STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH (CEI SOUTH) FOR: (1) APPROVAL OF CEI SOUTH'S 5-YEAR PLAN FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS PURSUANT TO IND. CODE CH. 8-1-39 ("TDSIC PLAN"); (2) AUTHORIZATION OF TDSIC TREATMENT AS PROVIDED IN IND. CODE CH. 8-1-39 FOR THE ELECTRIC TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (AND THE COSTS THEREOF) SET FORTH IN CEI SOUTH'S TDSIC PLAN; (3) APPROVAL OF CEI SOUTH'S USE OF ITS TDSIC RATE ADJUSTMENT MECHANISM AND RELATED ACCOUNTING DEFERRALS, PURSUANT TO IND. CODE 8-1-39, FOR THE TIMELY RECOVERY AND DEFERRAL OF COSTS RELATED TO SUCH TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (INCLUDING FINANCING COSTS INCURRED DURING CONSTRUCTION); AND (4) APPROVAL OF OTHER RELATED RATEMAKING RELIEF AND TARIFF PROPOSALS CONSISTENT WITH IND. CODE CH. 8-1-39.	)	**CAUSE NO. 45894**

<u>SUBMISSION OF CAC'S PUBLIC DIRECT TESTIMONY</u>

Citizens Action Coalition of Indiana, Inc. ("CAC") respectfully submits the Direct Testimony and Attachments of Benjamin Inskeep ("CAC Exhibit 1") in the above-referenced Cause to the Indiana Utility Regulatory Commission.

Respectfully submitted,

Jennifer A. Washburn

Jennifer A. Washburn, Atty. No. 30462-49
Citizens Action Coalition of Indiana, Inc.
1915 W. 18th Street, Suite C
Indianapolis, Indiana 46202
Phone: (317) 735-7764
Fax: (317) 290-3700
jwashburn@citact.org

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 16th day of August, 2023, to the following:

CEIS
Heather A. Watts
Jeffery A. Earl
CenterPoint Energy Indiana South
Heather.watts@centerpointenergy.com
Jeffery.earl@centerpointenergy.com

Nicholas K. Kile
Hillary J. Close
Lauren M. Box
Barnes & Thornburg LLP
Nicholas.kile@btlaw.com
Hillary.close@btlaw.com
Lauren.box@btlaw.com

OUCC
Thomas Harper
Matthew Kappus
Indiana Office of Utility Consumer Counselor
thharper@oucc.in.gov
MKappus@oucc.in.gov
infomgt@oucc.in.gov

Jennifer A. Washburn
Jennifer Washburn

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH (CEI SOUTH) FOR: (1) APPROVAL OF CEI SOUTH'S 5-YEAR PLAN FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS PURSUANT TO IND. CODE CH. 8-1-39 ("TDSIC PLAN"); (2) AUTHORIZATION OF TDSIC TREATMENT AS PROVIDED IN IND. CODE CH. 8-1-39 FOR THE ELECTRIC TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (AND THE COSTS THEREOF) SET FORTH IN CEI SOUTH'S TDSIC PLAN; (3) APPROVAL OF CEI SOUTH'S USE OF ITS TDSIC RATE ADJUSTMENT MECHANISM AND RELATED ACCOUNTING DEFERRALS, PURSUANT TO IND. CODE 8-1-39, FOR THE TIMELY RECOVERY AND DEFERRAL OF COSTS RELATED TO SUCH TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (INCLUDING FINANCING COSTS INCURRED DURING CONSTRUCTION); AND (4) APPROVAL OF OTHER RELATED RATEMAKING RELIEF AND TARIFF PROPOSALS CONSISTENT WITH IND. CODE CH. 8-1-39.	**)**	**CAUSE NO. 45894**

DIRECT TESTIMONY OF BENJAMIN INSKEEP

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC.

AUGUST 16, 2023

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Benjamin Inskeep, and I am Program Director at Citizens Action Coalition of Indiana, Inc. ("CAC"). My business address is 1915 West 18th Street, Suite C, Indianapolis, Indiana 46202.

Q. Please describe your current responsibilities.

A. I have served as CAC's Program Director since March 2022. In that role, I work to advance CAC's policy and programmatic priorities related to essential utility service and consumer affordability and protection, including serving as a subject matter expert in proceedings before the Indiana Utility Regulatory Commission ("IURC" or "Commission") and at the General Assembly.

Q. Please briefly summarize your prior employment and educational background.

A. I have more than a decade of experience working on energy, water, and utility issues. My prior employment includes working as a policy analyst at the North Carolina Clean Energy Technology Center at North Carolina State University (2014-2016), where I co-created and served as lead author and editor of *The 50 States of Solar*, a quarterly report series tracking distributed solar policy developments in U.S. states. I also conducted policy research and contributed to the *Database of State Incentives for Renewables and Efficiency (DSIRE)* project and provided technical support, analysis, and workshops for state and local governments through the U.S. Department of Energy's SunShot Solar Outreach Partnership.

I also worked for EQ Research LLC, a clean energy policy consulting firm, from 2016-2022. I managed EQ Research's general rate case subscription service, contributed as a researcher and analyst to other policy service offerings, such as a legislative and regulatory tracking services, and performed customized research and analysis for clients. In addition, my client engagements included participation in state utility regulatory proceedings, including analyzing utility proposals and serving as an expert witness on ratemaking and energy policy issues.

