge to $27.84 fails to comport with widely accepted rate design principles and would create rate shock for its customers.

- The Company's proposed residential customer charge increase would contravene key policy priorities—adversely impacting energy efficiency and conservation and imposing a disproportionate burden on lower-income customers.

- 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 practice, resulting in an overallocation of costs to the residential class and providing false justification for high customer charges.

Q Please summarize your recommendations.

A We offer the following recommendations:

1. The Commission should reject the Company's proposed annual step adjustments and return to traditional cost-of-service ratemaking.

2. If the Company wishes for the Commission to consider alternative ratemaking, it should file a comprehensive performance-based regulation proposal consisting of an MRP that separates Northern's revenues from its actual costs and includes performance incentive mechanisms.

3. The Commission should reject the use of the minimum system method for cost allocation and rate design. The Company should be required to allocate distribution mains on a demand-only basis.

4. The customer charge for the domestic schedule should be maintained at its current level of $22.20 per month.

III. OVERVIEW OF TESTIMONY

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

A The Company is proposing to increase base distribution revenues by approximately $7.8 million based on the calendar 2020 test year, followed by a series of three step adjustments to recover costs associated with non-growth-related capital investments made during the calendar years 2021, 2022, and 2023.[1] The $7.8 million revenue increase would represent a distribution revenue increase of approximately 8.1 percent.[2]

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

[1] Exhibit RBH-1, pages 17-18 (Bates 19-20).

[2] Exhibit CGDN-1, page 4 (Bates 56).

residential revenues by 125 percent of the system average increase, yielding a 25.4 percent increase in both the residential customer charge and the variable distribution rate.

Q What factors are driving the Company's overall revenue request and its proposal to increase residential rates by 25.4 percent?

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

1) unrecovered capital investments costs;[3]
2) future capital investments to improve and growth the distribution system;[4] and
3) the application of the minimum system method.

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

A The Company's filing provides 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. It also provides 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 the design of the Company's MRP and how its proposed step adjustments eliminate meaningful incentives to reduce costs and are therefore likely to result in over-investment and a continuation of rising rates.

[3] Exhibit RBH-1, page 10 (Bates 12).

[4] *Ibid*.

In addition to addressing the overall regulatory framework, we address the fact that the minimum system method results in inequitable cost increases for the residential class. 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. We recommend that the Commission require the Company to discontinue use of this method and instead classify distribution mains costs on a demand-only basis.

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

Q Please explain how traditional cost-of-service regulation creates an incentive for cost-containment by utilities?

A Under traditional cost-of-service regulation, "regulatory lag" creates an incentive for the utility to improve cost efficiency until the next rate case. The term "regulatory lag" refers to the time between when a utility's costs change and when new rates reflecting those costs become effective.[5] Under this model, the utility's rates are based on a historical test year and are fixed[6] until the utility files another rate case. This creates a situation where changes to a utility's costs between rate cases will impact its profits, assuming sales remain the same. For instance, if a utility can decrease costs, it can increase profits, all

[5] Lowry, M.N., J. Deason, M. Makos, L. Schwartz. 2017. *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Prepared for U.S. Department of Energy, page 3.2.

[6] Except for certain cost trackers that adjust rates as costs change.

else equal. Conversely, if utility costs increase, profits will decline until rates increase accordingly in a subsequent rate case.[7]

Q Please explain how multi-year rate plans create incentives for cost containment.

A MRPs are a core element of performance-based regulation (PBR). As described by the Vermont Public Utility Commission in 1996,[8] PBR "encourages companies to reduce their costs over time, by providing profit incentives to stimulate innovation, efficiency, and service quality improvements."[9] These objectives are accomplished largely through MRPs, which divorce a utility's revenues from its actual costs for a set period of time (the "stay-out period" between rate cases). During this period, utilities have an opportunity to enhance profits by reducing their costs between rate cases. However, this potential upside is traditionally balanced by prohibiting the utility from filing another rate case if its costs exceed its revenues.

Q What are the key components of MRPs?

A To drive utility cost efficiencies and promote innovation, MRPs typically include the following components:

1) Revenue Cap: A cap on revenues, not costs, for each year of the MRP.

[7] A utility can always choose to file a rate case when its costs exceed revenues under cost-of-service regulation, negating the effects of regulatory lag.

[8] The Vermont Public Utility Commission was then known as the Vermont Public Service Board.

[9] Vermont Public Service Board. Report and Order. Docket No. 5854, *Investigation into the Restructuring of the Electric Utility Industry in Vermont.* December 31, 1996, page 36. Available at https://puc.vermont.gov/sites/psbnew/files/orders/1996/5854RPT.pdf.

2) Attrition Relief Mechanism (ARM): Revenues, if not held fixed, can be adjusted according to a pre-defined formula such as an external cost index (e.g., inflation), costs forecasts, or a combination.

3) Stay-out Provision: A moratorium on filing a rate case for the duration of the MRP.

4) Utility incentives to improve efficiency: An earnings sharing mechanism that allows the utility to retain some or all the cost-efficiencies it creates.[10]

Q Does the Company's proposed MRP contain all these elements?

A No. While the Company's proposal resembles an MRP in many ways, it omits elements that would otherwise serve to incentivize utility cost control and reduce risk to customers.

Q Please describe the Company's proposed MRP.

A The Company's proposal is based on three annual step adjustments to recover the revenue requirement of non-growth-related capital investments made during the calendar years 2021, 2022, and 2023. The Company would make a step adjustment compliance filing on or before the last day in March for the prior year's non-growth-related capital investments, with resulting rate changes going into effect on August 1st.[11]

The Company also proposes a revenue requirement cap of $10.5 million, a base rate stay-out provision through 2024, and a Return on Equity (ROE) collar that would share

[10] M. Whited, C. Roberto. 2019. *Multi-Year Rate Plans: Core Elements and Case Studies*. Synapse Energy Economics Synapse prepared for Maryland PC51 and Case 9618, page 2.

[11] Exhibit CGDN-1, page 39 (Bates 91).

earnings above 11.00 percent equally between distribution customers and the Company, with the Company retaining the risk of earnings below 10.30 percent ROE.[12]

However, there are critical flaws in the design in several of these elements that negate their ability to create adequate incentives for cost containment over the course of the MRP. We discuss each design flaw in the sections below.

<u>Critical Flaws of the Proposed MRP</u>

Q Please explain the flaws with Northern's annual step adjustments.

A MRPs provide incentives for cost containment by divorcing a utility's actual costs from its revenues. Specifically, attrition relief mechanisms are designed to be "largely "external" in the sense that they give a utility an allowance for cost growth rather than reimbursement for its actual growth."[13]

In contrast, Northern's proposed annual step adjustments track the Company's actual costs. That is, each step adjustment will be based on the Company's actual investment in non-growth plant additions made in the prior year.[14] This is problematic because when revenues track with costs it removes the incentive for the utility to seek cost efficiencies, since the utility no longer benefits from the cost efficiencies it creates.

[12] *Id.*, pages 44-45 (Bates 96-97).

[13] Lowry, M., Makos, M., and Waschbusch, G. 2015. *Alternative Regulation for Emerging Utility Challenges: 2015 Update*. Edison Electric Institute, page 34.

[14] Northern Utilities, Inc. Response to OCA 2-14.

Q What are your concerns regarding the Company's proposed revenue cap?

A The Company's proposed cap on revenues is based on the sum of the Company's forecasted revenue requirements for investment years 2021-2023 plus an increase of approximately 10 percent.[15] Because of information asymmetry, this creates opportunities for forecasts to be inflated by the utility above efficient levels and shifts risks to customers.

Q Please explain what you mean by information asymmetry.

A Information asymmetry refers to the utility having more information than the regulator or stakeholders. This creates significant challenges for regulators to ensure that cost forecasts are reasonable and that the utility is operating efficiently. As explained by the National Regulatory Research Institute:

> "Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast."[16]

Because regulators and stakeholders can never completely vet the accuracy of forecasts, utilities have an inherent bias to overstate their costs and understate revenues. This bias

[15] Exhibit CGDN-1, page 44 (Bates 96).

