FILED
December 19, 2024
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-242.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM, TO THE EXTENT NECESSARY; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	)	**CAUSE NO. 46120**

<u>INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR</u>
<u>PUBLIC'S EXHIBIT NO. 12</u>
<u>REDACTED TESTIMONY OF OUCC WITNESS</u>
<u>MICHAEL W. DEUPREE</u>

Respectfully submitted,

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

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TABLE OF CONTENTS

I. <u>INTRODUCTION</u>

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana 70808.

Q. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT.

A. I am a research consultant with the Acadian Consulting Group ("ACG").

Q. PLEASE DESCRIBE ACG AND ITS AREAS OF EXPERTISE.

A. ACG is a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and located in Baton Rouge, Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the University of Kansas in Lawrence, Kansas. I began my professional career with the Staff of the Kansas Corporation Commission in 2008 while in graduate school conducting analyses of topics related to energy and the economy as a Research Assistant, eventually being promoted to a Research Analyst and later Senior Research Economist after graduation. I left the Kansas Corporation Commission to take a position with ACG in late 2011, where I have been promoted to positions of increasing responsibility since, including my current position which I started in mid-2021. At ACG I manage research teams supporting expert testimony and have overseen dozens of litigated proceedings, including several proceedings on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC") relating to rate design and class cost of service. Appendix A provides my professional resume, which includes a listing of my publications, presentations, pre-filed expert witness testimony, expert reports, and expert legislative testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I have been retained by the OUCC to provide an expert opinion to the Indiana Utility Regulatory Commission ("Commission") regarding cost of service and rate design elements of Northern Indiana Public Service Company LLC's ("NIPSCO" or the "Company") case-in-chief. My testimony and accompanying exhibits have been prepared by me or those under my direction and control.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Overview of NIPSCO's Filing
- Section IV: Allocated Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Rate Design
- Section VII: Conclusions and Recommendations

II. <u>SUMMARY OF RECOMMENDATIONS</u>

Q. WHAT ARE YOUR ALLOCATED COST OF SERVICE STUDY ("ACOSS") FINDINGS?

A. My alternative ACOSS analysis shows the Company's incorrect classification of production plant assets and secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I recommend the Commission rely on the results of my alternative ACOSS as a fair and reasonable estimation of relative costs of service between Company customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOSS results that also limits the rate increase to any single customer class to 1.15 times the overall system average increase. This, combined with the OUCC's recommended overall revenue increase of 11.25 percent, reduces the maximum total revenue increase to any single rate class to 12.93 percent, compared to the Company's proposed maximum rate increase of 30.23 percent.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RATE DESIGN?

A. I recommend the Commission not approve the proposed increases in customer charges because these charges disproportionately affect low-income customers and increases in fixed charges reduce price incentives in all customer classes to reduce usage, contrary to the public goal of promoting energy efficiency. Likewise, the Commission should deny the separation of residential customers into single and multi-family rates because of the limited load research data presented, which includes only 127 residential customers, or 0.03 percent of NIPSCO's total residential customers. Additional information beyond this limited load research data is required to support any proposed separation of residential classes in future cases. Finally, the Commission should not approve Petitioner's Low Income Program as proposed because, among other concerns, it is designed to shift burdens between residential customers and forces participation from all residential customers. The Company should instead focus on addressing growing revenue requirements.

III. OVERVIEW OF NIPSCO'S FILING

Q. WHAT RATE INCREASE IS THE COMPANY REQUESTING?

A. The Company is requesting a 20.1 percent increase in revenues, including a 20.1 percent increase in Residential Single Family rates.[1] The Company's proposed rate increase will allow it to support an overall 7.59 percent return on rate base,[2] compared to its currently calculated overall return on rate base of 4.15 percent.[3] The Company requests this rate increase to support a $3.3 billion increase in net utility plant.[4]

Q. HAVE YOU CONDUCTED AN ANALYSIS OF THE COMPANY'S RETAIL RATES RELATIVE TO PEER ELECTRIC UTILITIES?

A. Yes. Attachment MWD-1 examines the Company's historic retail rates relative to other regional public electric utilities. My analysis shows NIPSCO has some of the highest rates among its regional peers, especially for residential ratepayers, and that the affordability of the Company's rates relative to other regional peer utilities has not been improving over time.

Q. PLEASE DISCUSS THE DATA YOU UTILIZED IN YOUR PEER ANALYSIS.

[1] Petitioner's Exhibit No. 16, Verified Direct Testimony of John D. Taylor at 46:1-2.
[2] *Id.*
[3] *Id.* at 38:1-2.
[4] Direct Testimony of Erin E. Whitehead, 14:4-11.

A. My analysis started with the collection of a full decade's worth of Form 1, Annual Report data filed by regulated utilities with the Federal Energy Regulatory Commission ("FERC"). I examined specific investment and expense trends by major account as defined by the FERC Uniform System of Accounts ("USOA"). I developed average revenues (retail revenues divided by sales in megawatt-hour or "MWh" terms) by backing out fuel-related costs from overall sales revenues included in the Form 1.

Q. HOW DID YOU DETERMINE THE REGIONAL PEER UTILITIES?

A. I developed the peer utilities list by including 11 vertically integrated investor-owned utilities operating within Indiana, Michigan, or Kentucky.

Q. WHAT DOES YOUR RESIDENTIAL RATE COMPARISON SHOW?

A. Attachment MWD-1 shows that the Company's residential rates (average non-fuel revenues) have consistently been above the reported averages for the regional peer utilities. NIPSCO's ten-year average residential rate of $0.114/kWh is higher than the peer group's average residential rate of $0.089/kWh and among the highest in the region, exceeded in 2023 by only DTE Electric Company ("DTE").

Q. DO YOU SEE THE SAME KINDS OF RELATIONSHIPS IN THE COMPANY'S COMMERCIAL RETAIL RATES?

A. Yes. Attachment MWD-1 also compares the Company's estimated commercial base rates (average non-fuel revenues) to the regional peer utilities. This analysis shows the Company's commercial rates are also higher than those of regional peers. The Company's estimated commercial rates averaged $0.101/kWh over the past decade, compared to a peer average of $0.072/kWh over the same comparable period. NIPSCO, therefore, had among the highest rates in the region, exceeded in 2023 by only DTE Electric Company ("DTE").

Q. HOW DOES THE COMPANY'S INCREASED REVENUE REQUIREMENT AFFECT THE REQUIRED COST TO SERVE ITS VARIOUS RATE CLASSES?

A. The Company's ACOSS in the current proceeding shows a number of its rate classes would require significantly higher rate increases to meet the Company's projected increase in operating costs. For example, Rate 544 (Railroad Power Service), using the Company's allocation structure, is estimated by the Company to require a 107.2 percent increase in rates to meet its estimated cost of service going forward. The Company likewise estimates that Rate 511 (Residential Service – Single Family) would require a 53.3 percent increase in rates, reflective of 2.6 times NIPSCO's system average, to meet its growing cost of service.[5] In my opinion, the Company's COSS significantly overstates these increases.

Q. DOES THE COMPANY PROPOSE TO INCREASE RATES FOR ITS RATE CLASSES CONSISTENT WITH ITS ACOSS FINDINGS?

A. No. As discussed later in this testimony, the Company proposes eight mitigation steps when determining the proposed revenue responsibilities. On an overall basis, the Company proposes the increase to any single rate class be limited to no more than 1.5 times NIPSCO's overall system average increase of 20.10 percent, or 30.15 percent.[6] Excluded from this proposed mitigation are Rate 511 (Residential Service – Single Family) and Rate 544 (Railroad Power Service). Indiana law requires that rates for commuter transportation service be set equal to

[5] Direct Testimony of John D. Taylor at 38:1-2.
[6] *Id.* at 43:7-9.

or lower than the rate approved for any NIPSCO industrial or commercial consumer,[7] which the Company interprets as requiring the rate increase for Rate 544 to equal its proposed system average increase of 20.1 percent.[8] The Company likewise proposes Rate 511 rates by ostensibly applying the proposed system average,[9] but provides only limited explanation for this specific mitigation.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE COMPANY'S OVERALL PROPOSED RATE INCREASE IN THE CURRENT PROCEEDING?

A. Yes. It is crucial the Commission recognize NIPSCO's proposed 20.1 percent increase in rates comes shortly after a 17.9 percent increase in the Company's prior rate case, Cause No. 45772.[10] Residential customers receiving service from the Company face increasingly high energy burdens. The frequency of NIPSCO's rate increases, coupled with rider and tracker increases, will not improve this negative situation. Likewise, the Company's ACOSS finding that rates for Rate 511 (Residential Service – Single Family), representing 72.4 percent of all Company customers,[11] would need to be increased by 53.3 percent to reach full cost of service[12] demonstrates the unsustainable nature of the Company's rate increases. At a minimum, the OUCC's proposed allocation structure should be used in lieu of the percentage increases NIPSCO extrapolates. While NIPSCO proposes a 20.1 percent increase for residential customers, this number is not supported by NIPSCO's COSS evidence. The OUCC's alternative recommended revenue

[7] IC 8-1-2-46.1.
[8] Direct Testimony of John D. Taylor at 44:7-9.
[9] *Id.* at 43:12-14.
[10] Cause No. 5772, Step Two Compliance Filing, Attachment F-52.
[11] *See*, Taylor NIPSCO Electric External Allocators_2024_WORKPAPERS.xlsx.
[12] Direct Testimony of John D. Taylor at 38:1-2.

increases, however, are a function of my ACOSS modeling that addresses all customer classes appropriately.

Q. HOW DOES YOUR ACOSS MODELING ADDRESS ALL CUSTOMER CLASSES APPROPRIATELY?

A. As discussed later in this testimony, the Company incorrectly classifies production plant assets, especially in light of the Company's proposal to significantly increase renewable generation units, as well as secondary-voltage distribution plant. This results in an ACOSS that incorrectly over-assigns costs to low load factor residential customers, while under assigning costs to high load factor commercial and industrial customers. Specifically, my ACOSS analysis finds the Company incorrectly underestimated the residential class's current contribution to the Company's overall earnings by more than half.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING ENERGY AFFORDABILITY?

A. Customers that receive service from the Company face increasingly high energy burdens, and NIPSCO's proposed rate increase will not improve this negative situation. The Commission must consider the effect of the proposed rate increase on all of the Company's customers.

IV. ALLOCATED COST OF SERVICE

A. Introduction

Q. WHAT IS THE PURPOSE OF AN ACOSS?

A. An ACOSS is a modeling approach that reconciles utility costs and revenues across different customer classes. The goal of an ACOSS is to evaluate the cost of providing service and revenue responsibility for each individual customer class. ACOSS results are used to estimate class specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. HOW IS AN ACOSS PREPARED?

A. An ACOSS utilizes a set of historic or projected cost information that is (1) "functionalized," (2) "classified," and (3) "allocated." The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by "type", including those that are (1) demand-related, (2) commodity-related, or (3) customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. PLEASE EXPLAIN DEMAND-RELATED COSTS.

A. Demand-related costs are associated with meeting maximum electricity demands. At the distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in an ACOSS are those related to system Coincident Peaks ("CP") or Non-Coincident Peaks ("NCP"). At the production level, most power plants, also referred to as production plants or electric generation units ("EGU"), are typically viewed as being designed to serve both the energy and demand/capacity needs of the utility. The exact degree of this split between energy and demand depends on the individual EGU in question and how that unit is dispatched, with baseload units serving more of the utility's energy needs and peak units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant-in-service costs associated with a utility's generation fleet.

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kilowatt-hour ("kWh")) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a ACOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in an ACOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES AN ACOSS RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. An ACOSS is referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the ACOSS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. An ACOSS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs, whereas economic theory suggests the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with the presence of joint and common costs, difficult.

Q. ARE THERE ANY OTHER CONFOUNDING PROBLEMS THAT CAN ARISE WITH AN ACOSS?

A. Yes. The problems listed above are confounded by the fact that the cost information utilized in an ACOSS is usually historic and static, not dynamic and forward-looking. These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in an ACOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the ACOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use ACOSS results as a "guide" in setting rates and do not consider themselves unnecessarily bound by the ACOSS results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS ACOSS METHODOLOGIES?

A. The ACOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two processes focus on determining how much revenue will be recovered through rates, the ACOSS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various ACOSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers, and less costs to larger high load factor customer classes and off-peak customers. These approaches can also fail to capture the service being provided by the utility (i.e., electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

Q. PLEASE EXPLAIN THE BIAS IN METHODOLOGIES THAT ARE SKEWED TOWARD PEAK CONSIDERATIONS.

A. Residential and small commercial customer electricity loads are typically weather sensitive. On the other hand, larger industrial customers use electricity in processes that are generally not weather sensitive, and electric use thus tends not to cycle up and down, but rather runs on a more continuous basis. Because of this, daily and annual usage patterns for these two customer classes are significantly different. The peak loads for residential and small commercial customers tend to be more "peaked" than those for industrial customers, which are steadier and more evenly distributed across peak and non-peak hours. For example, an average residential customer may have relatively little electricity use during overnight hours and during weekday daytime working hours. Residential customers exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating. Similarly, small commercial customers see limited electricity use outside of workday hours. Thus, residential and small commercial customers tend to have relatively lower load factors than large industrial customers.

Q. PLEASE DEFINE "LOAD FACTOR."

A. A load factor is defined as the ratio of the average load in kilowatt hours supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by taking the energy used during a period and dividing it by the product of the maximum demand and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently, since usage is consistent and does not swing significantly between average and peak periods. Conversely, systems with low load factors must maintain idle capacity to meet the relatively large swings in load between average and peak periods.

Q. DOES A HIGH LOAD FACTOR INDICATE GREATER SYSTEM EFFICIENCY?

A. Yes, since a higher system load factor can be indicative of, or lead to better system resource utilization, other things being equal. However, it should be recognized that all utilities inherently have customers with different load profiles due to differences in how customers use electricity. Furthermore, the development of integrated wholesale bulk electricity transmission systems has allowed utilities to collectively diversify generation resources and individual system demands, which has reduced the impact of individual system load characteristics on generation needs in recent years. While rates should recognize and promote the efficient utilization of utility system resources, caution should be used in placing too much emphasis on this principle of rewarding high load factor industrial customers to the detriment of low load factor residential and small commercial customers.

Q. WHAT IMPACT DOES COST ALLOCATION HAVE ON REVENUE RECOVERY?

A. Higher use customers, such as industrial customers, are inherently more price sensitive than lower use customers due to the relative impact increases in rates can have on these customers' total utility bills and the margins of produced goods. These higher use industrial customers tend to have more energy supply alternatives, including fuel switching and self-generation, which is part of the reason why they are more price sensitive. These considerations can result in differences in revenue generation given the differences in the price elasticities of demand (i.e., price sensitivities) for the two sets of customers (residential, industrial).

Q. EXPLAIN HOW SOME ACOSS METHODS CAN BE BIASED AGAINST LOWER LOAD-FACTOR CUSTOMERS.

A. Utilities by their nature are capital intensive industries with high levels of capital expenditures required to develop systems to generate and transmit power to customers. Therefore, deciding the appropriate allocation of costs associated with utility capital investments (e.g., utility "plant in service") largely affects the cost of providing service. Utilities can often over-emphasize peak demand factors in allocating these large plant costs in order to assign more costs away from their price sensitive customers. Likewise, utilities can emphasize non-diversified single CP demands, NCP demands, and individual customer demands in allocating costs associated with transmission and distribution plant facilities to favor high-load factor customers relative to low-load factor customers. Finally, utilities can over-emphasize customer connection aspects of lower voltage distribution facilities to favor high-use customers relative to low-use customers.

