VERIFIED DIRECT TESTIMONY OF JOHN D. TAYLOR

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I. <u>Introduction and Summary of Testimony</u>

Q1. Please state your name, business address, and job title.

A1. My name is John D. Taylor. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head, SC 29926. I am a Managing Partner with Atrium Economics, LLC ("Atrium"). Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q2. Please describe Atrium's business activities.

A2. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management, revenue requirement development, allocated embedded and marginal cost of service studies, rate design and rate alignment, and affiliate and shared services. We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America, supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies and the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience in management positions inside electric and gas utilities and as advisors to our clients.

Q3. On whose behalf are you testifying?

A3. I am testifying on behalf of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company").

Q4. What has been the nature of your work in the utility consulting field?

A4. As a utility pricing and policy expert, I support a variety of energy and utility-related projects regarding matters pertaining to economics, finance, and public policy. In the public utility space, I have assisted with asset divestitures, allocated class cost of service studies, rate of return calculations, cash working capital impacts, tax litigation, revenue allocation, rate design, auction analysis, and affiliate cost allocation. I have reviewed and analyzed these subject matters considering the accounting treatment for, the financial investment in, and the operational configuration of a company's assets. For utility rate cases, I have performed: allocated class cost of service studies, revenue allocation; rate design; valuation modeling; affiliate cost allocation; and various cost of service analyses. Also, I have filed testimony on class cost of service studies, return on equity, and statistical audit sampling. Specifically, I have presented expert testimony to regulatory commissions in Delaware, Florida, Indiana, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, North Carolina, Oregon, Pennsylvania, South Carolina, Washington, West Virginia, and to FERC. Regarding my educational background and professional background, I studied electrical and mechanical engineering and worked for an industrial inspection company, which provided hands-on experience with electric utility assets and equipment. I received an undergraduate degree in Environmental Economics, emphasizing econometrics and regulatory policy. I also earned a Masters in Economics from American University in Washington, DC. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Attachment 16-A.

Q5. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A5. Yes. I testified on behalf of NIPSCO in previous electric rate cases, Cause Nos. 43969 and 45772 and NIPSCO gas rate case Cause No. 45967. I've submitted testimony on behalf of Indianapolis Power & Light in Cause No. 44576 and for CenterPoint Energy Indiana South Cause No. 45990.

Q6. For what purpose has NIPSCO retained Atrium?

A6. NIPSCO has retained Atrium as a consultant in the area of utility costing and rate design. Specifically, NIPSCO has requested Atrium to conduct a fully

Allocated Cost of Service Study ("ACOSS") to determine the embedded costs of serving the Company's electric retail customers and support its rate design efforts. In this regard, I am sponsoring the ACOSS that allocates NIPSCO's electric utility costs to its rate classes, class revenue increase apportionment, and proposed rate design.

Q7. Please summarize the purpose of your testimony.

A7. First, I discuss the purpose of an ACOSS and describe the Atrium Cost of Service Model ("Atrium Model") used for NIPSCO's electric cost of service study.

Second, I discuss various cost allocation principles, factors that influence the cost allocation framework, and the underlying methodology and basis used in the Company's electric cost of service studies. I describe the "Special Studies" employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes.

Third, I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS. This presentation discusses the resulting unit costs by class for customer, demand, and energy-related costs with the ACOSS. The detailed summary of the ACOSS results is presented in Attachment 16-C.

Fourth, I discuss revenue allocation and rate design principles and the appropriate guidelines for use in evaluating class revenue levels and rate structures. I explain and support the allocation of the Company's revenue deficiency to the various rate classes consistent with class revenue mitigation objectives.

Finally, I discuss NIPSCO's rate design proposals and discuss in detail the analyses conducted to support the new multi-family rate class and in support of increasing the fixed bill component for both single-family and multi-family customers.

Q8. Are you sponsoring any attachments to your direct testimony?

A8. Yes. I am sponsoring Attachments 16-A through 16-J, all of which were prepared by me or under my supervision and direction.

Q9. Please describe the attachments.

A9. As stated earlier, Attachment 16-A contains further background information summarizing my education, presentation of expert testimony, and other industry-related activities. The following is a listing of the remaining attachments:

- Attachment 16-B Rate 531 Contract Demand and Legacy Coal Costs
- Attachment 16-C Summary of Class Cost Allocation and Unit Costs – 4CP
- Attachment 16-D Summary of Class Cost Allocation and Unit Costs – 12CP
- Attachment 16-E Asset Functionalization and Classification
- Attachment 16-F External Allocation Factors - Special Studies
- Attachment 16-G Rate Mitigation
- Attachment 16-H Rate Design Schedules
- Attachment 16-I Residential Bill Impacts
- Attachment 16-J Updated Tracker Allocations

II. Purpose of an ACOSS

Q10. What is an ACOSS?

A10. An ACOSS is an analysis of costs that assigns to each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Q11. What is the purpose of an ACOSS?

A11. The purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return provided by each class of service of the utility can be determined. This resulting rate of return will be impacted by the cost allocation resulting from the methodology employed. The ACOSS is a tool that the analyst uses to assist in determining revenue responsibility by rate class and rate design. The results of the ACOSS will provide the analyst with the data necessary to design cost-based rates.

Q12. Please discuss the Company's selection of the Atrium Model for conducting the cost of service studies filed in this proceeding.

A12. NIPSCO selected the Atrium Model to conduct the ACOSS in this general rate case filing. Atrium's ACOSS Model is built using Microsoft Excel and is available for both electric and gas utilities. Atrium has developed this flexible and customizable model to meet the needs of electric and gas utilities for an improved cost analysis to facilitate the unbundling of supply, delivery services, and related products in today's competitive environment. The transparency provided by the structure of the Atrium Model allows for complete audit tracking capability, from account level input through each of the functionalization, classification, and allocation steps of a cost of service study.

Q13. Will an electronic copy of the Atrium Model be provided to the

Commission?

A13. Yes. The Atrium Model in Excel format with formulas intact is being provided to the Commission in accordance with 170 IAC 1-5-15(e)(2). NIPSCO has filed a Motion for Protective Order with the Commission requesting that the Commission find the Model to be confidential, proprietary, and competitively sensitive trade secret information that will be protected from public disclosure and access. As discussed in my Affidavit in support of the Motion, the Model was developed by Atrium on a proprietary basis for use in its consulting engagements. Disclosure of the Model to competitors of Atrium would cause economic harm to Atrium, and the Model is subject to reasonable efforts by Atrium to maintain its secrecy. Therefore, Atrium requests that the Commission allow the Model to be submitted under seal. The Atrium Model will also be provided to the Indiana Office of Utility Consumer Counselor and other parties subject to mutually agreeable nondisclosure agreements.

III. <u>Principles of ACOSS Preparation</u>

Q14. Is there a guiding principle that can support the appropriate allocation of costs?

A14. Although there may not be a perfect methodology for allocating costs, a principle of cost causation should be followed to produce more accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. Hence, the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. In other words, the costs assigned or allocated to particular customers should be those that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q15. What are the steps to performing an ACOSS?

A15. To establish the cost responsibility of each customer class, initially, a three-step analysis of the utility's total operating costs must be undertaken. The three steps that comprise the ACOSS modeling are: (1) cost functionalization, (2) cost classification, and (3) cost allocation of all the costs of the utility's system.

Q16. Please describe cost functionalization.

A16. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. NIPSCO's primary functional cost categories associated with electric service include Production, Transmission, Sub-Transmission, Primary Distribution, Secondary Distribution, Customer Service, and Fuel Expense. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent that their costs vary in response to different customer class characteristics.

Q17. Please describe cost classification.

A17. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers, (2) the need to meet the peak demand requirements that customers place on the system, and (3) the amount of electricity consumed by customers. These classification categories have been identified for purposes of the ACOSS as Customer Costs, Demand Costs, and Energy Costs, respectively.

Q18. How are these classification categories related to the Company's costs incurred?

A18. Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs largely depend on the number of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum-size distribution systems, line transformers, services, meters, and customer billing and accounting expenses.

Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, larger transformers, and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Energy Costs are those costs that vary with the amount of kilowatt hours ("kWh") sold to customers. For example, included in the instant study are base fuel rates that vary with the amount of energy produced. However, except for fuel, the vast majority of NIPSCO's costs are fixed with respect to energy usage, and very little of its remaining cost structure is energy related.

Q19. Please describe cost allocation.

A19. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Customers are generally divided into customer classes based on the type and character of services they require. Costs typically are allocated to these customer classes based on factors related to the number of customers, the amount of capacity demanded by customers, and the energy usage of customers. For example, much of the plant and equipment cost depends upon the customers' peak demand. These costs are allocated based on the coincident-peak or non-coincident peak demands of the rate class, depending on which characteristic more closely affects cost causation. Other portions of the cost depend upon the number of customers on the system, and these costs are allocated on a customer, or weighted-customer, basis. In addition, certain variable production costs, as well as fuel and purchased power costs, primarily depend upon the amount of energy a customer consumes. These costs are allocated based on the amount of energy consumed, adjusted for losses of energy that occur in the transmission and distribution process.

Q20. How does the cost analyst establish the cost and utility service relationships?

A20. To establish these relationships, the cost analyst must analyze a utility's electric system design, physical configuration and operations, accounting records, and system and customer load data, *e.g.*, peak period electric consumption levels. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q21. Please explain the term "direct assignment."

A21. The term direct assignment relates to specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a "Special Study," as is done with costs associated with meters and services.

Q22. What prompts the analyst to elect to perform a Special Study?

A22. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q23. How do you determine whether to directly assign costs to a particular customer or customer class?

A23. Direct assignments of plant and expenses to particular customers or classes of customers are developed by detailed analyses of the utility's maps and records, work order descriptions, property records, and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance needs to be placed on plant allocation methodologies associated with joint use plant.

Q24. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned to a specific customer or certain customer classes?

A24. No. The nature of utility operations is characterized by the existence of joint-use facilities. To the extent that a utility's plant and expenses cannot be directly assigned to customer classes, allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q25. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform an ACOSS.

A25. As stated above, to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

Q26. Are there factors that can influence the overall cost allocation framework utilized by an electric utility when performing an ACOSS?

A26. Yes. The factors which can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's electric system; (2) the availability of data within the utility; and (3) the state regulatory policies, precedents, and requirements applicable to the utility.

Q27. Why are these considerations relevant to conducting NIPSCO's ACOSS?

A27. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they indicate where efforts should be focused for conducting a more detailed analysis of the utility's system design and operations and understanding the regulatory environment in the State of Indiana regarding cost of service studies and electric ratemaking issues. Further, the structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, data segregation by operating unit or geographic region, and the types of available load data.

IV. <u>NIPSCO's ACOSS</u>

A. <u>Sources of the Underlying Data</u>

Q28. What were the sources of the cost data analyzed in NIPSCO's ACOSS?

A28. All cost of service data were extracted from the Company's total cost of service (i.e., base rate revenue requirement) contained in the instant general rate case filing, which is based upon a future test year ending December 31, 2025. Where more detailed information was required to perform various subsidiary analyses related to specific plant and expense elements, the data were derived from the historical books and records of the Company.