[16] Costello, K, 2016, *Multiyear Rate Plans and the Public Interest*, National Regulatory Research Institute, pages 35–36.

has been well-recognized by commissions and by organizations such as the National Regulatory Research Institute (NRRI). The bias exists because utilities have an incentive to add to the rate base,[17] and because there is little payback for a utility that underestimates costs since any overrun would jeopardize its rate of return and penalize its shareholders.[18]

Q Did the Company provide its forecast for non-growth-related capital additions over the course of the MRP?

A Yes. The Company provides actual spending and forecast spending in Sprague Leblanc Exhibit KSCL-2.[19]

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

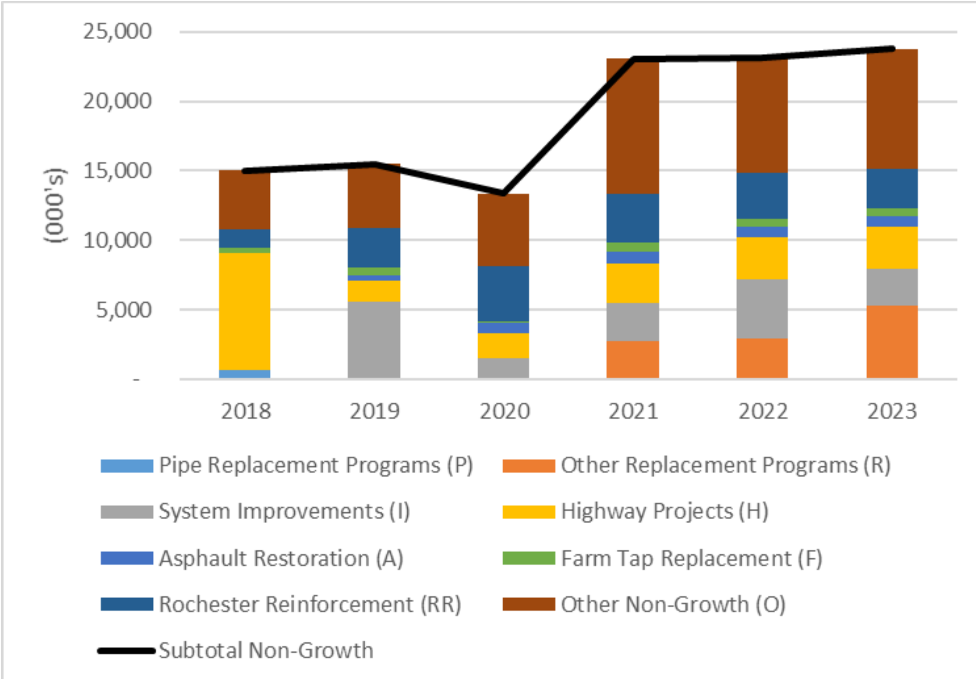
A Yes. Using Exhibit KSCL-2, We calculated the increase in the Company's non-growth-related capital spending between the three most recent years (2018-2020) and the MRP period (2021-2023). As shown in the figure below, the Company's forecasted spending represents a significant jump from historical spending levels. In particular, the Company's forecasted annual expenditures for non-growth-related investments during the MRP is nearly 50 percent higher than the average annual expenditures during the 2018–2020 period. This amplifies our concerns that the MRP does not provide adequate cost containment incentives and shifts risk to customers.

[17] Regulated utilities earn a return on capital investments. When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect.

[18] *Id.*, page 36.

[19] Northern Utilities, Inc. Response to Energy 4-2. Sprague Leblanc Exhibit KSCL-2.

Figure 1. Northern Utilities, Inc. Actual and Forecast Non-Growth-Related Capital Spend ($000's)



Q Does the Company's proposal to return any under-spend to ratepayers address your concerns?

A No, because utility cost forecasts are likely to be higher than the efficient level for two reasons. First, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This incentive must be offset by a regulatory framework that encourages the utility to operate efficiently through prioritizing only projects that are truly necessary and seeking cost reductions where possible. Basing a utility's revenue on cost forecasts does not provide such efficiency incentives, and thus the utility's spending is likely to be higher than the efficient level.

Second, the revenue cap creates an incentive for the utility to overstate cost forecasts in order to reduce the risk of cost overruns. Under the Company's proposal, if the Company exceeds its cumulative revenue requirement cap of $10.5 million, it would forego recovery of those costs until its next base rate case.[20] Since the Company's revenue cap is based on its forecast for non-growth-related capital investments, it would benefit the Company to inflate these costs to provide more certainty that it will not overrun the cap and forgo cost recovery.

Q Will the Company's proposed earnings sharing mechanism strengthen utility incentives for cost efficiency?

No. Earnings sharing mechanisms, like that proposed by Northern, typically allow a utility to keep a portion of earnings above its allowed ROE. This structure is intended to incentivize the utility to find cost efficiencies over the course of the MRP. If the utility can control costs, it can earn an ROE above its authorized return.

However, the design of Northern's MRP makes it almost impossible for the Company to earn above its allowed ROE through cost reductions, since any cost reduction in the Company's forecasted non-growth-related capital spend is returned to ratepayers.

While Northern states its "incentive for cost control lies in the Company's ability to retain earnings above its authorized return,"[21] it was unable to identify any actionable ways to control costs that would result in a higher ROE. When asked what actions the Company could take to increase its ROE under its proposed MRP, the Company stated it "does not see any feasible actions it could take to increase its Return on Equity ("ROE") under its proposed multi-year rate plan."[22] The Company goes on to state that,

[20] Northern Utilities, Inc. Response to OCA TS 2-1.

[21] Northern Utilities, Inc. Response to OCA 2-12(b).

[22] Northern Utilities, Inc. Response to OCA TS 1-2(a).

theoretically, it could reduce operating expenses to increase its ROE but did not believe that to be realistic.[23]

The one mechanism available to the Company to increase its ROE appears to be through its proposed decoupling mechanism. Here, the Company proposes a revenue per customer (RPC) approach. The RPC enables the Company to retain new customer revenues to offset the incremental costs to serve new customers. However, the RPC is based on average revenues per customer.[24] The Company indicates if the actual incremental cost of service for a new customer is less than the RPC, "incremental revenues that exceed incremental costs are retained by the Company between rate cases and credited to customers when base rates are reset."[25]

For these reasons, the earnings sharing mechanism is unlikely to provide the intended effect of incentivizing the Company to control costs.

Q What is your recommendation regarding the Company's proposed MRP?

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. Based on our review, traditional cost-of-service regulation would provide the Company with a greater incentive to control its costs than the proposed MRP, thereby better ensuring that rates are just and reasonable. If the Company wishes for the Commission to

[23] Id.

[24] Northern Utilities, Inc. Response to OCA 2-38(a-b).

[25] Northern Utilities, Inc. Response to OCA 2-38(e).

consider alternative ratemaking, it should file a comprehensive performance-based regulation proposal consisting of both an MRP and performance incentive mechanisms.

Q What components should a future performance-based regulation proposal contain?

A If the Company wishes to pursue a multi-year rate plan in the future, we recommend that it utilize a revenue requirement cap that is escalated based on an external index instead of a Company-specific forecast. Such external indices are often based on inflation rates and productivity factors. In addition, it should be coupled with performance incentive mechanisms that link Company earnings to performance in targeted areas that would provide net benefits to customers. If designed well, these components would help to deliver overall benefits to both the utility and ratepayers.

V. THE COMPANY'S PROPOSAL WOULD INCREASE ITS ALREADY EXCESSIVE CUSTOMER CHARGE

Q Please describe the Company's proposal for the residential customer charge.

A The Company proposes to increase the residential customer charge from $22.20 per month to $27.84 per month.

Q Why has the Company proposed to increase the customer charge for the residential class?

A The Company is seeking to increase the distribution revenues that it recovers from the residential class. It has proposed to raise both the residential customer charge and the variable distribution rate by the same 25.4 percent. The Company states that the increase in the residential customer charge is needed to bring the charge closer to the theoretically correct value, as determined by the Company's cost allocation study.

Q Are there any reasons why utilities may prefer higher customer charges?

A Yes. Higher customer charges provide greater certainty about future revenues. Lower customer charges, all else equal, mean the potential for more variability as a greater share of revenues are recovered through *variable* rates.