B. Overview of the Company's ACOSS

Q. PLEASE DESCRIBE NIPSCO'S ACOSS APPROACH.

A. The Company utilizes the traditional three-step approach to ACOSS. First the Company functionalizes its costs to seven separate functions: production; transmission; sub-transmission; primary distribution; secondary distribution; customer service; and fuel expenses.[13] Second, the Company classifies these functionalized costs to three separate purposes: customer costs; demand costs; and energy costs.[14] Finally, the Company defines a series of individual allocators to allocate these functionalized and classified costs to individual rate classes.[15]

Q. PLEASE DESCRIBE THE COMPANY'S COST ALLOCATION METHODOLOGY FOR PRODUCTION DEMAND-RELATED COSTS.

A. The Company classifies all fixed costs associated with production plant assets as 100 percent demand-related. The Company then utilizes the average class contribution to coincident system peak during the four summer months, June through September ("4CP"), of the test year to allocate these costs to various rate classes.[16] The Company notes it examined system monthly peak load data for the years 2010-2023 and found that its system peak loads failed at least two of the three tests used by the FERC to examine the appropriateness of 12CP measures of demand in each of the last six years (i.e. 2018-2023), with the Company's system peak loads failing all three tests in each of the last four years (i.e. 2020-

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[13] Direct Testimony of John D. Taylor, at 10, ll.1-2.
[14] *Id.* at 10:9-13.
[15] *Id.* at 11:16 to 12:13.
[16] *Id.* at 21:19 to 22:3.

2023).[17] The Company concluded from this finding that a 4CP peak demand measure was thus more appropriate than examining average contributions to each monthly coincident peak, i.e. "12CP".[18]

Q. PLEASE DESCRIBE THE COMPANY'S COST ALLOCATION METHODOLOGY FOR TRANSMISSION DEMAND-RELATED COSTS.

A. Similar to the Company's approach to fixed costs associated with production plant assets, the Company classifies all fixed costs associated with transmission plant assets as 100 percent demand-related. However, the Company allocates these costs based on 12CP.[19]

Q. PLEASE EXPLAIN HOW THE COMPANY CLASSIFIES ITS DISTRIBUTION PLANT INVESTMENTS.

A. The Company classifies all distribution plant investment costs as either customer- or demand-related, or a combination of these two factors.[20] The Company utilized a Minimum System Study ("MSS") to define a portion of secondary distribution system costs associated with utility poles (FERC Account 364), overhead conductors (FERC Account 365), underground conductors (FERC Account 366), and underground conduit (FERC Account 367) as partially customer-related, while classifying all other non-customer-related distribution as fully demand-related.[21]

Q. HAVE YOU EXAMINED THE COMPANY'S ACOSS RESULTS?

A. Yes. Attachment MWD-2 presents the results of the Company's ACOSS, which

[17] *Id.* at 22:10-13.
[18] *Id.* at 22:14-15.
[19] *Id.* at 22:3-5.
[20] *Id.,* Attachment 16-C.
[21] *Id.* at 20:11-18; and Attachment 16-E.

estimates an overall test year rate of return ("ROR") at current rates of 4.15 percent. Estimated individual class returns range from 0.03 percent for the Street Lighting class to 21.54 percent for the Renewable-Station Power class. The Residential Single-Family ("RS-511") rate class is estimated by the Company to have achieved an ROR of 0.56 percent during the test year under current rates, which is 0.13 of the system average on a relative rate of return ("RROR") basis.

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED ACOSS?

A. Yes. I disagree with the Company's classification of fixed production costs as exclusively demand-related. I also disagree with the Company's reliance on the results of its MSS to classify secondary distribution plant assets as being partially customer-related. I will discuss each of these disagreements in greater detail in the following sections of my testimony.

C. Classification of Production Plant

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES AND ALLOCATES PRODUCTION PLANT COSTS.

A. The Company classifies 100 percent of its fixed production plant costs as being demand-related and allocates all of such costs using each class's test year 4CP demand.[22]

Q. PLEASE EXPLAIN THE CONCERNS YOU HAVE WITH THIS COST ALLOCATION PROCESS.

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[22] *Id.* at 21:12-14.

A. I disagree with the Company's classification of production plant assets as only supporting the Company's maximum system demands. This is inconsistent with the role these production/generation assets play in serving the Company's system requirements and deviates from commonly accepted cost allocation practices. Furthermore, the Company's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets that provide limited capacity benefits.

Q. HOW DOES THE COMPANY'S ALLOCATION OF PRODUCTION PLANT DEVIATE FROM COMMONLY ACCEPTED COST ALLOCATION PRACTICES?

A. EGUs are typically viewed as serving both energy and demand/capacity needs of a utility. The exact degree of this demand/energy split, however, varies by individual utility depending on its composition of generation plants and the role each generating plant plays in system dispatch. Historically, "baseload" generation units were used to serve steady, consistent, multi-hour energy loads, whereas natural gas turbines and other "peakers" were used as demand changed in any given day. It is not uncommon, therefore, to develop composite energy and demand allocators that represent this mixed use and classification.

Q. HAVE OTHER REGULATORY AGENCIES RECOGNIZED THIS JOINT ENERGY AND DEMAND ROLE FOR PRODUCTION PLANT ASSETS?

A. Yes. Other regulatory agencies, such as the Michigan Public Service Commission ("MPSC"), have recognized that energy loads are an important contributing factor to production plant costs and classify a portion of these production costs as energy-related.[23] As an example, in a 2015 review of cost of service allocations for DTE Electric Company ("DTE Electric"), the MPSC explained that utilities do not directly design generation to meet the needs of their various customer types for only a few hours of the year, but rather, utilize a variety of generators to both provide sufficient capacity and provide low-cost energy to customers.

> The Commission agrees with the Staff, the Attorney General, Energy Michigan, and [Environmental and Consumer Advocates] that DTE Electric's production system was not designed and built solely for the purpose of providing capacity for four hours a year. Indeed, if that were the case, DTE Electric's generation asset portfolio would be very different and would certainly include far fewer of the large base load units that comprise much of the company's current fleet. Instead of building a system to simply meet demand, the company developed its production plant to both deliver energy and provide capacity at the lowest <u>overall</u> cost to <u>all</u> customers who use the system. Thus, DTE Electric's generating system includes a mix of base load plants that were significant investments, but that provide abundant, reliable, and low-cost energy to all customers, and peaking plants, with low fixed production costs and typically higher fuel costs than the base load units. These peaking plants are the units that are used to meet peak demand in the summer months.[24]

Q. CAN YOU PROVIDE SOME EXAMPLES OF COMMONLY USED CLASSIFICATION METHODS THAT REFLECT THE DIVERSITY OF PRODUCTION PLANT USE?

A. Yes. Examples of these composite energy and demand allocators include the Average and Peak ("A&P") cost allocation methodology, also called the Peak and

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[23] *In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11 (3) et seq., with regard to DTE Electric Company*, Case No. 17689, Opinion and Order, dated June 15. 2015.
[24] *Id*.

Average cost allocation methodology, and the Average and Excess ("A&E") cost allocation methodology.

Q. EXPLAIN HOW THE A&P METHOD CLASSIFIES PRODUCTION PLANT COSTS.

A. The A&P method is a subset of the larger category of production plant cost allocation methods categorized by the NARUC Electric Utility Cost Allocation Manual as "Judgmental Energy Weightings."[25] The A&P method has two components. The first component, referred to as the "average" component, represents each customer class's average hourly energy consumption throughout the test year and is calculated by simply dividing annual energy consumption for each customer class by 8,760, the number of hours in a year. The second component, referred to as the "peak" component, represents each class's contribution to system peak demand. Judgment is used to determine the appropriate weighting of each of these two components,[26] though one empirical way in which these weightings can be derived is based on a utility's system load factor. In this way the average component is weighted by the utility's overall system load factor, while the excess component is weighted by the inverse of the system load factor (i.e., one minus the system load factor).

Q. HAVE YOU CALCULATED THE SYSTEM LOAD FACTOR FOR THE COMPANY?

[25] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC"), pp. 57-59.
[26] *Id.* at p. 57.

A. Yes. Attachment MWD-3 shows the Company's system load factor for 2023 using the 4CP measure of peak demand. My analysis shows the Company's system load factor is 60.4 percent when using a 4CP measure of peak demand.

Q. ARE THE RESULTS OF YOUR ANALYSIS TIME-SPECIFIC?

A. No. Attachment MWD-3 shows the historic trends in the Company's system load factors for the five-year period 2019 through 2023, which tend to be relatively stable, between 60.0 and 63.2 percent.

Q. HAS THE COMPANY ESTIMATED SIMILAR SYSTEM LOAD FACTORS FOR THE 2025 TEST YEAR?

A. Yes. As shown in Attachment MWD-4, the Company forecasts a 2025 Test Year system load factor of 43.8 percent when using a 4CP measure of peak demand.

Q. WHAT DO THE COMPANY'S HISTORIC AND PROJECTED SYSTEM LOAD FACTORS IMPLY?

A. The results of the analyses presented in Attachment MWD-3 and Attachment MWD-4 suggest the current classification of fixed production costs as 100 percent demand is too heavily weighted towards demand considerations relative to energy, when compared to the Company's actual reported data.

Q. ARE THERE WAYS TO EMPIRICALLY ASSESS THE FUNCTION INDIVIDUAL GENERATION UNITS PROVIDE TO A UTILITY'S ELECTRICAL SYSTEM?

A. Yes. The most basic method is an examination of each individual unit's "capacity factor." The capacity factor is a measure of a generation plant's utilization. Units with high capacity factors are said to be operating at high utilization (like a baseload generation plant), whereas units with low capacity factors are typically held in reserve to meet peak loads that are typically stimulated by weather.

Q. HAVE YOU ANALYZED THE COMPANY'S GENERATOR-SPECIFIC CAPACITY FACTORS?

A. Yes. Attachment MWD-5 presents the results of an analysis associated with each of the Company's EGUs during the 2023 historic Test Year to characterize the role each unit serves in the Company's dispatch of electricity. All facilities with annual capacity factors less than 10 percent were assumed to be fully classified as serving the utility's demand requirements, while most other facilities were divided between energy and demand classifications. This means the Company's Sugar Creek facility, which had a 34.8 percent capacity factor during 2023, was classified as 34.8 percent energy-related and 65.2 percent demand-related.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF THE RELATIVE CLASSIFICATION OF INDIVIDUAL COMPANY GENERATION UNITS?

A. Attachment MWD-5 finds that 12.8 percent of the Company's 2023 gross plant in service is appropriately classified as being energy-related, and 87.2 percent is appropriately classified as being demand-related. Importantly, the Company plans to retire its two current RM Schahfer units and two of its three Michigan City coal-fired steam units by its 2025 Test Year. Excluding steam EGUs results in forecasted gross plant in service that is appropriately classified as 25.4 percent energy-related and 74.6 percent demand-related. The Company's methodology, however, would classify 100 percent of this gross generation plant in service as necessary to meet its peak demand requirements, regardless of how those units are typically utilized.

Q. ARE THERE OTHER WAYS TO ANALYZE GENERATION FUNCTIONS?

A. Yes. Besides examining individual capacity factors, one can also examine the levelized cost of each generation unit relative to established market analyses. For instance, Attachment MWD-6 presents the results of an analysis that examines the levelized annual cost for each of the Company's non-renewable EGUs compared with the "Cost of New Entry" ("CONE") prices estimated by MISO in its most recent Planning Resource Auction ("PRA") for planning year 2024-2025.[27] All costs less than the MISO CONE price can be classified as demand-related whereas prices above the MISO CONE price can be classified as energy-related.

Q. WHAT ARE THE RESULTS OF YOUR CONE ANALYSIS?

A. Attachment MWD-6 finds that, at most, 81.0 percent of the Company's non-renewable production plant in service in 2023 could be classified as being associated with the provision of demand functions. This again is significantly different than the Company's proposed methods, which classify 100 percent of its production plant as demand-related.

Q. ARE THERE OTHER CONCERNS WITH THE COMPANY'S CLASSIFICATION OF ALL FIXED COSTS ASSOCIATED WITH ITS PRODUCTION PLANT ASSETS AS 100 PERCENT DEMAND-RELATED?

A. Yes. The Company's classification of all fixed costs associated with its production plant assets as 100 percent demand-related ignores the significant portion of the

[27] Planning Resource Auction Results for Planning Year 2024-25 (April 25, 2024), MISO.

Company's production plant in service for the 2025 Test Year that is related to renewable EGUs. As stated previously, the composition of generation plants and the role each generating plant plays in system dispatch contribute to the classification of the assets for ACOSS purposes. Renewable generation facilities provide limited capacity service for a utility, mainly providing energy service.

Q. HAVE YOU EXAMINED THE COMPOSITION OF THE COMPANY'S PRODUCTION PLANT ASSETS?

A. Yes. Attachment MWD-7 examines the individual units comprising the Company's 2023 historic and 2025 forecasted Test Year production plant in service, including the unit, primary fuel, and gross and net plant in service. This analysis shows that zero percent of the Company's historic 2023 net plant in service was associated with non-hydro renewable generation resources; however, 77.5 percent of the Company's forecasted 2025 Test Year net plant in service is anticipated to be associated with non-dispatchable solar renewable generation resources.

Q. HAS THE UNIQUE ROLE OF RENEWABLE GENERATION ASSETS BEEN RECOGNIZED BY OTHER REGULATORY COMMISSIONS?

A. Yes. The Iowa Utilities Commission ("Iowa Commission"), previously known as the Iowa Utility Board, in a March 2014 Order involving the MidAmerican Energy Company found that demand-based allocations assume, as a basic premise, that all generation is built to meet peak demand, but this is not the case when examining renewable generation such as wind generators.[28] The Iowa Commission noted that at the time the average capacity accreditation for wind

[28] *In Re: MidAmerican Energy Co.,* Iowa Utilities Board Docket No. RPU-2013-0004, Order Approving Settlement, With Modifications, and Requiring Additional Information dated March 17, 2014, at 83.

generation by MISO was 14 percent, meaning 86 percent of nameplate capacity associated with these generators cannot be used to fulfill MISO's resource adequacy requirements.[29] The Iowa Commission thus found that allocating renewable generation using demand-based allocations produced unreasonable results compared to approaches that assume these resources are available to meet demand at all times.[30]

Q. ARE YOU AWARE OF OTHER COST OF SERVICE STUDIES SUPPORTED BY ELECTRIC DISTRIBUTION COMPANIES THAT HAVE RECOGNIZED THE NEED TO DISTINGUISH BETWEEN RENEWABLE AND NON-RENEWABLE GENERATION ASSETS?

A. Yes. In a November 4, 2022, rate case filing with the Montana Public Service Commission ("MPSC"), Montana-Dakota Utilities Company ("MDU") included an allocated cost of service study that recognized the need to distinguish between renewable and non-renewable generation assets.[31] Specifically, MDU estimated the demand-related portion of its renewable production plant assets separately from its fossil fuel production plant assets by examining the ratio of accredited Zonal Resource Credits ("ZRC") from MISO, compared to the asset's nameplate capacity.[32] A similar process has been used in a recent rate case filing by Interstate Power and Light ("IPL") before the Iowa Commission.[33]

[29] *Id*.
[30] *Id*.
[31] *In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electrical Service*; MPSC Docket No. 2022.11.099; Application at Schedule L-2 and Direct Testimony of David E. Dismukes at 17:16 to 18:5.
[32] *Id.* at 18:9-17.
[33] *In Re: Interstate Power and Light Company,* Iowa Utilities Board Docket No. RPU-2023-0002, Direct Testimony of Lucas Bressan at 11:9-19.

Q. HAS ANY WITNESS ASSOCIATED WITH AN INDIANA UTILITY SUPPORTED THE NEED TO DISTINGUISH BETWEEN RENEWABLE AND NON-RENEWABLE GENERATION ASSETS?