Q29. What customer classes are included in the ACOSS?

A29. All tariffed rate classes were included in the ACOSS with the addition of a new Rate 515 – Residential Multi-Family.[1] NIPSCO identified a group of customers on Rate 511 that exhibit a different character of service due to living in multi-family housing. These customers were migrated out of Rate 511 – Residential and into the new Rate 515 – Residential Multi-Family. The analyses relating to the new Rate 515 are covered within the NIPSCO's Proposed Rate Design section of this testimony.

Q30. Please describe NIPSCO's derivation of its total revenue requirement.

A30. The Company's base rates are proposed to recover the revenue requirement exclusive of the costs recovered in trackers and riders and associated taxes. As explained by NIPSCO Witness Weatherford, the Company's forecasted revenue requirement for the 12-month period ending December 31, 2025, is $2.198 billion. This is before revenue from any riders that would continue after retail base rates are established. In the setting of retail base rates, a base level

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[1] NIPSCO's currently effective tariff includes the 500 series rates and proposed tariff will convert the 500 series numbering to 600 series numbering. This testimony references 500 series numbering even though the new Residential Multi-Family rate does not exist under the 500 series numbering.

of miscellaneous other revenue is treated as a credit. The base retail rates proposed in this proceeding are designed to recover an amount net of these credits of $2.174 billion.

B. Functionalization and Classification of Costs

Q31. How did you functionalize and classify NIPSCO's costs?

A31. The process starts with each of the Company's FERC accounts and assigns the costs in each of these accounts to a specific function. In some instances, the costs in an account are first split into separate functions or classifications if the costs in the account are incurred to perform more than one function, or the costs in an account can be said to vary significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits have been separated into three functions: sub-transmission (34 kV), primary distribution (600 V – 12.5 kV), and secondary distribution (≤ 600 V). In addition, the secondary distribution portion of these costs has been further separated into demand and customer classifications. Some other distribution accounts are separated into sub-transmission, railroad, and other distribution system functions. Similarly, a portion of the production operation and maintenance expenses other than fuel have been classified as either fixed, demand-related costs or variable, energy-related costs.

Plant and operations and maintenance costs related to production, transmission, and distribution generally can be assigned directly to specific functions. Still, various indirect costs related to overheads such as intangible plant, general plant, and common plant, as well as administrative and general expenses, are allocated to functions based on the relative amount of certain costs that have been directly assigned to each function. The specific functional allocators used to assign overhead costs have been selected to reflect the type of direct costs that each overhead account generally supports.

Q32. How were costs assigned to the sub-transmission and railroad functions?

A32. Similar to past NIPSCO Electric rate cases, costs in Accounts 360-367 associated with the 34 kV facilities were identified and classified as "Sub-transmission" and allocated to classes based on their contribution to the non-coincidental peak demand at the sub-transmission voltage. In addition, some facilities in Accounts 360-364.1 were identified as being solely for the benefit of the railroad customer, South Shore Railway. Costs associated with railroad facilities are directly assigned to the railroad class (Rate 544). Attachment 16-E contains a summary of the functionalization of sub-transmission facilities and railroad facilities.

Q33. Please explain the primary-secondary study.

A33. Because costs associated with distribution facilities are not explicitly identified in the financial accounting records as being Primary Distribution (600 V–12.5 kV) or Secondary Distribution (≤ 600 V), the remaining distribution costs in Accounts 364.2–367 have been assigned to Primary or Secondary distribution functions based on cost-related ratios that were developed from analyses of the distribution plant records. The development of the ratios used to make these Primary-Secondary assignments is shown in Attachment 16-E.

Q34. Please explain the minimum system study.

A34. The costs associated with a distribution system are related to the peak load that the system is designed to deliver and the number of customers and premises it is designed to serve. Consequently, it is appropriate to allocate a portion of the distribution system costs on a demand-related basis and a portion on a customer-related basis. To classify certain secondary distribution system costs as demand-related or customer-related, a minimum system study was conducted, which included an analysis for poles and an analysis for conductors. The results of this study are shown in Attachment 16-E.

C. Allocations to Rate Classes

Q35. What was the next step in the ACOSS?

A35. After functionalizing and classifying the costs, the final step is the allocation of each functionalized and classified cost element to the individual rate classes. Costs typically are allocated on demand, customer, and commodity allocation factors. These allocation factors are either developed through special studies as presented in Attachment 16-F or developed internally in the ACOSS model based on the allocations applied therein.

D. Allocation of Production and Transmission Demand-Related Costs

Q36. How have the production demand-related costs been allocated in NIPSCO's proposed ACOSS?

A36. I utilized a coincident peak demand method to allocate generation and transmission costs and a non-coincident peak demand method to allocate demand-related distribution system costs. "Coincident Peak" ("CP") refers to the demand of a class at the time when the overall system demand is at a peak. "Non-coincident Peak" ("NCP") refers to the highest level of demand that an individual class experiences during the year. This non-coincident peak for a given class may coincide with the overall system peak, but in some instances, it occurs at other times that are off-peak for the system as a whole. The coincident peaks during the four summer months of the base period ("4CP"), June through September, were used to allocate the demand-related costs associated with the production functions. The coincident peak demands during each of the twelve months of the base period ("12CP") were utilized to allocate demand-related costs associated with the transmission functions. A summary of the firm peak load data used as a starting point to allocate demand-related costs is provided in Attachment 16-F.

Q37. Why did you select the 4CP method to allocate the production demand-related costs?

A37. Similar to past NIPSCO Electric rate proceedings, several years of monthly peak loads (2010-2023) were reviewed, and FERC's cost allocation tests for using a 12CP allocator were evaluated. As shown in Table 1 below, 2020 – 2023 failed all three tests, whereas 2019 and 2018 each failed two of the three tests. Thus, it is appropriate to use a 4CP allocator for NIPSCO's demand-related production costs in this proceeding.

Table 1 – FERC 12-CP Tests (2010-2023)

FERC 12-CP Tests			
	Peak - Off-Peak % Difference	Low/Annual Peak Ratio	Avg/Annual Peak Ratio
Use 12 CP if:	≤ 19.0%	≥ 66.0%	≥ 81.0%
2023	23.3%	60.6%	75.7%
2022	23.1%	65.3%	79.7%
2021	22.2%	63.7%	75.6%
2020	23.8%	56.7%	76.7%
2019	18.4%	65.7%	78.0%
2018	22.1%	67.7%	80.9%
2017	21.4%	69.7%	82.4%
2016	24.1%	67.4%	80.6%
2015	18.3%	69.8%	82.1%
2014	17.1%	70.5%	83.5%
2013	22.4%	65.8%	80.6%
2012	23.4%	64.4%	77.7%
2011	23.0%	67.5%	81.6%
2010	22.7%	66.6%	79.5%

Q38. Are there other considerations relating to the allocation of production demand-related costs that were taken into account?

A38. Yes. It is important to note the IURC's stated policy that governs when a review of the classification and allocation of production function costs is ripe. In the Cause No. 43839 Southern Indiana Gas & Electric Company (then-Vectren South) case, the Commission found:

> Vectren South has used a 4 CP methodology since at least the 1970s to allocate production and transmission costs on a demand-basis. We have noted our preference to utilize previously approved allocation methodologies unless evidence demonstrates that system operating characteristics have changed since the last approved COSS allocation methodology. Northern Indiana Public Serv. Co., 2010 Ind. PUC LEXIS 294, at *263. Dr. Swan provided no evidence that system

> operating characteristics have changed since the company's last COSS and Mr. Phillips and Mr. Heid both affirmatively testified that no such changes had occurred. Further, endorsing Dr. Swan's method would dramatically change the allocation of costs to customers as noted by Mr. Phillips. Changes in allocation methodology that significantly alter cost assignment may unreasonably disadvantage customers who have made investments in response to previous cost assignments. Of specific concern to the Commission are those investments made to foster demand response or to remove load during the Company's historical peak periods.[2]

Q39. Did you also conduct and are you presenting the results of the ACOSS model with production demand allocated on 12 CP in accord with the 2023 Rate Case Settlement[3]?

A39. Yes. The 2023 Rate Case Settlement includes the following language: "In its next electric base rate case, NIPSCO will prepare a 4 coincident peak ("CP") and 12 CP cost of service analysis for purposes of allocating production-related demand costs and make each analysis available to all parties in the case. NIPSCO will determine which cost of service analysis to propose in its case-in-chief, and all other parties will have the right to take any position with regard to cost of service in that case."[4] As further, described below an additional ACOSS with the 12 CP allocation of allocating production-related demand

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2 *S. Ind. Gas and Electric Co.*, Cause No. 43839 (IURC April 27, 2011), p. 64.

3 The Commission's Order in NIPSCO's last general rate case, Cause No. 45772, approved multiple settlement agreements, one of which resolved the revenue requirement and revenue allocation (the "2023 Rate Case Settlement").

4 2023 Rate Case Settlement at pp. 23

costs is being presented as Attachment 16-D.

E. Rate 531 Demand

Q40. What method was utilized by the Company to determine the level of demand for allocating costs to the Rate 531 class in accordance with the 2023 Rate Case Settlement?

A40. There are several terms relating to the method of establishing the level of demand used for allocating costs to the Rate 531 class in the 2023 Rate Case Settlement. The primary intent in the 2023 Rate Case Settlement was included in the settlement language, "Future reductions to Tier 1 load and cost allocations to Rate 531 as contemplated in the Rate 831/531 Settlement will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates."

To develop a level of demand for allocating costs to the Rate 531 class, an analysis was conducted to develop a revenue requirement difference that directly relates to the differences between steam production costs across 2023 to 2025 reflecting the retirement of coal facilities and impact on NIPSCO's cost of service. This revenue requirement difference was then compared to the allocation of demand under Rate 531's current level of demand allocation, 180MW, and an alternative level of demand was evaluated that equates to this revenue requirement difference.

Q41. Please provide details on this analysis.

A41. The below described method is provided in Attachment 16-B. The differences across the following rate base accounts were analyzed by comparing costs in 2023 to the Company's 2025 test year: Steam Production Net Plant and Depreciation Reserve Accounts 310-316, Rate Base Adjustments associated with Unit14/15 Retirement, Unit 17/18 Retirement, and Fuel Inventory. Next, the differences across the following Operation & Maintenance (O&M) accounts were analyzed: Steam Production – Operation Accounts 500-509 and Steam Production – Maintenance Accounts 510 – 514 and trackable fuel expenses. Lastly, the differences associated with Steam Production Depreciation Expense (FERC Accounts 310-316) and the RMS Unit 14/15/17/18 Amortization Expense were taken into account. As a result of this analysis, the Company's Steam Production rate base decreased by $395M due to the retirement of coal units, Steam Production O&M expenses have decreased by $48M, trackable fuel expenses decreased by $23M, and depreciation and amortization expenses increased by $25M resulting in a revenue requirement change of $83M. Once this figure was computed it was allocated to each of the rate classes based on

4CP and 12CP allocation factors with the current allocated demand of 180MW for Rate 531. Under the 4CP allocation method this resulted in a reduction of $6.3M to Rate 531 and under the 12CP allocation method this resulted in reduction of $7.8M to Rate 531.