I earned a Bachelor of Science in Psychology with Highest Distinction from Indiana University in 2009 and both a Master of Science in Environmental Science and a Master of Public Affairs from the O'Neill School of Public and Environmental Affairs at Indiana University in 2012. I completed the EUCI's Utility Accounting 101 course in April 2023.

Q. Have you previously filed testimony before the Indiana Utility Regulatory Commission?

A. Yes, I have testified on numerous issues before the Commission. Attachment BI-1 identifies the cases in which I have previously filed testimony.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of CAC.

Q. Are there attachments to your testimony?

A. Yes. I am sponsoring the following attachments:

- Attachment BI-1: Benjamin Inskeep's Expert Witness Testimony Experience
- Attachment BI-2: Relevant Discovery Responses and Attachments

Q. What is the purpose of your testimony in this proceeding?

A. On May 24, 2023, CenterPoint filed a five-year Transmission, Distribution, and Storage System Improvement Plan ("TDSIC Plan"). My testimony responds to certain proposals included in CenterPoint's proposed TDSIC Plan.

My silence on any issue raised by CenterPoint in its case-in-chief should not be construed as an endorsement or tacit approval of such a proposal.

Q. Please summarize your testimony and recommendations.

A. CenterPoint's TDSIC Plan would impose a substantial additional financial burden on customers who already pay the highest electricity bills in the state. The Commission should closely scrutinize the Plan's details to ensure it is reasonable. However, regardless of whether these investments are reasonable, CenterPoint's proposed TDISC Plan cost recovery mechanism to recover 100% of distribution costs from residential and small commercial customers through a fixed charge is not reasonable and should be denied.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- **Section II** describes concerns with CenterPoint's TDSIC Plan.
- **Section III** provides my recommendations and conclusions.

II. TDSIC PLAN

Q. Please describe CenterPoint's proposed TDSIC Plan.

A. CenterPoint is proposing a TDISC Plan for 2024-2028 that will cost approximately $454 million, an extraordinary additional burden on its customers who have been paying the highest electricity bills out of Indiana's investor-owned utilities for many years.[1] This cost estimate does not include potentially higher operating and maintenance costs associated with these capital investments. Notably, the TDSIC Plan is costlier than CenterPoint's prior

[1] IURC, Electricity Residential Bill Survey, https://www.in.gov/iurc/energy-division/electricityindustry/
electricity-residential-bill-survey/

$446.5 million TDSIC plan despite the new TDSIC Plan covering only five years in contrast to the seven years covered by its prior plan (2017-2023). Elements of the TDSIC Plan (and their estimated costs) include:

- Distribution 12kV Circuit Rebuild Program ($98.8 million)
- Distribution Underground Rebuild Program ($45.9 million)
- Distribution Automation Program ($19.6 million)
- Wood Pole Replacement Program ($45.0 million)
- Transmission Line Rebuild Program ($127.2 million)
- Substation Rebuild Program ($103.5 million)
- Substation Physical Security Program ($14.0 million)

Q. Were you able to verify CenterPoint's claims about the benefits of its TDSIC Plan investments for distributed generation?

A. No. CenterPoint made many unverifiable, unsupported claims about the benefits of its TDSIC Plan for distributed generation, including that:

- The TDSIC Plan would help with renewable energy and distributed generation deployment.[2]
- The Distribution Automation scheme "can assist DER applications to come back online quicker."[3]
- "Distributed Energy Resources could potentially push electricity onto our transmission system,"[4] an unlikely scenario given the relatively modest distributed generation adoption rates in CenterPoint's service area and current interconnection standards designed to ensure distributed generation facilities can safely interconnect.
- That FERC Order 2222 would require "a host of monitoring and control systems" without offering an explanation as to what monitoring and control systems were needed. CenterPoint also failed to note that FERC Order 2222 would not be

[2] *See* Rawlinson Direct Testimony, p. 13, lines 9-10, stating "The Company's TDSIC Plan will increase and continue to advance the electric grid design to support renewable investments by the state and by customers."
[3] Rawlinson Direct Testimony, p. 13, lines 13-14,
[4] Rawlinson Direct Testimony, p. 13, lines 17-18.

implemented until well *after* its TDSIC Plan, in late 2029, as currently proposed by the Midcontinent Independent System Operator.

When CAC attempted to get the most basic information on customer adoption of DER technologies to verify whether growing customer adoption of DER technologies was substantial enough to warrant large utility investments, CenterPoint objected and refused to answer the data request.[5] (CAC narrowly tailored its data request to understand EDG adoption because we already have access to information on net metering adoption through publicly available documents, such as CenterPoint's submissions under U.S. Energy Information Administration Form 861.) CenterPoint objected in part because it claimed the information was "unreasonably cumulative or duplicative and is obtainable from some other source that is more convenient, less burdensome, or less expensive,"[6] yet it did not identify said source and CAC is unaware of the existence of any such source. CAC is aware that CenterPoint reports EDG data in its performance metrics report filed in Cause No. 45564; however, data is only through the end of 2022 and does not address CAC's request for 2023 data.