A. Yes. Company witness John D. Taylor submitted testimony in a previous proceeding before the Commission arguing that renewable resources contain a "swapping of steel for fuel" aspect and that the Effective Load Carrying Capability ("ELCC", i.e. the accredited capacity) of intermittent renewable resources is low and will decline further as renewable penetrations increase.[34] Mr. Taylor further agreed that it is appropriate to classify a portion of renewable generation resources as energy-related, and specifically, that a method relying on capacity accreditation for individual renewable resources would be the correct approach to implement this classification.[35]

> While the system is planned as a single, integrated system, intermittent renewable resources have distinct characteristics which require the examination and allocation of those resources independent of the firm, dispatchable resources on the CEI South system. As I alluded to earlier, there is a "swapping of steel for fuel" aspect associated with renewable resources and the ELCC of intermittent renewable resources is low and will further decline as the penetration increases. The former (swapping steel for fuel) also aligns well contextually with the fuel symmetry associated with traditional fossil plants that the [Iowa Commission] has recognized when classifying all fixed plant as demand related then allocating the corresponding costs to the average of customer demands in the requisite hours that best reflect those currently driving investment in capacity, and allocating average fuel to classes on an average energy basis… <u>Consequently, it would be appropriate to classify and/or allocate a portion of those resources using an energy measure. This aligns</u>

[34] Cause No. 45990, Rebuttal Testimony of John D. Taylor at 16:14-16.
[35] *Id.* at 16:11 to 17:1.

> with the MidAmerican case that is referenced by OUCC Witness Dismukes (though care must be taken as the MidAmerican system is at a far greater penetration of renewable resources and this is a distinguishing factor that must be considered in planning and operations, and so it must in cost allocation as well).[36]

Q. DO REGIONAL TRANSMISSION ORGANIZATIONS PROVIDE GUIDANCE ON RENEWABLE ACCREDITATION METHODOLOGY FOR SOLAR RENEWABLE GENERATION UNITS?

A. Yes. MISO's current process for accrediting solar photovoltaic resources, for example, is based on three years of historical average output for hours ending 15, 16, and 17 eastern standard time ("EST") for the most recent spring, summer, and fall months and hours ending 8, 9, 19, and 20 EST for the most recent winter months.[37] New solar resources are accredited at 50 percent of nameplate capacity for spring, summer, and fall months and at 5 percent of nameplate capacity for winter months.[38] As shown in Confidential Attachment MWD-8, the Company provided expected accredited capacities for each of its four owned solar generation resources, which generally correspond to MISO's guidance that new solar resources be accredited at 50 percent of nameplate capacity.

Q. HAVE YOU ANALYZED THE PORTION OF TEST YEAR PRODUCTION PLANT THAT SHOULD BE CLASSIFIED AS 100 PERCENT ENERGY-RELATED?

A. Yes. Based on the information contained in Attachment MWD-7 and Confidential Attachment MWD-8, I find that 45.2 percent of the Company's test year net plant

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[36] Cause No. 45990, Rebuttal Testimony of John D. Taylor at 16:11 to 17:1 (emphasis added).
[37] Resource Accreditation White Paper (November 2023), Midcontinent Independent System Operator, version 1.1 at 12.
[38] *Id*.

in service should be classified as 100 percent energy-related with the remainder classified as serving joint demand and energy functions.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CLASSIFICATION OF COSTS RELATED TO PRODUCTION PLANT?

A. I recommend the Commission reject the Company's proposal to classify all production plant assets as being 100 percent demand-related. The Company's proposal is inconsistent with customer demands placed on the Company's system, inconsistent with the function generation serves as recognized by the Commission and other regulatory commissions in the past, and inconsistent with the capacity accreditation of the Company's renewable generation facilities. Instead, I recommend the Commission rely on the results of my alternative ACOSS which (1) classifies costs associated with the Company's renewable generation assets as fully energy-related based on accredited capacity, and (2) uses an A&P method to classify the remaining production plant costs based on the Company's observed test year system load factor. My proposed classification method classifies 67.6 percent of the Company's production plant costs as being energy-related, with the inverse (32.4 percent) being classified as demand-related for the test year.

D. Use of a Minimum System Study to Classify Distribution Plant Costs

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES THE CUSTOMER AND DEMAND COMPONENTS OF ITS SECONDARY-VOLTAGE DISTRIBUTION PLANT COSTS.

A. The Company conducted an MSS to determine the customer-related component of secondary-voltage distribution system costs included in FERC Account 364 –

Overhead Electric Poles; FERC Account 365 – Overhead Conductors; FERC Account 366 – Underground Conductors; and FERC Account 367 – Underground Conduits.[39] Attachment MWD-9 presents a summary of the results of the Company's MSS. The Company's MSS customer-related classification ranges from a low of 36.5 percent (FERC Account 365) to a high of 73.5 percent (FERC Accounts 366 and 367).[40]

Q. PLEASE EXPLAIN THE THEORETIC BASIS FOR A "MINIMUM SYSTEM" STUDY OR ANALYSIS.

A. Such studies are often advocated by those holding the view that higher level distribution plant investments are made to serve a dual-nature: one consisting of meeting system load requirements, the other being focused on customer interconnection or access that requires a customer-based allocation component. This minimum system component is determined through an MSS or a related Zero-Intercept Study.

Q. WHAT ARE MSS AND ZERO-INTERCEPT STUDIES?

A. MSS and zero-intercept studies are cost allocation methodologies that attempt to estimate separate customer-related versus load-related costs. An MSS does this by estimating the hypothetical costs of developing a "minimum" system that only provides customers with connection to a utility's electric distribution system but not a system sufficient to actually serve the customer's electrical requirements. Likewise, a zero-intercept study utilizes regression analysis techniques to estimate the relationship between the electric demand requirements on a system and costs

[39] Direct Testimony of John D. Taylor, 20:11-18; and Attachment 16-E.
[40] *Id*. Attachment 16-E.

associated with installation of new distribution plant assets. Using these regression analyses, a zero-intercept study then calculates a hypothetical minimum cost by calculating the costs of the distribution plant assets given zero demand requirements.

Q. PLEASE DESCRIBE THE MECHANICS OF AN MSS.

A. Many distribution system assets can be classified as having both a customer and an energy component. For instance, distribution substations are built to serve customers but are often expanded to meet increases in customer loads. An MSS study attempts to separate the customer-related portion of total system costs from those associated with serving loads (or service volumes). An MSS study estimates the hypothetical costs of developing a minimum system to serve customers with no load. These calculations involve subjectivity since they use accounting and engineering analyses to develop assumptions about the minimum sizes and costs associated with various distribution system components, while still satisfying system requirements such as pole height and efficient conductor and transformer sizes. The costs associated with these "minimum" components are then added together to derive the total minimum costs associated with the hypothetical system with no energy usage. This estimate is then divided by total actual system costs to approximate the customer-related share of overall distribution system costs.

Q. ARE THERE ANY THEORETICAL SHORTCOMINGS TO USING MSS AND ZERO-INTERCEPT STUDIES FOR CLASSIFICATION OF DISTRIBUTION PLANT ASSETS?

A. Yes. Both MSS and zero-intercept studies depend on deeply flawed counterfactual theoretical premises. MSS-based analyses deal in hypotheticals that do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the world that could or would be plausibly built to serve customers but not load. No such system exists, making the underlying assumptions and modeling of a "minimum system" difficult, if not impossible, to verify. Even if a minimum electric distribution system could be constructed in real life, it would still have the ability to service at least a portion of customers' loads, undermining this modeling approach's fundamental premise.

Q. DOES THE NARUC COST ALLOCATION MANUAL RECOGNIZE THESE CHALLENGES?

A. Yes. The NARUC Electric Cost Allocation Manual ("NARUC Manual") recognized this fundamental failing of MSS approaches in its discussion of the approach.

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[41]

Q. WHAT ARE THE THEORETICAL FAILINGS OF ZERO-INTERCEPT BASED STUDIES?

A. A zero-intercept-based approach is simply a statistically based MSS approach and suffers, conceptually, from the same shortcomings. A zero-intercept analysis attempts to model an empirical relationship that does not exist. One should

[41] Electric Utility Cost Allocation Manual (January 1992), NARUC, p. 95.

recognize that the argument that electric distribution costs are related to the number of customers on a utility's system is not a new argument, and the academic literature in utility regulation has questioned for quite some time the use of both MSS and zero-intercept studies.

Q. HOW HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

A. Dr. James Bonbright, in his seminal work on public utility regulation, published originally in the 1970s, raises a number of questions about the use of MSS and zero-intercept methodologies in classifying costs. Dr. Bonbright's primary concern was the lack of empirical support in the academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental cost of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the cost to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, a fact inherently ignored by MSS and Zero-Intercept methodologies.

> …the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum distribution costs] inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution

> system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[42]

Q. WHAT WAS DR. BONBRIGHT'S CONCLUSION REGARDING THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

A. Dr. Bonbright found attempts to classify costs associated with a minimum-sized distribution system, whether determined through the use of an MSS or a Zero-Intercept Study, as something other than demand-related as potentially of merit. However, he ultimately concluded that classifying these costs as customer-related as NIPSCO has done in the current proceeding is "clearly indefensible,"[43] due to the lack of a relationship between changes in the number of customers on a utility system and its distribution costs.

Q. IS A SIGNIFICANT PORTION OF THE COMPANY'S PROPOSED CAPITAL INVESTMENT ASSOCIATED WITH GROWTH ACTIVITIES?

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[42] James C. Bonbright, *et al*. Principles of Public Utility Rates. 1988 Edition. Arlington, VA: Public Utilities Reports, Inc., p. 491.
[43] *Id* at 492.

A. No. As shown in Attachment MWD-10, the majority of Company capital investment in 2024 was associated with reliability-related investments. Likewise, the Company anticipates that most of its capital expenditures in 2025 will be associated with investments required to further public policy. Only 12.3 percent of Company capital investment in 2024, and 10.8 percent of expected capital investment in 2025, is associated with investments required to meet growth-related needs.

Q. HAVE YOU QUANTITATIVELY ASSESSED THE HISTORIC CORRELATION BETWEEN INCREASES IN COMPANY DISTRIBUTION PLANT AND INCREASED NUMBER OF CUSTOMERS?

A. Yes. Attachment MWD-11 examines trends between changes in average number of customers on the Company's system and distribution plant accounts 364-367 for the years 2004 through 2023. This analysis finds that additions to the relevant distribution plant accounts are not highly correlated with changes in the Company's average number of customers. Specifically, I estimate the correlation coefficient for the FERC accounts in question to range from negative 0.176 to a positive 0.384. Overall, this demonstrates very weak correlation as observed by Dr. Bonbright decades ago.

Q. HAVE OTHER JURISDICTIONS REJECTED THE USE OF AN MSS?

A. Yes. In 2021, the MPSC rejected a proposal that Consumers Energy be required to submit an MSS in its next rate case.[44] Likewise, in 2010, the Rhode Island Public

[44] *In the Matter of the Application of Consumers Energy Co. for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief*, Case No. U-20963, Order, dated December 22, 2021.

Utilities Commission rejected a request that it require the use of a minimum system study for Narragansett Electric Company D/B/A National Grid.[45]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RELIANCE ON AN MSS TO ALLOCATE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ASSETS?

A. I recommend the Commission reject the Company's proposed MSS approaches in the classification of secondary-voltage distribution plant costs included in FERC Accounts 364-367. MSS and related zero-intercept approaches are fundamentally flawed and provide little to no value as to the just and reasonable setting of rates. Research has shown these methods are flawed, and some state regulatory commissions have gone so far as to expressly reject their use. Further, while MSS is used by some utilities, it is not commonly used by all utilities. Thus, I recommend the Commission appropriately classify assets included in the relevant distribution plant accounts as 100 percent demand-related.

E. Summary of ACOSS Findings

Q. PLEASE SUMMARIZE YOUR ACOSS FINDINGS.

A. Attachment MWD-12 presents the results of my alternative ACOSS which (1) classifies 77.5 percent of costs associated with net production plant in service related to non-dispatchable renewable generation resources based on accredited capacity; (2) utilizes an A&P cost allocation approach to allocate remaining net production plant in service; and (3) appropriately classifies costs associated with secondary-voltage distribution plant accounts included in FERC Accounts 364-367

[45] *In re: the Application of The Narragansett Elec. Co. D/B/A National Grid For Approval of A Change in Electric Base Distribution Rates*, Docket No. 4065, Decision and Order, dated April 29, 2010.

as 100 percent demand-related. My alternative ACOSS shows that the Company's incorrect classification of production plant and secondary-voltage distribution plant assets skews the allocation of costs and revenue responsibilities away from larger customers and onto residential and small commercial customers. I recommend the Commission rely on the results of my alternative ACOSS as a fair and reasonable estimation of the relative costs of service between Company customer classes.

V. REVENUE DISTRIBUTION

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn, is used to establish a new set of retail rates. The revenue distribution process often uses the results from the ACOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their ACOSS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis can result in a very significant and adverse rate impact for under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a set of broad ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. There are several generally accepted rate-making principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the principles I reference above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and resulting rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives.

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO REVENUE DISTRIBUTION.

A. The Company states cost of service was just one of several considerations or criteria the Company reviewed in establishing class revenue requirements.[46] Specifically, the Company considered several criteria related to the design of utility rates: (1) cost of service results, (2) class contributions to present revenue levels and the resulting inter-class subsidies, (3) customer bill impacts, and (4) the Company's belief that moderation should be employed in accomplishing movement towards system-wide ROR parities.[47]

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO ALLOCATE REVENUE REQUIREMENT TO CUSTOMER CLASSES.

A. The Company proposes a seven-factor approach to allocate revenue responsibilities between rate classes.

- (1) The Company proposes to cap individual class revenue increases to no more than 1.5 times the overall system average increase;[48]
- (2) The Company proposes that no class earn more than 1.5 times its current cost of service and that those that do receive a rate decrease;[49]
- (3) The rate increase to the new Residential Single-Family class be set equal to the overall system average increase;[50]
- (4) The rate increase to the new Residential Multi-Family class be set equal to the calculated cost of service;[51]

[46] Direct Testimony of John D. Taylor at 40:7-10.
[47] *Id.* at 42:14 to 43:1.
[48] *Id.* at 43:7-9.
[49] *Id.* at 43:10-11.
[50] *Id.* at 43:12-14.
[51] *Id.* at 43:15 to 44:3.

- (5) The rate increase to the Large Industrial Power Service class be set equal to the calculated cost of service with 164 MW of allocated demand;[52]
- (6) The rate increase for the Railroad class be set equal to the proposed system average increase in compliance with Indiana law;[53]
- (7) The remaining rate increases be equally allocated between remaining rate classes.[54]

Attachment MWD-13 presents the Company's estimated current class relative rates of return ("RROR") and its proposed revenue distribution.

Q. WHAT DO YOU MEAN BY RROR?

A. The RROR effectively standardizes the class-specific ROR estimated by an ACOSS to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR, and further assume that the system-wide average ROR estimated by the same ACOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than 1.0 indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 but

[52] *Id.* at 44:4-6.
[53] *Id.* at 44:7-9.
[54] *Id.* at 44:14 to 45:1.

greater than zero can be said to be making a less-than-average contribution to the overall system.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. Consistent with the principles identified above, there may be policy reasons to support a result that reflects a cross-subsidization. For example, the presence and/or continuation of a RROR below 1.0 could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct a revenue deficiency (relative to cost of service). In this example, the presence of a RROR below 1.0 is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally designed inequity.

Q. WHAT ARE THE CLASS RATE INCREASES UNDER THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. The Company proposes to increase base rates by 20.15 percent on a system-wide average basis. However, under the Company's proposed revenue distribution, Commercial Service-Heat Pumps (Rate 520), Street Lighting (Rate 550), and Area Dusk to Dawn Lighting (Rate 560) would receive a 30.23 percent increase in total rates. This is equal to 1.50 times the proposed system average increase of 20.15 percent.[55] Likewise, Wastewater Pumping (Rate 542) and Station Power-Renewable (Rate 543) would receive rate **reductions** of 1.5 and 4.7 percent respectively.