Next, the allocation of the Company's total production-related revenue requirement for 2025 test year was analyzed to assess what level of demand would result in the same decrease as determined in the above-mentioned analysis. Under the 4CP allocation method, the Rate 531 demand allocation could move from 180MW to 163.916MW to result in the same decrease of $6.3M to Rate 531. Under the 12CP allocation method, the Rate 531 demand allocation could move from 180MW to 163.614MW to result in the same decrease of $7.8M to Rate 531. As such, the methodology set forth above and informed by the 2023 Rate Case Settlement results in demand for allocating costs to the rate 531 class be set at 164MW.

Q42. How were rates designed for the Rate 531 class given 164MW of demand?

A42. First, it is important to note the process of setting rates for the Rate 531 customers in the 2023 case. While the allocation of costs to the Rate 531 class in the 2023 case utilized an allocated demand of 180MW, the customers only committed to take 170MW of contract demand for billing purposes. As such, the allocation of costs under the 180MW demand allocation level was divided by the 170MW of committed contract demand to develop the Tier 1 demand rate for Rate 531. In this proceeding, I have assumed in calculating rates that the 531 customers will sign contracts setting forth a total contract demand of 164MW, equal to the allocated demand. In so much as the contract demand commitments are different than 164MW when rates are implemented in this proceeding, the rates must be adjusted to ensure the same revenue amount is collected from this group of customers as their cost to serve.

Q43. How does the Company propose to adjust the rates so that contract demand from this class of customers recovers the same revenue amount as the allocated cost of demand?

A43. Between the filing of the Verified Petition in this Cause and the filing of rebuttal testimony, the Company will work in good faith with the Rate 531 customers to learn what level of demand to which they wish to commit and will execute either extensions or renewals of the contracts with these customers specifying their new respective contractual Tier 1 demands. There are 7 Rate 531 customers. At the time of rebuttal, NIPSCO will recompute the Tier 1 Demand Rate using the allocated 164 MW of demand but spreading that cost over the greater of the actual committed contractual demand at that time or 70 MW (the 10MW minimum level of 531 Tier 1 Demand times 7 customers). The revised rate using these new billing determinants will be filed as a part of rebuttal. The only rates that will change as a result of this effort will be the Rate 531 Tier 1 Demand rate and the corresponding Rate 531 Tier 1 Energy rate.

Q44. If there are no Rate 531 customers that execute renewed or extended contracts by the time rebuttal testimony is filed, what would that do to the Rate 531 Tier 1 Demand Rate?

A44. The 10 MW minimum of contract demand for each of the 7 customers would be 70,000 kW. This amount of assumed contractual demand for 12 months would be 840,000 kW (70,000*12). The same revenue allocation for Tier 1 demand of $69.5 million spread over 840,000 kW results in a Tier 1 demand rate of $82.69 per kW. That compares to the rate I have assumed for purposes of my rate design at the time of filing (using contractual demand equal to allocated demand of 164 MW) of $35.29/kW.

F. <u>Allocation of Distribution Demand-Related Costs</u>

Q45. Why did you use the non-coincident peak demands of customer classes to allocate the costs of demand-related distribution lines and substations?

A45. Although the production and transmission facilities are designed to meet the coincident peak demands of the entire system, as the system moves further from the generating plants and closer to the ultimate retail consumers, the primary factor affecting the planning and sizing of facilities is the level of peak demands in local areas. To the extent that customer classes have their individual peaks at different times, the Company must plan and install facilities to accommodate those individual peaks. In addition, to the extent that these facilities may be used jointly by different classes, the non-coincident peak method ensures that all classes share in the costs of these facilities. Consequently, the average of the 12 monthly non-coincident peak demands of each class was used in allocating costs associated with these distribution system facilities.

G. Allocation of Customer-Related Costs

Q46. How have the customer-related costs been allocated in the ACOSS?

A46. Because a significant portion of the distribution system costs are incurred simply to attach a customer to the system and are the same regardless of the amount of energy that the customer might consume, significant portions of the distribution system costs and customer-specific costs are allocated to classes using allocators that are related to the number of customers in the class. However, because there generally is a very wide difference between the customer classes in terms of the level of customer-related costs required per customer, many of the allocations of customer-related costs are weighted to reflect the relative differences in the average cost per customer of providing customer-related facilities or services for particular rate classes. Thus, customer-related costs such as meters, transformers, service lines, meter reading, billing, and customer service are allocated based on the cost-weighted number of customers in each class. The customer-related allocation factors and the relative-cost weights assigned to each class are shown in <u>Attachment 16-D.</u> The general methods used to develop the customer-related allocation factors are discussed below.

<u>Meters:</u> General Service and Industrial meters generally cost considerably more than Residential meters. For this reason, meter weights were developed for each customer class based on a list of the number and types of meters installed for each rate class and an estimate of the replacement costs of each type of meter. This provided an estimate of the relative cost of providing meters for each class. The relative-weight factor was then multiplied times the number of customers in the class to develop allocation factors used to allocate metering costs to each class.

<u>Service Lines:</u> For allocating the costs of the service lines that connect each premise to the distribution system, we analyzed the length and types of services used by each rate class and then calculated the replacement costs of those services. The relative-weight factor was then multiplied times the number of customers in the class to develop allocation factors used to allocate service line costs to each class.

<u>Transformers:</u> NIPSCO provided the total count of transformers by type at each pole/pad number, mapping of rate classes to each pole/pad number, and a replacement cost for each type of transformer. This data was used to calculate the total replacement cost of transformers for each rate class. These class replacement costs were then utilized to develop a weighted customer allocator, representing the relative expense of transformers for each rate class and customer category. This weighted customer allocator and forecasted customer count for the test year was then used to apportion the total cost of transformers to each rate class.

H. <u>Allocation of Energy-Related Costs</u>

Q47. How are the energy-related costs allocated in the ACOSS?

A47. Energy-related costs are allocated to the various rate classes based on the weather normalized and forecasted amount of energy used by each class adjusted for energy losses that occur in serving customers at different voltage levels. The development of these allocation factors is presented in <u>Attachment 16-F</u>.

I. <u>Internal Allocations</u>

Q48. How are overhead costs functionalized?

A48. Intangible Plant is allocated based on a combination of the direct labor and the direct plant allocators assigned to each function. General Plant is assigned to each function based on the "Direct Labor" allocator. Common Plant is assigned to functions based on the "Direct Labor" allocator with the exception of customer-related software (a portion of Account 303), which is allocated to rate classes based on the number of customers, and Organization (Account 301), which is allocated based on combination of the direct labor and the direct plant allocators assigned to each function. Administrative and General expenses were allocated to various functions using four different allocators: (1) Salaries, Office Supplies, Injuries and Damages, and Pensions and Benefits were allocated using the direct labor allocation factor; (2) Property Insurance was allocated using the relative amount of total plant in service associated with each function; (3) Outside Services, Public Utility Fees, Miscellaneous A&G, and Rents were allocated using a combination of the direct labor and the direct plant allocators, and (4) Maintenance of General Plant was allocated based on the Total General Plant assigned to each function.

J. Allocation of Depreciation Reserve and Expenses

Q49. Please describe the method used to allocate the reserve for depreciation and depreciation expenses.

A49. These items were allocated by account in the same manner as their associated plant accounts.

K. Allocation of O&M Expenses

Q50. How did the ACOSS allocate distribution-related O&M expenses?

A50. In general, these expenses were allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's distribution-related O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, i.e., expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis used to allocate the corresponding expense account.

L. <u>Allocation of Customer Accounting Expenses (901 – 904)</u>

Q51. How did the ACOSS allocate Customer Accounting Expenses (FERC Account No. 901 – No. 904)?

A51. Meter Reading Expense, Account No. 902, was allocated based on a weighting of meters read automatically using Automated Meter Reading ("AMR"), and meters read manually. For costs in Account 901-Customer Account Supervision and Account 903-Customer Records and Collections Expense, various Company departments and sub-functions dedicated to the customer service functions were analyzed. When it was determined that particular departments serve only certain rate classes, the costs of those departments were assigned or allocated to those classes that the particular department serves. For other departments or sub-functions, costs were allocated based on department managers' estimates of the time and expenses incurred related to a particular customer class. An analysis of the three-year average uncollectible expenses by class was conducted to allocate Account No. 904, Uncollectible Accounts Expense.

M. <u>Allocation of Customer Information, Demonstration, and Sales Expenses</u>

Q52. How did the ACOSS allocate Customer Information, Demonstrating, and Selling Expenses (FERC Account Nos. 908, 910, 912 and 913)?

A52. Similar to the analyses described above concerning costs charged to Account No. 901 and Account No. 903, time studies were used as the basis for assigning the costs recorded in Account No. 910 to the various rate classes. Account Nos. 908, 912 and 913 were allocated to the rate classes based on customer counts.

N. Allocation of Taxes other than Income Taxes

Q53. How did the ACOSS allocate taxes other than income taxes?

A53. The ACOSS allocated all taxes, except for income taxes, to reflect the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified based on the tax assessment method established for each tax category, *i.e.*, payroll, property, or function. In the ACOSS, Payroll related taxes were allocated based on labor expenses, Property related taxes were allocated based on total plant and Property and Public Utility Fee-related taxes were allocated based on total plant and labor.

Q54. How were income taxes allocated to each customer class?

A54. Current income taxes were allocated to each rate class based on each individual class's net operating income before income tax. For the determination of equal rates of return by class, a rate base allocator was used where income taxes are directly proportional to rate base.

VI. Results of NIPSCO's ACOSS

A. Summary of NIPSCO ACOSS by Rate Class

Q55. Have you prepared a summary of NIPSCO's ACOSS results?

A55. Yes. Attachment 16-C presents the summary results of the ACOSS at present rates under the Company's current 500 Series rate classes using the 4 CP allocation method for production demand-related plant and Attachment 16-D presents the ACOSS using the 12 CP allocation method for production demand-related plant. This exhibit presents the resulting allocation by customer class of NIPSCO's proposed revenue requirement based strictly on the results of the computations included in the ACOSS. These results provide cost guidelines for evaluating a utility's class revenue levels and rate structures. The rate of return, current revenue, cost of service at equal rate of return, required revenue increase, and percentage increase in revenues to match revenues to cost to serve are summarized in Table 2 below.

