

**STATE OF NORTH CAROLINA
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

In the Matter of:)	
)	
Application of Duke Energy Carolinas, LLC)	Docket No. E-7, Sub 1214
For Adjustment of Rates and Charges)	
Applicable to Electric Service in)	
North Carolina)	
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DIRECT TESTIMONY AND EXHIBITS OF

JONATHAN F. WALLACH

ON BEHALF OF

**THE NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL, AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY**

February 18, 2020

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EXHIBITS

- JFW-1 – Resume of Jonathan F. Wallach, Resource Insight, Inc.
- JFW-2 – George J. Sterzinger, *The Customer Charge and Problems of Double Allocation of Costs*, PUBLIC UTILITIES FORTNIGHTLY 30–32 (1981).
- JFW-3 – Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 3-3, Docket No. E-7, Sub 1214, January 20, 2020.
- JFW-4 – Duke Energy Indiana, LLC Response to Citizens Action Coalition Data Request 12-4, IURC Cause No. 45253, September 23, 2019.
- JFW-5 – Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 3-2, Docket No. E-7, Sub 1214, January 20, 2020.
- JFW-6 – Duke Energy Carolinas Revised Response to Public Staff Data Request Item No. 100-18, Docket No. E-7, Sub 1214, January 17, 2020.
- JFW-7 – Citations to Marginal-Price Elasticity Studies
- JFW-8 – Duke Energy Carolinas Supplemental Response to North Carolina Justice Center, *et. al.*, Data Request 1-4, Docket No. E-7, Sub 1214, January 13, 2020.
- JFW-9 – Letter from Paul Curl, Secretary of Washington Utilities and Transportation Commission, to Julian Ajello of the California Public Utility Commission, regarding review of the NARUC Electric Utility Cost Allocation Manual, June 11, 1992.

1 **I. INTRODUCTION AND SUMMARY**

2 **Q: PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS**
3 **ADDRESS.**

4 A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5
5 Water Street, Arlington, Massachusetts.

6 **Q: PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.**

7 A: I have worked as a consultant to the electric power industry since 1981. From
8 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In
9 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a
10 Senior Analyst at Komanoff Energy Associates. I have been in my current
11 position at Resource Insight since 1990.

12 Over the past four decades, I have advised and testified on behalf of clients
13 on a wide range of economic, planning, and policy issues relating to the
14 regulation of electric utilities, including: electric-utility restructuring; wholesale-
15 power market design and operations; transmission pricing and policy; market-
16 price forecasting; market valuation of generating assets and purchase contracts;
17 power-procurement strategies; risk assessment and mitigation; integrated
18 resource planning; mergers and acquisitions; cost allocation and rate design; and
19 energy-efficiency program design and planning.

20 My resume is attached as Exhibit JFW-1.

21 **Q: HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?**

22 A: Yes. I have sponsored expert testimony in more than 90 state, provincial, and
23 federal proceedings in the U.S. and Canada, including before this Commission in
24 the previous general rate cases for Duke Energy Carolinas (Docket No. E-7, Sub
25 1146) and for Duke Energy Progress (Docket No. E-2, Sub 1142). I also testified

1 in the most recent Duke Energy Carolinas and Duke Energy Progress rate cases in
2 South Carolina and in the most recent Duke Energy Indiana rate case. I include a
3 detailed list of my previous testimony in Exhibit JFW-1.

4 **Q: ON WHOSE BEHALF ARE YOU TESTIFYING?**

5 A: I am testifying on behalf of the North Carolina Justice Center, North Carolina
6 Housing Coalition, Natural Resources Defense Council, and Southern Alliance
7 for Clean Energy.

8 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

9 A: On September 30, 2019, Duke Energy Carolinas, LLC (“DEC” or “the
10 Company”) filed an application and supporting testimony for approval of
11 increased electric rates and charges. My testimony responds to the testimony by
12 Company witnesses:

- 13 • Michael J. Pirro, regarding the Company’s proposals to: (1) allocate among
14 the various retail rate classes the requested base revenue increase; and (2)
15 maintain the monthly Basic Facilities Charge (“BFC”) for residential
16 customers at its current rate.¹
- 17 • Janice Hager, regarding the Company’s cost of service study (“COSS”),
18 which served as the basis for the Company’s proposals for allocating the
19 requested base revenue increase and for setting the residential BFC.

20 Ms. Hager cites to a March 28, 2019 report by the Public Staff (“Public
21 Staff MSM Report”) as the basis in part for her endorsement of the Company’s

¹ On October 23, 2019, DEC filed a corrected version of Mr. Pirro’s direct testimony. I respond to the this corrected version of Mr. Pirro’s testimony.

1 COSS.² My testimony therefore also addresses the findings and recommendations
2 of this report.

3 **Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS WITH**
4 **REGARD TO DEC'S PROPOSAL FOR ALLOCATING THE**
5 **REQUESTED BASE REVENUE INCREASE.**

6 A: The Commission should reject the Company's proposal for allocating the
7 requested base revenue increase. The Company's proposal relies solely on the
8 results of a cost of service study that does not allocate costs to customer classes in
9 a manner that reasonably reflects each class's responsibility for such costs.
10 Specifically, the Company's COSS misallocates distribution costs by: (1)
11 misclassifying a portion of such costs as customer-related by relying on a flawed
12 "minimum-system" analysis to classify distribution costs; and (2) misallocating
13 the demand-related portion of such costs by relying on an allocator that fails to
14 account for the impact of load diversity on distribution equipment sizing and cost.
15 Because of these two errors, the Company's COSS allocates more distribution
16 plant costs to the residential rate classes than is appropriate under generally
17 accepted cost-causation principles.

18 The Commission should therefore direct DEC to discontinue its use of the
19 minimum-system method for classifying distribution costs in the Company's
20 COSS. Instead, consistent with best practice, DEC should rely on the "basic
21 customer method" for classifying such costs in its COSS. In addition, in order to
22 reasonably account for the effect of load diversity on distribution equipment
23 sizing and cost, demand-related distribution costs should be allocated to rate
24 classes on the basis of each class's diversified peak demand.

² *Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities*, Docket No. E-100, Sub 162 (March 28, 2019) [hereinafter "Public Staff MSM Report"].

1 Correcting for the misallocations in the Company’s COSS would
2 substantially reduce the allocation of the requested base revenue increase to the
3 residential rate classes. Accordingly, a fair and reasonable approach would be to
4 increase base revenues for the residential rate classes by the same percentage as
5 the overall system-average increase authorized by the Commission, if any.

6 **Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**
7 **WITH REGARD TO DEC’S PROPOSAL REGARDING THE**
8 **RESIDENTIAL BFC.**

9 A: The Company has not justified its proposal to maintain the residential BFC at its
10 current rate. As explained in more detail below, the Company’s proposal runs
11 contrary to long-standing principles for designing cost-based rates since it would
12 allow for the continued inappropriate recovery of usage-driven costs through the
13 fixed residential BFC. The Company’s proposal to continue recovering usage-
14 driven costs through the residential BFC would:

- 15 • Continue the current subsidization of high-usage residential customers’
16 costs by low-usage customers.
- 17 • Dampen price signals to consumers for controlling their bills through
18 conservation or investments in energy efficiency or distributed renewable
19 generation.

20 Consequently, the Commission should reject the Company’s proposal to
21 maintain the monthly BFC for residential customers at its current rate of \$14.00
22 per bill. Instead, I recommend that the residential BFC be reduced to \$11.15,
23 reflecting the actual cost to connect a residential customer. Consistent with long-
24 standing cost-causation and rate-design principles, a monthly BFC of \$11.15
25 would provide for the recovery of the cost of meters, service drops, and customer
26 services required to connect a residential customer.

1 **Q: PLEASE SUMMARIZE YOUR ASSESSMENT OF THE PUBLIC STAFF**
2 **MSM REPORT.**

3 A: The Public Staff MSM report fails to make the case for minimum-system
4 classification methods. The Public Staff’s endorsement of minimum-system
5 methods rests on its unsubstantiated belief that there is a minimum portion of the
6 cost for the distribution grid which is incurred regardless of demand. This notion
7 of a minimum distribution cost which lies at the foundation of minimum-system
8 methods simply does not comport with standard practice for distribution planning
9 and spending. Utilities do not first incur “minimum” distribution-grid costs for
10 the purposes of connecting customers at zeroload and then incur additional costs
11 to meet expected demand. Instead, utilities typically size and invest in
12 distribution systems based on an expectation of customer demands on those
13 systems. In other words, the notion that there is a minimum portion of a
14 distribution grid whose costs are “caused” by (i.e., varies with) the number of
15 customers is an unrealistic hypothetical construct. The reality is that distribution-
16 grid costs in total are primarily driven by customer demand.

17 This implausibility gap between the imagined and the actual causes of
18 investments in the distribution grid will only grow wider as DEC increases
19 spending on its proposed Grid Improvement Plan. It is therefore long past time
20 for North Carolina’s electric utilities to discard this false notion that there is a
21 minimum portion of distribution-grid costs. The Commission should
22 categorically reject as contrary to the public interest the use by DEC and other
23 electric utilities of minimum-system classification methods for either cost-
24 allocation or rate-design purposes. Instead, DEC should be directed to follow best
25 practice by adopting the basic customer method for classifying distribution costs
26 in its cost of service studies. In addition, the Commission should investigate
27 whether discretionary GIP costs, to the extent authorized, should be allocated to

1 rate classes in the Company’s COSS commensurate with the benefits to those
2 classes from GIP spending. In this way, the Commission can ensure that
3 distribution costs are allocated in the Company’s cost of service studies and
4 recovered through rates in a manner that is consistent with established cost-
5 causation and economic principles.

6 **Q: HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?**

7 A: In Section II, I describe how the Company’s proposal for allocating the requested
8 base revenue increase relies on a cost of service study that over-allocates
9 distribution plant costs to the residential rate classes. In Section III, I propose an
10 alternative approach for allocating any base revenue increase authorized by the
11 Commission in order to correct for the flaws in the Company’s COSS. In Section
12 IV, I explain how DEC’s proposal for the residential BFC violates long-standing
13 principles of cost-based rate design, would continue unreasonable cross-
14 subsidization within the residential class, and would dampen energy price signals.
15 In Section V, I comment on the Public Staff MS Report. Finally, I reiterate my
16 recommendations in Section VI.

17 **II. DEC’S COSS OVER-ALLOCATES COSTS TO THE RESIDENTIAL**
18 **RATE CLASSES**

19 **Q: PLEASE DESCRIBE THE COMPANY’S REQUESTED REVENUE**
20 **INCREASE.**

21 A: The Company is requesting that electric retail base rates be increased on average
22 by 9.7% in order to recover an expected revenue deficiency of about \$445.3
23 million in the 2018 test year.³ Of the total \$445.3 million requested base revenue

³ Derived from data provided in Pirro Exhibit 4, attached to *Corrected Direct Testimony of Michael J. Pirro for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1214 (October 23, 2019) [hereinafter “Corrected Pirro Direct”]. The 9.7% value represents the percentage increase over revenues under current base rates exclusive of current rider revenues.