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[55] *Id.* at 46, Table 3.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTIONS?

A. No. The Company's proposed revenue distributions suffer from major deficiencies. First, the Company's proposal is based on the results of a faulty ACOSS that overstates the extent of any current subsidy from high-load factor industrial customers to low-load factor residential customers. Second, the Company's proposed cap on proposed rate increases of 1.5 times the proposed system average rate increase is inconsistent with rate gradualism. Finally, the Company proposes rate reductions in the context of the current overall system rate increase.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOSS results that also limits the rate increase to any single customer class to 1.15 times the overall system average increase. This, combined with the OUCC's recommended overall revenue increase of 11.25 percent, reduces the maximum total revenue increase to any single rate class to 12.93 percent, compared to the Company's proposed maximum rate increase of 30.23 percent.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. Confidential Attachment MWD-14 presents an illustrative summary of the effects of my proposed revenue distribution combined with the OUCC's recommended revenue increase of 11.25 percent. My proposed revenue distribution would increase base rates for the residential class by 12.93 percent, compared to the Company's proposal, which would increase such rates by 20.10 percent. This recommendation is specifically tied to my ACOSS being adopted and no customer class receiving an increase of more than 1.15 of the system average. Importantly, I recommend against separating the current Residential Service tariff between single and multi-family customers, as discussed in the following section of this testimony.

VI. RATE DESIGN

A. Rate Design Objectives

Q. HOW ARE UTILITY RATES TYPICALLY STRUCTURED?

A. Electric utility rates are typically comprised of three basic elements. The first element is the fixed monthly customer charge, sometimes referred to as a basic service charge or a basic facility charge. The second is the energy-based component that is a volumetric rate applied toward a customer's monthly energy usage during a billing period, often measured in terms of kWh. Finally, demand rates are surcharges assessed based upon a customer's maximum usage during a billing period, commonly measured in terms of kW for those customers that are demand-metered. Historically, some smaller use customer classes, such as residential and small commercial classes, are not demand-metered and thus, only pay customer and energy charges. Customers with only customer and energy charges have bills that are based upon what is commonly called a "two-part tariff" (e.g., energy and customer charge), whereas large demand metered customers face a "three-part tariff" (e.g., energy, customer, and demand charges).

Q. HOW SHOULD POLICY BALANCE COST ASSIGNMENTS BETWEEN CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by the two-part and three-part tariff form, sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs need not serve as the sole or exclusive basis for rates for these to be set optimally (i.e., fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). There are other equally important considerations in setting rates in imperfect markets.

B. Customer Charge Proposals

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S BASIC RESIDENTIAL CUSTOMER CHARGE PROPOSAL.

A. The Company proposes to increase its residential monthly customer charge from $14.00 to $25.00, representing a 78.6 percent increase.[56] The Company also

[56] Direct Testimony of John D. Taylor at 67:14-15.

proposes to increase its small commercial customer charge from $32.50 to $41.40, representing a 27.4 percent increase.

Q. WHAT IS THE BASIS OF THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE INCREASE?

A. The Company claims its proposed residential customer charge increase will support low-income customers and better align with cost causation and efficient pricing.[57] These increased charges reflect a movement toward full customer-related cost responsibility; the Company calculated the per unit cost of customer related costs for a Residential Single-Family customer to be $33.84 per month and $31.78 per month for a Residential Multi-Family customer.[58]

Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Attachment MWD-15, which surveys current residential and small commercial customer charges for major electric utility companies operating in Indiana and surrounding states. The Company's current residential customer charge of $14.00 per month is above the average residential customer charge of $10.90 for other regional utilities. The proposed residential customer charge of $25.00 would require NIPSCO's customers to pay the highest residential customer charge in the region. Similarly, the Company's current small commercial customer charge of $32.50 is above the regional average of $19.48. The Company's proposed commercial customer charge of $41.40 would make it the highest commercial customer charge in the region.

[57] *Id*. at 68:15-69:10.
[58] *Id*. at 68:15-69:10.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE CUSTOMER CHARGE CONSISTENT WITH PROMOTING ENERGY EFFICIENCY AND CONSERVATION?

A. No. The Company's rate design proposal is inconsistent with energy efficiency, since it reduces economic incentives for ratepayers to control their monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable. Indeed, proposals to increase customer charges arguably penalize residential and non-residential customers that have already implemented energy efficiency measures by disproportionately increasing these customers' rates relative to customers who have not implemented energy efficiency measures.

Q. HAVE OTHER REGULATORS RECOGNIZED THE NEGATIVE IMPACTS THAT CUSTOMER CHARGE INCREASES CAN HAVE FOR ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission ("MD PSC") recognized the need to afford customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is

> consistent with and supports our EmPOWER Maryland goals.[59]

Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?

A. Yes. The Montana Public Service Commission ("MT PSC") previously rejected a proposed straight fixed variable rate design for Energy West Montana citing several reasons, including the impact of the proposal on energy conservation efforts. In its decision, MT PSC stated:

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> …
>
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[60]

Q. ARE THERE OTHER REGULATORY EXAMPLES IN WHICH A COMMISSION REJECTED A PROPOSED INCREASE IN FIXED CUSTOMER CHARGES DUE

[59] Maryland Public Service Commission Case No. 9299, *In the Matter of the Application of Baltimore Gas and Elec. Co. for Adjustment in its Electric and Gas Base Rates* (*"Case No. 9299")*. Order No. 85374 at p. 99, rel. February 22, 2013.

[60] *In The Matter of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas*, Montana Public Service Commission, Docket No. D2010.9.90, Order No, 7132c, at 29–30.

TO THE DETRIMENTAL EFFECT ON EFFORTS TO CONSERVE ELECTRICITY?

A. Yes. In 2012, the Missouri Public Service Commission ("MO PSC") rejected Ameren Missouri's proposed increase in the customer charge for residential and small service classes. The Commission expressed opposition to shifting costs from volumetric rates to fixed customer charges because it would send the erroneous message to customers that the Commission is discouraging efforts to conserve electricity:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message...[61]

Q. IS THERE A RECENT EXAMPLE OF A REGULATORY COMMISSION REJECTING A PROPOSED INCREASE IN RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER CHARGES?

A. Yes. In rejecting a request by Northern States Power Company to increase customer charges[62] as part of a larger rate design proposal, the Minnesota Public Utilities Commission ("MPUC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

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[61] Missouri Public Service Commission, Report and Order, *In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service*, File No. ER-2012-0166, December 12, 2012, pages 110-111.

[62] *In re the Appl. of Northern States Power Co., for Authority to Increase Rates for Elec. Serv. in the State of Minn.*, Docket E-002/GR-21-630, Findings of Fact, Conclusions, and Order, at 114 (MPUC July 17, 2023).

> Monthly customer charges are an important component of the Company's Residential and Small General Service rates by facilitating recovery of the costs caused by each customer that do not vary with the amount of energy used. However, higher fixed customer charges discourage customers from conserving energy and investing in renewable energy by reducing the impact of these efforts on the customers' bills. Customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills. The Commission notes that Minn. Stat. §216B.03 requires the Commission to design rates to encourage energy conservation and renewable-energy use to "the maximum reasonable extent." Considering this statutory mandate and the evidence submitted by the parties, the Commission agrees with the ALJ that it is reasonable and appropriate to lower the monthly customer charge for the Residential and Small General Service classes to $ 6.00.[63]

Q. ARE THESE COMMISSIONS ALONE IN THEIR BELIEF THAT HIGH FIXED CHARGES DISCOURAGE EFFICIENT USE OF ENERGY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners ("NARUC") lists a straight-fixed variable ("SFV") rate design as an alternative to decouple utility revenue from sales. An SFV places all fixed costs into fixed charges while relegating only variable costs to volumetric rates. The Company's current customer charge proposal, which attempts to recover an additional level of class revenue responsibilities through the customer charge, regardless of costs, could be thought of as a pricing proposal consistent with these SFV principles. However, the NARUC research noted this type of rate design is problematic because of its effects on customer incentives to conserve energy:

[63] *Id*. at 116-117.

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume</u>.[64]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and the U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that the SFV model had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. <u>While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies</u>. Such customer disincentives persist even when SFV rates are applied to individual

[64] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" Grants & Research Department, National Association of Regulatory Utility Commissioners, at 5 (Sept. 2007) (emphasis added), https://www.maine.gov/mpuc/legislative/archive/2006legislation/DecouplingRpt-AttachC.pdf.

> components of the bill, such as charges for distribution service.[65]

Q. CAN HIGH CUSTOMER CHARGES LEAD TO OTHER PROBLEMS?

A. Yes. In addition to disincentivizing energy efficiency, increased customer charges also shift the rate burden within a customer class to lower-use customers. This results in equity concerns, as lower-use customers have been shown to be associated with lower-income households in empirical research.[66]

Q. HAS THE COMPANY PERFORMED AN ANALYSIS ON THE RELATIONSHIP BETWEEN USAGE AND HOUSEHOLD INCOME?

A. Yes, the Company examined publicly available information from the American Community Survey ("ACS") conducted by the U.S. Census Bureau, which keeps a variety of data, including median household income, on a census tract level.[67] The Company mapped NIPSCO residential electric customers to U.S. census tracts, thus mapping average monthly usage to median household income for the census tract for each NIPSCO residential electric customer.[68] The Company overlaid this analysis with an analysis of low-income customers based on customers taking service on income-qualified rates or who qualify for customer assistance programs.[69]

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[65] Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design, National Action Plan for Energy Efficiency at 13-14, prepared by William Prindle, ICF International, Inc. (Sept. 2009) (emphasis added), https://www.epa.gov/sites/production/files/2015-08/documents/rate_design.pdf.
[66] *See* 2020 Residential Energy Consumption Survey ("RECS"), U.S. Energy Information Administration; *see also* Kontokosta, Constantine, *et al.* (2020), "Energy Cost Burdens for Low-Income and Minority Households," *Journal of the American Planning Association*, Vol. 86 no. 1; and Brown, Marilyn A, *et al.* (March 2020), "Low-Income Energy Affordability: Conclusions from a Literature Review," Oak Ridge National Laboratory.
[67] Direct Testimony of John D. Taylor at 59:4-8.
[68] *Id.* at 59:8-11.
[69] *Id.* at 58:6-13.

Q. WHAT WAS THE COMPANY'S FINDING FROM ITS ANALYSIS OF THE RELATIONSHIP BETWEEN USAGE AND HOUSEHOLD INCOME?

A. The Company claims its analysis revealed that low-income customers in NIPSCO's service territory had a higher baseline usage compared to other residential customers, and that this usage tended to increase a lower rate as a function of median income in each census tract compared to other residential customers.[70]

Q. DO YOU AGREE WITH THE COMPANY'S FINDINGS REGARDING THE RELATIONSHIP BETWEEN USAGE AND HOUSEHOLD INCOME?

A. No. The Company's analysis is fatally flawed in that it conflates information on median household income from the ACS with a separate analysis of low-income customers. Indeed, the Company's analysis includes low-income customers in all census tracts, regardless of the median household income level for the census tract. For example, the Company identifies 18 low-income customers in the highest two income census tracts in NIPSCO's service territory, each with medium household incomes of greater than $150,000 per year. It is doubtful that a household with annual earnings in this range would qualify as 'low-income.'

Q. DO YOU BELIEVE A CORRECTED ANALYSIS OF THE RELATIONSHIP BETWEEN USAGE AND HOUSEHOLD INCOME WOULD FIND THAT LOWER-USE CUSTOMERS TEND TO BE LOWER-INCOME CUSTOMERS?

A. Yes. Indeed, the Company acknowledges that its analysis finds this result to be the case, noting that "[a]s expected, the results of the analysis demonstrate a

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[70] *Id.* at 59:13-16.

positive correlation of usage with income."[71] This result is consistent with other analyses of this question, such as the 2020 EIA Residential Energy Consumption Survey ("RECS"), presented in Attachment MWD-16, which shows that, as a customer's income increases, on average so does monthly electric consumption.

C. Separation of Single and Multi-Family Residential Rates

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED SEPARATION OF RESIDENTIAL RATES.

A. The Company is proposing to separate the residential class rate into Single-Family ("SF") and Multi-Family ("MF") classes, claiming that there are distinctive characteristics for MF residential customers that warrant a separation of rates from SF residential customers.[72] The Company clarifies that this is an intra-class issue, and while "the combined cost responsibility for SF and MF residential customers is the same, the difference is the proportion of that cost responsibility that is attributed and thus recovered through the rates for SF and MF residential customers."[73]

Q. DID THE COMPANY PERFORM AN ANALYSIS TO JUSTIFY ITS PROPOSED SEPARATION OF RESIDENTIAL CLASS RATES?

A. Yes. The Company reviewed individual residential customer billing records, and Atrium Economics separated residential customers into SF and MF and compared monthly usage characteristics between the two groups through a monthly billing analysis.[74] The analysis found there was a significant difference in monthly usage

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[71] *Id.* at 61:5-6.
[72] *Id*. at 50:1-12.
[73] *Id*.
[74] *Id*. at 51:9-13.

between the SF and MF residential customers: SF customers had a higher monthly usage.[75] The analysis also found that MF customers had higher usage and peak demands in the winter months compared to summer months.[76] The Company classified a customer as MF if the customer was currently taking service on a gas multi-family rate or as an electric customer had "APT", "SUITE", or "UNIT" in the service address.[77]

Q. WHAT ARE THE IMPLICATIONS OF THE COMPANY'S MONTHLY BILLING ANALYSIS?

A. The Company's proposed creation of a MF rate was based on the analysis that showed that a new MF residential building would have a lower service cost per meter compared to an equivalent SF individually metered dwelling.[78] The Company also analyzed hourly electric consumption for SF and MF customers, finding that MF customers generally consumed electricity on a more consistent basis over the course of a year and, thus, have a higher load factor when compared to SF customers.[79]

Q. HOW DID THE COMPANY DETERMINE HOURLY LOADS ASSOCIATED WITH SF AND MF CUSTOMERS?

A. The Company relied on 127 load research sample meters deployed at residential service locations throughout its service territory. Of these 127 load research sample meters, 21 were identified as MF customers, with the remaining 106

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[75] *Id*.
[76] *Id*.
[77] *Id*. at 52:5-9.
[78] *Id*. at 57:3-5.
[79] *Id*. at 54, Table 7.

identified as SF customers.[80]

Q. DO YOU HAVE ANY CONCERNS ASSOCIATED WITH THE MONTHLY BILLING ANALYSIS?

A. Yes. I am concerned with the limited data supporting the Company's analysis. A sampling of 127 residential customers represents only 0.03 percent of the Company's total 431,840 residential customers. Furthermore, the Company's claim that MF customers have higher load factors compared to SF customers is based on a study of only 21 MF customers, while the Company estimates that there are approximately 68,195 MF customers on its system.[81]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO SEPARATE SINGLE AND MULTI-FAMILY RESIDENTIAL RATES IN THE CURRENT PROCEEDING?

A. I recommend the Commission deny the Company's request to separate existing residential rates into separate SF and MF rates. The Company's proposal is supported by very limited analysis and research upon customers' load that may not be representative of the Company's actual residential customer base. Furthermore, it is my understanding the Company is currently in the process of installing Advanced Metering Instruments ("AMI") across its service territory, meaning that in a future rate case the Company and the Commission will have the ability to review hourly load curves for a far greater population of Company residential customers than provided in the current proceeding.

[80] *Id*. at 53:6-12.
[81] *Id*. at 53, Table 6.