Q. Please describe CenterPoint's proposal for recovering TDSIC Plan costs.

A. CenterPoint is proposing to recover 100% of distribution-related TDSIC spending allocated to the residential and small commercial[7] classes through a fixed monthly charge, whereas transmission costs would be recovered through variable charges.

CenterPoint states that distribution-related costs total $254 million (56%) out of the total TDSIC Plan, which encompasses all or portions of the TDSIC Plan components for

[5] CenterPoint Response to CAC Data Request 1-012 (Attachment BI-2).
[6] CenterPoint Response to CAC Data Request 1-012 (Attachment BI-2).
[7] While my testimony generally focuses on the negative impacts to residential customers, the same critiques of collecting distribution costs through a fixed charge generally hold true for small commercial customers.

physical security projects, substation rebuilds, 12kV circuit rebuilds, underground rebuilds, wood pole replacements, and distribution automation.[8] The impact to residential customers would be substantial. ***CenterPoint estimates that this additional fixed monthly charge would balloon from $1.85 per month in 2024 to $9.08 in 2028 – nearly as high as its base monthly customer charge.***

Transmission-related costs would be recovered from residential customers through a per-kWh charge, forecasted to increase from $0.000702 per kWh in 2024 to $0.005604 per kWh in 2028.

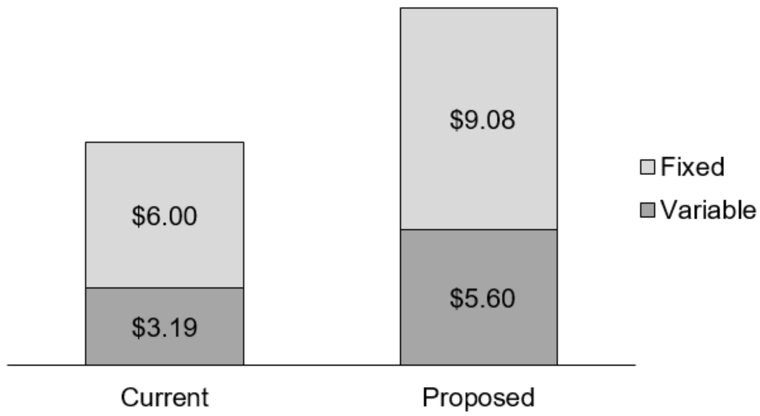
Q. What is the overall impact of the TDSIC Plan on residential bills?

A. A residential customer using 1,000 kWh of electricity currently pays a bill of $154.21 under rates currently in effect, excluding charges under its current TDSIC tracker. If CenterPoint's TDSIC Plan is approved as filed, the TDSIC tracker would increase such a bill by $2.55 (1.7%) in 2024, rising annually to $14.68 (9.5%) by 2028.

Compared to the current TDSIC tracker in effect, which results in monthly charges of $9.19 for 1,000 kWh of usage, ***the proposed TDSIC tracker's $14.68 bill impact in 2028 represents a 59.7% increase in the TDSIC tracker*** (Figure 1).

[8] Attachment SRR-1.

Figure 1. Residential TDSIC Charges (1,000 kWh)



Q. Could the bill impact to residential customers be even higher?

A. Yes. CenterPoint's proposed residential cost allocation (42.62% of transmission costs and 58.44% of distribution costs) could change as a result of its forthcoming electric rate case. If allocation factors adopted in that rate case increase the proportion of TDSIC costs allocated to the residential class, their bill impact of the TDSIC Plan will be even higher than currently estimated.

Q. Does CenterPoint propose to collect its distribution costs in the same manner from medium and large commercial and industrial customers?

A. No. CenterPoint is proposing to charge these customers a per-kW or per-kVA charge instead of a fixed charge.

Q. What costs are appropriate for a utility to recover through a fixed charge rate design?

A. Customer-related costs, or costs that are based on the number of customers on the utility's system, are appropriate to collect through a fixed charge. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual defines customer costs as "directly related to the number of customers served."[9] It provides

[9] NARUC Electric Utility Cost Allocation Manual, January 1992, at 20.

that customer-related costs should be "[a]llocated among the customer classes on the basis of the number of customers or the weighted number of customers."[10] These costs can be contrasted against costs that vary based on the amount of energy a customer consumes or when the customer consumes.

While utilities would prefer to collect as much revenue as possible through fixed charges on residential and small commercial customers because that stabilizes their revenue (in contrast to variable charges that provide varying levels of revenue month-to-month and season-to-season as usage fluctuates), that does not mean that a fixed charge is the most appropriate rate design for recovering a particular type of cost, or that it sends appropriate price signals and is fair to customers.

Q. What types of utility costs are classified as customer-related costs as opposed to energy- or demand-related costs?

A. The costs of metering, billing and collection, and customer assistance are customer costs.[11] Leading experts have demonstrated that collecting distribution equipment through a fixed charge is not economically efficient or cost based and can cause undesirable rate cross-subsidies, such as renters subsidizing homeowners.[12] Accordingly, they advise that the

---

[10] P. 22; *see also* pp. 98-99.

[11] "The customer service and facilities function includes the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection, and customer information and services. These investments and expenses are generally considered to be made and incurred on a basis related to the number of customers (by class) and are therefore of a fixed overhead nature." *See* National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January, 1992 (hereinafter "NARUC Electric Manual"), at 20, 89.