1 increase, DEC proposes to allocate about \$233.9 million to residential customers.
2 This amount represents a 10.7% increase over residential test-year revenues
3 under current base rates.⁴

4 **Q: WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED**
5 **ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO**
6 **THE RESIDENTIAL RATE CLASSES?**

7 A: According to DEC witness Michael J. Pirro, the Company's COSS served as the
8 basis for his revenue allocation proposal. Specifically, Mr. Pirro derived the
9 proposed allocation of the base revenue deficiency to rate classes in two steps,
10 each of which relied on the results of the Company's COSS. First, Mr. Pirro
11 allocated the requested base revenue increase to rate classes in proportion to each
12 class's allocation of total rate base in the Company's COSS.⁵ Second, Mr. Pirro
13 increased or decreased each class's allocation of the requested base revenue
14 increase by 25% of the increase or decrease, respectively, in each class's revenues
15 under current rates required to achieve the system-average rate of return under
16 current rates.⁶

17 **Q: WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?**

18 A: The primary purpose of a cost of service study is to allocate a utility's total
19 revenue requirements to rate classes in a manner that reasonably reflects each
20 class's responsibility for such revenue requirements. In other words, the primary

⁴ *Id.* The \$233.9 million amount represents the total allocation to all residential rate schedules. Standard residential service is provided under Rate Schedule RS. Rate Schedule RE is applicable to residential customers who use electricity for all major end-uses. Rate Schedule ES is applicable to residential customers whose homes meet Energy Star standards. Rate Schedule ESA is applicable to residential customers who use electricity for all major end-uses and whose homes meet Energy Star standards. Time-of-use residential service is provided under Rate Schedule RT.

⁵ Corrected Pirro Direct, 11.

⁶ Pirro Exhibit 4.

1 purpose of a cost of service study is to attribute costs to rate classes based on how
2 those classes cause such costs to be incurred.

3 **Q: PLEASE DESCRIBE HOW THE COMPANY’S COSS ALLOCATES**
4 **TOTAL-SYSTEM RETAIL REVENUE REQUIREMENTS TO RATE**
5 **CLASSES.**

6 A: In order to allocate costs to rate classes, the COSS first separates total costs into
7 production, transmission, distribution, and customer functions. Costs in each
8 function are then classified as energy-, demand-, or customer-related based on
9 whether costs are considered to be “caused” by energy sales, peak demand, or the
10 number of customers, respectively. Finally, costs classified as either energy-,
11 demand-, or customer-related are allocated to rate classes in proportion to each
12 class’s contribution to total-system energy sales, peak demand, or number of
13 customers, respectively.⁷

14 **Q: DOES THE COMPANY’S COSS REASONABLY ALLOCATE TEST-**
15 **YEAR REVENUE REQUIREMENTS?**

16 A: No. The Company’s COSS does not allocate costs to rate classes in a manner that
17 reasonably reflects each class’s responsibility for such costs. In particular, the
18 COSS misallocates distribution costs.

19 **Q: HOW DOES THE COMPANY’S COSS MISALLOCATE DISTRIBUTION**
20 **COSTS?**

21 A: As described in detail below, the Company’s COSS misallocates distribution
22 plant costs by inappropriately classifying a portion of such costs as customer-
23 related. The COSS then compounds this error by allocating demand-related
24 distribution plant costs on the basis of customer maximum demand, rather than

⁷ *Direct Testimony of Janice Hager for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1214, 5-6 (September 30, 2019) [hereinafter “Hager Direct”].

1 based on customer demand coincident with class peaks. Because of these two
2 errors, the Company’s COSS allocates more distribution plant costs to the
3 residential rate classes than is appropriate under generally accepted cost-
4 causation principles.

5 ***A. Misclassification of Distribution Plant Costs***

6 **Q: PLEASE DESCRIBE HOW COSTS ARE CLASSIFIED IN THE**
7 **COMPANY’S COSS.**

8 A: The Company classifies the costs of meters, service drops, and customer services
9 (“customer connection costs”) as customer-related in the COSS. In addition, the
10 Company relies on a “minimum-system” analysis to classify a portion of the
11 costs incurred for poles, conductors, conduits, and line transformers
12 (“distribution-grid costs) as customer-related.⁸

13 The remaining portion of pole, conductor, conduit, and line-transformer
14 costs not classified as customer-related are instead classified as demand-related in
15 the COSS, along with all production and transmission plant and fixed operations
16 and maintenance (“O&M”) costs. Finally, fuel and variable O&M costs are
17 classified as energy-related.

18 **Q: PLEASE DESCRIBE HOW THE COMPANY USES THE MINIMUM-**
19 **SYSTEM ANALYSIS TO CLASSIFY SOME POLE, CONDUCTOR,**
20 **CONDUIT, AND LINE-TRANSFORMER COSTS AS CUSTOMER-**
21 **RELATED.**

22 A: The Company’s minimum-system analysis attempts to estimate the cost to install
23 the same amount of poles, conductors, conduit, and line transformers as are
24 currently on the distribution system, assuming that each piece of distribution

⁸ Specifically, DEC applies a minimum-system analysis to the costs recorded in FERC accounts 364 (poles, towers, and fixtures), 365 (overhead conductors and devices), 366 (underground conduit), 367 (underground conductors and devices), and 368 (line transformers).

1 equipment is sized to meet minimal load.⁹ In other words, the Company's
2 minimum-system analysis attempts to estimate the cost to replicate the
3 configuration of the existing distribution grid using "minimum-size"
4 equipment.¹⁰ Consequently, this type of minimum-system analysis is typically
5 referred to as the "minimum-size" classification method.

6 The Company's COSS classifies the cost of this hypothetical minimum-size
7 distribution grid as customer-related. The remaining test-year cost of the
8 distribution grid is classified as demand-related in the COSS.

9 **Q: DOES THE COMPANY'S MINIMUM-SYSTEM ANALYSIS PRODUCE**
10 **COST CLASSIFICATIONS THAT ARE CONSISTENT WITH COST-**
11 **CAUSATION PRINCIPLES?**

12 A: No. The Company's minimum-system analysis suffers from a number of
13 conceptual and structural flaws that result in misclassifications of distribution-
14 grid costs. These misclassifications, in turn, lead to allocations of distribution-
15 grid costs which are contrary to cost-causation principles. Specifically, minimum-
16 system classifications result in an over-allocation of distribution-grid costs to the
17 residential rate classes.

18 **Q: WHY DOES THE COMPANY'S MINIMUM-SYSTEM ANALYSIS**
19 **PRODUCE COST CLASSIFICATIONS THAT ARE INCONSISTENT**
20 **WITH COST-CAUSATION PRINCIPLES?**

21 A: The Company's minimum-system analysis is premised on the false notion that
22 DEC incurs a "minimum" amount of distribution-grid costs to serve customers at

⁹ Hager Direct, 14.

¹⁰ The Company's minimum-system analysis of pole costs does not assume the same number of poles as currently installed on the DEC distribution system. Instead, DEC estimates the number of minimum-size poles required to carry a mile of minimum-size conductor and then calculates the total number of minimum-size poles required based on the number of miles of overhead conductor currently installed on the DEC distribution system.

1 zero load and then incurs additional costs to meet the total load of those
2 customers. In reality, utilities typically size their distribution systems, and incur
3 the costs to build those systems, based on an expectation regarding the total
4 demand of all customers connected to the grid.¹¹ In other words, distribution-grid
5 costs are typically driven by customer load, not by the number of customers.

6 Indiana Michigan Power Company offers an example of typical utility
7 practice with respect to the sizing of distribution systems. According to testimony
8 before the Indiana Utility Regulatory Commission, Indiana Michigan Power
9 Company's distribution-grid costs are driven by customer demand, not by the
10 number of customers:

11 The minimum system approach of classifying a portion of the costs
12 included in accounts 364-368 as customer related ... does not
13 recognize the Company's standard engineering practice of planning
14 and sizing distribution facilities to meet the peak demand of the
15 customers served by those facilities. As such, the peak demand on
16 Company facilities, not the number of customers served by the
17 facilities, causes the Company to incur distribution facility costs.¹²

18 Contrary to typical engineering and investment practice, the Company's
19 minimum-system analysis posits an imaginary world where some portion of the
20 Company's distribution-grid costs were incurred regardless of customer demand.
21 In this fictional world of the minimum system analysis, spending on the imagined
22 minimum grid is considered to be driven by number of customers and thus
23 classified as customer-related. But in the real world, spending on the actual
24 distribution grid is driven by customer demand and thus appropriately classified

¹¹ In fact, it is unlikely that DEC would incur the cost to connect a zero-load customer under the Company's line-extension policies and would instead require the zero-load customer to bear any such connection cost. The Company's line-extension policies and procedures are set forth in the *Distribution Line Extension Plan*, included as part of the electric tariff.

¹² *Pre-Filed Verified Rebuttal Testimony of Michael M. Spaeth*, Indiana Utility Regulatory Commission Cause No. 45235, 11-12 (September 17, 2019).

1 as demand-related.¹³ Consequently, applying the minimum-size method to the
2 Company's distribution-grid costs yields classifications that are inconsistent with
3 cost-causation.

4 **Q: ARE THERE OTHER ASPECTS OF THE COMPANY'S MINIMUM-SIZE**
5 **APPROACH TO COST CLASSIFICATION THAT ARE INCONSISTENT**
6 **WITH COST-CAUSATION PRINCIPLES?**

7 A: Yes. Even if one accepts the false premise of a minimum distribution system, the
8 Company's minimum-system analysis suffers from a number of structural defects
9 which lead to classifications and allocations of distribution-grid costs that are
10 contrary to cost-causation principles.

11 For one, the Company's approach erroneously assumes that the minimum
12 system would consist of the same amount of equipment (e.g., number of
13 transformers) as the actual system.¹⁴ In reality, load levels help determine the
14 amount of equipment, as well as their size. Minimum-system analyses ignore the
15 effect of loads on the amount or type of equipment installed, classifying some
16 costs as customer-related even though they are really driven by demand. Any
17 such costs misclassified as customer-related will therefore be misallocated to rate
18 classes on the basis of customer number, contrary to cost-causation principles.

19 For another, the Company's minimum-system analysis fails to account for
20 the fact that even the minimum-size equipment currently installed on the system
21 has some amount of load-carrying capability. Consequently, some portion of the

¹³ This part of my testimony addresses cost allocation, not rate design. As I discuss below in Section V with regard to the Public Staff's Minimum System Method Report, it would not be appropriate to recover costs classified as demand-related in the Company's COSS in a residential demand charge.

¹⁴ As noted above, the exception is the Company's assumption with regard to the number of minimum-size poles. On the other hand, DEC simply assumes without any reasonable basis that all conduits currently installed on the system are minimum-size. Thus, the Company's approach arbitrarily classifies all conduit costs as customer-related.

1 cost for this minimum-size equipment should be classified as demand-related.
2 However, under the minimum-size method, that demand-related portion of the
3 cost of the minimum-sized equipment instead would be misclassified as
4 customer-related.