D. Low Income Program

Q. HAS THE COMPANY PREVIOUSLY PETITIONED FOR APPROVAL OF A LOW-INCOME PROGRAM?

A. Yes. The Commission has repeatedly not approved the Company's alternative Low Income Program proposals in previous cases. NIPSCO first sought approval of such a program in 2015 in Cause No. 44688; however, due to opposition from reporting parties, the Commission did not approve the program, and the settlement reached did not provide for the program.[82] NIPSCO then submitted a request for approval of an electric low income program in Cause No. 45159 and, as detailed in the settlement agreement, the Company committed to request approval of a voluntary low-income program.[83] In Cause No. 45465, NIPSCO proposed an "opt out, round up" program in which all electric customers would automatically participate in the program by having their monthly bill rounded up to the next whole dollar, unless they opted out.[84] The funds from the program were proposed to help low-income customers afford their monthly electric bill. The Commission rejected the proposal for various reasons, including that the program was not voluntary as required by the terms of the Revenue Settlement; concerns that customers were being required to make a contribution they might not have knowledge of, including low-income customers; customers could be required to pay for both the gas Universal Service Program and the electric low income program; the gas Universal Service Program was approved as a result of settlement and, therefore, not

[82] Direct Testimony of Whitehead at 47:14-48:4.
[83] *Id*. at 49:4-9.
[84] *Id*. at 49:12-50:16.

precedential; and concerns over the lack of an annual contribution to the program by NIPSCO.[85] Finally, in its most recent electric rate case, Cause No. 45772, NIPSCO proposed a program in which customers would pay $0.40 per month, with the funds collected to be utilized to reduce low-income customers' electric bills from July to October. However, NIPSCO withdrew the proposal after failing to agree whether an opt-in, opt-out, or non-by-passable program design was best.[86]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED LOW INCOME PROGRAM IN THIS CAUSE.

A. The Company is proposing what NIPSCO characterizes as a Universal Service Program ("USP") rider, referred to as the "Low Income Program", and if the Commission does not approve this rider, the Company requests an alternative regulatory plan.[87] The Company is proposing a nearly identical program to what was proposed in its last electric rate case - a $0.40 per month contribution from all customers.[88] Funds collected will be used to reduce electric bills for low income customers for the billing months of July to October through a flat bill discount, based on different tiers.[89] NIPSCO projects to collect $2.3 million per year through this program and proposes to contribute $400,000 per year as well.[90]

Q. DO YOU HAVE ANY CONCERNS ASSOCIATED WITH THE PROPOSED LOW-INCOME PROGRAM?

A. Yes. First, the Company's Low Income Program proposal has been rejected by

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[85] *Id*. at 49:12-50:16.
[86] *Id*. at 50:19-51:18.
[87] *Id*. at 47:5-11.
[88] *Id*. at 52:17-53:9.
[89] *Id.*
[90] *Id*. at 53:12-17.

multiple parties and the Commission in Cause Nos. 44688, 45159, 45465, and 45772. The Commission has expressed concerns over the proposed program as it amounts to forced charity of non-qualified customers and has raised issues with the design of the program. The Commission's concerns are well placed, and it would be more productive to find ways to mitigate the Company's growing revenue requirement needs rather than recycling proposals designed to shift burdens between customers.

E. Rate Design Recommendations

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RATE DESIGN?

A. I recommend the Commission reject NIPSCO's proposed increases in customer charges because of the disproportionate impact on low-income customers in Indiana. In addition, increases in fixed charges reduce customer price incentives to reduce usage, contrary to public goals of promoting energy efficiency. Likewise, the Commission should not approve the proposed separation of residential customers into single and multi-family rates at this time because of the limited load research data presented, which included only 127 residential customers, or 0.03 percent of NIPSCO's total residential customers. Additional information beyond this limited load research data should be required to support any proposed separation of residential classes in the Company's future cases. Finally, the Commission should also not approve the proposed Low-Income Program because it is designed to shift burdens between residential customers and forces participation from all residential customers. The Company should instead focus on addressing its growing revenue requirements.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED RATE DESIGN?

A. Yes. Attachment MWD-17 presents a summary of current, Company proposed, and my alternative rates resulting from my proposed revenue allocation and rate design.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR ACOSS FINDINGS?

A. My alternative ACOSS analyses show that the Company's incorrect classification of production plant assets and secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I recommend the Commission rely on the results of my alternative ACOSS as a fair and reasonable estimation of relative costs of service between Company customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOSS results that also limits the rate increase to any single customer class to 1.15 times the overall system average increase. This, combined with the OUCC's recommended overall revenue increase of 11.25 percent, reduces the maximum total revenue increase to any single rate class to 12.93 percent, compared to the Company's proposed maximum rate increase of 30.23 percent. *See* Confidential Attachment-MWD-14.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RATE DESIGN?

A. I recommend the Commission reject the proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Likewise, the Commission should deny the separation of residential customers into single and multi-family rates in this Cause because of the limited load research data presented in this Cause, which includes only 127 residential customers, or 0.03 percent of NIPSCO's total residential customers. Additional information beyond the limited load research data should be required and provided to support any proposed separation of NIPSCO's residential classes in the future. Finally, the Commission should deny Petitioner's Low-Income Program as proposed because it is designed to shift burdens between residential customers and mandates participation from all customers. The Company should instead focus on addressing and mitigating its growing revenue requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council – Kansas Corporation Commission

Summer 2008 – Spring 2009	Research Assistant

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1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

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2. Expert Report. (2011). *2011 Kansas Generation Planning Survey*. On behalf of the Kansas Corporation Commission Staff.

3. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

4. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

5. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

6. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

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Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

8. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

9. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.

10. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.

Table of Attachments

Title	Attachment
Comparison of NIPSCO Rates to Regional Peers	Attachment MWD-1
Summary of Results of Company's Proposed COSS	CONFIDENTIAL Attachment MWD-2
NIPSCO Historic System Load Factors, 2019-2023	Attachment MWD-3
NIPSCO Estimated System Load Factor for 2025 Test Year	Attachment MWD-4
Analysis of NIPSCO Electric Generation Unit Capacity Factors	Attachment MWD-5
Analysis of NIPSCO Generation Unit Costs to MISO Estimated Default CONE Price	Attachment MWD-6
Summary of 2023 and 2025 Test Year Electric Generation Units	Attachment MWD-7
Comparison of Nameplate to Accredited Capacity	CONFIDENTIAL Attachment MWD-8
Summary of Company's MSS	Attachment MWD-9
Capital Investment Allocation, 2023-2025	Attachment MWD-10
Correlation of Customers and Distribution Network	Attachment MWD-11
Summary of Results of Alterantive COSS	CONFIDENTIAL Attachment MWD-12
Summary of Company's Proposed Revenue Allocation	CONFIDENTIAL Attachment MWD-13
Summary of Results of Alterantive Revenue Distribution	CONFIDENTIAL Attachment MWD-14
Survey of Regional Customer Charges	Attachment MWD-15
Average Monthly Household Consumption	Attachment MWD-16
Comparison of Current and Proposed Rates	Attachment MWD-17

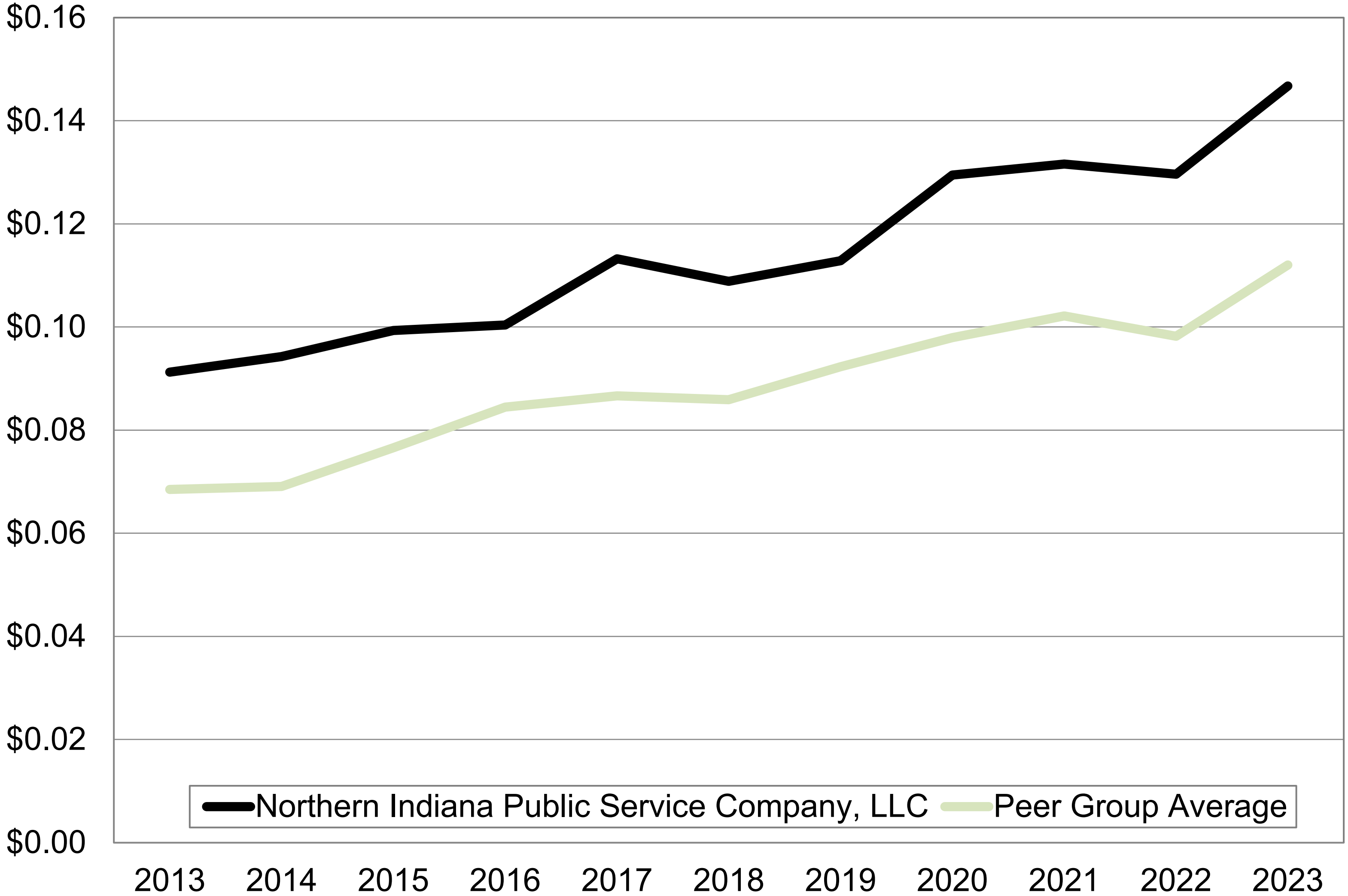
Comparison of NIPSCO Rates to Regional Peers: Residential Class

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($/kWh)										
Northern Indiana Public Service Company, LLC	**$0.091**	**$0.094**	**$0.099**	**$0.100**	**$0.113**	**$0.109**	**$0.113**	**$0.129**	**$0.132**	**$0.130**	**$0.147**
Consumers Energy Co	0.091	0.091	0.097	0.106	0.109	0.108	0.111	0.109	0.127	0.116	0.145
DTE Electric Company	0.117	0.108	0.117	0.129	0.129	0.129	0.136	0.147	0.151	0.143	0.170
Indianapolis Power & Light Co	0.057	0.054	0.061	0.071	0.075	0.075	0.080	0.083	0.085	0.074	0.086
Indiana Michigan Power Co	0.041	0.054	0.064	0.072	0.078	0.085	0.099	0.115	0.115	0.108	0.134
Kentucky Utilities Co	0.058	0.059	0.065	0.070	0.075	0.069	0.077	0.082	0.085	0.087	0.092
Louisville Gas & Electric Co	0.061	0.061	0.070	0.073	0.078	0.073	0.080	0.086	0.085	0.087	0.092
Duke Energy Indiana, LLC	0.068	0.072	0.076	0.078	0.080	0.079	0.083	0.087	0.092	0.084	0.093
Duke Energy Kentucky	0.050	0.046	0.048	0.053	0.053	0.057	0.061	0.064	0.070	0.071	0.079
Kentucky Power Co	0.034	0.035	0.053	0.074	0.074	0.076	0.079	0.082	0.089	0.087	0.097
Southern Indiana Gas & Elec Co	0.110	0.110	0.114	0.117	0.116	0.109	0.118	0.124	0.122	0.124	0.132
Peer Group Average	**$0.069**	**$0.069**	**$0.077**	**$0.084**	**$0.087**	**$0.086**	**$0.092**	**$0.098**	**$0.102**	**$0.098**	**$0.112**

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	(Ranking)										
Northern Indiana Public Service Company, LLC	**9**	**9**	**9**	**8**	**9**	**9**	**9**	**10**	**10**	**10**	**10**
Consumers Energy Co	8	8	8	9	8	8	8	7	9	8	9
DTE Electric Company	11	10	11	11	11	11	11	11	11	11	11
Indianapolis Power & Light Co	4	4	3	3	4	4	5	4	3	2	2
Indiana Michigan Power Co	2	3	4	4	6	7	7	8	7	7	8
Kentucky Utilities Co	5	5	5	2	3	2	2	3	2	6	3
Louisville Gas & Electric Co	6	6	6	5	5	3	4	5	4	4	4
Duke Energy Indiana, LLC	7	7	7	7	7	6	6	6	6	3	5
Duke Energy Kentucky	3	2	1	1	1	1	1	1	1	1	1
Kentucky Power Co	1	1	2	6	2	5	3	2	5	5	6
Southern Indiana Gas & Elec Co	10	11	10	10	10	10	10	9	8	9	7

Source: EIA form 861

Comparison of NIPSCO Rates to Regional Peers: Residential Class



Source: EIA form 861

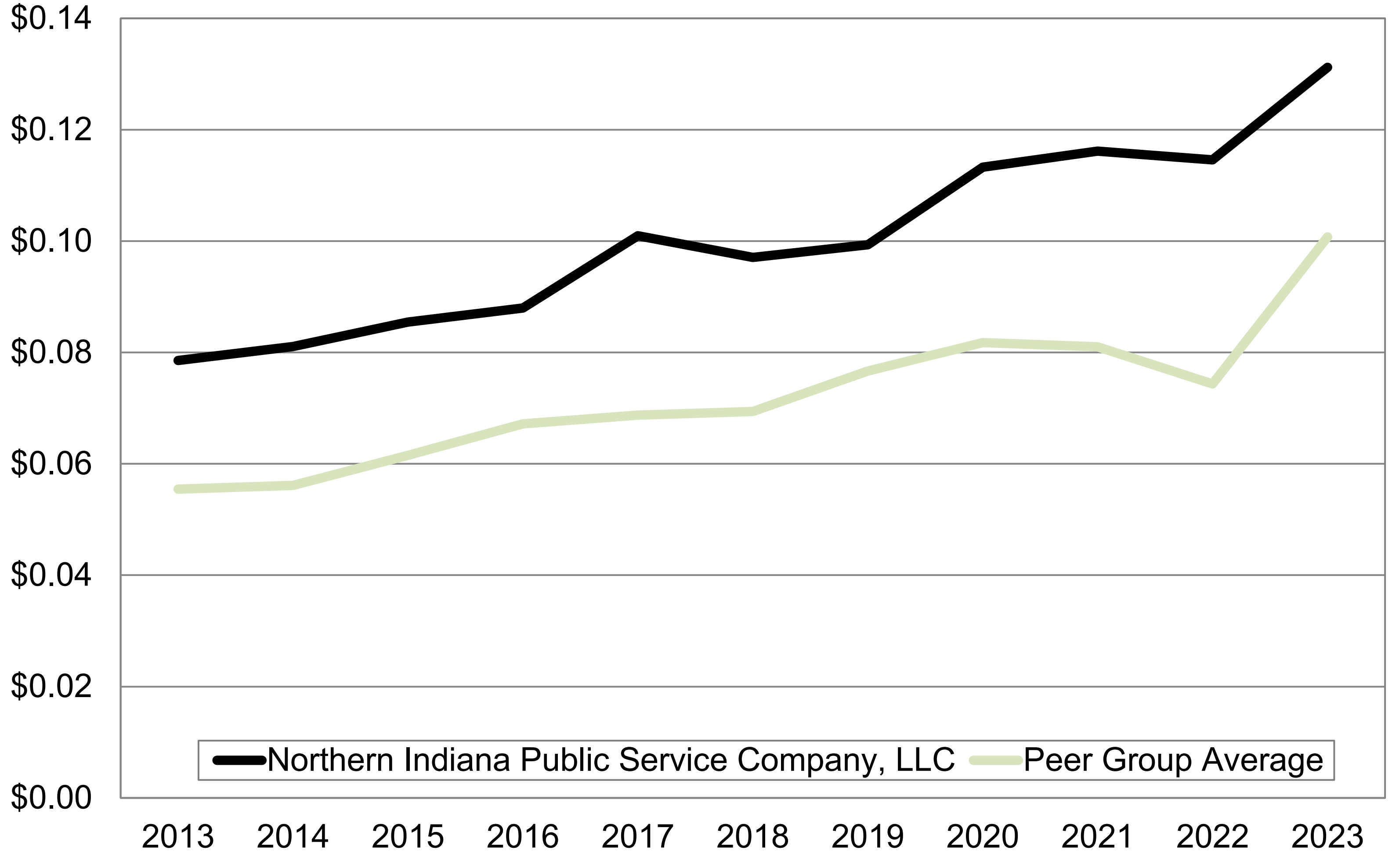
Comparison of NIPSCO Rates to Regional Peers: Commercial Class