Table 2 - Results of Cost of Service Study

Rate	Current Rate of Return	Current Revenue	Cost of Service	Required Revenue Increase	Percentage Increase to Cost to Serve
Rate 511	0.56%	$ 617,900,197	$ 947,007,427	$ 329,107,230	53.3%
Rate 515	5.38%	$ 76,353,364	$ 85,917,158	$ 9,563,795	12.5%
Rate 520	2.75%	$ 1,250,233	$ 1,544,651	$ 294,418	23.5%
Rate 521	6.84%	$ 318,873,596	$ 333,687,894	$ 14,814,298	4.6%
Rate 522	11.81%	$ 1,062,722	$ 895,371	$ (167,351)	-15.7%
Rate 523	6.33%	$ 154,460,778	$ 165,406,466	$ 10,945,688	7.1%
Rate 524	10.32%	$ 227,324,359	$ 202,551,802	$ (24,772,558)	-10.9%
Rate 525	7.03%	$ 9,344,577	$ 9,412,617	$ 68,040	0.7%
Rate 526	6.99%	$ 199,905,810	$ 203,495,820	$ 3,590,010	1.8%
Rate 531	4.78%	$ 149,682,559	$ 175,683,067	$ 26,000,508	17.4%
Rate 532	8.00%	$ 17,531,731	$ 16,944,489	$ (587,242)	-3.3%
Rate 533	15.36%	$ 27,156,687	$ 20,878,068	$ (6,278,619)	-23.1%
Rate 541	12.56%	$ 5,931,735	$ 4,864,668	$ (1,067,067)	-18.0%
Rate 542	20.84%	$ 66,780	$ 43,857	$ (22,923)	-34.3%
Rate 543	21.54%	$ 3,509,114	$ 2,230,107	$ (1,279,007)	-36.4%
Rate 544	-0.97%	$ 1,631,503	$ 3,381,206	$ 1,749,704	107.2%
Rate 550	0.03%	$ 7,592,020	$ 13,537,063	$ 5,945,042	78.3%
Rate 555	10.29%	$ 1,162,803	$ 1,037,317	$ (125,486)	-10.8%
Rate 560	0.56%	$ 3,186,419	$ 4,442,408	$ 1,255,989	39.4%
Interdepartmental	9.27%	$ 5,671,930	$ 5,298,079	$ (373,851)	-6.6%
System Total	**4.15%**	**$ 1,829,598,917**	**$ 2,198,259,535**	**$ 368,660,619**	**20.1%**

Q56. Please describe the results of your ACOSS with respect to classified costs.

A56. The ACOSS summarized the costs allocated to the rate classes on a classified basis, i.e., by demand, customer, and energy basis. Of particular interest are the customer and demand-related costs. Attachment 16-C summarizes the functionalized and classified costs by rate class at equalized rates of return and shows the costs on a unit rate basis for the 4 CP allocation of production demand-related plant with Attachment 16-D presenting the same information using the 12 CP allocation of production demand-related plant. Revenue Allocation and Rate Design Principles

B. Cost Guidelines for Use in Evaluating Class Revenue Levels and Rate Structures

Q57. How can the ACOSS results provide guidelines for rate design?

A57. ACOSS results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the revenue-to-cost ratios show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service, resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q58. Do the ACOSS results guide in establishing rates within each rate class as well?

A58. Yes. The classified costs, as allocated to each class of service within the ACOSS, provide useful cost information in determining the level of customer, demand, and energy charges. As mentioned earlier, Attachment 16-C summarizes the Company's functionalized revenue requirement per unit of billed demand, annual energy consumption, and customer count for each rate class using the 4 CP allocation method for production demand-related plant.

C. <u>Other Policy Considerations or Criteria that should be used in the Design of Utility Rates.</u>

Q59. Should other factors be considered that would prevent the Company from simply translating the unit costs into rates for the various tariff services?

A59. Yes. Completely restructuring a utility's rates mechanistically to match the unit costs from the ACOSS is often not desirable due to the resulting adverse impact on certain customer classes, particularly for low use, low load factor customers. The unit costs provide useful information for designing portions of tariff services, particularly for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either demand metering is available, or algorithm-based billing demands can be determined. Demand-based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q60. Please describe other considerations or criteria that should be used in the design of utility rates.

A60. Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, cross-subsidization within customer classes, as well as customer bill impact considerations, must be factored into the rate design process. Market conditions within the utility service territory concerning the general economic environment and competitive fuel prices, where appropriate, could be a factor. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound rate-making practice to recover a substantial portion of fixed costs, such as customer-related costs, which bear no relationship to customer consumption patterns, in the volumetric portion of the rate structure. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of electricity can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics due to energy conservation efforts, among other factors. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well-founded energy consumption decisions based on the actual costs of various types and levels of utility service.

Q61. How are the foregoing guidelines and criteria incorporated into the rate

design process?

A61. A reasonable balance between the various cost guidelines and other criteria must be established in the process of designing rates, which consists of both the recovery of the revenue requirement from among the various customer classes and the determination of rate structures within tariff schedules. Economic, social, historical, and regulatory policy considerations can impact the rate design process. Both quantitative and qualitative factors must be considered in reaching a final rate design. Thus, it is necessary to allow the rate design process to be influenced by judgmental evaluations.

VII. <u>NIPSCO's Proposed Revenue Allocation by Class</u>

A. <u>Description of Proposed Revenue Allocation Methodology Employed</u>

Q62. Please describe the approach followed to apportion the current revenue responsibility to the Company's various rate classes.

A62. As described earlier in my testimony, the allocation of revenues among rate classes consists of deriving a reasonable balance between various guidelines and criteria that relate to the design of utility rates. The following criteria were considered in this process: (1) cost of service results, (2) class contribution to present revenue levels and the resulting inter-class subsidies, (3) customer bill impacts, and (4) the Company's belief that while movement toward parity with the system-wide rate of return is the ultimate goal, moderation should be employed in accomplishing that goal.

Q63. How were the proposed revenue responsibilities for the various rate classes derived?

A63. The process of determining the proposed revenue responsibilities for each rate class, including certain mitigation steps, is described below:

1. Cap individual class revenue increases to 1.5 times the overall system increase, so that no customer class would receive more than 1.5 times the overall system increase.

2. No class should have proposed revenues greater than 1.5 times their cost of service.

3. Rate 511- Residential Single-Family increase was set equal to the overall system increase. This resulted in Rate 511's targeted revenues being set at 78% of their cost to serve.

4. Rate 515—Residential Multi-Family's revenues were set equal to its cost of service, fully eliminating the intraclass subsidy between single-family and multi-family customers and not creating any interclass subsidy

between multi-family and other classes while simultaneously reflecting a lower cost to serve for the multi-family customers compared to single-family customers.

5. Rate 531's revenues were set equal to its cost of service with the newly set allocated demand of 164 MW of demand of Tier 1, reflecting the reduction in legacy coal costs as described above in this testimony.

6. To comply with the Indiana Code (Title 8, Article 1, Chapter 2, Section 46.1),[5] it was necessary to limit Rate 544 – Railroad's revenue increase to the system average increase.

7. After increasing Rate 511, Rate 515, Rate 531, and Rate 544 based on the above criteria and providing decreases to those classes that were above 1.5 times their cost to serve, classes requiring an increase were set equal to their cost of service.

8. The remaining increase required was then allocated to all classes based on current revenue for each class, except Rate 511, Rate 515, Rate 531,

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[5] Sec 46.1. In providing for a classification of service, the commission shall approve a rate for furnishing traction power for a commuter transportation system (IC 8-5-15) that is equal to or lower than the rate approved for any industrial or commercial consumer of the public utility. The rate established under this section is subject to timely payments as negotiated between the utility and the district for furnishing traction power.

and Rate 544, which were already set based upon the above criteria

Attachment 16-G shows each of the steps in the process of calculating the proposed revenue responsibility of each rate class. Further, it is worth noting this process is nearly identical to that proposed in NIPSCO's last rate case, Cause No. 45772, with the need to add a method to set Rate 515's increase and, in that case, Rate 544's increase was set to 1.5 times the overall system increase and remained compliant with the Indiana Code referenced above.

B. Resulting Revenues at Proposed Rates by Customer Class

Q64. How does NIPSCO propose to distribute the revenue increase among the rate classes?

A64. Table 3 below provides the proposed distribution of the proposed revenue increase among the rate schedule based on the process described above.

Table 3 - Proposed Revenue Increase by Rate Class

Rate	Proposed Rate of Return	Current Revenue	Proposed Revenue	Proposed Revenue Increase	Proposed Percentage Increase
Rate 511	3.37%	$ 617,900,197	$ 742,405,883	$ 124,505,686	20.1%
Rate 515	7.59%	$ 76,353,364	$ 85,917,158	$ 9,563,795	12.5%
Rate 520	8.83%	$ 1,250,233	$ 1,628,112	$ 377,879	30.2%
Rate 521	11.04%	$ 318,873,596	$ 391,689,555	$ 72,815,959	22.8%
Rate 522	16.28%	$ 1,062,722	$ 1,256,026	$ 193,304	18.2%
Rate 523	10.94%	$ 154,460,778	$ 193,502,181	$ 39,041,403	25.3%
Rate 524	14.37%	$ 227,324,359	$ 268,673,629	$ 41,349,270	18.2%
Rate 525	11.56%	$ 9,344,577	$ 11,112,353	$ 1,767,777	18.9%
Rate 526	11.44%	$ 199,905,810	$ 239,857,781	$ 39,951,970	20.0%
Rate 531	7.59%	$ 149,682,559	$ 175,683,067	$ 26,000,508	17.4%
Rate 532	12.69%	$ 17,531,731	$ 20,720,673	$ 3,188,942	18.2%
Rate 533	21.07%	$ 27,156,687	$ 31,317,101	$ 4,160,415	15.3%
Rate 541	17.00%	$ 5,931,735	$ 7,010,690	$ 1,078,956	18.2%
Rate 542	19.49%	$ 66,780	$ 65,786	$ (994)	-1.5%
Rate 543	19.19%	$ 3,509,114	$ 3,345,160	$ (163,954)	-4.7%
Rate 544	0.93%	$ 1,631,503	$ 1,960,247	$ 328,745	20.1%
Rate 550	3.07%	$ 7,592,020	$ 9,886,687	$ 2,294,666	30.2%
Rate 555	14.10%	$ 1,162,803	$ 1,374,311	$ 211,509	18.2%
Rate 560	6.02%	$ 3,186,419	$ 4,149,505	$ 963,086	30.2%
Interdepartmental	12.93%	$ 5,671,930	$ 6,703,628	$ 1,031,698	18.2%
System Total	**7.59%**	**$ 1,829,598,917**	**$ 2,198,259,535**	**$ 368,660,619**	**20.1%**

The result of the distribution of the proposed revenue increase is that almost all customer classes are moving closer to their cost to serve. This can be seen through comparing the Current Parity Ratio (Class Rev. to Cost Ratio/System) at line 27 on pages 1-3 of Attachment 16-C to the Parity Ratio - Revenue to Cost Ratio at line 66 on pages 4-6 of Attachment 16-C. In all instances, the revenue to cost parity ratio moves towards parity, that is it moves towards 1.0, except for Rates 520, 521, and 523, which is a result of the aforementioned revenue allocation process. Further, it is important to note that Attachment 16-C does provide the subsidies at current rates at line 34 and repeated on line 67 and the subsidies at proposed rates on line 68, as well as the percentage difference associated with those line items on line 70, as required by the Commission's Minimum Standard Filing Requirements [170 Ind. Admin. Code 1-5-15(b)(7) and (b)(9)]. In my experience, the most informative indicator of moving a customer class closer to their cost to serve and measuring this movement relative to other customer classes is by analyzing the revenue to cost ratio. The revenue-to-cost ratios portray the ratio between the cost to serve these customers and the revenues from these customers. The parity ratios portray the relative difference between the revenues currently recovered from each class and the costs to serve each class at the system average rate of return. A revenue-to-cost ratio below 1.00 means that the current rates and revenues of the particular customer class are below its indicated cost of service, while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the customer class are above its indicated cost of service. The parity ratio provides insights into the relative differences across the classes once all classes are adjusted for system-level over- or under-recovery.