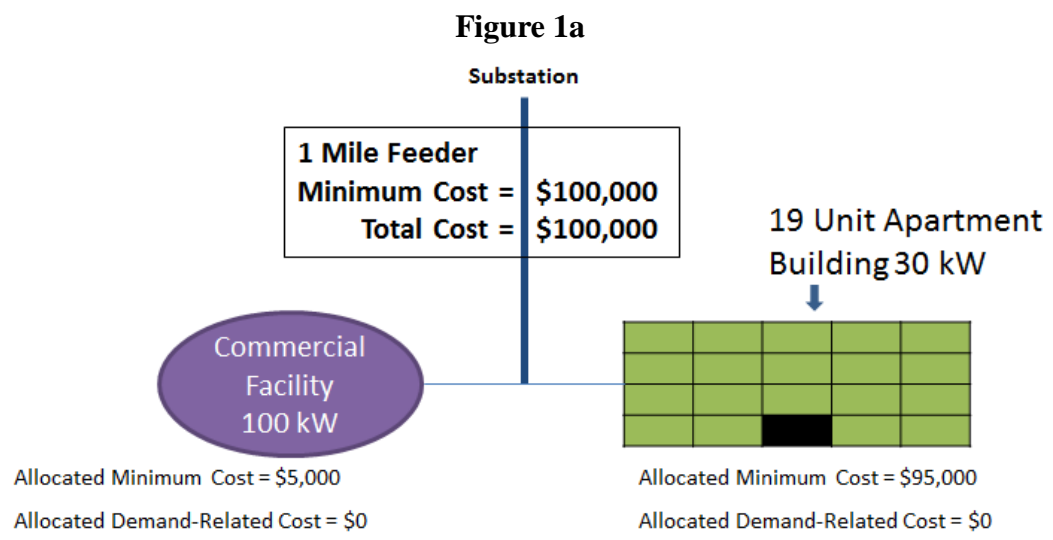
5 The failure to account for the load-carrying capability of minimum-size
6 equipment distorts the allocation of distribution-grid costs in two ways. First, the
7 load-carrying portion of minimum-grid costs are misallocated to rate classes on
8 the basis of customer number, contrary to cost-causation principles. Second, the
9 remaining demand-related portion of distribution-grid costs will be allocated to
10 rate classes on the basis of each class's total demand, even though some of that
11 demand was carried by the minimum-size portion of the distribution grid and
12 therefore did not cause those remaining demand-related costs to be incurred. In
13 other words, the Company's COSS will double-allocate the costs to carry a
14 portion of a class's demand: once through the allocation of the load-carrying
15 portion of minimum-grid costs and again through the allocation of the remaining
16 demand-related costs on the basis of the demand carried by the minimum grid.¹⁵

17 **Q: PLEASE PROVIDE AN ILLUSTRATIVE EXAMPLE OF THIS DOUBLE-**
18 **ALLOCATION PROBLEM.**

19 A: Figures 1a and 1b illustrate this problem of double-allocation of demand-related
20 costs when using the minimum-size method. Figures 1a and 1b assume a
21 hypothetical distribution system consisting of a single one-mile feeder. In the
22 example shown in Figure 1a, there are 20 customers served by the feeder: 19
23 units in an apartment building with a combined load of 30 kilowatt ("kW") and a
24 single commercial facility with a load of 100 kW. In this example, the minimum-

¹⁵ George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, (July 2, 1981). A copy of this article is attached as Exhibit JFW-2.

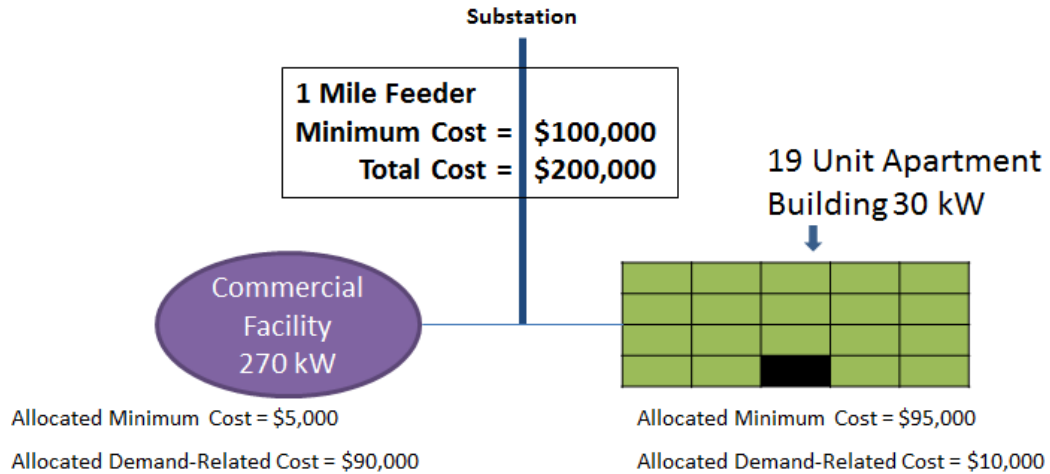
1 size feeder is assumed to be large enough to cover the combined load on the
 2 system, meaning that the minimum cost is equal to the total cost of the feeder.
 3 Consequently, under the minimum-size approach, 100% of the total cost of the
 4 feeder is inappropriately classified as customer-related and the residential class
 5 (with 19 of the 20 customer accounts served by the hypothetical distribution
 6 system) is allocated 95% of this cost, even though those 19 residential apartment
 7 dwellers are responsible for less than 25% of the load.¹⁶



8 The example shown in Figure 1b assumes the same number of customers as
 9 in Figure 1a. However, in this example, the commercial facility has a load of 270
 10 kW, requiring a larger feeder. As in Figure 1a, the residential class would be
 11 allocated 95% of the minimum cost of the feeder. Unlike the case in Figure 1a,
 12 however, the residential class would also be allocated 10% of the demand-related
 13 feeder costs – those costs in excess of the cost of a minimum-size feeder – even
 14 though such costs would not have been incurred without the additional
 15 commercial load on the system. Instead, all such excess costs in this example
 16 should instead be allocated to the commercial class.

¹⁶ As discussed above, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

Figure 1b



1 **Q: IS THERE AN ALTERNATIVE METHOD USED BY UTILITIES THAT**
2 **CLASSIFIES DISTRIBUTION COSTS IN ACCORDANCE WITH COST-**
3 **CAUSATION PRINCIPLES?**

4 A: Yes. Numerous utilities across the country rely on the basic customer method of
5 cost classification to classify distribution costs in accordance with cost-causation
6 principles. Under the basic customer method, only the costs of meters, service
7 drops, and customer services are classified as customer-related and all other
8 distribution costs are classified as demand-related. The Regulatory Assistance
9 Project recently published a comprehensive study of cost-allocation methods
10 which declares the basic customer method to be best practice.¹⁷

11 **Q: WHICH UNITED STATES UTILITIES RELY ON THE BASIC**
12 **CUSTOMER METHOD TO CLASSIFY DISTRIBUTION COSTS?**

13 A: I have not done a comprehensive survey of classification methods by U.S.
14 utilities.¹⁸ However, I am aware of a number of utilities which rely on the basic

¹⁷ Jim Lazar, et. al., *Electric Cost Allocation for a New Era: A Manual*, Regulatory Assistance Project, 18 (January, 2020), available at <https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/> [Hereinafter "RAP Cost Allocation Manual"].

¹⁸ According to a study commissioned by the National Association of Regulatory Utility Commissioners, the basic customer approach is employed in more than thirty states. See

1 customer method in Arkansas, California, Colorado, District of Columbia,
2 Illinois, Indiana, Iowa, Maryland, Massachusetts, Michigan, Oregon, South
3 Carolina, Texas, Utah, and Washington.

4 **Q: DOES DEC OR ITS UTILITY AFFILIATES IN OTHER JURISDICTIONS**
5 **USE THE BASIC CUSTOMER METHOD TO CLASSIFY**
6 **DISTRIBUTION COSTS?**

7 A: Yes. Up until its most recent rate case, DEC in South Carolina had been relying
8 on the basic customer method to classify distribution-grid costs as demand-
9 related, and had been doing so ever since the South Carolina Public Service
10 Commission ordered the Company's predecessor to stop relying on the
11 minimum-system classification method in 1991.¹⁹ The Company's utility affiliate
12 in Indiana likewise has been using the basic customer method to classify
13 distribution costs for the past 25 years.

14 **Q: HAS DEC ESTIMATED THE IMPACT OF ITS MISCLASSIFICATION**
15 **OF DISTRIBUTION PLANT COSTS ON THE ALLOCATION OF THE**
16 **REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL**
17 **RATE CLASSES?**

18 A: Yes. In response to a data request, DEC modified its COSS to classify distribution
19 plant costs based on the basic customer method rather than on the minimum-size
20 method.²⁰ Specifically, DEC classified all pole, conductor, conduit, and line

Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*,
Regulatory Assistance Project, 30 (December, 2000), available at
<https://pubs.naruc.org/pub.cfm?id=536F0210-2354-D714-51CF-037E9E00A724>.

¹⁹ Public Service Commission of South Carolina, *Order Approving Rate Increase*, Order No.
91-1022, Docket No. 91-216-E, 7 (November 18, 1991). Because the Company's most recent
rate case in South Carolina was settled, the Public Service Commission explicitly declined to
rule on the merits of the Company's proposal to switch from the basic customer method to the
minimum-system method. See Public Service Commission of South Carolina, *Order*, Order
No. 2019-323, Docket No. 2018-319-E, 22 (May 21, 2019).

²⁰ DEC response to NC Justice Center et al. Data Request Item No. 3-3. Attached as Exhibit
JFW-3.

1 transformer costs as demand-related for this version of the COSS. This modified
2 COSS without minimum-system classification of distribution plant costs
3 therefore classifies only the cost of meters, service drops, and customer services
4 as customer-related.

5 Correcting for the misclassification of distribution plant costs in the
6 Company's COSS substantially reduces the allocation of 2018 test-year base
7 revenue requirements to the residential class. As discussed above, DEC is
8 requesting an increase in base revenues (i.e., excluding rider revenues) of 9.7%
9 on average for all customers and proposing an increase of 10.7% for residential
10 customers. In contrast, under Mr. Pirro's proposed approach for allocating the
11 requested base revenue increase, residential base revenues would be increased by
12 only 9.7% – equivalent to the system-average increase – if distribution plant costs
13 were correctly classified in the Company's COSS with the basic customer
14 method.

15 **Q: WHAT DO YOU RECOMMEND WITH REGARD TO THE**
16 **CLASSIFICATION OF DISTRIBUTION PLANT COSTS IN THE**
17 **COMPANY'S COSS?**

18 A: The classification of distribution plant costs in the Company's COSS does not
19 reasonably reflect cost-causation. The Commission should therefore direct DEC
20 to discontinue its use of the minimum-system method for classifying distribution
21 plant costs in the Company's COSS. Instead, DEC should rely on the basic
22 customer method for classifying such costs in its COSS.