[12] *See, e.g.,* Jim Lazar and Wilson Gonzalez, "Smart Rate Design for A Smart Future," July 2015, p. 9, stating, "Although some utilities and regulators use customer charges to recover distribution system costs, this paper demonstrates that this is neither cost-based nor economically efficient. High customer charges impose unfair costs on small-use residential consumers, including most low-income household and apartment residents."

fixed charge should not exceed the customer-specific costs attributable to an incremental consumer.

Q. Why is it inappropriate for CenterPoint to recover 100% of its TDSIC Plan distribution costs through a fixed charge?

A. First, it is unusual for an electric utility to increase its fixed charges on residential customers outside of a base rate case. In my experience, cost recovery approved outside of a rate case (e.g., through a rider or tracker) for residential customers is nearly always through variable per-kWh charges, regardless of whether it is for generation, transmission, or distribution system investments, making CenterPoint's proposal here an outlier.

Second, CenterPoint customers with higher or growing demand put additional strain on the distribution system, which can lead to the need for upgrades and expansions, resulting in additional capital and operating costs ultimately borne by customers.[13] CenterPoint should therefore recover distribution costs on the basis of customer end-use consumption. This also produces beneficial and more appropriate price signals, as it allows customers to reduce their total charges by reducing their usage, which can help reduce strain on the distribution grid. CenterPoint seems to acknowledge this point in responding to a CAC data request by stating in part:[14]

> Design of transmission and distribution infrastructure to meet customer service and reliability standards entails anticipating peak usage of the infrastructure. The most equitable means to charge those customers causing the peak infrastructure demand to be incurred is through a demand charge. Investments in distribution infrastructure should be recovered from the customers who cause those investments to be made …

[13] Jim Lazar and Wilson Gonzalez, "Smart Rate Design for A Smart Future," July 2015, p. 37.
[14] CenterPoint Response to CAC Data Request 1-10 (Attachment BI-2).

In other words, CenterPoint admits that the distribution costs included in the TDSIC Plan do not vary by the number of customers, but rather by the demands placed on the distribution system by customers. Yet, CenterPoint goes on in the same response to state that "once such investments are made then the appropriate price signal is to recover those fixed costs through fixed charges or demand-based charges." Such a claim is not supported by economic principles, rate design principles, or the NARUC Electric Utility Cost Allocation Manual.

Customer energy usage (kWh) tends to be correlated with their peak demand (kW), and variable per-kWh charges have been used for many decades to collect demand-related costs from the residential class and other classes that have historically not had demand charges. For example, a retired couple on a fixed income living in multifamily housing might use a modest amount of electricity and impose a modest demand on the distribution system. In contrast, a large household living in a large house with a pool with an electric heater and two electric vehicle charging stations may use a large amount of electricity and impose a large peak demand on the distribution system – possibly several times that of the retired couple in this example. These two types of customers cause very different amounts of distribution system costs, so it would not be just and reasonable to impose an identical charge – as CenterPoint proposes – on these very different customers. Collecting distribution costs on such customers through a variable per-kWh charge is therefore appropriate, consistent with long-standing ratemaking principles, and more reflective of cost causation than a fixed charge.

Finally, while CenterPoint may believe distribution costs are "fixed costs," this is neither accurate nor relevant in determining the appropriate rate design. All costs, including distribution system costs, are actually variable in the long run.[15] As CenterPoint noted in the quoted excerpt above, these costs are not actually fixed, but are related to the demand placed on the distribution system; reduced demand would therefore result in reduced distribution system costs being incurred in the future. Rate design should be fashioned with establishing appropriate price signals for consumers. Here, incentivizing consumers to use less electricity by collecting TDSIC Plan charges exclusively through variable per-kWh charges would also encourage those same customers to reduce peak demand, as many actions consumers take to reduce kWh consumption also reduce peak demand (e.g., purchasing more energy efficiency appliances and fixtures like low wattage lightbulbs; behavioral responses like setting thermostats to higher temperatures in the summer). The distinction between fixed and variable costs faced by the utility is also not particularly relevant for rate design, as there is no economic rationale for collecting what the analyst deems to be "fixed costs" through "fixed charges." For more than a century, utilities have been collecting an assortment of large "fixed costs," for generation, transmission, and distribution system investments primarily through variable – not fixed – charges on customers. There is no reason to change that model now. Indeed, if CenterPoint actually believed its argument, it would have also proposed collecting 100% of its transmission system costs and 100% of distribution system costs allocated to medium and large commercial and industrial customers through fixed charges. It would also propose to collect most generation plant costs through a fixed charge, as power plant costs are "fixed"

---

[15] *E.g., see* James Bonbright, *Principles of Public Utility Rates*, p. 336, "[A]s setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or 'capacity costs' as variable costs."

in the short run. Obviously, such an outcome is absurd on its face, as it would likely lead to $100+ per month fixed charges on residential customers, and consumers would never have a meaningful incentive to conserve electricity to help reduce generation, transmission, and distribution system costs over the long run.

Q. Would CenterPoint be harmed if TDSIC Plan costs allocated to residential and small commercial customers are recovered through per-kWh charges instead of fixed charges?