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($/kWh)										
Northern Indiana Public Service Company, LLC	**$ 0.079**	**$ 0.081**	**$ 0.085**	**$ 0.088**	**$ 0.101**	**$ 0.097**	**$ 0.099**	**$ 0.113**	**$ 0.116**	**$ 0.115**	**$ 0.131**
Consumers Energy Co	0.068	0.067	0.073	0.074	0.077	0.077	0.083	0.083	0.084	0.071	0.103
DTE Electric Company	0.076	0.067	0.070	0.073	0.076	0.076	0.081	0.085	0.089	0.081	0.115
Indianapolis Power & Light Co	0.065	0.065	0.071	0.081	0.079	0.080	0.090	0.094	0.087	0.079	0.092
Indiana Michigan Power Co	0.024	0.032	0.041	0.049	0.054	0.058	0.069	0.081	0.078	0.070	0.088
Kentucky Utilities Co	0.057	0.059	0.064	0.069	0.073	0.068	0.079	0.086	0.088	0.091	0.136
Louisville Gas & Electric Co	0.053	0.053	0.062	0.064	0.067	0.063	0.071	0.077	0.077	0.079	0.115
Duke Energy Indiana, LLC	0.052	0.055	0.056	0.059	0.060	0.061	0.066	0.070	0.069	0.061	0.096
Duke Energy Kentucky	0.042	0.038	0.037	0.042	0.040	0.048	0.057	0.059	0.054	0.049	0.079
Kentucky Power Co	0.036	0.043	0.056	0.074	0.075	0.078	0.079	0.084	0.087	0.072	0.077
Southern Indiana Gas & Elec Co	0.082	0.083	0.084	0.088	0.088	0.085	0.091	0.099	0.098	0.092	0.108
Peer Group Average	**$ 0.055**	**$ 0.056**	**$ 0.062**	**$ 0.067**	**$ 0.069**	**$ 0.069**	**$ 0.077**	**$ 0.082**	**$ 0.081**	**$ 0.074**	**$ 0.101**

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	(Ranking)										
Northern Indiana Public Service Company, LLC	**10**	**10**	**11**	**10**	**11**	**11**	**11**	**11**	**11**	**11**	**10**
Consumers Energy Co	8	8	9	8	8	7	8	5	5	4	6
DTE Electric Company	9	9	7	6	7	6	7	7	9	8	8
Indianapolis Power & Light Co	7	7	8	9	9	9	9	9	7	7	4
Indiana Michigan Power Co	1	1	2	2	2	2	3	4	4	3	3
Kentucky Utilities Co	6	6	6	5	5	5	5	8	8	9	11
Louisville Gas & Electric Co	5	4	5	4	4	4	4	3	3	6	9
Duke Energy Indiana, LLC	4	5	4	3	3	3	2	2	2	2	5
Duke Energy Kentucky	3	2	1	1	1	1	1	1	1	1	2
Kentucky Power Co	2	3	3	7	6	8	6	6	6	5	1
Southern Indiana Gas & Elec Co	11	11	10	11	10	10	10	10	10	10	7

Source: EIA form 861

Comparison of NIPSCO Rates to Regional Peers: Commercial Class



Source: EIA form 861

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OUCC ATTACHMENT MWD-2
CAUSE NO. 46120

NIPSCO Historic System Load Factors, 2019-2023

	2019	2020	2021	2022	2023
Total MWh Sold	15,713,180	14,620,305	15,607,008	15,170,142	14,776,345
Total Hours in Year	8,760	8,784	8,760	8,760	8,760
Avg. Demand Factor	**1,794**	**1,664**	**1,782**	**1,732**	**1,687**
4 CP Peak Demand	2,838	2,774	2,888	2,822	2,792
System Load Factor	**63.2%**	**60.0%**	**61.7%**	**61.4%**	**60.4%**

Sources: FERC Form 1

NIPSCO's Estimated System Load Factor for 2025 Test Year

Item	Calculation
Monthly Coincident Peak (kW)	
January	2,093,063
Febuary	2,064,468
March	2,070,518
April	1,879,925
May	2,415,886
June	2,571,893
July	2,820,606
August	3,040,850
September	2,707,238
October	2,293,271
November	1,999,219
December	1,949,943
12 CP Average (Jan-Dec)	**2,325,573**
4 CP Average (Jun/Jul/Aug/Sept)	**2,785,147**
Loss-Adjusted Energy at Generation (kWh)	10,683,959,164
Annual Hours	8,760
Average Hourly Demand (kW)	**1,219,630**
12 CP Load Factor	**52.44%**
4 CP Load Factor	**43.79%**

Sources: Taylor NIPSCO Electric External Allocators_2024_WORKPAPERS, Tab "CP Summary"

Analysis of NIPSCO's Electric Generation Unit Capacity Factors

Witness: Deupree
Cause No. 46120
Attachment MWD-5

Station Name	Plant Type	Nameplate Capacity (MW)	2023 Net Generation (MWh)	Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
RM Schahfer	Steam	1,943	1,536,668	9.03%	0.00%	100.00%	$ -	$ 1,452,873,251	$ 1,452,873,251
Michigan City	Steam	540	1,426,731	30.16%	30.16%	69.84%	260,204,406	602,516,684	862,721,090
Sugar Creek	Combine Cycle	620	1,889,625	34.79%	34.79%	65.21%	72,415,686	135,723,006	208,138,692
RM Schahfer	Combustion Turbine	258	19,207	0.85%	0.00%	100.00%	-	77,193,119	77,193,119
Subtotals:							**$ 332,620,093**	**$ 2,268,306,059**	**$ 2,600,926,152**
					Production Plant Classification:		**12.8%**	**87.2%**	**100.0%**

Sources: FERC Form 1

Analysis of NIPSCO Generation Unit Costs to MISO Estimated CONE Price

Witness: Deupree
Cause No. 46120
Attachment MWD-6

Station Name	Plant Type	Estimated Service Life	Nameplate Capacity (MW)	Total Plant in Service	Fixed Cost ($/year)	Variable Costs ($)	Levelized Cost ($/kW-year)	MISO CONE Zone 6 ($/MW-day)	MISO CONE Zone 6 ($/kW-year)	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
RM Schahfer	Steam	17.0	1,943	1,452,873,251	85,675,546	161,697,237	127	329.70	120.34	5.48%	94.52%	79,589,048	1,373,284,203	1,452,873,251
Michigan City	Steam	17.0	540	862,721,090	50,874,432	74,270,876	232	329.70	120.34	48.07%	51.93%	414,738,211	447,982,879	862,721,090
Sugar Creek	Combine Cycle	17.0	620	208,138,692	12,273,883	36,742,211	79	329.70	120.34	0.00%	100.00%	-	208,138,692	208,138,692
RM Schahfer	Combustion Turbine	43.9	258	77,193,119	1,759,661	1,846,063	14	329.70	120.34	0.00%	100.00%	-	77,193,119	77,193,119
Subtotals:												**$ 494,327,259**	**$2,106,598,893**	**$2,600,926,152**
											Production Plant Classification:	**19.01%**	**80.99%**	**100.00%**

Sources: FERC Form 1 and CONE Price

Summary of 2023 and 2025 Test Year Electric Generation Units: 2023 Test Year

Unit Name	Primary Fuel	Renewable (Y/N)	Net Plant ($000)	Percent of Total (%)
Michigan City Units 2, 3 and 12	Coal	N	$ 403,730	42.0%
Schahfer Units 14, 15, 17 and 18	Coal	N	232,988	24.2%
Total Coal			**$ 636,718**	**66.2%**
Sugar Creek Generating Unit	Natural Gas	N	$ 177,139	18.4%
Schahfer Units 16A and B	Natural Gas	N	60,287	6.3%
Total Natural Gas			**$ 237,426**	**24.7%**
Norway Hydro	Hydro	Y	$ 41,876	4.4%
Oakpark Hydro	Hydro	Y	45,085	4.7%
Total Hydro			**$ 86,961**	**9.0%**
Fairbanks Solar	Solar	Y	$ -	0.0%
Gibson Solar	Solar	Y	-	0.0%
Cavalry Solar Plus Storage	Solar/Battery	Y	-	0.0%
Dunns Bridge Solar Plus Storage	Solar/Battery	Y	-	0.0%
Total Solar			**$ -**	**0.0%**
Total Generation Plant			**$ 961,106**	**100.0%**

Sources: Company's Response to OUCC 13-34, Attachments A and B.

Summary of 2023 and 2025 Test Year Electric Generation Units: 2025 Test Year

Unit Name	Primary Fuel	Renewable (Y/N)	Net Plant ($000)	Percent of Total (%)
Michigan City Unit 12	Coal	N	$ 266,561	10.4%
Schahfer Units 17 and 18	Coal	N	(26,880)	-1.0%
Total Coal			**$ 239,681**	**9.3%**
Sugar Creek Generating Unit	Natural Gas	N	$ 182,620	7.1%
Schahfer Units 16A and B	Natural Gas	N	76,390	3.0%
Total Natural Gas			**$ 259,009**	**10.1%**
Norway Hydro	Hydro	Y	$ 38,920	1.5%
Oakpark Hydro	Hydro	Y	41,117	1.6%
Total Hydro			**$ 80,037**	**3.1%**
Fairbanks Solar	Solar	Y	$ 470,387	18.3%
Gibson Solar	Solar	Y	389,439	15.1%
Cavalry Solar Plus Storage	Solar/Battery	Y	379,525	14.7%
Dunns Bridge Solar Plus Storage	Solar/Battery	Y	757,219	29.4%
Total Solar			**$ 1,996,569**	**77.5%**
Total Generation Plant			**$ 2,575,296**	**100.0%**

Sources: Company's Response to OUCC 13-34, Attachments A and C.

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OUCC ATTACHMENT MWD-8

CAUSE NO. 46120

Summary of Company's MSS

FERC Account	Classification	
	Customer	Demand
Secondary Poles, Towers and Fixtures		
FERC Account 364	56.7%	43.3%
Secondary Overhead Conductors and Devices		
FERC Account 365	36.5%	63.5%
Secondary Underground Conduit		
FERC Account 366	73.5%	26.5%
Secondary Underground Conductors and Devices		
FERC Account 367	73.5%	26.5%

Source: Petitioner's Exhibit No. 16

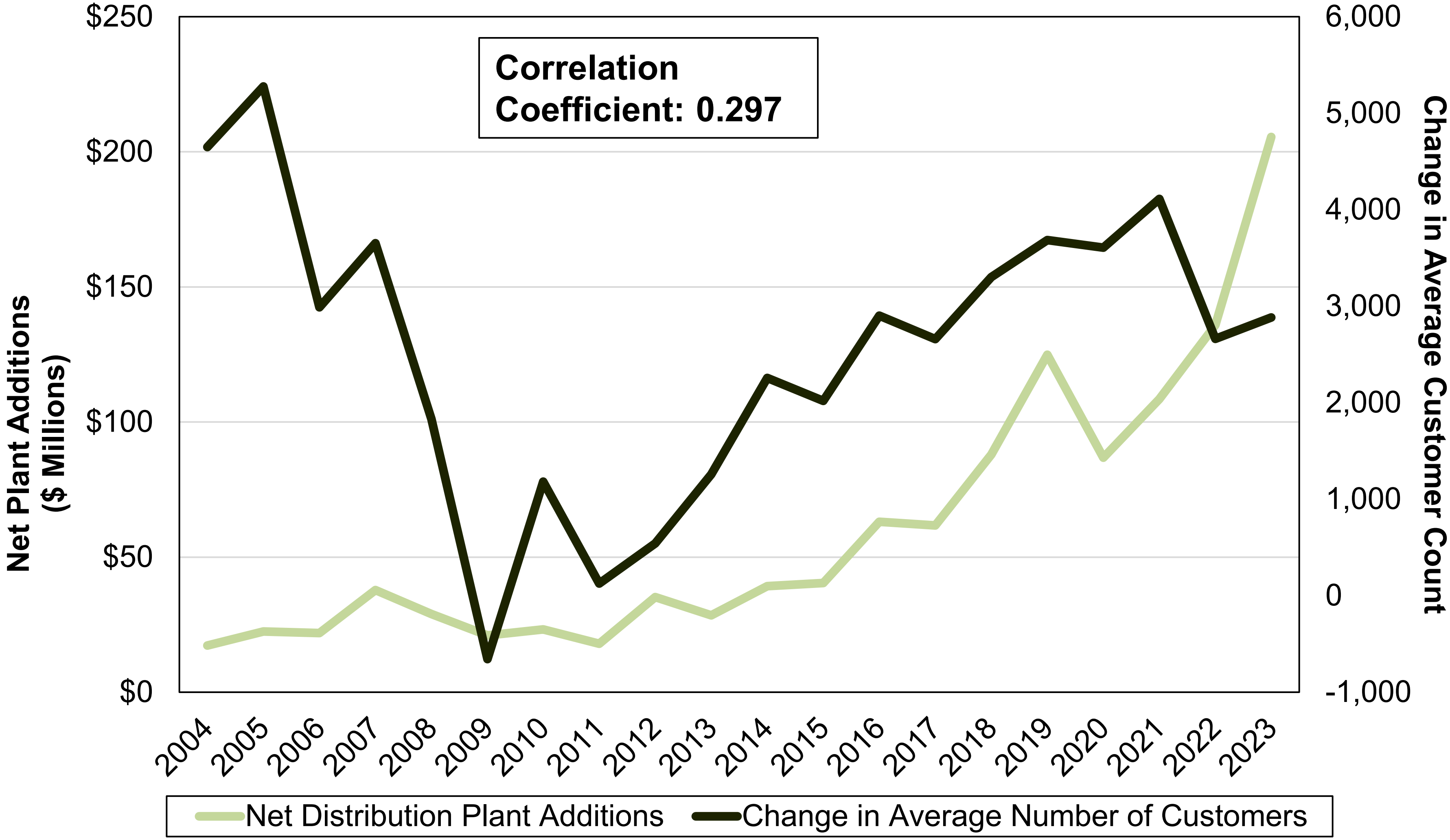
Capital Investment Allocation, 2023-2025