23 ***B. Misallocation of Demand-Related Distribution Plant Costs***

24 **Q: HOW DOES THE COMPANY'S COSS ALLOCATE DEMAND-RELATED**
25 **DISTRIBUTION PLANT COSTS?**

1 A: As discussed above, DEC classifies a portion of distribution plant costs as
2 customer-related based on a minimum-system analysis, allocating those costs to
3 rate classes in the COSS based on the number of customers in each class. The
4 remaining portion is then classified as demand-related and allocated to rate
5 classes in the Company's COSS on the basis of what DEC refers to as "non-
6 coincident peak" demand ("NCP"). The Company derives class NCP by summing
7 individual customers' maximum demand during the test year. The NCP allocator
8 derives each class's percentage share of demand-related distribution plant costs as
9 the ratio of: (1) the class NCP for the test year; and (2) the sum of all rate classes'
10 NCPs in the test year.²¹

11 **Q: DOES THE NCP ALLOCATOR REASONABLY REFLECT COST-**
12 **CAUSATION?**

13 A: No. The NCP allocator does not account for the effect of load diversity on
14 distribution equipment loading and thus does not reasonably reflect the drivers of
15 the Company's distribution plant costs. By failing to account for load diversity,
16 the NCP allocator likely overstates the residential rate classes' contributions to
17 distribution costs and thus over-allocates such costs to the residential classes.

18 **Q: HOW DOES LOAD DIVERSITY AFFECT THE SIZING OF**
19 **DISTRIBUTION PLANT?**

20 A: Residential customers reach their individual maximum demands on different days
21 and in different hours of the day. This diversity of demand among a group of
22 residential customers served by a piece of shared distribution equipment results in
23 a group peak demand that is lower than the sum of customers' individual
24 maximum demands.

²¹ Hager Direct, 11.

1 I illustrate the impact of load diversity in Table 1 with an example that
 2 assumes that three residential customers take service from a single transformer.
 3 For simplicity's sake, this example further assumes that there are four hours in
 4 the year and that the three residential customers have hourly demands as shown
 5 in Table 1.

Table 1: Impact of Load Diversity

	Customer #1 Demand (kW)	Customer #2 Demand (kW)	Customer #3 Demand (kW)	Total Demand (kW)	
Hour 1	3	2	1	6	
Hour 2	7	4	2	13	
Hour 3	5	6	3	14	Diversified Peak Demand
Hour 4	2	3	4	9	
Maximum	7	6	4	17	Sum of Maximum Demand

6 As indicated in Table 1, the sum of the individual customers' maximum
 7 demands is 17kW in this example. In contrast, the diversified peak demand on the
 8 shared transformer is only 14kW, or about 18% less than the sum of individual
 9 maximum demands, because of load diversity.

10 **Q: DOES DEC ACCOUNT FOR LOAD DIVERSITY IN THE SIZING OF**
 11 **DISTRIBUTION PLANT?**

12 A: Yes. As is typical for electric utilities, DEC sizes distribution plant to meet the
 13 diversified peak demand in total of the group served by that plant, not to meet the
 14 sum of the maximum demands of the individual customers in that group.
 15 Referring to diversified peak demand as “non-coincident peak” and the sum of
 16 maximum demands as “Individual Customer Maximum Demand (ICMD)”, DEC
 17 states in its response to the Public Staff in Docket No. E-100, Sub 162 that:

1 Duke's position is that all customers do not impose their maximum
2 demand on the distribution system at the same time. Rather, individual
3 customers will use their maximum demand at different times than
4 other customers who are served by the same distribution facilities, and
5 as a group, will have a non-coincident peak [i.e., diversified peak] that
6 is less than the group's ICMD. (For obvious reasons, this load
7 diversity is higher the farther away the distribution equipment is from
8 the customer.) Thus, Duke Energy "sizes" distribution equipment to
9 meet this non-coincident peak [i.e., diversified peak].²²

10 **Q: PLEASE PROVIDE AN EXAMPLE OF HOW DEC ACCOUNTS FOR**
11 **LOAD DIVERSITY WHEN SIZING DISTRIBUTION EQUIPMENT.**

12 A: In response to discovery in an ongoing rate case in Indiana, Duke Energy Indiana
13 provided a copy of the guidelines used to size transformers in Duke Energy's
14 service territories in the Carolinas and the Midwest.²³ According to these
15 guidelines, DEC sizes transformers based on an estimate of the diversified peak
16 load of the customers sharing the transformer. As indicated in the following
17 excerpt from the guidelines, the Company assumes that load diversity increases
18 with the number of customers taking service from a transformer, i.e. that the ratio
19 of load on the transformer to the sum of the individual customers maximum
20 demand ("coincidence factor") decreases as the number of customers taking
21 service from a transformer increases.

²² "Duke Energy Response to Public Staff Initial Data Request", 11-12 (emphasis added).
Provided in Appendix 1 of Public Staff MSM Report.

²³ A copy of this discovery response is attached as Exhibit JFW-4.

Diversity (Coincidence Factor)

Carolinas

<u>Customers</u>	<u>Heat Pump</u>	<u>A/C</u>
1	1	1
2	.695	.82
3	.568	.73
4	.486	.645
5	.427	.58
6	.377	.515
7	.352	.49
8	.337	.475
9	.323	.47
10	.314	.46
11	.314	.46
12 & up	.314	.46

1 For example, these guidelines indicate that DEC assumes a coincidence
2 factor of 0.486 for the purposes of sizing a transformer that will serve four
3 residential customers with heat pumps. This means that DEC assumes that load
4 on that transformer (i.e., diversified demand) will be less than half of the sum of
5 the maximum demands of the four customers taking service from the transformer
6 (i.e., non-coincident demand), because of the diversity between the individual
7 customer demands.

8 **Q: WHY DOES THE NCP ALLOCATOR OVER-ALLOCATE DEMAND-**
9 **RELATED DISTRIBUTION PLANT COSTS TO THE RESIDENTIAL**
10 **CLASS?**

11 A: The NCP allocator over-allocates costs to the residential class because it does not
12 account for the effect of load diversity on equipment sizing and thus on
13 equipment cost.

14 Specifically, the NCP allocator does not account for the fact that
15 distribution equipment serving many small residential customers can be smaller
16 (and less expensive) than equipment that serves fewer large industrial customers,
17 even when the sum of the residential maximum demands is equal to the sum of

1 industrial maximum demands. As the number of customers served by distribution
2 equipment increases, so too does the diversity of maximum hourly demands
3 among those customers. And as the diversity of maximum demands increases, so
4 too does the variance between the sum of individual customers' maximum hourly
5 demands (i.e., group NCP) and the maximum demand for the group as a whole
6 (i.e., group diversified demand.) By not accounting for load diversity, the NCP
7 allocator allocates cost to classes as if the sizing and cost of distribution
8 equipment is driven by each class's NCP rather than by the class's diversified
9 demand on the equipment.

10 **Q: HAS DEC ESTIMATED THE IMPACT OF ITS MISALLOCATION OF**
11 **DEMAND-RELATED DISTRIBUTION PLANT COSTS ON THE**
12 **ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO**
13 **THE RESIDENTIAL CLASS?**

14 A: No. In response to a data request, DEC declined to modify its COSS to allocate
15 demand-related distribution plant costs based on diversified peak demand rather
16 than on non-coincident peak, stating that "the Company does not have this data
17 available".²⁴

18 While DEC has refused to modify its COSS to correct for the misallocation
19 of demand-related distribution plant costs, it's likely that such a correction would
20 have further reduced the residential allocation of the requested base revenue
21 increase beyond that achieved by correcting for the minimum-system
22 misclassification of distribution plant costs discussed above. In other words,
23 under Mr. Pirro's proposed approach for allocating the requested revenue
24 increase, the residential base revenue increase would likely be less than the 9.7%

²⁴ DEC response to NC Justice Center et al. Data Request Item No. 3-2. Attached as Exhibit JFW-5. In a follow-up e-mail, the Company's counsel clarified that the data is available, but that revising the Company's COSS to incorporate such data "is not easily done and would require original work". A copy of this e-mail is included in Exhibit JFW-5.

1 requested system-average increase if the Company's COSS were corrected for
2 both the minimum-system misclassification of distribution plant costs and the
3 NCP misallocation of the demand-related portion of such costs.

4 **Q: HOW SHOULD DEMAND-RELATED DISTRIBUTION PLANT COSTS**
5 **BE ALLOCATED?**

6 A: As DEC acknowledges in its response to the Public Staff in Docket No. E-100,
7 Sub 162, the Company sizes its distribution equipment based on diversified peak
8 demand not on customer maximum demand. Thus, in order to reasonably account
9 for the effect of load diversity on distribution equipment sizing and cost, demand-
10 related distribution plant costs should be allocated on the basis of each class's
11 diversified peak demand.²⁵ Class diversified peak demand is simply the peak
12 hourly demand for the class as a whole.

13 **III. RESIDENTIAL BASE REVENUES SHOULD BE INCREASED BY NO**
14 **MORE THAN THE APPROVED SYSTEM-AVERAGE INCREASE**

15 **Q: PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR INCREASING**
16 **RESIDENTIAL BASE REVENUES.**

17 A: As discussed above in Section II, The Company is requesting that electric retail
18 base rates be increased on average by 9.7% in order to recover an expected
19 revenue deficiency of about \$445.3 million in the 2018 test year. Of the total
20 \$445.3 million requested base revenue increase, DEC proposes to allocate about
21 \$233.9 million to residential customers. This amount represents a 10.7% increase
22 over residential test-year revenues under current base rates.

23 Company witness Pirro derived the proposed allocation of the base revenue
24 deficiency to the residential rate classes in two steps, each of which relied on the

²⁵ RAP Cost Allocation Manual, 150.

1 results of the Company's COSS. Under Mr. Pirro's proposed allocation method,
2 the residential class is first allocated \$229.8 million of the total requested \$445.3
3 million base revenue increase based on the allocation of total rate base in the
4 Company's COSS. The Company's COSS also indicates that residential revenues
5 under current rates would need to be increased by an additional \$16.2 million in
6 order to achieve the system-average rate of return under current rates. Under Mr.
7 Pirro's proposed allocation method, the residential class is then allocated an
8 additional \$4.0 million, representing 25% of the current under-earnings relative
9 to the system-average achieved rate of return.²⁶

10 **Q: WOULD THE COMPANIES' PROPOSAL PROVIDE FOR A FAIR**
11 **ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO**
12 **THE RESIDENTIAL RATE CLASSES?**

13 A: No. As discussed above in Section II, the Company's COSS does not provide a
14 reasonable basis for the allocation of the requested revenue increase to the
15 residential rate classes. Specifically, the Company's COSS over-allocates
16 distribution plant costs to the residential rate classes by: (1) misclassifying a
17 portion of such costs as customer-related; and (2) misallocating the remaining
18 demand-related portion of such costs.

19 Based on the results of the Company's COSS, Mr. Pirro proposes to
20 increase residential base revenues by 10.7%. In contrast, if the misclassification
21 of distribution plant costs in the Company's COSS were corrected, residential
22 base revenues would increase by only 9.7% (equivalent to the requested system-
23 average increase) under Mr. Pirro's approach for allocating the requested base
24 revenue increase. In fact, with distribution plant costs classified in accordance
25 with cost-causation principles, the Company's COSS shows that the residential

²⁶ Pirro Exhibit 4.

1 rate classes in aggregate are currently over-earning relative to the system-average
2 achieved rate of return. The increase in residential base revenues would be even
3 less than 9.7% under Mr. Pirro's approach if the misallocation of demand-related
4 distribution plant costs in the Company's COSS were also corrected.