A. No. Rates would be designed to collect exactly the same revenue requirement, so CenterPoint would recover the same amount from its customers. There is also a cost reconciliation mechanism in the TDSIC tracker, so even if CenterPoint experienced a temporary shortfall in the collection of revenues, that shortfall would be trued-up with ratepayers. (Of course, CenterPoint could just as easily experience an *over collection* in revenues.)

Although increasing fixed charges stabilizes revenues for CenterPoint, creating a perceived benefit for its shareholders, this shifts risk onto ratepayers by improving CenterPoint's cash flow and decreasing a customer's ability to control their bills.

Q. Are you aware of any electric utility that recovers 100% of distribution costs through a fixed charge?

A. No. CenterPoint's proposal is an outlier in this respect. I have never heard of any other utility in the nation recover, or even propose, 100% of its distribution costs allocated to residential customers through a fixed charge. While the TDSIC Plan does not represent all of CenterPoint's annual distribution costs, it does span a broad variety of types of distribution costs, ranging from substation rebuilds and physical security, to Distribution Automation, to rebuilding 12kV circuits.

Q. How are distribution plant expenses tracked by utilities?

A. The Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts requires separate accounts for distribution investment (accounts 360-373) and expenses (accounts 580-598). The NARUC Electric Utility Cost Allocation Manual clearly identifies that at all or portions of most of these accounts are demand-related.[16] It also repeatedly emphasizes that careful study is needed to appropriately allocate distribution costs between demand-related and customer-related (although many utility regulators have moved away from allocating any or most distribution costs as customer-related, as detailed further below). For example, it states that "[t]he amounts between classifications [customer-related and demand-related] may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components."[17] It goes on to say:[18]

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both.… Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation.

Q. Has CenterPoint performed the analysis referenced in the NARUC Electric Utility Cost Allocation Manual to determine the nature of distribution plant and expenses to ensure costs are assigned correctly?

[16] Pp. 87-88.
[17] Footnote 2, pp. 87 and 88.
[18] P. 89.

A. No. CenterPoint has performed no such analysis.

Q. Please provide a specific example from CenterPoint's TDSIC Plan to explain why CenterPoint's investments allocated to distribution are inappropriate to be recovered through a fixed charge.

A. CenterPoint's TDSIC Plan includes both a Substation Rebuild Program and Substation Physical Security Program that have distribution-allocated components. These costs do not vary by the number of customers. For example, adding an additional residential customer would not result in any added physical security costs to the substation. The NARUC Electric Utility Cost Allocation Manual specifically notes that:[19]

> Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. **The reason is that costs are incurred to serve area load, rather than a specific number of customers**. Distribution substations costs (which include Accounts 360-Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because **substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.**

(Emphasis added.) ***The NARUC cost allocation manual goes on to detail several possible methodologies for determining the portion of distribution costs that should be allocated as customer-related and demand-related, <u>a step that CenterPoint did not follow</u>.***

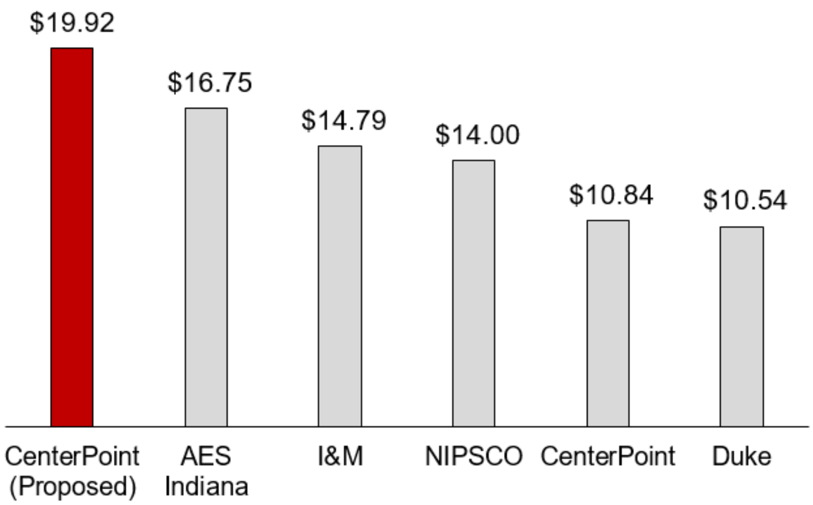
Since substation costs included in the TDSIC Plan are to serve load and are not affected by the number of customers to be served, these costs should not be recovered through a fixed charge.

Q. How does CenterPoint's proposed Residential monthly fixed charge compare to other Indiana electric investor-owned utilities ("IOUs")?

[19] P. 90.

A. As shown in Figure 2, CenterPoint's proposed fixed component of the TDSIC tracker combined with its customer charge established in base rates would result in it going from the second-least expensive base fixed charge to the most expensive total fixed charge among Indiana's five electric IOUs. Any increase in CenterPoint's fixed customer charge arising from its forthcoming electric rate case would be additional.