Q65. Will a portion of the Proposed Mitigated Revenue shown in Column L of

Attachment 16-G be collected through Other Revenue?

A65. Yes. After crediting an amount of Other Revenue to reduce the revenue requirement for each class, the final amount of the proposed revenue to be recovered in base rates is shown in Column K of Attachment 16-G.

Q66. Have you evaluated the impact on the proposed revenues that would occur using your proposed mitigation discussed above, but with the 12 CP allocation of production demand-related costs?

A66. Yes. Table 4 below provides a summary of the mitigation approach applied to the 12 CP model presented in Attachment 16-D. As can be seen in this table there is no material impact to Rate 511 – Residential Single-Family; however, there would be an additional $1.3M increase to Rate 515 – Residential Multi-Family. As a result of the 12 CP method, there would be an additional increase of $16.9M to Rate 531 and associated differences across other commercial and industrial classes based on the mitigation approach described above. As described above NIPSCO supports the continued use of the 4 CP allocation of production demand-related costs and has used that model's results as an input to the mitigation process.

Table 4 - 4 CP vs 12 CP Cost to Serve and Mitigated Revenue

Rate	Cost of Service 4 CP	Cost of Service 12 CP	Cost of Service Difference	Mitigated Revenue 4 CP	Mitigated Revenue 12 CP	Mitigated Revenue Difference
Rate 511	$ 947,007,427	$ 857,359,695	$ (89,647,731)	$ 742,405,883	$ 742,306,703	$ (99,180)
Rate 515	$ 85,917,158	$ 87,186,045	$ 1,268,887	$ 85,917,158	$ 87,186,045	$ 1,268,887
Rate 520	$ 1,544,651	$ 2,355,212	$ 810,560	$ 1,628,112	$ 1,629,084	$ 972
Rate 521	$ 333,687,894	$ 350,441,252	$ 16,753,357	$ 391,689,555	$ 388,551,477	$ (3,138,078)
Rate 522	$ 895,371	$ 1,446,510	$ 551,139	$ 1,256,026	$ 1,384,587	$ 128,561
Rate 523	$ 165,406,466	$ 175,429,179	$ 10,022,713	$ 193,502,181	$ 193,889,792	$ 387,611
Rate 524	$ 202,551,802	$ 227,160,225	$ 24,608,424	$ 268,673,629	$ 254,517,117	$ (14,156,512)
Rate 525	$ 9,412,617	$ 11,848,862	$ 2,436,245	$ 11,112,353	$ 12,171,869	$ 1,059,516
Rate 526	$ 203,495,820	$ 214,903,908	$ 11,408,087	$ 239,857,781	$ 238,795,780	$ (1,062,000)
Rate 531	$ 175,683,067	$ 192,530,079	$ 16,847,012	$ 175,683,067	$ 192,530,079	$ 16,847,012
Rate 532	$ 16,944,489	$ 19,421,937	$ 2,477,448	$ 20,720,673	$ 21,517,416	$ 796,743
Rate 533	$ 20,878,068	$ 22,613,999	$ 1,735,931	$ 31,317,101	$ 30,403,955	$ (913,147)
Rate 541	$ 4,864,668	$ 5,320,303	$ 455,635	$ 7,010,690	$ 6,641,102	$ (369,588)
Rate 542	$ 43,857	$ 48,639	$ 4,782	$ 65,786	$ 72,959	$ 7,173
Rate 543	$ 2,230,107	$ 2,008,646	$ (221,460)	$ 3,345,160	$ 3,012,969	$ (332,191)
Rate 544	$ 3,381,206	$ 3,621,862	$ 240,656	$ 1,960,247	$ 1,960,514	$ 266
Rate 550	$ 13,537,063	$ 13,952,327	$ 415,264	$ 9,886,687	$ 9,887,184	$ 498
Rate 555	$ 1,037,317	$ 1,117,286	$ 79,969	$ 1,374,311	$ 1,301,851	$ (72,460)
Rate 560	$ 4,442,408	$ 4,573,455	$ 131,047	$ 4,149,505	$ 4,149,662	$ 157
Interdepartmental	$ 5,298,079	$ 4,920,115	$ (377,964)	$ 6,703,628	$ 6,349,389	$ (354,239)
System Total	**$ 2,198,259,535**	**$ 2,198,259,535**	**$ (0)**	**$ 2,198,259,535**	**$ 2,198,259,535**	**$ (0)**

VIII. <u>NIPSCO's Proposed Rate Design</u>

A. <u>Analysis and Development of NIPSCO's Multi-Family Rate</u>

Q67. Why is the Company proposing to separate the residential class rate into Single-Family and Multi-Family classes for cost allocation and rate design?

A67. Pursuant to the 2023 Rate Case Settlement, the Company committed to study the cost-of-service characteristics of its residential customers, specifically to assess whether use and cost characteristics for multi-family ("MF") residential customers were distinctive from single-family ("SF") residential customers. While I will discuss the particulars of the analysis in detail below, the conclusion of the analysis was that there are distinctive characteristics for MF residential customers that would warrant separating these customers apart from the SF residential customers for purposes of cost-allocation and rate design. It is worth noting that this is predominately an intra-class issue and consequently does not affect revenue apportionment to other classes. Said another way, the combined cost responsibility for SF and MF residential customers is the same; the difference is the proportion of that cost responsibility that is attributable and thus recovered through the rates for SF and MF residential customers.

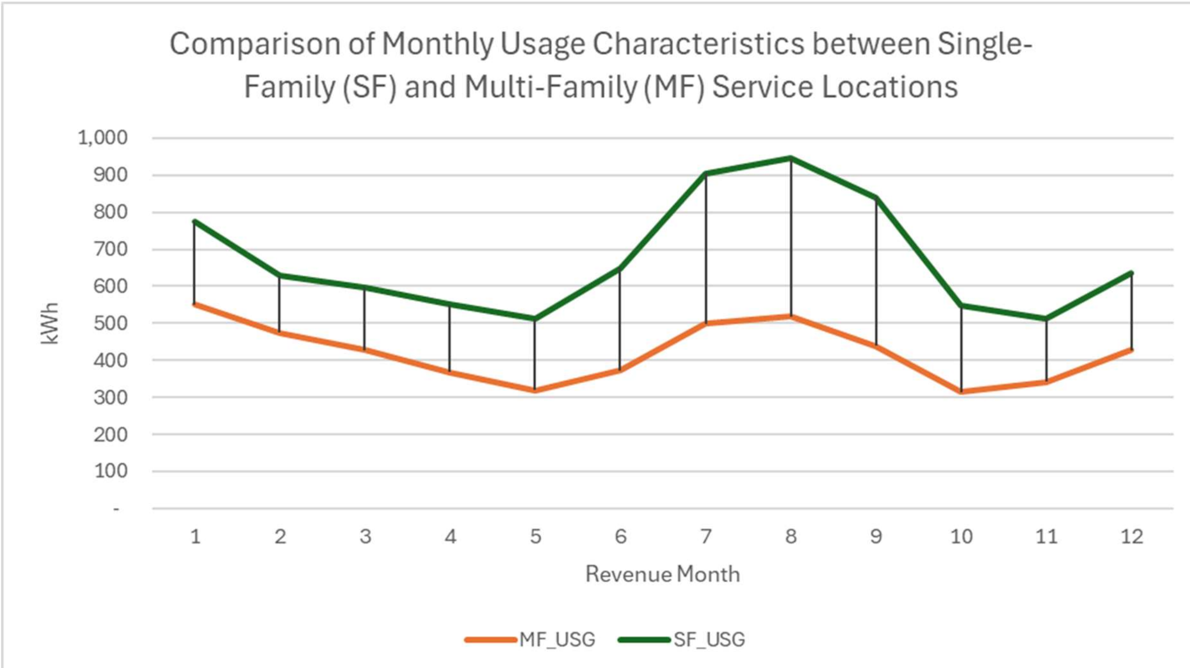
Q68. Please describe the process undertaken to analyze the demand and energy usage characteristics of the SF and MF residential customers.

A68. The first step in the process was to review individual residential customer billing records provided by the Company. This data was pulled from their Customer Information System ("CIS") and contained monthly customer billing records, addresses, monthly usage used in billing, and other information for the residential customers that were provided service by the Company in 2023. Using this data, Atrium was able to separate the residential customers into SF and MF designations and compare monthly usage characteristics across the two subsets of customers. This analysis demonstrated that there were indeed distinctive monthly usage differences between the SF and MF residential customers. Atrium was also able to use the CIS data to identify load research sample meters deployed to statistically analyze the residential class hourly usage characteristics that were located at SF and MF service locations. This sample data further allowed Atrium to analyze not just differences in monthly consumption, but also to estimate distinct hourly profiles between SF and MF customers.

Q69. Please summarize the results of the monthly billing analysis.

A69. The results of the monthly billing analysis showed that, on average, there was a significant difference in monthly usage between the SF and MF residential customers. Furthermore, the analysis demonstrated that the MF customers exhibit higher usage and higher peak demands in the winter months compared to the summer months. Table 5 below presents this information graphically.

Table 5 – Comparison of Monthly Usage SF and MF



Q70. How did Atrium identify the SF and MF residential customer subsets?

A70. Using the information contained in the CIS data, Atrium separated the electric residential customers into SF and MF designations based on the following criteria: (1) if a customer was both a gas and electric customer, and that customer was currently taking service on a gas multi-family rate; or (2) as an electric customer had "APT", "SUITE", or "UNIT" in the service address; the customer was flagged as MF. Customers not flagged as MF were designated as SF. Table 6 below summarizes the estimated SF and MF customer counts by month for 2023.