5 **Q: HOW SHOULD ANY BASE REVENUE INCREASE AUTHORIZED BY**
6 **THE COMMISSION BE ALLOCATED TO THE RESIDENTIAL RATE**
7 **CLASSES?**

8 A: In light of the magnitude of the misallocation of distribution plant costs in the
9 Company's COSS and the impact of correcting for such misallocations to the
10 residential rate classes, I recommend that base revenues for the residential rate
11 classes be increased on a percentage basis by no more than the overall system-
12 average increase authorized by the Commission, if any.

13 **IV. THE CURRENT BASIC FACILITIES CHARGE FOR RESIDENTIAL**
14 **CUSTOMERS IS NOT COST-BASED**

15 **Q: WHAT IS THE BASIC FACILITIES CHARGE?**

16 A: The BFC is a fixed fee charged to each customer on their monthly bill regardless
17 of the customer's energy usage during that month.

18 **Q: WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE BFC**
19 **FOR RESIDENTIAL CUSTOMERS?**

20 A: The Company proposes to maintain the residential BFC at its current rate of
21 \$14.00 per monthly bill.²⁷

22 **Q: IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BFC**
23 **REASONABLE?**

²⁷ Corrected Pirro Direct, 12.

1 A: No. As discussed in detail below, the current rate for the residential BFC
2 inappropriately recovers usage-driven costs through the BFC. This recovery of
3 usage-driven costs in the fixed BFC rather than through the volumetric energy
4 rate gives rise to cross-subsidization within the residential rate classes and
5 dampens energy price signals to consumers for controlling their bills through
6 conservation, energy efficiency, or distributed renewable generation.²⁸

7 ***A. DEC’s Proposal for the Residential BFC Violates Principles of Cost-Based***
8 ***Rate Design***

9 **Q: WHAT ARE THE RELEVANT CONSIDERATIONS IN DESIGNING**
10 **COST-BASED RATES FOR RESIDENTIAL CUSTOMERS?**

11 A: The primary challenge in rate design is to reflect the costs that customers impose
12 on the system, both to encourage them to use utility resources responsibly and to
13 share costs fairly. Accordingly, fixed customer charges should reflect the fact that
14 each customer contributes equally to certain types of costs (e.g., billing costs)
15 regardless of that customer’s energy usage. Volumetric energy rates, on the other
16 hand, recognize that customers of different sizes and load profiles contribute to
17 other types of costs (e.g., distribution-grid costs) at different levels. If usage-
18 driven costs are inappropriately collected through fixed customer charges, then
19 customers will have reduced incentives to control their bills through conservation
20 or investments in energy efficiency or distributed renewable generation.²⁹

²⁸ These problems of cross-subsidization and economically inefficient pricing would be even more pronounced if the residential BFC were increased to the level that Mr. Pirro believes would “better reflect all customer-related costs”. [Corrected Pirro Direct, 11.] For example, Mr. Pirro believes that it would be appropriate to increase the BFC for Rate Schedule RS customers to \$22.56 per bill. [Pirro Exhibit 8.] However, such an increase would result in the inappropriate recovery through the BFC of demand-related costs that had been misclassified as customer-related through application of the Company’s flawed minimum-system analysis.

²⁹ National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at <https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0>.

1 **Q: GIVEN THESE CONSIDERATIONS, WHAT CATEGORIES OF COSTS**
2 **ARE APPROPRIATELY RECOVERED THROUGH THE VOLUMETRIC**
3 **ENERGY RATE?**

4 A: In order to provide efficient price signals, volumetric energy rates should be set at
5 levels that recover those categories of costs that tend to increase with customer
6 usage over the long run, including plant, fuel, and O&M costs for the production,
7 transmission, and distribution functions, along with certain customer-service
8 costs that tend to vary with usage such as uncollectible costs.³⁰ In other words,
9 volumetric energy rates should reflect long-run marginal costs.

10 As James Bonbright explains in his seminal text, *Principles of Public*
11 *Utility Rates*:

12 In view of the above-noted importance attached to existing utility
13 rates as indicators of rates to be charged over a somewhat extended
14 period in the future, one may argue with much force that the cost
15 relationships to which rates should be adjusted are not those highly
16 volatile relationships reflected by short-run marginal costs but rather
17 those relatively stable relationships represented by long-run marginal
18 costs. The advantages of the relatively stable and predictable rates in
19 permitting consumers to make more rational long-run provisions for
20 the use of utility services may well more than offset the admitted
21 advantages of the more flexible rates that would be required in order
22 to promote the best available use of the existing capacity of a utility
23 plant.³¹

³⁰ Uncollectible costs are the billed amounts not recovered from customers as a result of those customers' non-payment of all or a portion of their monthly bills.

³¹ James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

1 I conclude this chapter with the opinion, which would probably
2 represent the majority position among economists, that, as setting a
3 general basis of minimum public utility rates and of rate relationships,
4 the more significant marginal or incremental costs are those of a
5 relatively long-run variety – of a variety which treats even capital
6 costs or “capacity costs” as variable costs.³²

7 Almost three decades later, Alfred Kahn affirmed Bonbright’s opinion in his
8 text, *The Economics of Regulation*:

9 ... the practically achievable benchmark for efficient pricing is more
10 likely to be a type of average long-run incremental cost, computed for
11 a large, expected incremental block of sales, instead of SRMC [short-
12 run marginal cost]³³

13 **Q: WHICH COSTS ARE APPROPRIATELY RECOVERED THROUGH**
14 **FIXED CUSTOMER CHARGES?**

15 A: In contrast to the volumetric energy rate, the fixed customer charge is intended to
16 reflect the cost to connect a customer who uses very little or zero energy to the
17 distribution system. Such “customer connection costs” are generally limited to
18 plant and maintenance costs for a service drop and meter, along with meter-
19 reading, billing, and other customer-service expenses. As Bonbright explains:

20 But this twofold distinction [between demand and energy in rate
21 design] overlooks the fact that a material part of the operating and
22 capital costs of utility business is more directly and more closely
23 related to the number of customers than to energy consumption on the
24 one hand or maximum kilowatt demand on the other hand. The most
25 obvious examples of these so-called customer costs are the expenses
26 associated with metering and billing.³⁴

³² *Id.*, 336.

³³ Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988).

³⁴ Bonbright, *op. cit.*, 311.

1 In their text, *Public Utility Economics*, economists Paul Garfield and
2 Wallace Lovejoy also describe which costs are truly customer-related and
3 therefore appropriately recovered through the fixed customer charge:

4 The purpose of both the connection charge and the minimum charge is
5 to cover at least some of the costs incurred by the utility whether or
6 not the customer uses energy in a particular month. For small
7 customers under the block meter-rate schedule, a charge of this kind is
8 intended to cover the expenses relating to meter service and
9 maintenance, meter reading, accounting and collecting, return on the
10 investment in meters and the service lines connecting the customer's
11 premises to the distribution system, and others. Such expenses as
12 these represent as a minimum the "readiness-to-serve" expenses
13 incurred by the utility on behalf of each customer.³⁵

14 More recently, Severin Borenstein restated these principles for designing
15 cost-based fixed customer charges as follows:

16 When having one more customer on the system raises the utility's
17 costs regardless of how much the customer uses – for instance, for
18 metering, billing, and maintaining the line from the distribution
19 system to the house – then a fixed charge to reflect that additional
20 fixed cost the customer imposes on the system makes perfect
21 economic sense. The idea that each household has to cover its
22 customer-specific fixed costs also has obvious appeal on ground of
23 fairness or equity.³⁶

24 **Q: IT IS OFTEN CLAIMED THAT FIXED COSTS SHOULD BE**
25 **RECOVERED THROUGH FIXED CHARGES. HOW DOES THIS CLAIM**
26 **SQUARE WITH LONG-STANDING PRINCIPLES OF COST-BASED**
27 **RATE DESIGN?**

28 A: The notion that fixed costs should be recovered through fixed charges sounds
29 appealing, but is often applied inappropriately. The fixed customer charge should

³⁵ Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964).

³⁶ Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at <https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/>.

1 be designed to recover only those costs that are truly fixed, in other words, those
2 costs that do not vary with customer usage over the long run. Sunk costs that vary
3 with usage over time, but appear to be “fixed” only from a short-run accounting
4 perspective, should not be treated as fixed for purposes of rate design.

5 **Q: IS THE COMPANY’S PROPOSAL FOR THE RESIDENTIAL BFC**
6 **CONSISTENT WITH THESE LONG-STANDING PRINCIPLES OF**
7 **COST-BASED RATE DESIGN?**

8 A: No. Contrary to these principles, the Company’s proposal would recover through
9 the residential BFC not just customer connection costs – i.e., the costs for meters,
10 service drops, and customer services – but also the costs allocated to the
11 residential class under the Company’s COSS for: (1) uncollectible accounts; and
12 (2) customer-related distribution-grid plant.

13 **Q: WHY IS IT INCONSISTENT WITH COST-BASED RATE DESIGN TO**
14 **RECOVER UNCOLLECTIBLE COSTS THROUGH THE RESIDENTIAL**
15 **BFC?**

16 A: Uncollectible costs tend to vary with revenues and thus with usage. Thus, as
17 discussed above, such costs are appropriately recovered through the volumetric
18 energy rate.

19 **Q: HOW DOES DEC ESTIMATE THE CUSTOMER-RELATED**
20 **DISTRIBUTION-GRID COSTS THAT ARE INAPPROPRIATELY**
21 **RECOVERED THROUGH THE CURRENT RESIDENTIAL BFC?**

22 A: As discussed in Section II, DEC relies on the results of its minimum-system
23 analysis to estimate the “customer-related” portion of distribution-grid costs.

24 **Q: WHY WOULD IT BE UNREASONABLE FOR DEC TO RECOVER**
25 **COSTS THROUGH THE RESIDENTIAL BFC THAT WERE**
26 **CLASSIFIED AS “CUSTOMER-RELATED” USING A MINIMUM-**
27 **SYSTEM ANALYSIS?**

1 A: As discussed in Section II, any distribution-grid costs that are currently recovered
2 through the residential BFC are actually demand-related costs that have been
3 misclassified as customer-related in the Company's minimum-system analysis.
4 Recovering such demand-related costs through the residential BFC would be
5 contrary to long-standing principles of cost-based rate design.

6 Even if the results of the Company's minimum-system analysis were
7 accepted for *cost-allocation* purposes, such results should not be used for *rate-*
8 *design* purposes. Minimum-system analyses overstate the minimum cost *per*
9 *customer* because they assume that a minimum system carrying minimal load
10 would have the same amount of distribution equipment (e.g., the same number of
11 transformers) as would a distribution system designed to carry actual distribution
12 load. In other words, the minimum-system method assumes that each piece of
13 distribution equipment would serve the same number of customers on average,
14 regardless of whether the customers are average-sized (as for the actual system)
15 or have minimal demand (as for the hypothetical minimum-size system.)

16 This is not a realistic assumption, since even a minimally sized piece of
17 distribution equipment should be able to serve more minimal-usage customers
18 than the number of average-usage customers served by an average-sized piece of
19 distribution equipment. Consequently, the true distribution-grid cost to serve a
20 customer with minimal usage is likely to be less than that derived using a
21 minimum-system analysis. Indeed, since the minimum-system method attempts
22 to estimate the distribution-grid cost incurred regardless of usage – i.e., the cost
23 to serve load approaching zero – the true minimum distribution-grid cost per
24 customer is zero since distribution equipment that carries zero load can serve an
25 infinite number of customers with zero load.