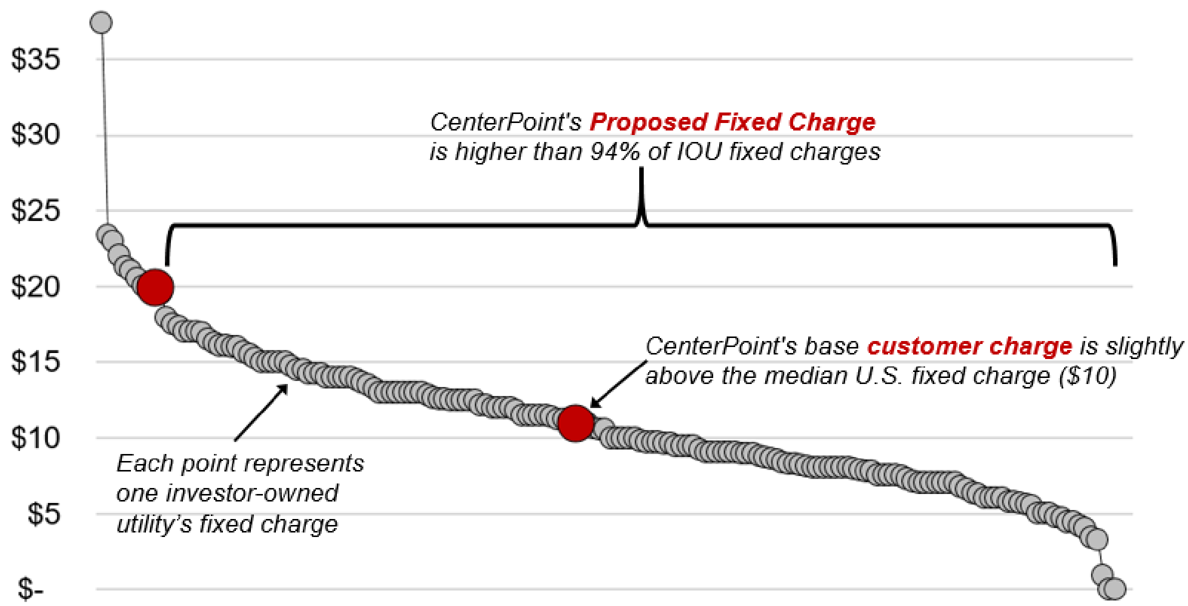
Figure 2. CenterPoint's Proposed Residential Monthly Fixed Charges in 2028 Compared to Indiana Electric IOUs' Base Fixed Charges



Q. How does CenterPoint's total proposed residential monthly fixed charge compare to other electric investor-owned utilities nationwide?

A. CenterPoint's total residential fixed charge would be among the most expensive of any electric IOU in the U.S. In fact, ***if CenterPoint's fixed charge TDSIC tracker is approved as proposed, it would have the 10th-highest total residential fixed charge out of 171 U.S. investor-owned electric utilities.*** This is illustrated in Figure 3, which plots each U.S. investor-owned electric utility's approved fixed charge, sorted highest (left side) to lowest (right side). CenterPoint's base fixed charge and proposed total fixed charge under the TDSIC tracker in 2028 are each identified. CenterPoint's proposed $19.91 total fixed charge is nearly double the median approved monthly residential fixed charge of $10.00 (*average* = $10.96) across U.S. investor-owned electric utilities (*N* = 171).

Figure 3. CenterPoint's Base Customer Charge and Proposed Total Fixed Charge Compared to 171 U.S. Investor-Owned Electric Utility Fixed Charges[20]



Q. What do you conclude based on these comparisons to other Indiana utilities and electric utilities across the U.S. more broadly?

A. CenterPoint's proposed total fixed charge would have the dubious distinction of being the most expensive among electric IOUs in the state of Indiana, and one of the most expensive across all U.S. electric IOUs. ***CenterPoint's proposed fixed charge cost recovery mechanism is also inconsistent with how other Indiana investor-owned utilities recover TDSIC distribution costs; AES Indiana, Duke Energy Indiana, and NIPSCO all recover these costs through per-kWh charges on residential customers***.

Q. What are the drawbacks to consumers of high residential fixed charges?

[20] Figure based on data from EQ Research, LLC and from CenterPoint's case-in-chief.

A. High residential fixed charges have numerous, substantial drawbacks compared to cost recovery through variable per-kWh rate. These drawbacks include:

- **Reduced customer control.** High fixed charges disempower customers because regardless of how much or when the customer uses electricity, the customer must pay the same fixed charge. The only way to avoid paying the fixed charge is to stop being a customer of the utility.
- **Low usage customers disproportionately impacted.** Customers who use less electricity than average, such as seniors on fixed incomes, experience higher percentage bill increases when the utility collects costs through a fixed charge.
- **Low income customers disproportionately impacted.** Since low-income customers tend to have lower average usage than the average residential customer,[21] high fixed charges have a regressive impact, disproportionately harming low-income customers.
- **Reduced financial viability of deploying energy efficiency and distributed generation.** Collecting more of a customer class's revenue requirement through fixed charges reduces the proportion of revenue that is collected through variable charges, resulting in lower per-kWh charges. This reduces the value of a kWh saved or self-generated by the customer. Higher fixed charges in concert with lower per-kWh variable charges thereby reduce the financial benefit to the customer of energy efficiency measures and distributed generation. Also, energy efficiency and distributed generation installer jobs are inherently local jobs.
- **Higher electric system costs.** Higher fixed charges in combination with lower per-kWh variable charges alters consumer price signals, resulting in higher electricity consumption. Higher electricity consumption results in higher system costs because it results in the need for new power plants, power lines, substations, and other utility investments, thereby raising costs on all customers.