Table 6 – Estimated SF and MF Customers by Month

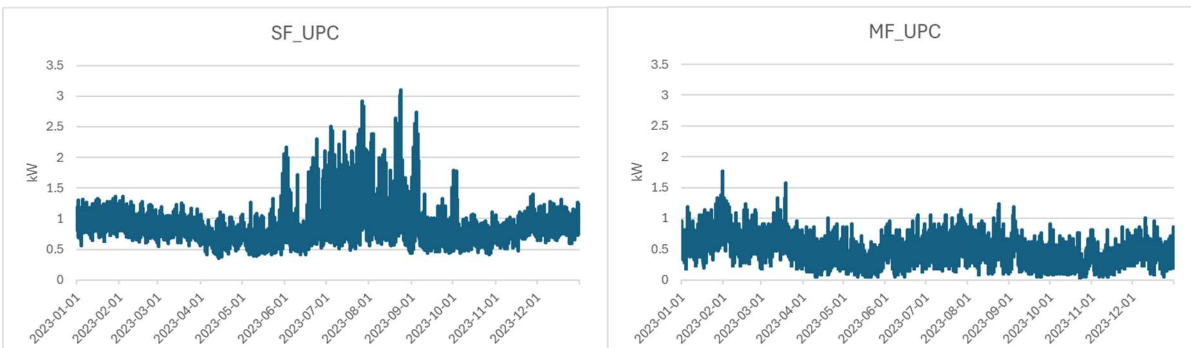
Estimated Single-Family ("SF") and Multi-Family ("MF") Residential Customers by Month, 2023

Month	SF Customer Count	SF Use per Customer	MF Customer Count	MF Use per Customer	MF % of Total
1	361,353	776	67,678	550	15.75%
2	361,883	628	67,783	474	15.75%
3	363,678	598	68,410	427	15.81%
4	363,360	550	68,111	368	15.77%
5	364,027	511	68,384	318	15.80%
6	364,094	648	68,260	372	15.76%
7	363,601	906	68,147	499	15.75%
8	364,370	945	68,783	517	15.85%
9	364,488	840	68,314	439	15.75%
10	365,228	548	68,388	315	15.75%
11	364,105	513	68,117	341	15.74%
12	363,553	635	67,965	428	15.73%
Annual Average	363,645	675	68,195	421	15.79%

Q71. Please describe how Atrium extended this analysis utilizing the load research sample meters deployed at residential service locations.

A71. Using the service address locations and the SF/MF designations described above, Atrium was able to separate the residential load research sample meters into SF and MF subsets. Currently, the Company has 127 load research sample meters deployed at residential service locations. Of those 127 load research sample meters, 106 were identified at SF service locations, and 21 were identified at MF service locations – a similar proportion to the overall customer base breakdown presented above in Table 6. Table 7 below presents the hourly use-per-customer profiles for the SF and MF residential customer subsets. This data clearly reinforces the conclusions from the monthly billing analysis, and further identifies that not only is monthly consumption distinct, but also the times and magnitude of peak demands for the MF customers is different than that of the SF customers. Atrium utilized this information to estimate distinct usage characteristics (contribution to coincident peak hours, and non-coincident peaks) for the SF and MF residential customer segments.

Table 7 – Hourly Load Research SF and MF



Comparison of Monthly Peak Demand from Average (UPC) Single-Family ("SF") and Multi-Family ("MF") Residential Customer Load Research Sample Data

Month	SF kW	MF kW	Date/Time of SF Peak	Date/Time of MF Peak
1	1.40	1.76	2023-01-15 5 PM	2023-01-31 5 AM
2	1.47	1.33	2023-02-17 7 PM	2023-02-01 10 AM
3	1.34	1.57	2023-03-18 8 AM	2023-03-19 8 AM
4	1.14	1.00	2023-04-17 5 PM	2023-04-19 6 AM
5	2.06	0.90	2023-05-31 2 PM	2023-05-07 6 PM
6	2.30	1.05	2023-06-24 3 PM	2023-06-25 3 PM
7	2.92	1.14	2023-07-27 3 PM	2023-07-27 6 PM
8	3.20	1.24	2023-08-24 3 PM	2023-08-24 1 PM
9	2.74	1.19	2023-09-04 4 PM	2023-09-04 6 PM
10	1.79	0.90	2023-10-01 2 PM	2023-10-01 1 PM
11	1.41	0.86	2023-11-28 5 PM	2023-11-23 11 AM
12	1.31	1.00	2023-12-30 5 PM	2023-12-10 4 PM

Q72. How was this information used to estimate metrics to allocate costs between SF and MF residential customers?

A72. Atrium used information from the CIS database (customer count and kWh) and the load research sample meters CP and NCP to develop estimated hourly profiles for the SF and MF residential customers. This data, when combined, reconciles back to the aggregate residential class prior to separating the SF and MF customers. This approach leads to a monthly separation factor for both energy and contribution to monthly CP hours between SF and MF residential customers that preserves the aggregated class's energy and CP profiles. The approach also allows for explicit estimation of individual monthly NCP for both the SF and MF residential customers as these are not anticipated (as shown above) to occur in the same hours.

Q73. Did Atrium also examine whether customers identified as MF also tended to be "low-income"?

A73. Yes, but it bears noting that neither NIPSCO nor Atrium have customer-specific income information. That said, approximately 10% of NIPSCO's electric customers are also gas customers taking service on an income qualified rate or are identified as eligible for an electric assistance program, and Atrium has identified, through census block median household income information, a greater proportion of MF residential customers in geographical areas within the NIPSCO service territory that have lower incomes generally. In short, the proposed MF rate will both provide a more cost-based rate for MF customers and also ease the energy burden of low income customers who are also MF customers. I will come back to this topic later in my testimony.

Q74. Do the differences identified in the usage characteristics between SF and MF residential customers delineate differences in the cost to serve these customers?

A74. Yes. The differences in usage characteristics show that the typical MF customer imposes a lower burden on the system than the typical SF customer, given the lower per customer energy usage and lower coincidence with the overall system demands. As such, the separation of these customer types will lead to a lower rate being offered to MF customers compared to a single residential rate.

Q75. Are there other identified differences in the cost to serve MF residential customers compared to SF residential customers?

A75. Yes. Atrium also spoke with NIPSCO's engineering and distribution planning groups to better understand potential cost differentials in service connections.

Many different factors go into new service connections, and it is not always "apples-to-apples" when comparing historical or actual costs between an SF or MF installation. However, based on these discussions, Atrium discerned that a new MF residential building would have a lower service cost per meter compared to an equivalent number of individually metered SF dwellings.

The length and type of a new service conductor required for an assumed four-unit apartment building was estimated to be 2.5 times the cost of an SF dwelling; however, because it serves four customers rather than one, the resulting service cost per customer for MF is 62.5% (2.5 / 4 = 0.625) of the costs for an SF home. In contrast, there was no indication that the relative cost of meters or transformers was different for MF customers than SF dwellings.

Q76. What do you conclude with respect to the proposed separation of the residential class into SF and MF components?

A76. Given the unique usage and cost characteristics imposed on the system by the individual SF and MF residential customers, the separation of rates for these two groups will lead to rates more aligned with the cost to serve each customer group; consequently, creation of a MF rate is an improvement in the overall design of rates for NIPSCO's customers.

B. Description of NIPSCO's Low Income Usage Analysis and Considerations in Rate Design

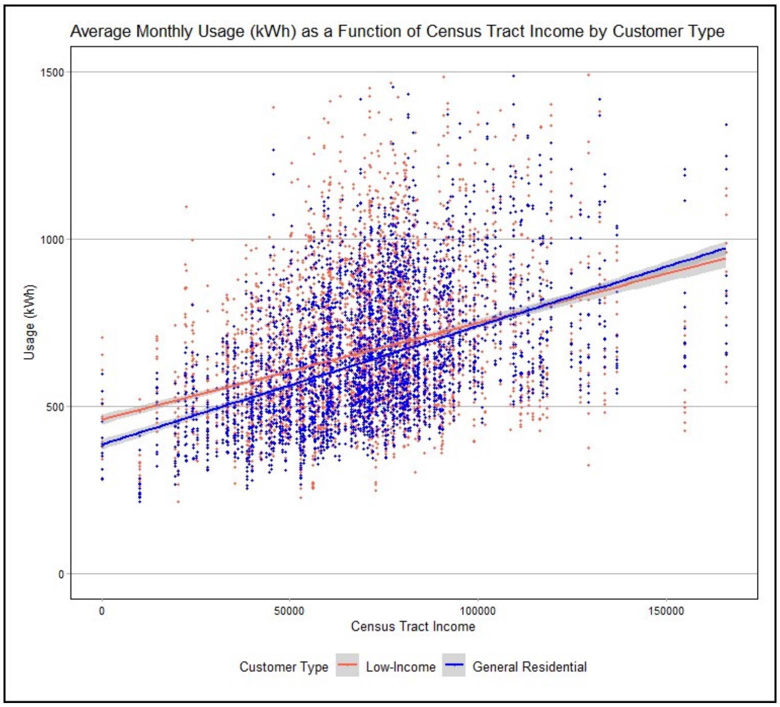
Q77. As you discussed the multi-family analysis above, you mentioned some data analysis related to low-income customers. Please describe that analysis in detail.

A77. Similar to the analysis I described earlier related to Single-Family ("SF") and Multi-Family ("MF") residential customers, Atrium also sought to identify Low-Income ("LI") from other residential customers. Atrium approached this identification explicitly in two ways: (i) as we did with the MF separation, Atrium identified electric customers that were also gas customers and took gas service on an income-qualified rate; and (ii) using an indicator included in the CIS data we identified whether a customer was eligible for a currently offered assistance program. If either of these conditions was met, then a specific customer was flagged as being LI. Using these designations, approximately 5-6% of the residential customer base would be considered LI. However, Atrium also recognized that there are likely additional customers that this type of identification process would overlook due to the gas and electric divisions operating across different geographies. Thus, we also sought to explore other ways of examining usage patterns using US Census data - though this approach would not allow Atrium to identify specific customers and leads to more general conclusions.

Q78. How did Atrium attempt to use publicly available census data to examine usage trends across different residential customer segments?

A78. Atrium used the publicly available US Census Bureau Application Programming Interface (API) to map service addresses to census tracts. The US Census Bureau keeps a variety of data and statistics based on the decennial census American Community Survey (ACS), and census tracts give additional flexibility to look more closely at a smaller area of a city or county. Upon mapping NIPSCO's residential electric customers to US census tracts, we were able to examine trends of usage by census tract as a function of the census tract's median income. Further, through the identification process discussed previously, we analyzed residential usage patterns overall or by the identified LI and other customer segments. The results of the analysis revealed that LI customers in NIPSCO's service territory had a *higher* baseline usage than other residential customers and usage tended to *increase* at a lower rate as a function of median income in each census tract compared to other residential customers. This is presented graphically in Table 8 below. It should be noted that while a census tract may report a specific level of median income, there will be a distribution of actual incomes within that census tract as well as consumption patterns. We did observe that the proportion of identified LI customers is greater in lower income census tracts but almost all census tracts contain some identified LI customers regardless of the median income of the census tract.