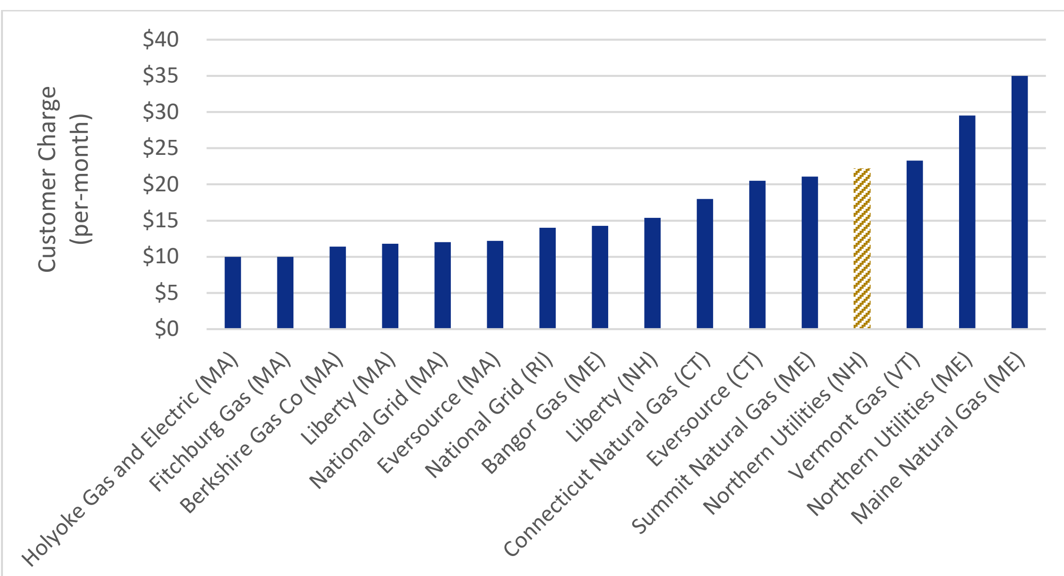
Q Is the Company's proposed customer charge high?

A Yes, the proposed residential customer charges appear to be very high. Even the Company's current customer charge is high.

Q Why do you say that the Company's current residential customer charge is high?

A This observation is based on a review of residential rates at all New England gas utilities. To make things simpler, since some gas utilities have multiple residential rates, we compared only the highest residential customer charge in effect for each company. Figure 2 summarizes this information.

Figure 2. Residential customer charges at New England gas utilities



Q **What conclusions do you draw from your review of utility tariffs?**

A We conclude that the Company's current residential customer charge is already higher than those of nearly every other New England gas utility, as is shown in Figure 2. Should the proposed increase be granted, the Company would surpass Vermont Gas to take third place in the customer charge rankings—behind only its Maine affiliate and another Maine gas utility.

Q **Why are other utilities' fixed charges relevant to the instant proceeding?**

A Because these examples appear to support lower residential fixed charges. The data on rate structures across New England demonstrate the collective judgement of a range of different utilities and public utility commissions in favor of residential fixed charges that are lower than the Company's charge.

Q **Please explain your use of the term "judgement" in reference to setting the customer charge.**

A Rate design necessarily includes both quantitative and qualitative factors. On the quantitative side, rate design may be grounded in cost allocation studies and other quantitative data. Yet the exercise of judgement in rate design is critical because rate design intersects with key policy interests and goals. The exercise of judgement is also critical since some of the quantitative methods may not be universally accepted and may be far from settled science.

Q Does the Company recognize the need for judgement in rate design?

A Yes. The Company has stated 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."[26]

Q Can you provide an example of a quantitative issue that is not settled?

A Yes. One key example relevant to this case is the question of how to classify distribution mains. In previous cases, the Company classified these on a demand-only basis.[27] In the instant proceeding, the Company has changed its approach with its use of the minimum system method—with rather dramatic implications for the assignment of responsibility for mains costs.

Q Is the minimum system method universally accepted approach to classifying distribution mains?

A No, it is not. The Company invokes the NARUC Gas Rate Design Manual in support of its transition to this approach. While it is true that the NARUC manual describes two minimum system methods, it also indicates that treating *any* portion of the distribution main costs as customer-related is "controversial."[28] The Company selectively omits this portion of the relevant section in its reference to the NARUC manual.

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

[27] Exhibit RAJT-1, page 19 (Bates 962).

[28] NARUC Gas Rate Design Manual, page 22.

Q How should the Commission address the Company's use of the minimum system method?

A As we will discuss later in our testimony, we believe that the minimum system method is flawed. Even under the most favorable light, the minimum system method is controversial. We recommend that the Commission reject the minimum system method on two counts. First, because the Company's use of this approach leads to an overcollection of revenues from the residential class. Second, to clearly send the message that the results of the minimum-system method should not be treated as a lodestar or long-term target for the residential customer charge.

VI. KEY POLICY CONSIDERATIONS WEIGH AGAINST RAISING THE CUSTOMER CHARGE

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.[29]

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 explains that its approach to rate design is informed by Bonbright.[30]

Q Does the Company's proposed fixed charge increase violate Bonbright's principles?

A Yes, it does. 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. While we are concerned about rate shock arising from the overall increase in residential rates that have been proposed, we focus here in particular on the implications of the requested customer charge increase. Raising the customer charge by the proposed margin would have two undesirable effects: (1) it would make all customers' bills increasingly fixed, and (2) it would have disproportionately negative impacts on the customers who use the least gas.

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

[30] Exhibit RAJT-1, page 36 (Bates 979) and page 41 (Bates 984).

Q How much will the Company's proposed rate changes affect the extent to which customer bills are fixed?

A All customer bills will become more fixed with the proposed rate changes. The impact of these changes on the share of customer bills that is fixed is shown below in Table 1.

Table 1. Impacts of rate changes to fixed share of residential bills, by usage

Percentile	Monthly use (therms)	Fixed share (current)	Fixed shared (proposed)	Change in fixed share
10	5.91	71.0%	73.8%	2.8%
20	22.05	39.6%	43.0%	3.4%
30	37.57	27.8%	30.7%	2.9%
40	52.37	21.7%	24.1%	2.5%
50	67.18	17.7%	19.9%	2.1%
60	82.99	14.9%	16.7%	1.9%
70	101.23	12.5%	14.1%	1.6%
80	124	10.5%	11.8%	1.4%
90	155.63	8.5%	9.7%	1.2%
100	240.82	5.7%	6.5%	0.8%

Source: Schedule JDT-3

This table shows that at all consumption levels, increasing the fixed charge and the variable distribution rate by the same percentage results in an increasingly fixed bill. However, as noted above, lower-use customers experience greater relative increases in the fixed portions of their bills. This effect can be seen in the final column of Table 1, labeled "Change in fixed share."

Q What is the problem with increasingly fixed bills?

A By increasing the proportion of a customer's bill that is fixed and that cannot be mitigated through conservation, the Company's proposed rate design would reduce the incentive for customers to conserve. This means that unduly increasing the customer charge conflicts with Bonbright's eighth principle, which is discouraging wasteful use of service. It also runs counter to state policies that aim to enhance environmental protection and encourage energy efficiency. For example:

- In RSA 12-P:7-a (the act establishing the requirement for the state's Ten-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.

- In RSA 378:37, which established the Least Cost Integrated Resource Plan requirement, 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

- In RSA 374-F:3, X, which lists energy efficiency among the policy principles that guide the restructuring of the electric industry.

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:

> 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.[31]

The principle articulated by the Commission applies in the instant proceeding. Given the choice between increasing fixed charges or increasing volumetric rates, the latter will better promote conservation.

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

A Yes, the negative effects of increasing customer 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 attempt to conserve energy or respond to AMI-enabled peak pricing incentives, they cannot reduce fixed customer charges.[32]

[31] Docket No. DG 17-048. Order No. 26,122, page 54.

[32] 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, page 110.

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.[33]

Q Please explain your concern about disproportionate impacts to lower-use customers.

A We have already noted above that lower-use customers will see the fixed portion of their bill grow by a greater share than customers with higher gas consumption. These lower-use customers will also see their bills increase by a greater percentage than their higher use peers. These two effects interact unfavorably for lower-use customers, as they experience disproportionate bill increases while simultaneously suffering a decline in their ability to mitigate against the bill increases through conservation.

Q How much disproportionate will the bill impacts to low use customers be?

A Customers in the lowest usage quintile will see their bills grow at nearly double the rate of customers in the highest quintile. These impacts are summarized below in Table 2.

[33] 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, pages 110-111.