26 **Q: ONCE THE EXCESS UNCOLLECTIBLE AND CUSTOMER-RELATED**
27 **DISTRIBUTION COSTS FROM THE MINIMUM-SYSTEM ANALYSIS**

1 **HAVE BEEN REMOVED, WHAT IS THE RESULTING COST TO**
2 **CONNECT A RESIDENTIAL CUSTOMER TO THE DISTRIBUTION**
3 **GRID?**

4 A: As shown in Table 2 below, I estimate that a residential BFC of \$11.15 per bill
5 would recover the truly customer-related costs of meters, service drops, and
6 customer services allocated to the residential rate classes. I therefore recommend
7 that the residential BFC be reduced from its current rate of \$14.00 to \$11.15.

8 **Q: HOW DID YOU DERIVE YOUR ESTIMATE OF THE COST TO**
9 **CONNECT A RESIDENTIAL CUSTOMER TO THE DISTRIBUTION**
10 **GRID?**

11 A: In response to a data request, DEC provided the unit cost results from a cost of
12 service study that classifies distribution costs using the basic customer method.³⁷
13 These results show an allocation to the residential rate classes of about \$244.5
14 million in customer-related costs. I then adjusted this total in order to remove
15 uncollectible costs for the reasons discussed above. Dividing the net amount of
16 \$234.9 million by the number of residential bills yields a connection cost per
17 residential customer of \$11.15 per month.

18 **Table 2: Derivation of the Cost to Connect a Residential Customer**

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	\$244,483,314	21,061,063	\$11.61
Less			
Uncollectible Expense	(\$9,605,989)	21,061,063	(\$0.46)
Total	\$234,877,326		\$11.15

19 **Q: WHAT ACCOUNTS FOR THE \$2.85 DIFFERENCE BETWEEN YOUR**
20 **\$11.15 ESTIMATE OF THE RESIDENTIAL CONNECTION COST AND**
21 **THE CURRENT RATE OF \$14.00 FOR THE RESIDENTIAL BFC?**

³⁷ DEC response to Public Staff Data Request Item No. 100-18 (revised). Attached as Exhibit JFW-6.

1 A: The \$2.85 difference between my \$11.15 estimate of the cost to connect a
2 residential customer and the current \$14.00 BFC represents usage-driven costs
3 that would be inappropriately recovered through the fixed customer charge under
4 the Company's proposal.

5 **Q: WHY SHOULD THE COMMISSION BE CONCERNED ABOUT THE**
6 **RECOVERY OF \$2.85 IN USAGE-DRIVEN COSTS THROUGH THE**
7 **CURRENT RESIDENTIAL BFC?**

8 A: As I discuss below, this recovery of usage-driven costs in the fixed customer
9 charge rather than through the volumetric energy rate gives rise to cross-
10 subsidization within the residential class and dampens energy price signals to
11 consumers for controlling their bills through conservation, energy efficiency, or
12 distributed renewable generation.

13 ***B. The Current Residential BFC Creates Intra-Class Cost Subsidies***

14 **Q: HOW DOES THE CURRENT RESIDENTIAL BFC CAUSE**
15 **SUBSIDIZATION WITHIN THE RESIDENTIAL CLASS?**

16 A: As discussed above, the current residential BFC recovers usage-driven costs.
17 Such costs are driven by residential load and are therefore appropriately
18 recovered from each residential customer in proportion to their contribution to
19 class load. To the extent that usage-driven costs are recovered through the fixed
20 customer charge rather than through the volumetric energy rate, residential
21 customers with below-average usage bear a disproportionate share of usage-
22 driven costs and consequently subsidize customers with above-average usage. In
23 other words, a residential customer with below-average usage pays more, and a
24 residential customer with above average-usage pays less, than their fair share of
25 such costs.

1 **Q: WHAT IS THE EXTENT OF THE INTRA-CLASS SUBSIDIZATION**
2 **UNDER THE CURRENT RESIDENTIAL BFC?**

3 A: The Company estimates about 21.1 million residential bills in the test year.³⁸ This
4 means that about \$60.0 million of usage-driven costs are inappropriately
5 recovered annually through the current residential BFC.³⁹

6 If the usage-driven costs recovered through the current residential BFC
7 were instead recovered through the volumetric energy rate, each residential
8 customer would appropriately contribute to recovery of these costs in proportion
9 to their usage. The Company estimates residential sales in the test year of about
10 22.8 million megawatt-hours.⁴⁰ Therefore, if the \$60.0 million of usage-driven
11 costs were instead recovered through the volumetric energy rate rather than
12 through the current residential BFC, they would be charged at a rate of 0.26 cents
13 per kilowatt-hour (“¢/kWh”).⁴¹ In this case, a residential customer with below-
14 average monthly usage of 500 kWh would contribute about \$16 per year toward
15 recovery of the \$60.0 million of usage-driven costs while a customer with above-
16 average monthly usage of 1,500 kWh would contribute about \$47 per year.⁴²
17 Thus, the 1,500 kWh customer would contribute three times more than the 500
18 kWh customer, in direct proportion to their usage and consistent with accepted
19 principles of cost-causation.

³⁸ The Company’s estimate of the number of residential bills in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

³⁹ The \$60.0 million result is derived by taking the product of the annual number of residential bills (21.1 million) and the amount of the current residential BFC in excess of residential connection cost (\$2.85 per bill).

⁴⁰ The Company’s estimate of residential sales in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

⁴¹ The 0.26¢/kWh result is derived by dividing \$60.0 million by residential sales of 22.8 million megawatt-hours.

⁴² Based on data provided in NCUC Form E-1 Data Request, Item No. 42(c), I estimate monthly usage of 1,081 kWh for an average residential customer.

1 In contrast, with the current recovery of \$60.0 million of usage-driven costs
2 through the residential BFC, each residential customer contributes about \$34 per
3 year toward recovery of such costs, regardless of that customer’s usage. A below-
4 average 500 kWh customer therefore pays more than double their fair share of
5 these usage-driven costs with the current BFC while an above-average 1,500
6 kWh customer pays only 72% of their fair share.

7 **Q: WOULD SUBSIDIZATION OF HIGH-USAGE RESIDENTIAL**
8 **CUSTOMERS BY LOW-USAGE CUSTOMERS BE ELIMINATED IF**
9 **THE RESIDENTIAL BFC WERE SET AT YOUR RECOMMENDED**
10 **RATE OF \$11.15?**

11 A: No. Even with the residential BFC set at my estimate of residential connection
12 cost, low-usage customers would likely continue to subsidize high-usage
13 customers’ costs because customer charges and energy rates are priced at the cost
14 to serve an average-usage customer. For example, Rate Schedule RS customers
15 who reduce their on-peak (and overall) usage with energy efficiency or rooftop
16 solar generation pay the same energy rate as larger, peakier customers even
17 though the latter customers may impose more generation costs per kWh of usage
18 than the former due to their proportionately greater on-peak usage.

19 Likewise, lower-usage customers in an apartment building will typically
20 share a service drop, whereas higher-usage single-family homes will typically be
21 connected with their own service drop. Yet, the lower-usage apartment resident
22 will contribute through the BFC the same amount toward recovery of service-
23 drop costs as the higher-usage single-family customer even though the cost of a
24 service drop per customer is lower for the former than for the latter customer.

25 Finally, all residential customers will contribute the same amount for
26 recovery of Advanced Metering Infrastructure (“AMI”) costs through the
27 residential BFC even though these customers will probably not share equally in

1 the benefits from the Company’s investment in residential AMI meters. The
2 National Association of Regulatory Utility Commissioners describes cost
3 causation as “an attempt to determine what, or who, is causing costs to be
4 incurred by the utility.”⁴³ In this case, the “what” causing DEC to make
5 discretionary investments in AMI meters is the expectation that such investments
6 would provide benefits to customers, and the “who” are the customers who would
7 share in these benefits as a result of the Company’s AMI investments. Thus, in
8 the case of AMI meters, cost-causation requires that customers contribute toward
9 recovery of AMI costs in proportion to their share of the AMI benefits.

10 Within the residential class, higher-usage energy consumers will likely reap
11 greater benefits than lower-usage customers from AMI technologies and
12 services.⁴⁴ For example, these higher-usage customers will have more
13 opportunities to take advantage of (and to benefit from) innovative rate designs
14 that reward load shifting than will their lower-usage counterparts. It therefore
15 would be consistent with cost-causation principles for larger users to contribute a
16 greater share toward recovery of AMI costs than smaller users. However, even
17 with the residential BFC set at the cost to connect a residential customer, each
18 residential customer regardless of usage will contribute the same amount toward
19 recovery of AMI costs.

20 In all of these cases, any differences in the cost to serve smaller and larger
21 customers are socialized across the residential class, resulting in subsidization of
22 high-usage customers by low-usage customers.

⁴³ National Association of Utility Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, 38 (January 1992).

⁴⁴ For a description of the expected direct customer and utility benefits from the Company’s investment in AMI meters, see *Direct Testimony of Donald L. Schneider, Jr. for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1214 (September 30, 2019).

1 ***C. The Current Residential BFC Dampens Energy Price Signals***

2 **Q: DOES THE CURRENT RESIDENTIAL BASIC FACILITIES CHARGE**
3 **SEND APPROPRIATE PRICE SIGNALS?**

4 A: No. As discussed above, the current residential BFC is set at a rate that exceeds
5 the cost to connect a residential customer. The amount in excess of customer
6 connection cost represents usage-driven costs that are more appropriately
7 recovered in the volumetric energy rate. The recovery of these usage-driven costs
8 in the current fixed BFC rather than in the volumetric energy rate dampens price
9 signals and discourages economically efficient behavior by residential customers.

10 **Q: TO WHAT EXTENT DOES THE CURRENT RESIDENTIAL BFC**
11 **DAMPEN PRICE SIGNALS PROVIDED BY THE RATE SCHEDULE RS**
12 **VOLUMETRIC ENERGY RATE?**

13 A: With a fixed amount of revenue requirements to be recovered from Rate Schedule
14 RS customers, the higher the BFC, the lower the volumetric energy rate, and vice
15 versa. With the fixed BFC set at its current rate of \$14.00 per bill, DEC proposes
16 a volumetric energy rate of 9.91¢/kWh for Rate Schedule RS customers. If,
17 instead, the BFC were set at the cost-based rate of \$11.15, I estimate that the
18 volumetric energy rate would have to be increased to 10.38¢/kWh to recover the
19 same allocated revenue requirement.

20 In other words, DEC is proposing a Rate Schedule RS energy rate that is
21 0.47¢/kWh, or about 4.5%, less than what the volumetric rate would be if the
22 BFC were set at the cost-based rate of \$11.15. Thus, the current residential BFC
23 dampens the price signal provided by the volumetric energy rate by about 4.5%.⁴⁵

⁴⁵ If the BFC were instead set at \$22.56 per bill, as Mr. Pirro believes would be appropriate, I estimate that the volumetric energy rate would have be set at 9.09¢/kWh in order to recover the Company's proposed allocation of revenue requirements to the RS rate class. At \$22.56, the residential BFC would dampen the price signal provided by the volumetric energy rate by 12.4%.