Table 8 - Monthly Usage Low Income and General Residential Usage



Q79. Please explain Table 8 and the underlying analysis used to create the table

A79. Table 8 presents the estimated relationship between average monthly usage by customers in NIPSCO's service territory as a function of Census Tract Median Income separated by customers identified as LI or General Residential ("GR"). The relationship is estimated by way of a weighted regression that considers the number of customers in each census tract, as well as differences in monthly consumption and census tract median income. Weighting the regression was included as the number of customers in each census tract was skewed and, for example, I did not want to allow for a single low-income customer living in a high-income census tract to be given the same weight as 300 low-income customers living in a low-income census tract. As expected, the results of the analysis demonstrate a positive correlation of usage with income. Furthermore, the analysis shows that low-income customers tend to be less sensitive to income level, meaning that the rate at which consumption is expected to increase given an increase in the census tract median income is lower for LI compared to GR customers. However, and contrary to common assumptions, the LI customers tended to consume more energy compared to GR customers in lower income census tracts. To further cement this observation, I have tabulated the predicted consumption by month for LI and GR customers at different census tract income levels using the relationship estimated and presented in Table-8. In doing so, I also estimated the census tract income inflection point where GR customers would begin to typically use more energy than LI customers. This occurs at a census tract income of $123,962. This is presented in Table 9 below. Furthermore, using this information, I also have estimated that approximately 99% of the LI customers live in census tracts below this threshold. In short, the overwhelming vast majority of LI customers are in low income census tracts where it is reasonable to assume they will have on average usage above general residential customers.

	Predicted Monthly Usage for "0" Income Census Tract		Predicted Monthly Usage for "25,000" Income Census Tract		Predicted Monthly Usage for "123,962" Income Census Tract		Predicted Monthly Usage for "150,000" Income Census Tract	
Month	Low-Income Residential Usage	General Residential Usage	Low-Income Residential Usage	General Residential Usage	Low-Income Residential Usage	General Residential Usage	Low-Income Residential Usage	General Residential Usage
1	616	487	691	576	984	926	1062	1019
2	491	349	565	437	859	788	937	881
3	451	318	525	406	819	757	896	850
4	378	269	452	358	746	709	824	801
5	313	230	387	318	681	669	759	762
6	385	359	459	448	753	798	831	891
7	588	600	663	689	956	1040	1034	1132
8	628	636	702	725	996	1076	1073	1168
9	532	534	606	622	900	973	978	1065
10	312	263	386	351	680	702	758	794
11	330	233	404	322	698	673	775	765
12	457	349	531	438	825	788	903	881
Min	**312**	**230**	**386**	**318**	**680**	**669**	**758**	**762**
Average	**457**	**386**	**531**	**474**	**825**	**825**	**902**	**917**

Q80. What are your thoughts as to why these observed trends would occur?

A80. While traditional conceptions and consumer advocate narratives are that low income tends to equate with low usage, there are many logical reasons why the opposite may hold true. Generally speaking, low income customers are less likely to be able to afford new and efficient appliances or updates to weatherize / insulate homes, are more likely to live in rentals where the appliances and insulation of the residence are outside their control, as updating the dwelling would represent a cost to the owner whereas utilities are generally paid for by the renter. Low income customers may also have less flexibility in terms of how or when they use electricity given differences of work-from-home flexibility afforded to "white-collar" workers compared to "blue-collar" workers. This can lead to differences in how customers can respond to different rate structures and timing of consumption and contributions to peak demand.

Q81. Please expand on your last statement.

A81. When certain aspects that drive how and when a customer uses energy are more rigid, it limits how those customers can shift and/or reduce electric consumption - such as a rental tenant not being able to alter the appliances or weatherize/improve insulation in a dwelling or a worker who must be onsite (whether it be an office, job site, construction site, etc.). In these cases, the tenant has no choice but to accept the efficiencies of the rental, or may not be able to "pre-cool" the dwelling depending on the type of thermostat installed. These are just two simple examples, but easily extendable to other differences in flexibility that could limit the ability of customers to respond to volumetric rates.

It is also important to note that low income households tend to choose to respond to volumetric prices by reducing their cooling load during hot weather. In July 2024, JPMorgan Chase released a research paper that analyzed how households manage their electricity bills and other spending when faced with hot weather. The primary finding is that, "low-income households primarily manage high electricity bills in hot months by using less air conditioning and enduring more heat (and) the health costs of under-cooling likely exceed the amount households save on their electricity bills."[6] The report also reiterates points I made above that low income homeowners may find it difficult to make energy efficiency and weatherization investments because of the large upfront costs, and "low-income renters are very unlikely to make these investments because the value of the capital investment will accrue to the landlord." This usage relationship is evidenced in an article by the U.S. Department of Energy that outlines high consumption as a key factor to the energy burden placed on low-income households.[7]

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[6] JPMorgan Chase & Co. (July 18, 2024). *How households manage high air conditioning bills*. Retrieved from https://www.jpmorganchase.com/institute/all-topics/financial-health-wealth-creation/how-households-manage-high-air-conditioning-bills

[7] See "Low-Income Household Energy Burden Varies Among States — Efficiency Can Help In All of Them" by U.S DOE https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf

Q82. What conclusions can you draw from the analysis you have conducted?

A82. The results of the data analysis demonstrate the best way to reduce the bills, on average, for NIPSCO's LI customers is to move more towards a Straight Fixed-Variable ("SFV") rate design. This is because the data shows that the LI customers identified in NIPSCO's service territory have a greater baseline usage then non-LI customers, and the LI customers in the lower income census tracts (which represents proportionally higher number of LI customers) tend to use more energy on average than the other residential customers in those same census tracts. Thus, any fixed costs recovered in volumetric rates would be regressive in its application to LI customers, given that low income customers may have little control over their use of energy or choose to reduce their usage to save money where the health costs of under-cooling likely exceed the amount saved on their bill.

Q83. Do all low income customers use more than the average of other residential customers?

A83. No. The analysis conducted with NIPSCO's specific customer data indicates that LI customers, *on average*, use more than the average of other residential customers, but there will be LI customers that use less than average. This is the nature of rate design – Rates can be designed on average concepts, but rates cannot be designed for each and every individual customer. However, as indicated above in the SF and MF discussion, there is a correlation seen between LI customers and MF customers - and those MF customers have lower usage and a lower cost to serve which, as discussed below, NIPSCO is reflecting in its proposed rate design.

Continuing to limit the customer charges will harm most LI customers who, as shown through the above testimony, use more than average energy. NIPSCO's proposed electric universal service program, as detailed in Company Witness Whitehead's testimony, is more suitable than artificially manipulating rate design, to address lower than average use LI customers and concerns relating to bill impacts and affordability. Rate design is not the appropriate social tool to help the most vulnerable populations within a segment of society; targeted programs such as bill discounts, financial assistance, weatherization assistance, and energy efficiency assistance are much more effective. There is no reason to send the wrong price signal to all customers when the impacts on low income customers are mixed (*i.e.*, their inability to respond to higher variable charges, the lower quality of living that may result from forgoing using electricity that is volumetrically priced, and the fact that low-income customers that use higher than average will disproportionately be impacted by higher variable charge) - particularly when there are programs in place that target assistance for low income customers, as NIPSCO's electric universal service program is designed to do.

C. <u>Description of NIPSCO's Proposed Rate Design</u>

Q84. How were the proposed rates for each rate schedule calculated?

A84. Detailed calculations for each rate component of each Rate Schedule are included in Attachment 16-H. As the exhibit shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 16-H provides a presentation of the transition of revenues at current rates and existing 500 series rate classes to the proposed revenues at the 600 series rate classes.

Q85. Do the proposed rates include increases to the existing monthly customer charges?

A85. Yes. The proposed rates would increase the Residential monthly customer charge from $14.00 to $25.00. Similarly, the General Service customer charges (Rates 520, 521, 522) are being increased to $41.60 per month from $32.50. Both of these changes are being made to more closely reflect the costs of serving each customer, as indicated by the ACOSS.

Q86. What process did you use in designing the rates?

A86. Using the revenue apportioned to each rate class as described above, I generally followed the following process: First, for Rates 511, 615, 520, 521, and 522, I established the monthly customer charge as described above with the remaining revenue being collected through the energy charge. For those rates with no customer charge, I increased each rate component by an equal percentage as the overall class increase to base rates. Where there are energy block rate structures in place, I retained the differences by increasing all blocks by the same percentage change. Lastly, for lighting rates (Rate 560 – Dusk to Dawn, Rate 555 – Traffic and Directive Lighting, and Rate 550 – Streetlighting) lamp charges, service drop charges, and energy charges were all increased at an equal percentage as the overall class increase to base rates.

Q87. Do the proposed monthly customer charge levels reflect the Company's intention to move to a greater recovery of fixed utility costs in fixed charges?

A87. Yes. In addition to supporting affordability for LI customers as I have explained, the proposed monthly customer charges also better align with cost causation and efficient pricing. The Company has proposed monthly customer charges at levels that reflect movement toward full customer-related cost responsibility. The Company utilized the Unit Cost Analysis from the ACOSS

(Attachment 16-C) to identify costs related to providing both monthly utility service to customers (customer related costs) and annual levels of utility capacity (demand related costs). The level of customer related costs is shown for the Residential Single-Family class of customers in the Unit Cost Analysis to be $33.84 per customer per month and the combined customer and demand related costs excluding production costs to be $97.21 per customer per month. In contrast, Rate 515 Residential Multi-Family Unit Cost Analysis to be $31.78 per customer per month with the combined customer and demand related costs excluding production costs to be $62.24 per customer per month (see Attachment 16-C).

Q88. Why are setting customer charges more in alignment with the fixed cost of service an important outcome of ratemaking?

A88. These proposed customer charges help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood, convey more appropriate price signals with respect to recovery of fixed utility costs, benefit low income customers that have higher than average use, and are not regressive in application to low-income customers who may have little control over their use of energy and are negatively impacted when recovering more costs in volumetric charges.

Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric block prices, which has the effect of causing some customers to pay too much while others pay too little.

The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether electricity is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure recovery by the Company of a greater portion of its fixed costs of providing service. Inasmuch as costs are not related to usage, they should be recovered, to the extent possible, through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers easily understand fixed cost charges and are used to these pricing structures in their everyday lives.[8] Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is hot, and conversely should not pay less when the weather is cold.

Q89. Has the IURC offered guidance on moving customer charges closer to a point where they recover 100% of fixed costs of service?

A89. Yes. In Cause No. 43180, the Commission conducted an investigation into rate design alternatives for natural gas utilities. The investigation was commenced as a result of numerous natural gas utilities requesting various types of decoupling mechanisms. Indeed, the investigation was initiated following the approval of CenterPoint Indiana North's, (f/k/a Vectren North) decoupling mechanism. After hearing the positions of the respondents and stakeholders, the Commission ultimately approved the basic framework for future decoupling mechanisms; however, the Commission noted that the long-term

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[8] There is a multitude of examples of fixed prices in our economy: gym memberships, leases for housing and vehicles, all payments on debt including mortgages, online subscriptions such as Amazon Prime & online streaming services such as Hulu, Netflix, Xbox Game Pass, cell phone payment plans, cell phone service plans, insurance premiums, property taxes, etc.

goal was Straight-Fixed-Variable ("SFV") pricing. Abrupt movement to SFV pricing could lead to rate shock, and utilities should, through general rate cases, make steady movement towards the goal of SFV in each rate case:

> Going forward, the Commission finds that straight fixed-variable rate designs are attractive because they align basic cost causation principals of ratemaking. However, these designs do present concerns regarding rate shock and conservation efforts. Issues of rate shock could be tempered in a phased manner through a steady transition, reducing volumetric rate design by a fixed percentage in each rate case. This transition period would be consistent with Commission efforts to reduce inter-class subsidies, i.e., gradualism. The placement of efficiency or low-income assistance program charges on the higher usage block rates may be a reasonable means of designing intra-class subsidies while creating an inclining block rate structure conducive to conservation. All of these concerns should be addressed in the context of base rate cases.[9]

In other words, while decoupling would be a mechanism available to natural gas utilities to address concerns about issues such as declining residential usage per customer and weather variations, moving to SFV pricing would be the ultimate rate design goal. NIPSCO's proposal to increase the Rate 511 customer charge and the level of the newly created Rate 515 makes this movement.