Table 2. Impacts of rate changes on total bills for residential customers, by usage

Percentile	Total consumption (therms)	Total bill (current)	Total bill (proposed)	Change in bill
10	5.91	$31.26	$37.73	20.7%
20	22.05	$56.01	$64.72	15.6%
30	37.57	$79.81	$90.68	13.6%
40	52.37	$102.50	$115.44	12.6%
50	67.18	$125.21	$140.21	12.0%
60	82.99	$149.46	$166.66	11.5%
70	101.23	$177.43	$197.17	11.1%
80	124	$212.34	$235.25	10.8%
90	155.63	$260.84	$288.16	10.5%
100	240.82	$391.47	$430.66	10.0%

Source: Schedule JDT-3

Q Why are your concerns about unequal bill impacts?

A The fact that lower-use customers will experience disproportionate bill impacts is problematic in its own right, but we are particularly concerned about disproportionate bill impacts that will face low-income, low-use customers. The data suggests that lower-income customers tend to use less gas than higher income customers, so we conclude that lower-income customers, on average, are apt to see greater percentage increases in their bills if the customer charge increase is to be granted.

Q Why do you suggest that lower-income customers use less gas than other customers?

A This observation is based on data from the U.S. Department of Energy's Low-Income Energy Affordability Data (LEAD) tool.[34] While the LEAD data reports spending on natural gas by household income level rather than total consumption by household

[34] United States Department of Energy, Office of Energy Efficiency & Energy Efficiency (EERE). *Low-Income Energy Affordability Data (LEAD) Tool*. Available at: https://www.energy.gov/eere/slsc/maps/lead-tool.

income, the spending data should proxy for consumption. It is clear from the LEAD data that gas consumption rises with household income. For example:

- A household with an income of between 200 percent and 400 percent of the federal poverty level (likely a below-median income household) spends about 29 percent more annually on gas than does a household at or below the federal poverty level.

- A household at greater than 400 percent the federal poverty level spends about 17 percent more on gas than a household at or below the poverty level.

These data suggest that lower-income customers will experience disproportionate increases in their monthly bills as a result of the proposed customer charge increase.

Q If low-income customers spend less on gas, doesn't that mean that they'll be less affected by the proposed rate changes?

A Unfortunately, no. While it is true that lower-income households spend less on gas, they spend a far greater share of their income on energy. In other words, their energy burdens are much worse. For example:

- A New Hampshire household that uses utility gas for heat and has an income of greater than 400 percent of the federal poverty level can expect to spend less than one percent of annual income on natural gas.

- A household at or below the federal poverty level that heats with utility gas will spend an average of 8 percent of income on gas. That same low-income

> household can expect to spend about 20 percent of income on energy overall. For context, an energy burden exceeding 10 percent is often considered severe.[35]

The fact that low-income customers have such high energy burdens means that the proposed rate increases will disproportionately impact the customers that are least able to bear additional bill increases.

VII. THE COMPANY'S COST ALLOCATION METHODOLOGY IS FLAWED

Q Please elaborate on your concerns about the Company's cost allocation method.

A Our primary concern hinges upon the use of the minimum system method for classifying distribution mains 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. While this source addresses cost allocation for the electric grid, its perspective on the minimum system method is also relevant to the gas sector. Indeed, the Company also references

[35] American Council for an Energy-Efficient Future (ACEEE). 2020. *National and Regional Energy Burdens.* Available at: https://www.aceee.org/sites/default/files/pdfs/ACEEE-01%20Energy%20Burden%20-%20National.pdf.

electric sector-oriented materials in support of its proposals for gas sector cost allocation. The relevant pages from the manual are included as Attachment CLBH-8. Key critiques of the minimum system method from the RAP manual are summarized below:[36]

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.

2) A large portion of the cost of the distribution system 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 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 without expanding the distribution system.

[36] 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.

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."[37]

Q Are you aware of other Commissions that have found fault with the minimum system method?

A Yes. In its 2021 decision in a Columbia Gas rate case, the Pennsylvania Public Utility Commission rejected the Company's proposed minimum system method, writing:

> [W]e remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment because it is the load that determines the main investment, not the number of customers served. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served.[38]

Q How do you recommend that the Company approach cost allocation of distribution mains?

A We recommend that the Company not classify any distribution mains costs on a customer basis. The recommended approach appears to be consistent with the Company's approach in the previous rate case. This 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 power consumption."[39]

[37] Lazar, Chernick, and Marcus, page 146.

[38] PA PUC. Docket No. R-2020-3018835. Opinion and Order, page 234.

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

VIII. 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 proposal for an MRP with annual step adjustments that track to the Company's actual costs lacks any meaningful cost control incentives or performance commitments to ratepayers. 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.

2. The Company's proposal to increase the residential customer charge to $27.84 fails to comport with widely accepted rate design principles and would contravene key policy priorities. It should be rejected and the residential customer charge should be maintained at its present level.

3. The Commission should reject the use of the minimum system method for cost allocation and rate design. The Company should be required to allocate distribution mains on a demand-only basis.

Q Does this conclude your testimony?

A Yes, it does.

Schedules and Attachments

Courtney Lane, Senior Associate

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clane@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Associate,* November 2019 – Present.

Provides consulting and researching services on a wide range of issues related to the electric industry including performance-based regulation, benefit-cost assessment, rate and bill impacts, and assessment of distributed energy resource policies and programs. Develops expert witness testimony in public utility commission proceedings.

National Grid, Waltham, MA. *Growth Management Lead*, *New England,* May 2019 – November 2019, *Lead Analyst for Rhode Island Policy and Evaluation,* June 2013 – April 2019.

- Portfolio management of product verticals including energy efficiency, demand response, solar, storage, distributed gas resources, and electric transportation, to optimize growth and customer offerings.
- Strategy lead for the Performance Incentive Mechanisms (PIMs) working group.
- Worked with internal and external stakeholders and led the development of National Grid's Annual and Three-Year Energy Efficiency Plans and System Reliability Procurement Plans for the state of Rhode Island.
- Represented energy efficiency and demand response within the company at various Rhode Island grid modernization proceedings.
- Led the Rhode Island Energy Efficiency Collaborative; a group focused on reaching consensuses regarding energy efficiency plans and policy issues for demand-side resources in Rhode Island.
- Managed evaluations of National Grid's residential energy efficiency programs in Rhode Island, and benefit-cost models to screen energy efficiency measures.

Citizens for Pennsylvania's Future, Philadelphia, PA. *Senior Energy Policy Analyst*, 2005–2013.

- Played a vital role in several legislative victories in Pennsylvania, including passage of energy conservation legislation that requires utilities to reduce overall and peak demand for electricity (2009); passage of the $650 million Alternative Energy Investment Act (2008); and important amendments to the Alternative Energy Portfolio Standards law vital to the development of solar energy in Pennsylvania (2007).
- Performed market research and industry investigation on emerging energy resources including wind, solar, energy efficiency and demand response.
- Planned, facilitated and participated in wind energy advocates training meetings, annual partners retreat with members of wind and solar companies, and the PennFuture annual clean energy conference.

Northeast Energy Efficiency Partnerships, Inc., Lexington, MA. *Research and Policy Analyst,* 2004–2005.

- Drafted comments and testimony on various state regulatory and legislative actions pertaining to energy efficiency.
- Tracked energy efficiency initiatives set forth in various state climate change action plans, and federal and state energy regulatory developments and requirements.
- Participated in Regional Greenhouse Gas Initiative (RGGI) stakeholder meetings.
- Analyzed cost-effectiveness of various initiatives within the organization.

Massachusetts Executive Office of Environmental Affairs, Boston, MA. *Field Projects Extern,* 2003.

- Worked for the Director of Water and Watersheds at the EOEA, examining the risks and benefits of different groundwater recharge techniques and policies throughout the U.S.
- Presented a final report to both Sea Change and the EOEA with findings and policy recommendations for the state.

EnviroBusiness, Inc., Cambridge, MA. *Environmental Scientist,* July 2000 – May 2001

- Conducted pre-acquisition assessments/due diligence assignments for properties throughout New England. Environmental assessments included an analysis of historic properties, wetlands, endangered species habitat, floodplains, and other areas of environmental concern and the possible impacts of cellular installations on these sensitive areas.
- Prepared and managed NEPA reviews and Environmental Assessments for telecommunications sites.