Q. Have other utility commissions rejected utility attempts to use methodologies that recover distribution costs through fixed charges?

A. Yes. Many state utility commissions have approved methods of calculating the residential fixed charge that do not classify distribution system equipment upstream of the service line as a customer cost. One of these methods, which I support, is the basic customer approach,

[21] John Howat, John T. Colgan, Wendy Gerlitz, Melanie Santiago-Mosier, and Karl R. Rábago, "Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition," p. 2, https://www.nclc.org/wp-content/uploads/2022/08/report-reversing-energy-system-inequity.pdf (showing National Consumer Law Center analysis of U.S. EIA 2015 Residential Energy Consumption Survey Data that finds households with the lowest incomes are on average the very lowest energy users in all regions of the U.S.).

under which only costs that can be traced to a specific customer should be assigned as customer costs, because those are the only costs that vary based on the number of customers in a class. In contrast, the minimum system method and zero-intercept approach allocate portions of distribution system costs as customer-related. For example:

- The Illinois Commerce Commission has rejected the Minimum System and zero intercept approach on multiple occasions and adopted the basic customer approach, finding that "attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic."[22]
- The Missouri Public Service Commission has determined that "There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power." [23]
- The Public Utilities Commission of Texas found that "[s]pecifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service."[24] It determined that "[i]t is appropriate to use a 100% demand allocator for distribution accounts 364 through 368," which is consistent with an application of the Basic Customer approach.[25]
- The Arkansas Public Service Commission found that "accounts 364-368 should be allocated to the customer classes using a 100% demand methodology," finding that there was not "sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes."[26]
- The Idaho Public Utilities Commission moved from the minimum system approach to the basic customer approach in 1998 because it found that the basic customer approach was a superior methodology.[27]

---

[22] Final Order, *Commonwealth Edison Company Proposed General Increase in Electric Rates (Tariffs filed October 17, 2007)*, at 208 (Sep. 10, 2008), Docket No. 07-0566 (Illinois Commerce Commission).
[23] Missouri Public Service Commission Report & Order, File No. ER-2014-025, April 29, 2015.
[24] Order No. 40, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344*, at 6 (Nov. 22, 2000) Docket No. 22344 (Public Utility Commission of Texas).
[25] Order, *Application of AEP Texas Central Company for Authority to Change* Rates, at 17 (Dec. 13, 2007) Docket No. 33309 (Public Utility Commission of Texas).
[26] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).
[27] Order No. 28097, *In the Matter of the Application of the Washington Water Power Company (Now Avista Corporation dba Avista Utilities—Washington Water Power Division) For an Order Approving Increased Rates and Charges for Electric Service in the State of Idaho*, at 24–27 (July 29, 1999), Case No. WWP-E-98-11 (Idaho Public Utilities Commission).

Similar determinations have been made in states including Washington,[28] Connecticut,[29] Rhode Island,[30] Maryland,[31] and Colorado.[32]

Q. What do you conclude about CenterPoint's proposal to recover distribution system costs allocated to residential and small commercial customers through a fixed charge component?

A. I conclude that this fixed charge proposal:

- Is inconsistent with sound cost allocation and rate design principles, and would not produce just and reasonable rates.
- Is an outlier in that I know of no other utility in the nation to recover, or even propose, 100% of its distribution costs allocated to residential customers through a fixed charge.
- Would make CenterPoint the #1 highest residential fixed charge in Indiana and the #10 highest total residential fixed charge out of 171 U.S. investor-owned electric utilities.
- Is unsupported by NARUC Electric Utility Cost Allocation Manual findings and does not follow NARUC's recommendations for studies.
- Would create a very large residential fixed charge that recovers costs that many public utility regulators have found to be inappropriate for inclusion in fixed charge cost recovery.
- Is unfairly targeting residential and small commercial customers, whereas CenterPoint is proposing to collect the same costs from medium and large commercial and industrial customers via a per-kW or per-kVa charge rather than a fixed charge.

---

[28] Ninth Supplemental Order on Rate Design Issues, *Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Benefits*, (Aug. 16, 1993) Docket No. UE-920433 (Washington Utilities and Transportation Commission) (1993 WL 13812140), at 5–6.

[29] CT Gen. Stat. § 16-243bb (2020).

[30] Decision and Order, *In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution* Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

[31] Order No. 83907, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base* Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland) (internal citations omitted).

[32] Colorado Public Utilities Commission. (June 15, 2018). Proceeding No. 17AL-0477E, Decision No. C18-0445 in rate case for Black Hills/Colorado Electric Utility Co. https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=25270

Q. What do you recommend regarding CenterPoint's TDSIC rate design proposal for residential and small commercial customers?

A. The Commission should reject CenterPoint's proposal to collect TDSIC costs through a fixed customer charge component. All cost recovery for the TDISC Plan should occur through variable per-kWh charges for residential and small commercial customers.