1 **Q: HOW WOULD RATE SCHEDULE RS CUSTOMERS LIKELY RESPOND**
2 **TO THE REDUCTION IN THE ENERGY PRICE SIGNAL RESULTING**
3 **FROM THE COMPANY'S PROPOSAL TO MAINTAIN THE**
4 **RESIDENTIAL BFC AT ITS CURRENT RATE?**

5 A: Since the volumetric energy rate under the Company's proposal for the residential
6 BFC would be lower than the volumetric energy rate with a cost-based BFC of
7 \$11.15, we would expect Rate Schedule RS customers to consume more energy
8 with the current BFC than they would with a cost-based BFC. The magnitude of
9 the increase in energy consumption would depend on: (1) the extent to which the
10 volumetric energy rate with the current BFC is lower than the volumetric energy
11 rate with a cost-based BFC; and (2) the price elasticity of electricity demand.

12 **Q: WHAT IS THE PRICE ELASTICITY OF ELECTRICITY DEMAND?**

13 A: Residential customers respond to the price incentives created by the electrical rate
14 structure. Those responses are generally measured as price elasticities, i.e., the
15 ratio of the percentage change in consumption to the percentage change in price.
16 Price elasticities are generally low in the short term and rise over several years,
17 because customers have more options for increasing or reducing energy usage in
18 the medium to long term. For example, a review by Espey and Espey (2004) of
19 36 articles on residential electricity demand published between 1971 and 2000
20 reports short-run elasticity estimates of about -0.35 on average across studies and
21 long-run elasticity estimates of about -0.85 on average across studies.⁴⁶ In other
22 words, on average across these studies, consumption decreased by 0.35% in the
23 short term and by 0.85% in the long term for every 1% increase in price.

24 Studies of electric price response typically examine the change in usage as a
25 function of changes in the marginal rate paid by the customer.⁴⁷ Table 3 below

⁴⁶ The citation for this study is provided in Exhibit JFW-7.

⁴⁷ For Rate Schedule RS customers, that would be the energy rate.

1 lists the results of seven studies of marginal-price elasticity over the last forty
2 years.⁴⁸

3 **Table 3: Summary of Marginal-Price Elasticities**

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	-0.35 to -0.7
McFadden, Puig, and Kirshner	1977	-0.25 without electric space heat and -0.52 with space heat
Barnes, Gillingham, and Hageman	1981	-0.55
Henson	1984	-0.27 to -0.30
Reiss and White	2005	-0.39
Xcel Energy Colorado	2012	-0.3 (at years 2 and 3)
Orans et al., on BC Hydro inclining-block rate	2014	-0.13 in 3 rd year of phased-in rate

4 **Q: WHAT WOULD BE A REASONABLE ESTIMATE OF THE MARGINAL-**
5 **PRICE ELASTICITY FOR CHANGES IN THE RATE SCHEDULE RS**
6 **VOLUMETRIC ENERGY RATE?**

7 A: From Table 3, it appears that -0.3 would be a reasonable mid-range estimate of
8 the impact over a few years.

9 **Q: WHAT WOULD BE A REASONABLE ESTIMATE OF THE EFFECT ON**
10 **ENERGY USE FROM THE COMPANY'S PROPOSAL TO MAINTAIN**
11 **THE CURRENT RATE FOR THE RESIDENTIAL BFC?**

12 A: As discussed above, if the residential BFC continued at \$14.00, the Rate
13 Schedule RS volumetric energy rate would be about 4.5% less than it would be if
14 the BFC were set at \$11.15. Assuming an elasticity of -0.3, this 4.5% reduction in
15 the volumetric energy rate would result in an increase in energy consumption of
16 about 1.4% for the average Rate Schedule RS customer. This means that all else
17 equal, Rate Schedule RS load after a few years with a \$14.00 BFC is expected to

⁴⁸ The citations for these studies are provided in Exhibit JFW-7.

1 be about 1.4% higher than it would be if the BFC were set at the cost-based rate
2 of \$11.15.

3 For comparison, DEC forecasts that residential energy-efficiency savings in
4 both North and South Carolina will increase each year over the next five years by
5 an amount equivalent to about 0.2% of forecasted annual residential energy
6 sales.⁴⁹ Assuming that such savings are spread uniformly across all residential
7 rate classes in the Company's North and South Carolina service territories, the
8 consumption increase due to the Company's proposal to retain the current \$14.00
9 BFC would undo about seven years of Rate Schedule RS energy-efficiency
10 savings.

11 **V. THE PUBLIC STAFF MSM REPORT FAILS TO MAKE THE CASE FOR**
12 **MINIMUM-SYSTEM CLASSIFICATION METHODS**

13 **Q: WHY DID THE PUBLIC STAFF ISSUE ITS REPORT ON THE**
14 **MINIMUM SYSTEM METHODOLOGY?**

15 A: In its order in the previous rate case for DEC, the Commission directed the Public
16 Staff to determine whether continued use of minimum-system approaches is
17 warranted for cost-allocation purposes:

⁴⁹ Estimated based on data regarding residential sales and energy efficiency savings for the entire DEC service territory provided in response to NC Justice Center et al. Data Request Item No. 1-4 (supplemental). Attached as Exhibit JFW-8.

1 Just considering the grid modernization programs alone suggests that
2 distribution system cost allocation among customer classes will take
3 on heightened importance in future rate cases. The implications of
4 using a suboptimal methodology or incorrectly applying an otherwise
5 acceptable methodology, could be significant in the future. The
6 Commission concludes that a more focused and explicit evaluation of
7 options for distribution system cost allocation and an assessment of
8 the extent to which any single allocation methodology is being
9 consistently applied by the utilities is warranted. Therefore, the
10 Commission directs the Public Staff to facilitate discussions with the
11 electric utilities to evaluate and document a basis for continued use of
12 minimum system and to identify specific changes and
13 recommendations as appropriate.⁵⁰

14 **Q: DOES THE PUBLIC STAFF MSM REPORT COMPLY WITH THE**
15 **COMMISSION’S DIRECTIVE TO “DOCUMENT A BASIS FOR**
16 **CONTNUED USE OF MINIMUM SYSTEM” FOR COST-ALLOCATION**
17 **PURPOSES?**

18 A: No. In fact, the Public Staff MSM Report offers no specific guidance or
19 recommendations regarding the appropriate approach for classifying distribution
20 costs in a cost of service study. Nor does the report address whether the specific
21 minimum-system methods used by each of the electric utilities are reasonable.
22 Instead, the Public Staff simply states in the report that it “believes” generally
23 that it is reasonable to use the results of a minimum-system approach “for
24 establishing the maximum amount to be recovered in the fixed or basic customer
25 charge” and to use the results a basic customer approach to determine the
26 “minimum amount recovered in the fixed charge.”⁵¹

27 This general belief notwithstanding, the Public Staff recommends that the
28 Commission “request that NARUC, or some other independent entity, undertake

⁵⁰ North Carolina Utilities Commission, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Subs 819, 1110, 1146, and 1152, 87 (June 22, 2018).

⁵¹ Public Staff MSM Report, 16-17.

1 a study of these issues from a national perspective, so as to gain insight from best
2 practices and ideas across the country”.⁵²

3 **Q: HOW DO YOU RESPOND TO THE PUBLIC STAFF’S**
4 **RECOMMENDATION FOR A NATIONAL STUDY OF DISTRIBUTION**
5 **COST CLASSIFICATION BEST PRACTICES?**

6 A: The Regulatory Assistance Project (“RAP”) commissioned such a national study
7 and published the results of that study in January of this year. The RAP study
8 concludes that the basic customer method represents best practice with respect to
9 the classification of distribution costs.⁵³

10 **Q: WHAT IS THE BASIS FOR THE PUBLIC STAFF’S BELIEF THAT THE**
11 **RESULTS OF A MINIMUM-SYSTEM ANALYSIS SHOULD BE USED TO**
12 **SET THE MAXIMUM AMOUNT TO BE RECOVERED THROUGH THE**
13 **CUSTOMER CHARGE?**

14 A: The Public Staff’s endorsement of minimum-system methods as the basis for
15 designing the customer charge rests on its unsubstantiated belief that there is a
16 minimum portion of the cost for the distribution grid which is incurred regardless
17 of demand.⁵⁴ By the Public Staff’s logic, these minimum costs are “fixed” – i.e.,
18 they do not vary with customer demand – since they are incurred regardless of
19 customer demand. Consequently, Public Staff asserts that recovery of such costs
20 in the volumetric energy rate would give rise to intra-class cross-subsidization.⁵⁵

21 **Q: IS THIS IDEA OF A MINIMUM PORTION OF UTILITY SPENDING ON**
22 **DISTRIBUTION SYSTEMS A REALISTIC PORTRAYAL OF TYPICAL**
23 **DISTRIBUTION PLANNING PRACTICE?**

⁵² *Id.*, 17.

⁵³ RAP Cost Allocation Manual, 18.

⁵⁴ Public Staff MSM Report, 8.

⁵⁵ *Id.*, 9.

1 A: No. As discussed above in Section II, this notion of a minimum distribution cost
2 which lies at the foundation of minimum-system methods simply does not
3 comport with standard practice for distribution planning and spending. Utilities
4 do not first incur “minimum” distribution-grid costs for the purposes of
5 connecting customers at zero load and then incur additional costs to meet
6 expected demand. Instead, as described in the textbook *Electric Power*
7 *Distribution System Engineering*, utilities typically size and invest in distribution
8 systems based on an expectation of customer demands on those systems:

9 The objective of distribution system planning is to assure that the
10 growing demand for electricity, in terms of increasing growth rates
11 and high load densities, can be satisfied in an optimum way by
12 additional distribution systems ... which are both technically adequate
13 and reasonably economical.⁵⁶

14 Therefore, distribution system planning starts at the customer level.
15 The demand, type, load factor, and other customer load characteristics
16 dictate the type of distribution system required.⁵⁷

17 The load growth of the geographical area served by a utility company
18 is the most important factor influencing the expansion of the
19 distribution system.⁵⁸

20 In other words, the notion that there is a minimum portion of a distribution
21 grid whose costs are incurred regardless of customer demand is unrealistic. The
22 reality is that distribution-grid costs in total are primarily driven by customer
23 demand.

24 **Q: IS THIS NOTION OF A MINIMUM PORTION OF DISTRIBUTION**
25 **INVESTMENT ANY MORE PLAUSIBLE WHEN APPLIED TO**

⁵⁶ Turan Gonen, *Electric Power Distribution System Engineering*, McGraw-Hill, Inc., 3-4 (1986).

⁵⁷ *Id.*, 4.

⁵⁸ *Id.*, 5.