SKILLS

Software: SPSS, Arcview GIS, IMPLAN, Access, Microsoft Excel, Word, Power Point

EDUCATION

Tufts University, Medford, MA
Master of Arts; Environmental Policy and Planning, 2004.

Colgate University, Hamilton, NY
Bachelor of Arts; Environmental Geography, 2000, *cum laude.*

PUBLICATIONS

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.

Lane, C., S. Kwok, J. Hall, I. Addleton. 2021. *Macroeconomic Analysis of Clean Vehicle Policy Scenarios for Illinois*. Synapse Energy for the Natural Resources Defense Council.

Lane, C., K. Takahashi. 2020. *Rate and Bill Impact Analysis of Rhode Island Natural Gas Energy Efficiency Programs.* Synapse Energy Economics for National Grid.

Chang, M., J. Frost, C. Lane, S. Letendre, PhD. 2020. *The Fixed Resource Requirement Alternative to PJM's Capacity Market: A Guide for State Decision-Making*. Synapse Energy Economics for the State Energy & Environmental Impact Center at the NYU School of Law.

National Energy Screening Project. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. E4TheFuture, Synapse Energy Economics, Energy Futures Group, ICF, Pace Energy and Climate Center, Schiller Consulting, Smart Electric Power Alliance.

TESTIMONY

Maryland Public Service Commission (Docket No. 9655): Direct and Surrebuttal Testimony of Courtney Lane regarding the application of Potomac Electric Company for a Multi-Year Plan and Performance Incentive Mechanisms. On behalf of the Maryland Office of People's Counsel. March 3, 2021 and April 20, 2021.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020830): Direct testimony of Alice Napoleon and Courtney Lane regarding PECO Energy Company's proposed Act 129 Phase IV Energy Efficiency and Conservation Plan. On behalf of the Natural Resources Defense Council. January 14, 2021.

Maryland Public Service Commission (Case No. 9645): Direct and Surrebuttal Testimony of Courtney Lane regarding the Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People's Counsel. August 14, 2020 and October 7, 2020.

Maryland Public Service Commission (Case No. 9619): Comments of Maryland Office of People's Counsel Regarding Energy Storage Pilot Program Applications, attached Synapse Energy Economics Report. June 23, 2020.

Public Service Commission of the District of Columbia (Formal Case No. 1156): Direct, Rebuttal, Surrebuttal, and Supplemental Testimony of Courtney Lane regarding the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia. On behalf of the District of Columbia Government. March 6, 2020, April 8, 2020, June 1, 2020, and July 27, 2020.

Rhode Island Public Utilities Commission (Docket No. 4888): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2019 Energy Efficiency Program (EEP). On behalf of National Grid. December 11, 2018.

Rhode Island Public Utilities Commission (Docket No. 4889): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2019 System Reliability Procurement Report (SRP). On behalf of National Grid. December 10, 2018.

Rhode Island Public Utilities Commission (Docket No. 4755): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2018 Energy Efficiency Program (EEP). On behalf of National Grid. December 13, 2017.

Rhode Island Public Utilities Commission (Docket No. 4684): Oral testimony of Courtney Lane regarding the RI Energy Efficiency and Resource Management Council (EERMC) Proposed Energy Efficiency Savings Targets for National Grid's Energy Efficiency and System Reliability Procurement for the Period 2018-2020 Pursuant to §39-1-27.7. On behalf of National Grid. March 7, 2017.

Rhode Island Public Utilities Commission (Docket No. 4684): Oral testimony of Courtney Lane regarding National Grid's 2018-2020 Energy Efficiency and System Reliability Procurement Plan. On behalf of National Grid. October 25, 2017.

Rhode Island Public Utilities Commission (Docket No. 4654): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2017 Energy Efficiency Program Plan (EEPP) for Electric & Gas. On behalf of National Grid. December 8, 2016.

Rhode Island Public Utilities Commission (Docket No. 4580): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2016 Energy Efficiency Program Plan (EEPP) for Electric & Gas. On behalf of National Grid. December 2, 2015.

Pennsylvania Public Utility Commission (Docket No. P-2012-2320369): Direct testimony of Courtney Lane regarding the Petition of PPL Electric Utilities Corporation for an Evidentiary Hearing on the Energy Efficiency Benchmarks Established for the Period June 1, 2013 through May 31, 2016. On behalf of PennFuture. October 19, 2012.

Pennsylvania Public Utility Commission (Docket No. P-2012-2320334): Direct testimony of Courtney Lane regarding the Petition of PECO Energy for an Evidentiary Hearing on the Energy Efficiency Benchmarks Established for the Period June 1, 2013 through May 31, 2016. On behalf of PennFuture. September 20, 2012.

Pennsylvania Public Utility Commission (Docket No. I-2011-2237952): Oral testimony of Courtney Lane regarding the Commission’s Investigation of Pennsylvania’s Retail Electricity Markets. On behalf of PennFuture. March 21, 2012.

Committee on the Environment Council of the City of Philadelphia (Bill No. 110829): Oral testimony of Courtney Lane regarding building permitting fees for solar energy projects. On behalf of PennFuture. December 5, 2011.

Pennsylvania Public Utility Commission (Docket No. M-00061984): Oral testimony of Courtney Lane regarding the En Banc Hearing on Alternative Energy, Energy Conservation, and Demand Side Response. On behalf of PennFuture. November 19, 2008.

PRESENTATIONS

Lane, C. 2021. “Accounting for Interactive Effects: Assessing the Cost-Effectiveness of Integrated Distributed Energy Resources.” Presentation at the 2021 American Council for an Energy-Efficient Economy (ACEEE) National Conference on Energy Efficiency as a Resource, October 27, 2021.

Lane, C. 2019. “The RI Test.” Presentation for AESP Webinar: Emerging Valuation Approaches in Cost-Effectiveness and IRPs, October 31, 2019.

Lane, C., A. Flanders. 2017. “National Grid Rhode Island: Piloting Wireless Alternatives: Forging a Successful Program in Difficult Circumstances.” Presentation at the 35th Annual Peak Load Management Association (PLMA) Conference, Nashville, TN, April 4, 2017.

Lane, C. 2013. “Regional Renewable Energy Policy Update.” Presentation at the Globalcon Conference, Philadelphia, PA, March 6, 2013.

Lane, C. 2012. “Act 129 and Beyond.” Presentation at the ACI Mid-Atlantic Home Performance Conference, October 1, 2012.

Lane, C. 2012. “Act 129: Taking Energy Efficiency to the Next Level.” Presentation at the Energypath Conference, June 28, 2012.

Lane, C. 2011. “Pennsylvania’s Model Wind Ordinance.” Presentation at Harvesting Wind Energy on the Delmarva Peninsula, September 14, 2011.

Lane, C. 2011. “Electric Retail Competition and the AEPS.” Presentation at the Villanova Law Forum, November 4, 2011.

Lane, C. 2009. “Act 129: Growing the Energy Conservation Market.” Presentation at the Western Chester County Chamber of Commerce, March 25, 2009.

Resume updated March 2022

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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, and distributed energy resources (DER) growth.

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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Impact. Prepared by Synapse Energy Economics and Slipstream for Iowa Economic Development Authority.

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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

Public Utilities Commission of New Hampshire (Docket No. DE-21-030): Direct testimony of Melissa Whited and Ben Havumaki regarding Unitil Energy Systems, Inc.’s request for change in rates. On behalf of the Office of Consumer Advocate. November 18, 2021.

Rhode Island Division of Public Utilities & Carriers (Docket No. 5189): Direct Testimony of Tim Woolf and Ben Havumaki. November 17, 2021.

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 March 2022

REQUEST:

Regarding Exhibit CGDN-1, Bates 96, lines 6-12, will each step adjustment equal the Company's eligible Non-Growth Plant Addition investments made in the prior year? Please explain why or why not.

RESPONSE:

Correct, but for clarity the Company has provided the proposed timeline and applicable investment years for each step adjustment.

The first step adjustment in the three-year program is proposed to be filed with the Commission on March 31, 2022 with the rate increase becoming effective on August 1, 2022. The first step adjustment will be based on actual investment year 2021 non-growth plant additions.

The second step adjustment in the three-year program is proposed to be filed with the Commission on March 31, 2023 with the rate increase becoming effective on August 1, 2023. The second step adjustment will be based on actual investment year 2022 non-growth plant additions.