Witness: Deupree
Cause No. 46120
Attachment MWD-10

Investment type	Dollar Amount ($) 2024	Dollar Amount ($) 2025	Percentage (%) 2024	Percentage (%) 2025
Policy				
Public Improvement	$ 16,240,111	$ 15,857,643	1%	1%
Generation Strategy	551,430,050	1,352,524,443	40%	63%
Total Policy	**$ 567,670,161**	**$ 1,368,382,086**	**41%**	**64%**
Reliability				
TDSIC	$ 424,862,025	$ 323,161,957	31%	15%
Generation	32,825,815	32,851,004	2%	2%
Transmission	27,621,641	30,049,858	2%	1%
Distribution	58,868,942	48,363,428	4%	2%
Shared Services	90,614,881	96,066,710	7%	5%
Other	5,777,499	3,481,386	0%	0%
Total Reliability	**$ 640,570,803**	**$ 533,974,342**	**46%**	**25%**
Growth				
Growth	$ 112,310,789	$ 138,852,110	8%	7%
Generation	8,677,389	14,115,000	1%	1%
Transmission	7,301,684	12,911,440	1%	1%
Distribution	15,561,799	20,780,181	1%	1%
Shared Services	23,953,726	41,276,719	2%	2%
Other	1,527,262	1,495,837	0%	0%
Total Growth	**$ 169,332,649**	**$ 229,431,288**	**12%**	**11%**
Total Capital Spending	**$ 1,377,573,613**	**$ 2,131,787,716**	**100%**	**100%**

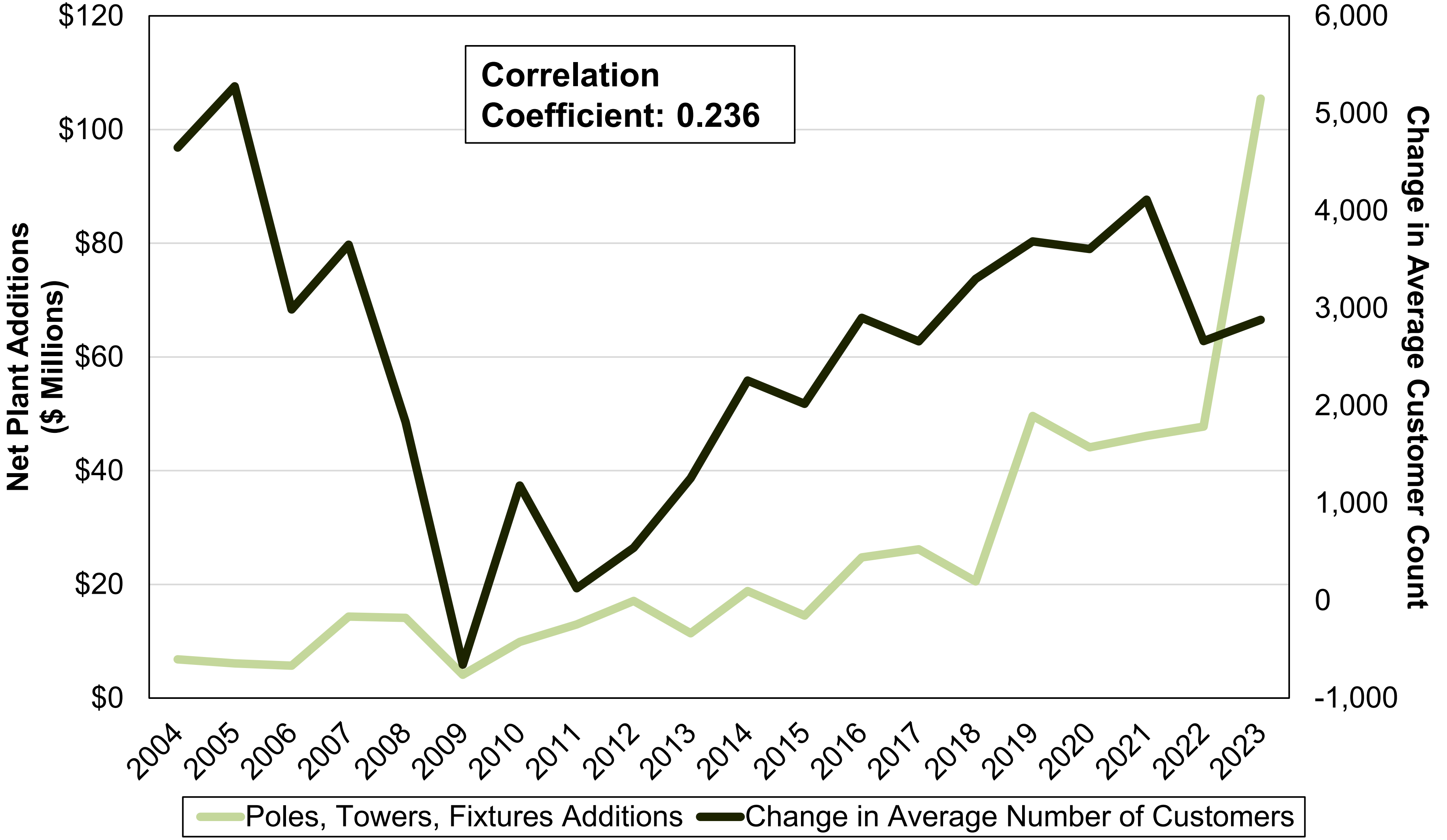
Source: Direct Testimony of Emily J. Bytnar at 19

Correlation of Customers and Distribution Additions: Net Distribution Plant Additions



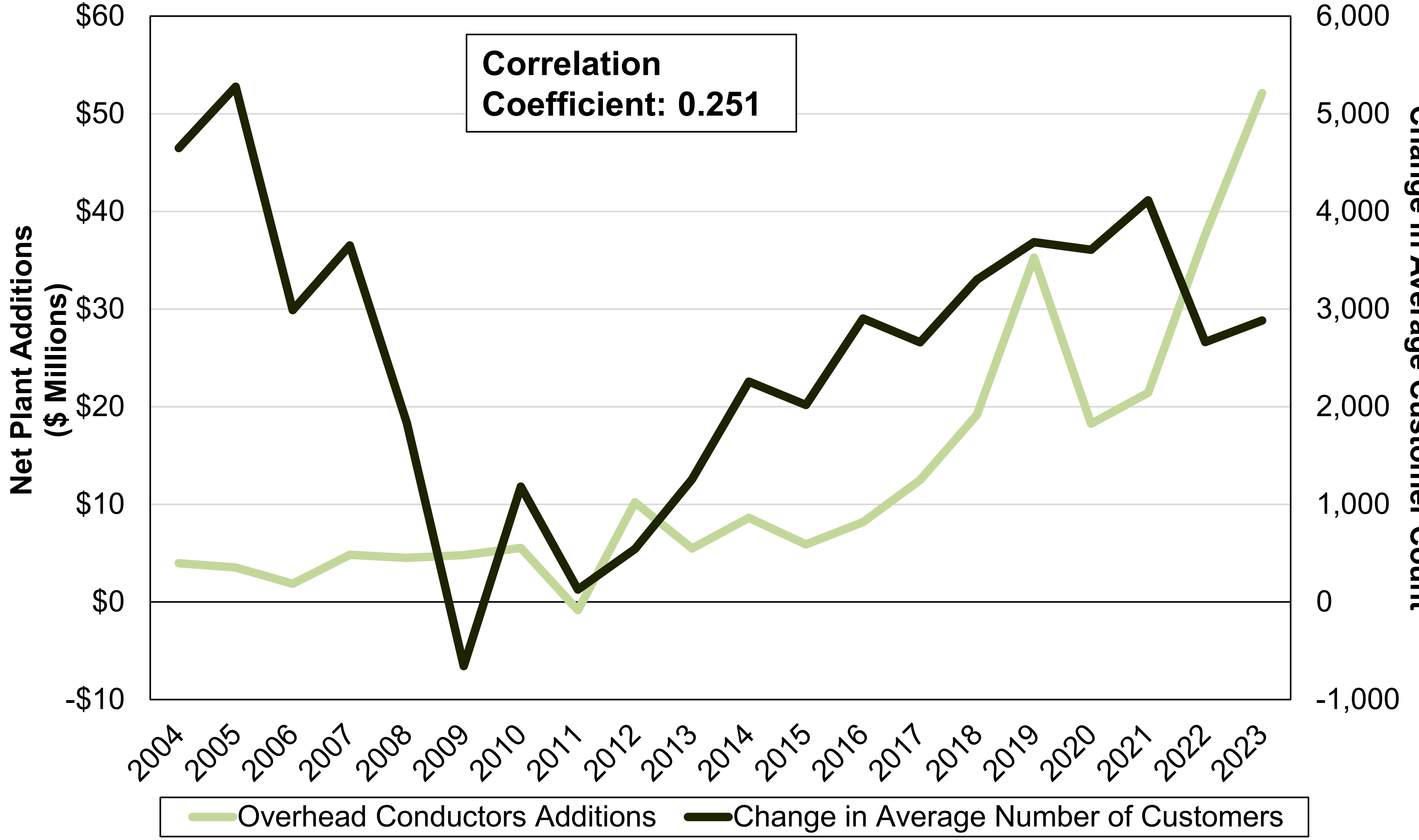
Source: S&P Global

Correlation of Customers and Distribution Additions: Poles, Towers, Fixtures Additions



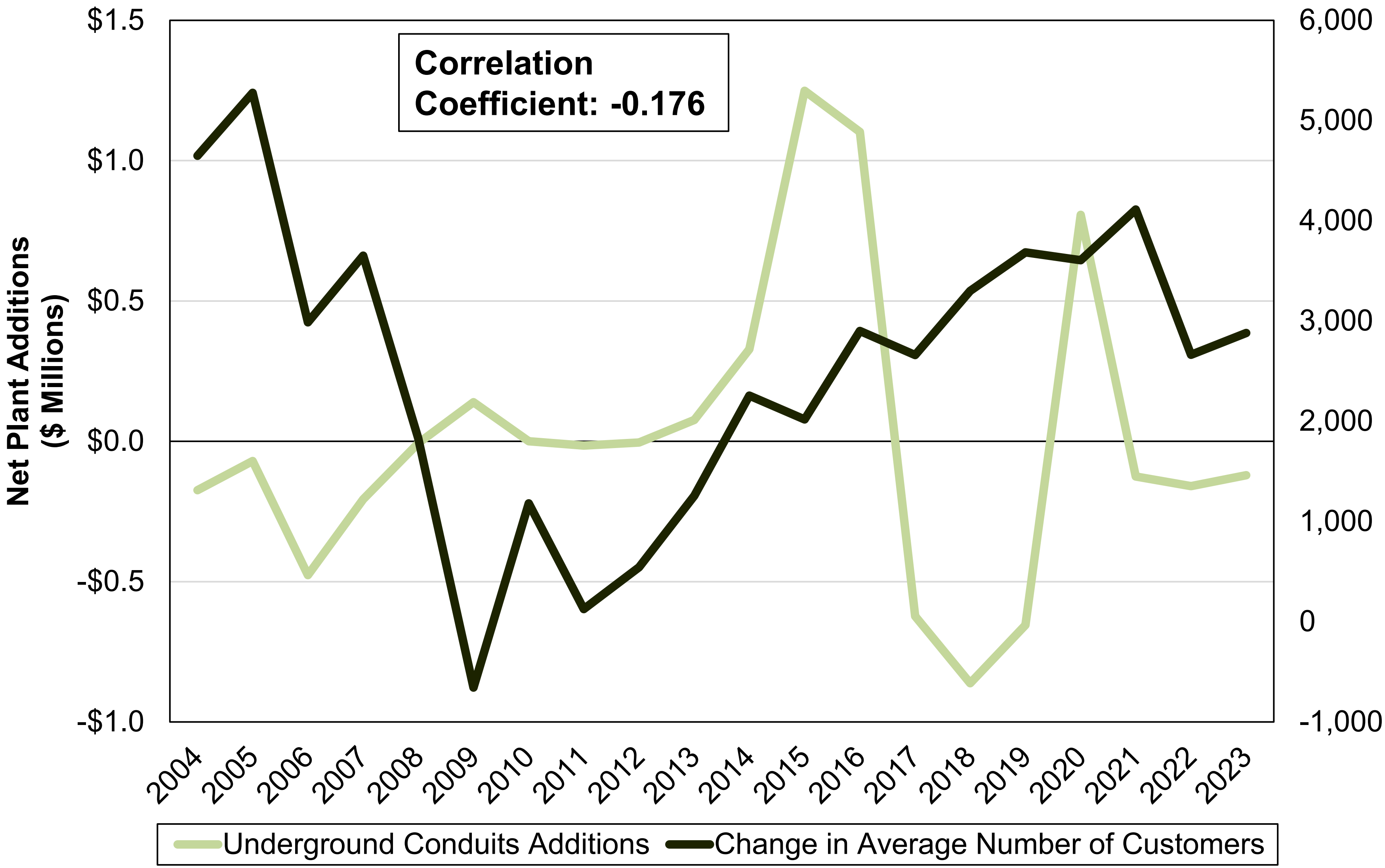
Source: S&P Global

Correlation of Customers and Distribution Additions: Overhead Conductors Additions



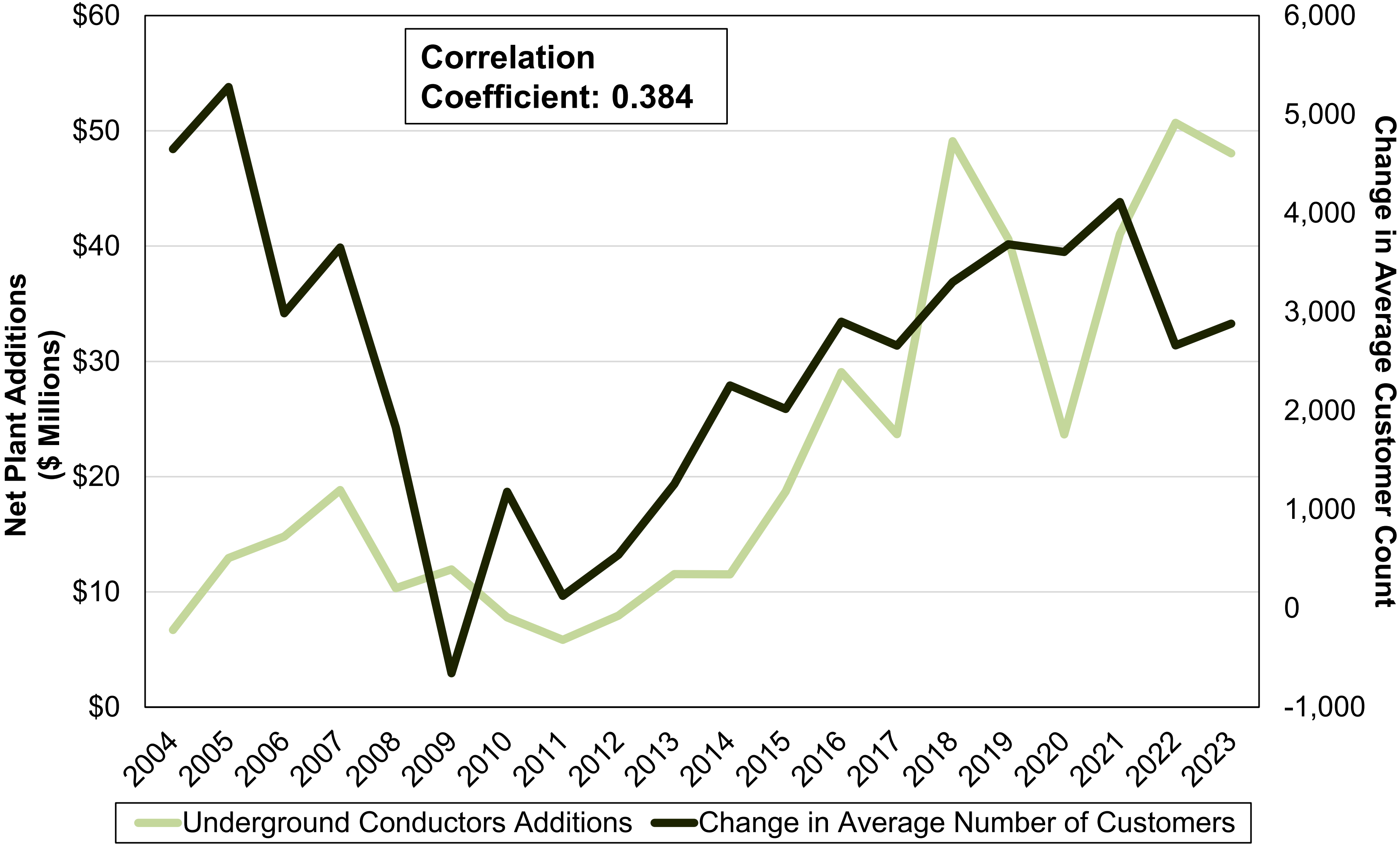
Source: S&P Global

Correlation of Customers and Distribution Additions: Underground Conduits Additions