1 **THE COMPANY’S PROPOSED INVESTMENTS IN THE GRID**
2 **IMPROVEMENT PLAN (“GIP”)?**

3 A: No. To the contrary, it makes no sense to apply the minimum-system construct to
4 GIP costs since these investments are in no way intended to simply connect
5 customers to the distribution grid. Instead, as described by Company witness Jay
6 W. Oliver, DEC has purportedly designed the Grid Improvement Plan to more
7 reliably, intelligently, and economically serve load in the 21st century.⁵⁹

8 **Q: SHOULD ALL GIP COSTS INSTEAD BE ALLOCATED ON THE BASIS**
9 **OF CLASS PEAK DEMAND?**

10 A: Not necessarily. According to Mr. Oliver, the primary driver of the Company’s
11 discretionary investments in the Grid Improvement Plan is the expected
12 economic benefits from such investments.⁶⁰ Thus, from a cost-causation
13 perspective, these discretionary investments are “caused” by, and therefore
14 appropriately allocated in proportion to, the expected benefits from such
15 investments.

16 The Maryland Public Service Commission came to just such a conclusion
17 with respect to Baltimore Gas and Electric’s proposed allocation of its
18 discretionary “Smart Grid Initiative” costs:

19 [Maryland Office of People’s Counsel] notes, and we agree, that
20 contrary to cost-causation principles, the [embedded cost of service
21 study] does not allocate Smart Grid Initiative costs to customer classes
22 commensurate with the allocation of Smart Grid benefits to those
23 classes.⁶¹

⁵⁹ *Corrected Direct Testimony of Jay W. Oliver for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1214, 9 (October 23, 2019).

⁶⁰ *Id.*

⁶¹ Maryland Public Service Commission, Order No. 87591, Case No. 9406, 187 (June 3, 2016) [emphasis added].

1 On that basis, the Maryland commission committed to considering a benefits-
2 based approach for allocating smart grid investments in future rate cases.⁶² I urge
3 the Commission to likewise consider the merits of a benefits-based approach to
4 allocating the Company’s discretionary GIP costs to the extent those costs are
5 authorized.

6 **Q: DOES THE PUBLIC STAFF LOOK TO THE NATIONAL ASSOCIATION**
7 **OF REGULATORY UTILITY COMMISSIONERS’ (“NARUC”)**
8 ***ELECTRIC UTILITY COST ALLOCATION MANUAL FOR SUPPORT OF***
9 ***ITS ENDORSEMENT OF MINIMUM-SYSTEM METHODS?***

10 A: Yes. Noting that NARUC’s Electric Utility Cost Allocation Manual (“NARUC
11 Manual”) “continues to be considered an important resource for the calculation
12 and allocation of electric utility cost of service”, the Public Staff MSM Report
13 highlights the fact that the NARUC Manual describes only minimum-system
14 methods and not the basic customer method as possible approaches for
15 classifying distribution-grid costs.

16 **Q: IS IT TRUE THAT THE NARUC MANUAL DOES NOT INCLUDE THE**
17 **BASIC CUSTOMER METHOD AS A POSSIBLE APPROACH FOR**
18 **CLASSIFYING DISTRIBUTION PLANT COSTS?**

19 A: No. The Public Staff is incorrect in its claim that the basic customer classification
20 method is not included in the NARUC manual. To the contrary, the NARUC
21 Manual describes the basic customer method as a classification option in the
22 discussion of marginal cost of service studies:

⁶² *Id.*, 184.

1 A number of analysts have argued, and commissions have accepted,
2 that the customer component of the distribution system should only
3 include those features of the secondary distribution system located on
4 the customer's own property. Portions of the distribution system that
5 serve more than one customer cannot be avoided should one customer
6 cancel service. Similarly, if the customer component of the marginal
7 distribution cost is described as the cost of adding a customer, but no
8 energy flows to the system, there is no reason to add to the distribution
9 lines that serve customers collectively or to increase the optimal
10 investment in the lines that are carrying the combined load of all
11 customers. Therefore, the marginal customer cost of the jointly used
12 distribution system is zero.⁶³

13 Moreover, according to a 1992 letter from the Washington Utilities and
14 Transportation Commission (“WUTC”) to the chair of the NARUC task force
15 responsible for drafting the NARUC Manual, earlier drafts of the manual
16 included a discussion of the basic customer method in the chapter on embedded
17 cost of service studies.⁶⁴ This discussion was inexplicably removed from the
18 chapter on embedded cost of service studies before final publication.

19 **Q: DOES THE FACT THAT THE BASIC CUSTOMER METHOD WAS NOT**
20 **DISCUSSED IN THE CHAPTER ON EMBDEDDED COST OF SERVICE**
21 **STUDIES INDICATE THAT THIS METHOD WAS NOT WIDELY USED**
22 **AT THAT TIME?**

23 A: No. Despite the short shrift given to the basic customer method in the NARUC
24 Manual, the fact is that the use of this classification method was long-established
25 and widespread at that time. According to the 1992 letter from the WUTC:

⁶³ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 136 (January, 1992).

⁶⁴ I attach a copy of this letter as Exhibit JFW-9.

1 Our Commission has been extremely clear about one thing in this
2 area: that the “minimum-distribution” [i.e., minimum-size] and
3 “minimum-intercept” methods are not acceptable, and that the only
4 costs which should be considered customer-related are the costs of
5 meters, services, meter reading and billing. Our staff believes that is
6 the most common approach taken by Commissions around the
7 country.⁶⁵

8 Indeed, as discussed above in Section II, the South Carolina Public Service
9 Commission rejected the use of minimum-system methods and directed the
10 Company’s predecessor to use the basic customer method in an order issued one
11 year prior to publication of the NARUC Manual. And despite the fact that the
12 chapter on embedded cost of service studies does not discuss the basic customer
13 method, the Company’s affiliate in Indiana chose to adopt this classification
14 method two years after publication of the NARUC Manual.

15 **Q: DO YOU HAVE ANY OTHER COMMENTS REGARDING THE PUBLIC**
16 **STAFF MSM REPORT?**

17 A: Yes. The Public Staff contends in its report that costs classified as demand-related
18 in a cost of service study should be recovered through demand charges.⁶⁶ The
19 Public Staff furthermore recommends that electric utilities “utilize data gained
20 from AMI meters to implement ... demand charges for all rate classes”.⁶⁷

21 The Commission should reject any such recommendation for the residential
22 rate classes. Residential rates designed to formulaically reflect cost classifications
23 in a cost of service study would neither reflect cost causation nor provide
24 appropriate price signals. In particular, recovery of demand-related costs through
25 a residential demand charge would dampen price signals for conservation,

⁶⁵ Exhibit JFW-9. Emphasis in original.

⁶⁶ Public Staff MSM Report, 8.

⁶⁷ *Id.*, 17.

1 promote inefficient customer behavior, and undermine customers' ability to
2 control electricity costs.

3 **Q: WHY WOULD A RESIDENTIAL DEMAND CHARGE DAMPEN PRICE**
4 **SIGNALS FOR CONSERVATION, PROMOTE INEFFICIENT**
5 **CUSTOMER BEHAVIOR, AND UNDERMINE CUSTOMERS' ABILITY**
6 **TO CONTROL ELECTRICITY COSTS?**

7 A: Demand charges on a monthly bill are typically determined based on the
8 customer's maximum demand, whenever that maximum occurs during the month.
9 In order to control monthly demand costs, customers would therefore need to
10 have detailed information regarding their load profiles for each day of the month
11 as well as an in-depth understanding of which combination of appliance- or
12 equipment-usage gives rise to monthly maximum demands. Even with such
13 information and knowledge, it would be difficult for a residential customer to
14 reduce demand charges, since even a single failure to control load during the
15 month would result in the same demand charge as if the customer had not
16 attempted to control load at all.

17 A demand charge would also provide little or no incentive for residential
18 customers to take actions that reduce distribution-system costs. As discussed
19 above in Section II, distribution equipment costs typically are driven by the
20 diversified peak load for all customers sharing the equipment. An individual
21 customer is unlikely to reach her maximum demand at the same time as when the
22 diversified peak on the distribution system occurs. Thus, a demand charge would
23 provide an incentive to a residential customer to control load at the time that
24 customer reaches her individual maximum demand, which does not necessarily
25 correspond to the time of peak load on the distribution system. In fact, some
26 customers might respond to a demand charge by shifting loads from their own
27 peak to the peak hour on the local distribution system, thereby increasing their

1 contribution to maximum or critical loads on the local distribution system and
2 further stressing the system during peak periods.

3 Finally, shifting recovery of demand-related costs from the energy rate to a
4 demand charge would send the wrong energy price signal. Shifting demand-
5 related costs to a demand charge would lower the energy rate and thereby
6 perversely encourage increased energy consumption, some of which might occur
7 at times of peak load on the distribution system – when energy conservation is
8 most needed. Shifting costs from the energy rate to a demand charge could
9 therefore increase distribution system costs and offset any (limited) benefits from
10 a residential demand charge.

11 Severin Borenstein aptly summed up the shortcomings (and the antiquated
12 nature) of demand charges when he wrote: “It is unclear why demand charges
13 still exist.”⁶⁸

14 **Q: WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THE PUBLIC**
15 **STAFF MSM REPORT?**

16 A: The Commission should give no weight to the Public Staff’s endorsement of
17 minimum-system classification methods since that endorsement rests on the
18 Public Staff’s unsubstantiated belief that there is a minimum portion of the cost
19 for the distribution grid which is incurred regardless of demand. This notion of a
20 minimum distribution cost is an unrealistic hypothetical construct which does not
21 comport with standard practice for distribution planning and spending.

22 The reality is that distribution-grid costs are primarily driven by customer
23 demand. And it is the basic customer classification method, not minimum-system

⁶⁸ Severin Borenstein, “The Economics of Fixed Cost Recovery by Utilities”, in *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Lawrence Berkeley National Laboratory, 60 (2016). Available at <http://eta-publications.lbl.gov/sites/default/files/lbnl-1005742.pdf>.

1 methods, which classifies distribution-grid costs consistent with this reality. In
2 other words, the basic customer method represents best practice for classifying
3 distribution costs.

4 It is long past time for North Carolina's electric utilities to discard this
5 false notion that there is a minimum portion of distribution-grid costs. It is also
6 past time to stop treating a 1992 NARUC Manual as the final, cast-in-stone word
7 on distribution cost classification, and to finally acknowledge that the NARUC
8 Manual does not accurately portray best practice at the time of its publication or
9 represent best practice for classifying distribution spending by electric utilities
10 today.

11 **VI. RECOMMENDATIONS**

12 **Q: WHAT DO YOU RECOMMEND TO THE COMMISSION?**

13 A: I recommend that the Commission:

- 14 • Reject the Company's use of a minimum-system analysis to classify
15 distribution plant costs in its COSS and instead direct DEC to classify such
16 costs using the basic customer classification method.
- 17 • Reject the Company's use of the NCP allocator to allocate demand-related
18 distribution plant costs in its COSS and instead direct DEC to allocate such
19 costs based on class diversified peak demand.
- 20 • Increase base revenues for the residential rate classes by no more than the
21 overall system-average percentage increase authorized by the Commission,
22 if any.
- 23 • Deny the Company's request to maintain the residential BFC at its current
24 rate of \$14.00 per bill and instead direct DEC to reduce the rate to \$11.15
25 per bill.

1 • Investigate whether discretionary GIP costs, to the extent authorized, should
2 be allocated to rate classes in the Company's COSS commensurate with the
3 benefits to those classes from GIP spending.

4 **Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

5 A: Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Jonathan F. Wallach on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 18th day of February, 2020.

s/ David L. Neal

David L. Neal