The third step adjustment in the three-year program is proposed to be filed with the Commission on March 31, 2024 with the rate increase becoming effective on August 1, 2024. The third step adjustment will be based on actual investment year 2023 non-growth plant additions.

REQUEST:

Excel Schedules and Workpapers: Please provide versions of live excel spreadsheets, with all links and equations intact, for all schedules and associated workpapers included in the Company's filing, except for any live excel spreadsheets that have already been provided. In the response, please note which spreadsheets have already been provided.

RESPONSE:

Live Excel spreadsheets or Word documents are being provided in this data response as follows:

Email 1: Filing Requirements and Revenue Requirement
Goulding / Nawazelski
Sprague / Leblanc
Diggins / Francoeur
Giegerich
Cochrane
Allis
Lyons

Email 2: Hurstak

Email 3: Amen / Taylor

To date, Energy 1-11 Attachment 1 has been the only live Excel file provided.

Northern Utilites Capital Spending 2017 - 2025

	Actual Spending ($000's)				Forecast Spending ($000's)				
Category	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Growth									
Customer Additions (C)	3,788	4,537	4,054	4,000	4,521	4,672	4,756	5,174	5,261
Mains Extensions (M)	2,726	3,732	4,096	5,551	2,449	2,492	2,524	2,764	2,779
Subtotal Growth	6,514	8,268	8,150	9,552	6,970	7,165	7,280	7,938	8,040
Non-Growth									
Pipe Replacement Programs (P)	6,076	608	68	-	-	-	-	-	-
Other Replacement Programs (R)	-	-	-	-	2,709	2,908	5,238	2,296	6,204
System Improvements (I)	-	-	5,460	1,502	2,733	4,303	2,682	4,623	700
Highway Projects (H)	6,884	8,487	1,576	1,746	2,917	2,985	3,026	3,283	3,319
Asphault Restoration (A)	-	-	331	757	762	790	804	847	869
Farm Tap Replacement (F)	361	310	597	164	714	508	513	568	568
Rochester Reinforcement (RR)	859	1,353	2,853	3,982	3,464	3,338	2,894	-	-
Other Non-Growth (O)	4,213	4,256	4,594	5,211	9,779	8,291	8,609	10,775	11,442
Subtotal Non-Growth	18,394	15,014	15,479	13,363	23,078	23,123	23,766	22,392	23,102
Total	24,908	23,282	23,630	22,915	30,048	30,288	31,046	30,330	31,143

% Growth	26%	36%	34%	42%	23%	24%	23%	26%	26%
% Non-Growth	74%	64%	66%	58%	77%	76%	77%	74%	74%
% Eligible Facilities	68%	62%	39%	50%	32%	31%	29%	22%	21%

Eligible Facilities	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pipe Replacement (P)	6,076	608	68	-	-	-	-	-	-
Mains Extension excl. services (M)	2,726	3,732	4,096	5,551	2,449	2,492	2,524	2,764	2,779
Highway Projects (H)	6,884	8,487	1,576	1,746	2,917	2,985	3,026	3,283	3,319
Farm Tap Replacements (F)	361	310	597	164	714	508	513	568	568
Rochester Reinforcement (RR)	859	1,353	2,853	3,982	3,464	3,338	2,894	-	-
Total	16,907	14,490	9,190	11,444	9,543	9,324	8,958	6,615	6,666

REQUEST:

Refer to Company Response to Request No. OCA 2-11 (Witness Robert B. Hevert), and answer the following:

a. What if your spending exceeds the cap of $10.5 million? Would the Company forego recovery of those costs until the excess spending gets folded into rate base in the next rate case, or would the Company seek recovery of those costs in some manner prior to the next rate case?

RESPONSE:

In the event that cumulative Revenue Requirement related to Eligible Facilities exceeds the proposed cap of $10,500,000 the Company would forego recovery of those costs until the Company's next base rate case.

REQUEST:

Refer to Exhibit RGH-1, Bates 23, lines 5-9, and answer the following:

a. Please explain the justification for 11.00 percent.
b. Does earning sharing account for operation and maintenance expenses? If it does not, what protections are in place to support cost control of operation and maintenance spending?

RESPONSE:

a. In Docket No. DE 21-030 (Unitil Energy Systems, or "UES"), UES proposed a Return on Equity of 10.00 percent, and an Earnings Sharing Mechanism in which earnings above 11.00 percent would be shared equally between the company and its customers (see, Docket No. DE 21-030, Testimony of Robert B. Hevert, at Bates 39). In that case, the sharing band was 100 basis points above the proposed ROE. In this case, rather than set the sharing band at 100 basis points above the proposed ROE of 10.30 percent, the Company chose to propose a sharing band consistent with the UES level. Consequently, rather than propose 11.30 percent (that is, 10.30 percent plus 100 basis points), Northern Utilities proposes a sharing band 30 basis points lower, at 11.00 percent. Also consistent with the UES structure, Northern Utilities would retain the risk of earnings below its authorized return (although it would have the right to request rate relief if the actual return were to fall below 7.00 percent).

b. Yes, it does. As explained at Bates 188, the earned Return on Equity is that which is submitted in the Company's PUC 509.01 F-1 filing. OCA 2-12 Attachment 1, which is the Company's filing for December 2021, provides that calculation. As OCA 2-12 Attachment 1 indicates, operating and maintenance expenses are removed from revenue (along with other cost items) to arrive at the earned Return on Equity. Consequently, the earnings sharing mechanism does take operating and maintenance expenses into consideration. Incentive for cost control lies in the Company's ability to retain earnings above its authorized return (to 11.00 percent, after which earning are shared equally with customers), and in its responsibility to retain the risk of earning less than its authorized return.

Unitil

February 10, 2022

BY OVERNIGHT AND ELECTRONIC FILING

Daniel C. Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

RE: PUC 509.01 – F-1 Rate of Return
for the Twelve Months Ended December 31, 2021

Dear Director Howland:

Northern Utilities, Inc. ("Northern") hereby submits its F-1 Rate of Return report for its New Hampshire Division, showing the historical weather-normalized rate of return on rate base for the twelve months ended December 31, 2021, in accordance with PUC 509.01.

Northern's F-1 Rate of Return report reflects the following:

Cost of Service

- Federal and state income taxes are calculated at statutory rates to reflect the Tax Cuts and Jobs Act of 2017

Rate Base

- Rate base is calculated for the year ending December 31, 2021.
- Cash working capital is calculated using a 23.97-day net lag based on the most recent lead lag study filed with the Commission in Docket 17-070.

Cost of Capital

- Cost of Capital reflects Northern's current cost of capital and capital structure.

Corporate Office

6 Liberty Lane West
Hampton, NH 03842-1720

Phone: 603-772-0775
Fax: 603-773-6605

Email: corp@unitil.com

If you have any questions, please contact me at 603-379-3836.

Sincerely,

Daniel Nawazelski
Manager, Revenue Requirements
Unitil Service Corp.

cc: Donald Kreis, Consumer Advocate

Northern Utilities, Inc.
New Hampshire Division
Puc 509.01 -- F-1 Rate of Return
12 Months Ending December 31, 2021

Schedule 1: Calculation of Per Books Rate of Return

Cost of Service		Period End
Gas Service Revenue	$	41,499,099
Other Operating Revenue		1,146,287
Weather Adjustment		1,271,867
Total Revenue - Adjusted		**43,917,253**
Gas Costs		443,594
Other Production		68,237
Distribution		3,717,023
Customer Accounting		2,459,653
Sales & New Business		54,247
General & Administrative		6,783,827
Federal & State Income Tax - Adjusted		2,764,711
Property Tax		4,881,937
Other Tax		229,577
Depreciation		9,458,253
Amortization		954,871
Interest on Customer Deposits		7,355
Total Operating Expenses		**31,823,287**
Operating Income - Adjusted	**$**	**12,093,966**