Source: S&P Global

Correlation of Customers and Distribution Additions: Underground Conductors Additions



Source: S&P Global

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CAUSE NO. 46120

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OUCC ATTACHMENT MWD-13

CAUSE NO. 46120

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OUCC ATTACHMENT MWD-14
CAUSE NO. 46120

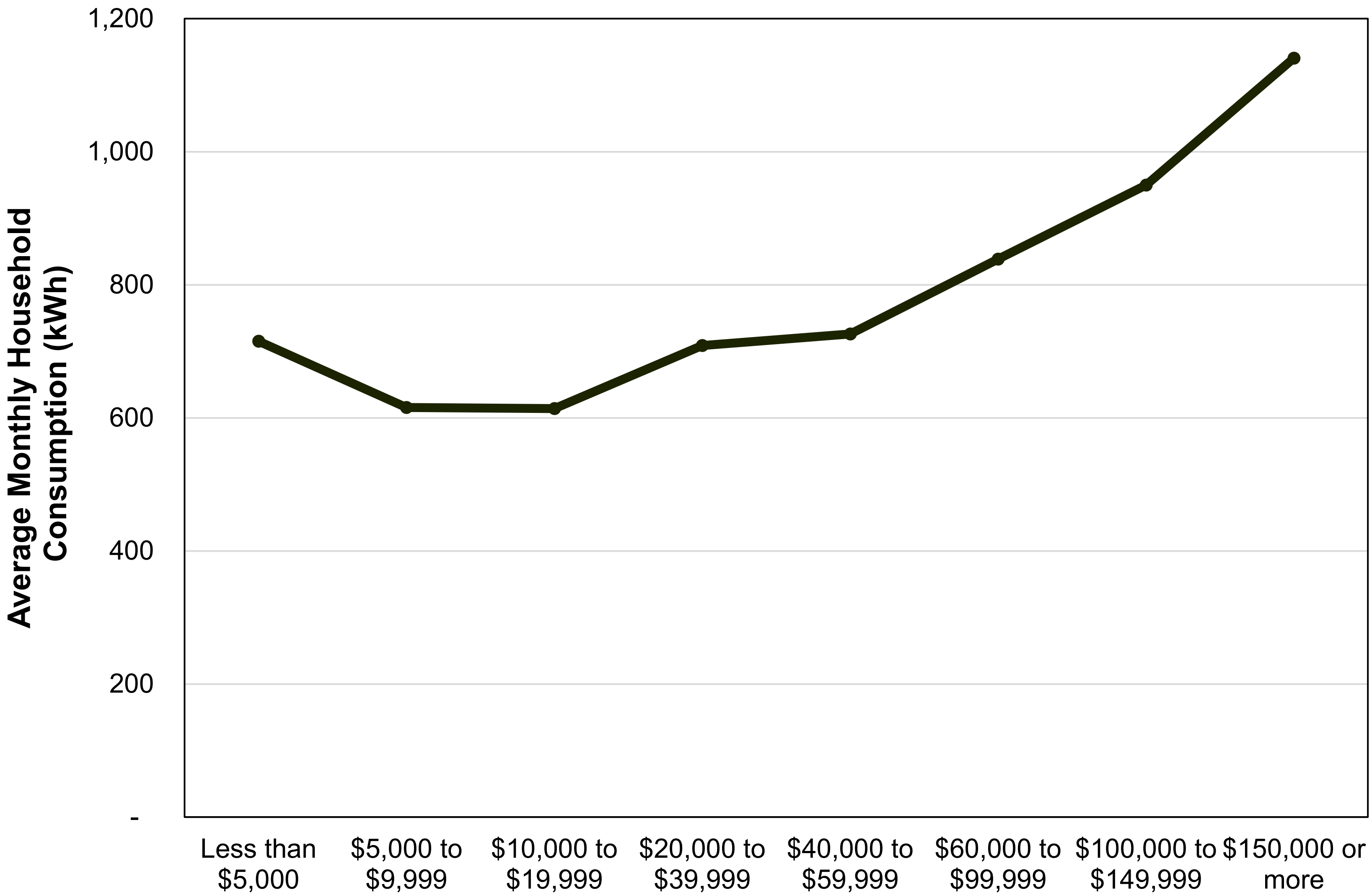
Survey of Regional Customer Charges

Witness: Deupree
Cause No. 46120
Attachment MWD-15

Company	State	Residential Customer Charge ($/month)	Small Commercial Customer Charge ($/month)
Northern Indiana Public Service Company (Current)	**IN**	**$ 14.00**	**$ 32.50**
Northern Indiana Public Service Company (Proposed)	**IN**	**$ 25.00**	**$ 41.40**
Ameren Illinois Company	IL	6.67	17.11
Cleveland Electric Illum Co	OH	4.00	7.00
Commonwealth Edison Co	IL	12.45	13.93
Consumers Energy Co	MI	8.00	20.00
Dayton Power & Light Co	OH	22.12	21.18
DTE Electric Company	MI	8.50	11.25
Duke Energy Indiana, LLC	IN	10.54	10.70
Duke Energy Kentucky	KY	13.00	15.00
Duke Energy Ohio Inc	OH	8.00	23.00
Indianapolis Power & Light Co	IN	12.50	40.00
Indiana Michigan Power Co	IN	15.00	29.00
Indiana Michigan Power Co	MI	7.58	23.30
Kentucky Power Co	KY	20.00	28.00
Kentucky Utilities Co	KY	16.12	41.06
Louisville Gas & Electric Co	KY	13.69	35.28
Ohio Edison Co	OH	4.00	7.00
Ohio Power Co	OH	10.00	9.40
Southern Indiana Gas & Elec Co	IN	10.84	10.84
The Toledo Edison Co	OH	4.00	7.00
Peer Group Average		**$ 10.90**	**$ 19.48**

Sources: Companies' tariffs

Average Monthly Household Consumption



Source: EIA, Residential Energy Consumption Survey, Energy Consumption and Expenditures Tables.

Comparison of Company's Present and Proposed Rates

Description	Company's Present Rate	Company's Proposed: Company's Proposed Rate	Company's Proposed: Increase from Present Rate	Recommended: Alternative Rate	Recommended: Increase from Present Rate
Residential Rates:					
Residential Single-Family (RS-511)					
Customer Charge	$ 14.00	$ 25.00	78.6%	$ 14.00	0.0%
Energy Charge	$ 0.1326	$ 0.17297	30.5%	$ 0.17689	33.4%
Residential Multi-Family (515)					
Customer Charge	$ 14.00	$ 25.00	78.6%	$ -	-100.0%
Energy Charge	$ 0.13257	$ 0.15019	13.3%	$ -	-100.0%
Commercial Service Rates:					
Commercial and General Service Heat (520)					
Customer Charge	$ 32.50	$ 41.40	27.4%	$ 32.50	0.0%
Energy Charge	$ 0.0867	$ 0.14537	67.6%	$ 0.12455	43.6%
Commercial Spaceheating (522)					
Customer Charge	$ 32.50	$ 41.40	27.4%	$ 32.50	0.0%
Energy Charge	$ 0.0952	$ 0.13948	46.5%	$ 0.13485	41.6%
General Service Rates:					
Small General Service (521)					
Customer Charge	$ 32.50	$ 41.40	27.4%	$ 32.50	0.0%
Energy Charge	$ 0.14118	$ 0.19168	35.8%	$ 0.17069	20.9%
Medium General Service (523)					
Demand Charges:					
First 10 kW	$ 33.54	$ 43.70	30.3%	$ 39.10	16.6%
Over 10 kW	$ 15.31	$ 19.95	30.3%	$ 17.85	16.6%
Energy Charge:	$ 0.08285	$ 0.12243	47.8%	$ 0.10682	28.9%
Thermal Storage Charge:	$ 0.06352	$ 0.10101	59.0%	$ 0.08767	38.0%
Large General Service (524)					
Demand Charges:					
First 50 kW	$ 27.16	$ 33.25	22.4%	$ 30.28	11.5%
Next 1,950 kW	$ 17.76	$ 21.74	22.4%	$ 19.80	11.5%
Over 2.000 kW	$ 17.05	$ 20.87	22.4%	$ 19.01	11.5%
Discounts - Billed kW:					
Primary Service	$ (1.02)	$ (1.25)	22.5%	$ (1.14)	11.8%
Transmission Service	$ (1.27)	$ (1.55)	22.0%	$ (1.42)	11.8%
Energy Charge					
First 30,000 kWh	$ 0.0813	$ 0.11302	39.0%	$ 0.10065	23.7%
Next 70,000 kWh	$ 0.0709	$ 0.10050	41.7%	$ 0.08924	25.8%
Next 900,000 kWh	$ 0.0662	$ 0.09473	43.2%	$ 0.08398	26.9%
Over 1,000,000 kWh	$ 0.0613	$ 0.08887	45.0%	$ 0.07865	28.3%
Thermal Storage	$ 0.0635	$ 0.10101	59.0%	$ 0.08767	38.0%
Metal Melting Service (525)					
Demand Charges:					
First 500 kW	$ 31.10	$ 38.34	23.3%	$ 36.73	18.1%
Over 500 kW	$ 29.70	$ 36.62	23.3%	$ 35.08	18.1%
Energy Charge	$ 0.03331	$ 0.05485	64.7%	$ 0.05147	54.5%
Off-Peak Service (526)					
Demand Charges:					
First 200 kW	$ 40.87	$ 49.73	21.7%	$ 47.21	15.5%
Next 500 kW	$ 39.32	$ 47.85	21.7%	$ 45.42	15.5%
Next 1,300 kW	$ 37.77	$ 45.96	21.7%	$ 43.63	15.5%
Over 2.000 kW	$ 36.99	$ 45.01	21.7%	$ 42.73	15.5%
Discounts - Billed kW:					
Primary Service	$ (1.02)	$ (1.25)	22.5%	$ (1.14)	11.8%
Transmission Service	$ (1.27)	$ (1.55)	22.0%	$ (1.42)	11.8%
Energy Charge	$ 0.0180	$ 0.03664	104.0%	$ 0.03346	86.3%

Source: Taylor NIPSCO Electric Rate Design_2024_Workpaper.xlsx

Comparison of Company's Present and Proposed Rates

Description	Company's Present Rate	Company's Proposed: Company's Proposed Rate	Company's Proposed: Increase from Present Rate	Recommended: Alternative Rate	Recommended: Increase from Present Rate
Industrial Power Service Rates:					
Large Industrial Power Service (531)					
Demand Charge:	$ 27.45	$ 35.29	28.6%	$ 35.29	28.6%
Energy Charge					
Tier 1 kWh	$ 0.0035	$ 0.00317	-8.9%	$ 0.00317	-8.9%
Transmission kWh	$ 0.0115	$ 0.01601	39.3%	$ 0.01551	34.9%
Transmission kWh - Tier 2	$ 0.0115	$ 0.01601	39.3%	$ 0.01551	34.9%
Transmission kWh - Tier 3	$ 0.0115	$ 0.01601	39.3%	$ 0.01551	34.9%
Adjacent Affiliate Qualifying Facility Premise	$ 0.0034	$ 0.00480	39.3%	$ 0.00465	34.9%
Discounts - Bill kW:	$ (0.32)	$ 0.32	-200.0%	$ 0.32	-200.0%
Small Industrial Power Service (532)					
Demand Charge	$ 14.87	$ 17.67	18.8%	$ 17.03	14.5%
Energy Charge					
First 450 hours	$ 0.0334	$ 0.05404	61.8%	$ 0.05117	53.2%
Next 50 hours	$ 0.1039	$ 0.13782	32.6%	$ 0.13190	27.0%
Over 500 hours	$ 0.2105	$ 0.26453	25.6%	$ 0.25403	20.7%
Discounts - Bill kW:	(0.32)	$ 0.32	-200.0%	0.32	-200.0%
Small-HLF Industrial Power Service (533)					
Demand Charge	$ 22.92	$ 26.26	14.6%	$ 25.88	12.9%
Energy Charge					
First 600 hours	$ 0.0240	$ 0.04043	68.7%	$ 0.03944	64.5%
Next 60 hours	$ 0.0194	$ 0.03518	81.4%	$ 0.03428	76.7%
Over 660 hours	$ 0.0179	$ 0.03351	86.8%	$ 0.03263	81.9%
Discounts - Bill kW:	$ (0.32)	$ 0.32	-200.0%	$ 0.32	-200.0%
Other Rates:					
Municipal Power (541)					
Customer Charge					
Minimum Charge	$ 9.80	$ 11.85	20.9%	$ 10.98	12.0%
Three Phase	$ 40.07	$ 48.44	20.9%	$ 44.88	12.0%
Warning Signal	$ 9.80	$ 11.85	20.9%	$ 10.98	12.0%
Demand Charges:					
First 25 hp of connected load	$ 3.10	$ 3.75	21.0%	$ 3.47	11.9%
Next 475 hp of connected load	$ 1.51	$ 1.83	21.2%	$ 1.69	11.9%
Over 500 hp of connected load	$ 0.75	$ 0.91	21.3%	$ 0.84	12.0%
Energy Charge	$ 0.1137	$ 0.14943	31.5%	$ 0.13659	20.2%
Intermittent Wastewater Pumping (542)					
Customer Charge:	$ 60.00	$ 60.00	0.0%	$ 60.00	0.0%
Residential - Pump Charge	$ 1.19	$ 1.18	-0.8%	$ 1.22	2.5%
Commercial - Pump Charge	$ 1.41	$ 1.40	-0.7%	$ 1.45	2.8%
Renewable (543)					
Demand Charge	$ 12.50	$ 12.50	0.0%	$ 12.50	0.0%
Energy Charge	$ 0.0263	$ 0.29602	1025.3%	$ 0.03663	39.2%
Railroad Power Service (544)					
Demand Charge	$ 24.06	$ 31.90	32.6%	$ 29.78	23.8%
Energy Charges:					
First 660 hours	$ 0.0225	$ 0.04885	116.9%	$ 0.04392	95.0%
Over 660 hours	$ 0.0194	$ 0.04467	130.6%	$ 0.04001	106.6%
Load Factor Adjustment	$ 0.0014	$ 0.00190	32.6%	$ 0.00178	23.8%
Interdepartmental					
Energy Charge	$ 0.1573	$ 0.21518	36.8%	$ 0.19166	21.8%

Source: Taylor NIPSCO Electric Rate Design_2024_Workpaper.xlsx

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Michael Deupree

Michael William Deupree
Research Consultant
Acadian Consulting Group

Cause No. 46120
NIPSCO, LLC

Date: December 19, 2024

CERTIFICATE OF SERVICE

This is to certify that a copy of the **Indiana Office of Utility Consumer Counselor Public's Exhibit No. 12 Redacted Testimony of OUCC Witness Michael Deupree** has been served upon the following counsel of record in the captioned proceeding by electronic service on December 19, 2024.

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