III. <u>CONCLUSION</u>

Q. Please summarize your recommendations.

A. I recommend that the Commission:

- Scrutinize CenterPoint's TDSIC Plan to ensure its proposals are reasonable, including, but not limited to, claims about the benefits related to distributed generation.
- Deny CenterPoint's proposal for TDSIC Plan cost recovery of distribution system investments through a fixed charge on residential and small commercial customers and instead approve cost recovery for these customers through variable per-kWh charges.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Ben Inskeep, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Benj Inskeep ______________________ August 16, 2023 ________________
Ben Inskeep

ATTACHMENT BI-1

Attachment B-1: Benjamin Inskeep's Expert Witness Experience

Indiana Utility Regulatory Commission

Cause No.	Case Description
45870	Indiana-American Water 2023 Rate Case
45849/45850	NIPSCO Electric/Gas 2024-26 DSM
45816	IURC Investigation regarding the Infrastructure Investment and Jobs Act
45868	I&M 4 Solar Projects
38703 FAC 133-S1	AES Indiana Eagle Valley Outage
45504	AES Indiana Excess Distributed Generation Tariff
45505	NIPSCO Excess Distributed Generation Tariff
45506	I&M Excess Distributed Generation Tariff
45508	Duke Energy Indiana Excess Distributed Generation Tariff
45700	NIPSCO Michigan City Coal Ash Compliance Project
45701	I&M Demand-Side Management Plan 2023-2025
45722	CenterPoint Securitization of AB Brown
45740	Duke Energy Indiana and International Paper Special Contract
45749	Duke Energy Indiana Coal Ash Compliance Project
45772	NIPSCO Electric Rate Case
45775	Duke Energy Indiana Low-Income Consumer Protections
45795	CenterPoint Culley East Coal Ash Compliance Project
45797	NIPSCO Schahfer Coal Ash Compliance Project
45803	Duke Energy Indiana Demand-Side Management Plan 2024-2026
45836	CenterPoint Wind Project CPCN
45843	AES Indiana EV Portfolio

Kentucky Public Service Commission

Case No.	Case Description
2020-00174	Kentucky Power's 2020 Rate Case
2020-00349	Kentucky Utilities' 2020 Rate Case
2020-00350	Louisville Gas & Electric's 2020 Rate Case

ATTACHMENT BI-2

1.10 Please refer to Rice Direct Testimony, p. 10, line 22 through p. 11, line 3.

a) On what basis is CIES proposing to recover the distribution component via a fixed charge on the small customer rate schedules? Please explain why this is the most appropriate rate design for these customers.

b) On what basis is CIES proposing to Distribution component is recovered via a per-kW or per-kVa demand charge for Rate DGS, Rate MLA, Rate OSS, Rate LP, and Rate HLF? Please explain why this is the most appropriate rate design for these customers.

Response:

CEI South customers currently pay for a distribution component of TDSIC through either a capped, fixed charge with costs in excess of the cap recovered on a per-kWh basis, or on a per-kW or per k-Va basis. As a result of the Company's proposed rate design, all customers will receive more accurate price signals and fixed distribution costs will be more fairly recovered from each customer. Design of transmission and distribution infrastructure to meet customer service and reliability standards entails anticipating peak usage of the infrastructure. The most equitable means to charge those customers causing the peak infrastructure demand to be incurred is through a demand charge. Investments in distribution infrastructure should be recovered from the customers who cause those investments to be made, and that once such investments are made then the appropriate price signal is to recover those fixed costs through fixed charges or demand-based charges. Customers should not receive a signal that these types of investments, once completed, vary based on the amount of energy consumed. In addition, see the Commission's Order in Cause No. 44576.

1.12 Please refer to Rawlinson Direct Testimony, p. 13, lines 7-24 and the Excess Distributed Generation ("EDG") tariff.

a) Please identify how many residential and non-residential customer Excess Distributed Generation tariff applications, and the associated capacity (kilowatts), have been submitted to the Company but have not yet been approved by the Company.
b) For each month since the Excess Distributed Generation tariff went into effect, please provide the following information in an executable format (e.g., Excel file).
    i. Number of new residential systems
    ii. Capacity of new residential systems in kilowatts.
    iii. Number of new residential battery energy storage systems that are associated with EDG systems.
    iv. Capacity of new residential battery energy storage systems that are associated with EDG systems. Please provide both kW and kWh system size information to the extent the Company has such data in its possession.
    v. Total dollar amount of Excess Distributed Generation credits provided to residential customers for excess distributed generation.
    vi. Number of new non-residential systems.
    vii. Capacity of new non-residential systems in kilowatts (in units of both AC and DC if available; if not, please identify whether the capacity values provided are in AC or DC units).
    viii. Number of new non-residential battery energy storage systems that are associated with EDG systems.
    ix. Capacity of new non-residential battery energy storage systems that are associated with EDG systems. Please provide both kW and kWh system size information to the extent the Company has such data in its possession.
    x. Total dollar amount of Excess Distributed Generation credits provided to non-residential customers for excess distributed generation.

Objection:

CEI South objects to these requests because they are outside the scope of this proceeding, seek information that is not relevant to the issues in this case, and are not reasonably calculated to lead to the discovery of admissible evidence. Mr. Rawlinson's testimony does not make any reference to an Excess Distributed Generation tariff either at the cited location in the request or anywhere else in the testimony.

CEI South further objects to these requests because they seek information that is unreasonably cumulative or duplicative and is obtainable from some other source that is more convenient, less burdensome, or less expensive.

Response:

See Objections.