Rate Base		Period End
NH Plant	$	317,616,204
Supplemental Plant Adjustment		557,537
Total Plant		318,173,741
Less: Reserve for Depreciation & Amortization		97,613,421
Net Utility Plant		**220,560,319**
Plus :		
Materials and Supplies		2,825,003
Cash Working Capital Requirement		1,713,335
Regulatory Assets		-
Less :		
Customer Deposits		214,324
Accumulated Deferred Income Taxes		22,159,223
Regulatory Liabilities		6,572,092
Reimbursable Contributions		-
Total Rate Base	**$**	**196,153,018**
Utility Operating Income - Curr Cost of Capital	$	14,286,120
Utility Operating Income - Adjusted		12,093,966
Operating Income Deficiency (Surplus)	**$**	**2,192,153**
Income Tax Gross-Up		814,215
Revenue Deficiency (Surplus)	**$**	**3,006,368**
Return on Rate Base - Actual		**6.17%**
Current Cost of Capital		**7.28%**
ROE - Actual		**7.33%**
ROE - Authorized		**9.50%**

Schedule 2: Current Cost of Capital

		Amount Outstanding	Percent Total	Cost Rate	Weighted Cost Rate
Common Equity	$	244,360,885	51.5%	9.50%	4.89%
Long Term Debt		230,000,000	48.5%	4.93%	2.39%
Short Term Debt (a)		-	0.00%	1.25%	0.00%
Total Allowed	**$**	**474,360,885**	**100.0%**		**7.28%**

(a) Excluding Accrued Revenue, Purchased Gas Working Capital, and CWIP

REQUEST:

Refer to Goulding and Nawazelski Testimony, Bates Page 96, Lines 21-22 and Bates Page 97 Lines 1-3; in regard to the Company's proposed Return on Equity collar

a. Please explain what actions the Company could take to increase its Return on Equity under its proposed multi-year rate plan.
b. Please explain what factors would cause the Company's earnings to fall below 10.30 percent under its proposed multi-year rate plan.

RESPONSE:

a. The Company does not see any feasible actions it could take to increase its Return on Equity ("ROE") under its proposed multi-year rate plan. Theoretically the Company could increase its ROE by reducing its operating expenses. The Company does not believe that it is realistic that operating expenses will decrease for many reasons. First, the Company, as is the rest of the country, is experiencing ongoing inflationary pressures. The Company has included a pro forma inflation adjustment in its revenue requirement to combat some of these inflationary pressures, but cost pressures will still impact over the course of the 2021 Rate Plan. Next, as described in part b of this response many of the Company's costs are fixed in nature with little Company discretion to avoid or reduce these costs. It is important to note that regardless of all of these cost pressures, the Company's top priority is to provide safe and reliable gas distribution service to its customers using the most cost-effective practices.

b. As described in the initial testimony of Robert B. Hevert, Northern like all natural gas utilities, is capital-intensive. This leads to continual investment in long-lived assets and the fixed costs that are required to safely and reliably maintain those investments. The Company's multi-year rate plan provides for cost recovery of Non-Growth Plant Additions, but over the Company's proposed three year rate plan the Company will invest over $20 million of investment that will not be recovered under any rate mechanism. The Company anticipates inflationary cost pressures on its operations and maintenance expense over the period as well, which the

Company's proposed 2021 Rate Plan does not provide recovery of. The Company expects customer growth over this period, but the increased revenue from these customers will not keep face with the increased costs.

REQUEST:

Refer to Exhibit TSL-1, Bates 1073, lines 9-11, and answer the following:

a. If the revenues per customer (“RPC”) is based on the authorized revenues divided by the number of customers included in the authorized rate design, please explain how it reflects the marginal cost of serving a new customer?
b. Is the RPC based on average revenues per customer? If yes, does the Company make any adjustments to reflect the marginal cost to serve a new customer?
c. If the RPC is based on the average cost per customer, provide the marginal costs per customer for each rate class in LIVE Excel format.
d. If the actual marginal cost of serving a new customer is more than the RPC, how will this impact the Company’s earnings?
e. If the actual marginal cost of serving a new customer is less than the RPC, how will this impact the Company’s earnings?

RESPONSE:

a. As an initial matter, the request makes several references to “marginal cost”. The testimony does not use the term “marginal cost”. However, we assume the reference to “marginal cost” is related to the Company’s statements regarding “incremental cost”.[1] Consequently, the responses below are provided in the context of incremental cost rather than marginal cost.

   The proposed revenue per customer approach enables the Company to retain new customer revenues to offset the incremental costs to serve new customers. Please refer to the Company’s response to OCA TS 1-6 for an illustrated comparison between the revenue per customer and total revenue approaches. The incremental cost to serve a new customer depends on their service, investment, and operating cost requirements.

b. Yes, the RPC based on average revenues per customer. The Company does not adjust the RPC to reflect the incremental cost to serve a new customer.

c. Please refer to (a). The incremental cost to serve a new customer

[1] Marginal cost is generally defined as a change in cost relative to a change in demand.

would depend on their service, investment, and operating cost requirements.

d. Please refer to the Company's response to OCA TS 1-5. The Company's line extension policy ensures that the incremental cost to serve new customers does not exceed the incremental customer revenues.[2] The Company's line extension policy utilizes incremental costs and revenues rather than average costs and revenues to reflect the economics of adding new customers.

e. Incremental revenues that exceed incremental costs are retained by the Company between rate cases and credited to customers when base rates are reset.

[2] Unitil line extension policy is located at: https://unitil.com/sites/default/files/2021-05/d%20-Section%20III%20%28Line%20Extensions%29.pdf

REQUEST:

Refer to Exhibit TSL-1, Bates 1073, lines 9-11, and answer the following:

a. If the revenues per customer ("RPC") is based on the authorized revenues divided by the number of customers included in the authorized rate design, please explain how it reflects the marginal cost of serving a new customer?
b. Is the RPC based on average revenues per customer? If yes, does the Company make any adjustments to reflect the marginal cost to serve a new customer?
c. If the RPC is based on the average cost per customer, provide the marginal costs per customer for each rate class in LIVE Excel format.
d. If the actual marginal cost of serving a new customer is more than the RPC, how will this impact the Company's earnings?
e. If the actual marginal cost of serving a new customer is less than the RPC, how will this impact the Company's earnings?

RESPONSE:

a. As an initial matter, the request makes several references to "marginal cost". The testimony does not use the term "marginal cost". However, we assume the reference to "marginal cost" is related to the Company's statements regarding "incremental cost".[1] Consequently, the responses below are provided in the context of incremental cost rather than marginal cost.

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b. Yes, the RPC based on average revenues per customer. The Company does not adjust the RPC to reflect the incremental cost to serve a new customer.

c. Please refer to (a). The incremental cost to serve a new customer

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e. Incremental revenues that exceed incremental costs are retained by the Company between rate cases and credited to customers when base rates are reset.

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https://unitil.com/sites/default/files/2021-05/d%20-Section%20III%20%28Line%20Extensions%29.pdf

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).

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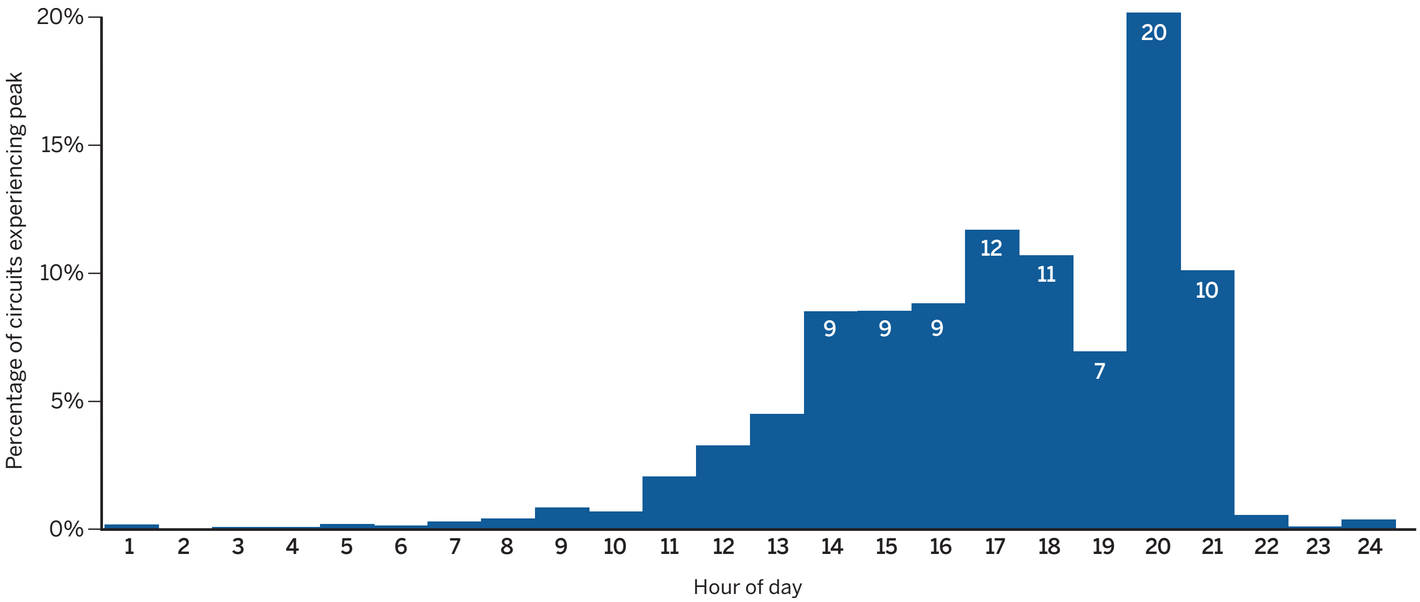
Figure 40. San Diego Gas & Electric circuit peaks



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.

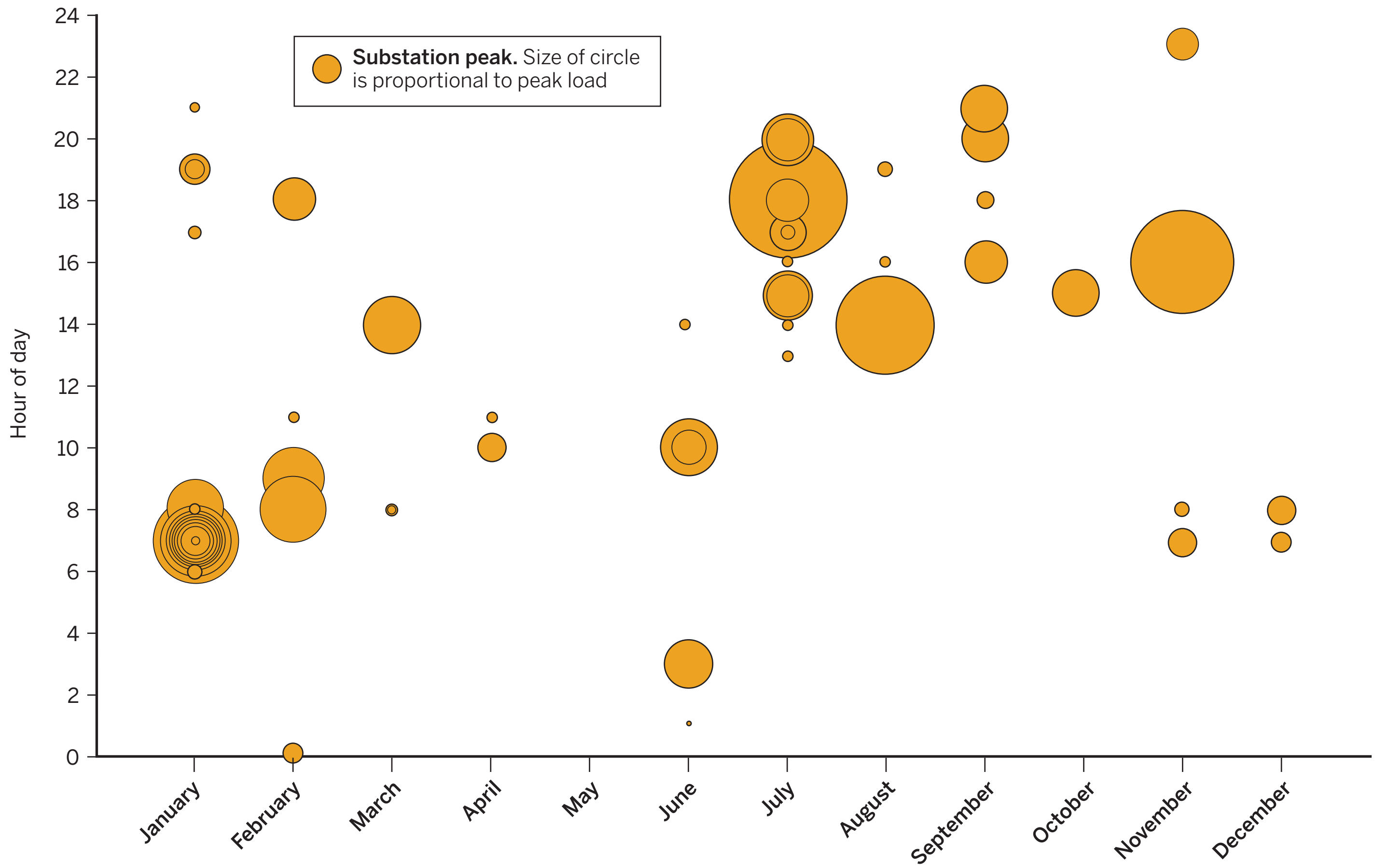
Figure 41 on the next page shows the distribution of substation peaks for Delmarva Power & Light over a period of one year (Delmarva Power & Light, 2016). The area of each bubble is proportional to the peak load on the station. Clearly, no one peak hour (or even a combination of monthly peaks) is representative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

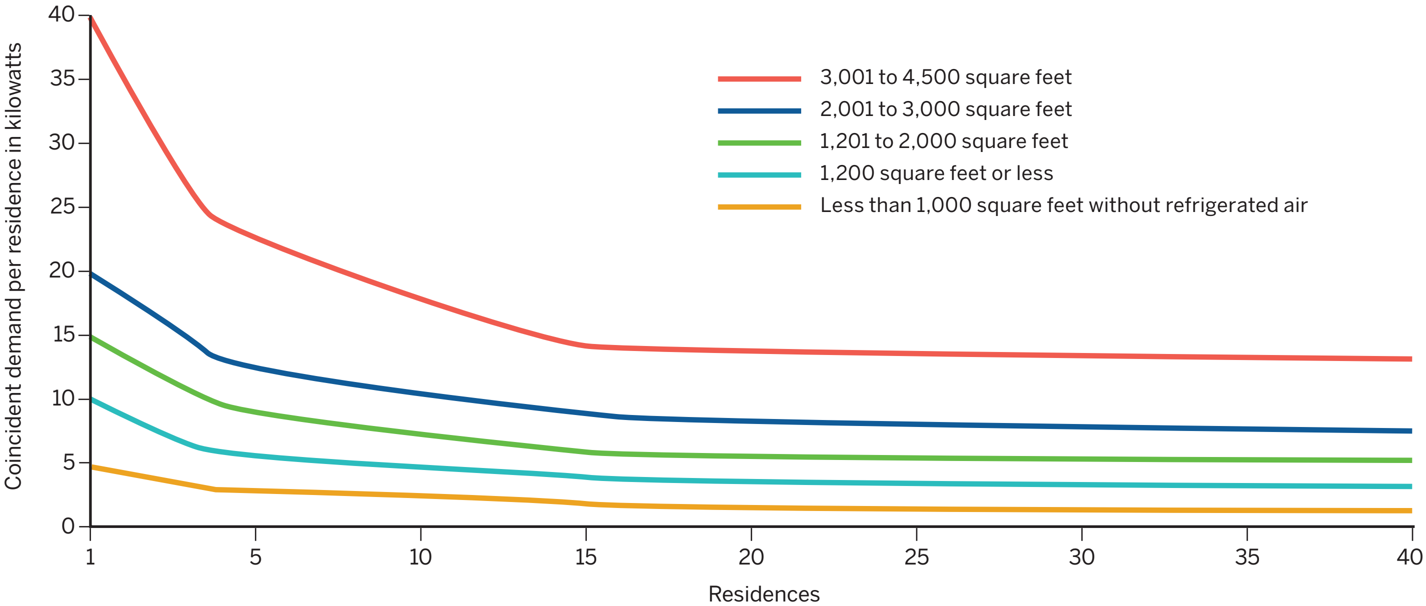
The average transformer serving residential customers may serve a dozen customers, depending on the density of the service territory and the average customer NCP, which for the example in Figure 42 suggests that the customers' average contribution to the transformer peak load would be about 40% of the 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.

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Table 31. Smart grid cost classification

Smart grid element	Legacy approach — Equivalent cost	FERC account	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.

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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.