Q90. Is the IURC guidance presented in Cause No. 43180 applicable to electric

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[9] Cause No. 43180 (IURC 10/21/2009), p. 72.

utilities?

A90. Yes. The Commission in the 2016 IP&L rate case decision stated the premises in Cause No. 43180 are reasonably applicable to electric utilities:

> Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided. The Commission investigated the rate design issue with regard to natural gas service in Cause No. 43180, and the general premise appears to be reasonably applicable to electric utilities in the context of distribution-related costs.[10]

Q91. Does your proposed rate design move fully to SFV pricing for distribution related costs?

A91. No. The proposed rate design makes some movement towards SFV pricing but does not fully move to SFV pricing.

Q92. Does NIPSCO's proposed rate design reduce intraclass subsidies?

A92. Yes.[11] First, the segmentation of the residential class between SF and MF fully eliminates the intraclass subsidy that was occurring between MF and SF

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10 Cause No. 44576 (IURC 03/16/2016), p. 10.

11 The term subsidy in the context of setting rates simply represents instances when one group of customers is paying less than their cost to serve, and another is paying more than their cost to serve. Within economic and policy literature, the term subsidy is reserved for instances where payments, tax breaks, or other forms of economic support are given by governments to individuals, firms, or other governmental units to promote policy objectives. There is no transfer of dollars from one group of customers to another in the context of interclass nor intraclass subsidies.

customers, where MF customers have, on average, a lower cost to serve than SF customers. In addition, the increase in the customer charges supports a further reduction of intraclass subsidies where each customer is paying a higher portion of the fixed distribution costs that are incurred for the provision of service irrespective of the energy used.

D. Bill Impacts for the Residential Class

Q93. Do you have an attachment that shows how the proposed rates will affect various residential customers?

A93. Yes. The typical bill impacts for residential customers are shown on Attachment 16-I, which contains three bill impact analyses, (1) for single-family customers who will remain on 611, (2) for multi-family customers who will be on the new 615 rate, and (3) the bill impact for multi-family customers resulting from the movement of 611 to 615 (i.e., as a result of creating the new 615 class). As can be seen from these bill impact tables the average use multi-family customer will see a 9% decrease in their bills as a result of being on the multi-family rate as opposed to the single-family rate.

E. Other Rate Design Analyses

Q94. Has Atrium conducted other rate design analyses in preparation for this filing?

A94. Yes. As part of the 2023 Rate Case Settlement NIPSCO committed as part of preparing its cost of service study for its next electric base rate case, "study operational and usage characteristics of each of the Members of the RV Group[12] to determine if a new or adjusted rate schedule is appropriate for these customers and customers of similar characteristics who would qualify." Atrium has conducted this analysis and found that there are no distinguishing characteristics of the Members of the RV Group that would justify a new rate offering for these customers. In addition, in the 2023 Rate Case Settlement NIPSCO committed to, "study operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to this rate or the creation of another rate for current customers in Rate 532 is appropriate."

Q95. Please provide more details on the RV Group analysis.

A95. First, it is important to note that the members of the RV Group consist of five holding companies that operate several businesses within the RV Industry with 152 separately metered customer locations. These separately metered customer locations are geographically dispersed and are served across four different NIPSCO rate offerings (Rate 521, 523, 524, and 526). Atrium analyzed

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[12] The RV Group is the RV Industry User's Group – RV being an acronym for Recreational Vehicle.

the load factors for each of these customer locations for those rates that are demand billed (Rates 523, 524, and 526) and found that their load factors are generally in alignment with the load factor for the class, albeit slightly lower than the average. In addition, the average usage for these customers across Rates 523, 524, and 526 were in alignment with the average usage of the class. The data did show that the RV Group's separately metered customer locations served on Rate 521 do have higher consumption than the average for that class but they have lower usage than the average 521 customers within the largest strata of Rate 521 load research meters (i.e., they are larger than the average but not as large as the largest group of 521 customers). As such, the analysis concluded that there are no unique operating or usage characteristics of these 152 separately metered customer locations to warrant any changes to NIPSCO's rate offerings or the need for new rate offerings to be developed. These customer locations can move on to any of the rate schedules that are best suited for their usage characteristics, and the fact that they currently are on four different rate schedules indicates that they are diverse and benefit from the diversity of rate offerings already offered. This is no different than any other commercial or small industrial manufacturing facilities that operate within NIPSCO's service territory.

Q96. Are there strategies that the RV Group could implement to reduce their energy costs?

A96. Yes. Depending on the location, an improvement in a customer's load factor can decrease the average kWh rate paid (if they already have a high load factor an improvement will not be as impactful as those with a low load factor). There are also cost benefits to energy efficiency investments or weatherization investments that would reduce energy costs. In fact the 2023 Rate Case Settlement included a provision that, "NIPSCO commits to fund energy efficiency audits of up to $50,000 per customer for each of the four RV Group members." In addition, if a holding company were to consolidate multiple facilities into one location there could be benefits to their energy bill. NIPSCO's major accounts team provided examples of this consolidation, where small industrial manufacturing customers consolidated some of their operations into a single meter, made upgrades to the interconnection with NIPSCO, and was able to move to a more favorable rate structure, which provided an overall decrease in their energy costs. While I realize this may not be feasible for all the RV Group locations, it does demonstrate that the strategic business choices to operate in geographically dispersed areas have implications for energy costs as those geographically dispersed interconnections with NIPSCO have different costs to serve than a single consolidated facility.

Q97. What conclusions resulted from the review of Rate 532?

A97. Rate 532 is available to industrial customers taking service at transmission or subtransmission voltage where the customer is responsible for providing transformation equipment and they must contract for capacity which shall be not less than 15,000 kW and not exceed 25,000 kW. Currently, Rate 532 is comprised of five customers - three of which are legacy customers on the rate with contract demand amounts lower than the 15,000 kW minimum. A change to the portion of Rate 532 revenue recovered in the demand rate, or the change in the minimum contract demand requirements would have an overly adverse effect on these legacy customers. NIPSCO is open to suggestions from customers during this proceeding regarding viable alternative structures, but is cautious about proposing changes that may materially impact one group of Rate 532 customers over another.

F. Updated Tracker Allocations

Q98. Is NIPSCO proposing updates to the tracker allocators in this preceding?

A98. Yes. NIPSCO is proposing to update the tracker allocations based on proposed rate class level revenue allocations, ACOSS results, and energy allocations. Attachment 16-J provides the updated allocation factors for NIPSCO's various trackers. The methods employed to develop these allocation factors are the same as those utilized in NIPSCO's most recent base rate proceeding. The demand allocators are based on the proposed revenue allocation by rate class (i.e., the mitigated allocation of the ACOSS revenue). The Rate 531 allocation was adjusted to reduce the ACOSS revenue down to the revenue associated with Tier 1.[13] The energy allocators are based on the sales allocator from the ACOSS. The Rate 531 sales are strictly the Tier 1 sales, so no adjustment is required. The TDSIC transmission allocators are based on the transmission and sub-transmission allocation of the revenues in the ACOSS. Rate 531 has been adjusted to the transmission volumes for Tier 1. The TDSIC distribution allocators are derived from the primary and secondary distribution revenue from the ACOSS.

Q99. Does this conclude your prepared direct testimony?

A99. Yes.

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[13] Note my earlier testimony, that at rebuttal NIPSCO will adjust the Tier 1 Demand rate to reflect the greater of actual contract demand or 70 MW. This adjustment will also impact the tracker allocations.

VERIFICATION

I, John D. Taylor, Managing Partner, Atrium Management Consulting, LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

John D. Taylor

John D. Taylor

Dated: September 11, 2024

John D. Taylor

Managing Partner

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

19

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- California – Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Maryland Public Service Commission
- Massachusetts Department of Public Utilities

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- South Carolina Public Service Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA and Decoupling mechanisms for utilities including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

Cause No. 46120

NIPSCO Electric
Change in Legacy Coal Costs Due to Retirements
Changes in Rate 531 Contract Demand

4CP Allocation

Line No.	Direct Related Legacy Coal Revenue Requirement	Total	Rate 531	All Other Classes
1	Normalized Twelve Months Ended 12-31-2023	$ 756,989,983	$ 57,740,943	$ 699,249,039
2	Revenue Requirement Pro Forma at Proposed Rates 12-31-2025	$ 673,998,701	$ 51,410,615	$ 622,588,085
3	Delta (Line 2-1) - Reduction in Rev. Req. due to Legacy Coal Retirements	$ (82,991,282)	$ (6,330,328)	$ (76,660,954)
4	**New Contract Demand**	163,916	**Current CD**	180,000
5	Test Year 4 CP @ Generation	168,607		185,152
6	4 CP @ Generation Percent to 531	6.99%		7.63%
7	**Production Revenue Requirement**	$ 998,622,374		
8	Allocated to Rate 531 - Current Contract Demand	$ 998,622,374	$ 76,171,943	$ 922,450,431
9	Allocated to Rate 531 - New Contract Demand	$ 998,622,374	$ 69,841,615	$ 928,780,759
10	Delta (Line 9-8) - Reduction in Allocation of Prod. Rev. Req. due to Change in CD		$ (6,330,328)	$ 6,330,328
11	Delta Due to Decrease in Legacy Coal Costs	$ (6,330,328)		
12	Delta Due to Decrease in Contract Demand	$ (6,330,328)		
13	Difference (Set to Zero with Goal Seek via Line 4)	$ 0		

12CP Allocation

Line No.	Direct Related Legacy Coal Revenue Requirement	Total	Rate 531	All Other Classes
1	Normalized Twelve Months Ended 12-31-2023	$ 756,989,983	$ 71,916,126	$ 685,073,857
2	Revenue Requirement Pro Forma at Proposed Rates 12-31-2025	$ 673,998,701	$ 64,031,727	$ 609,966,974
3	Delta (Line 2-1) - Reduction in Rev. Req. due to Legacy Coal Retirements	$ (82,991,282)	$ (7,884,400)	$ (75,106,883)
4	**New Contract Demand**	163,614	**Current CD**	180,000
5	Test Year 12 CP @ Generation	168,296		185,152
6	12 CP @ Generation Percent to 531	8.71%		9.50%
7	**Production Revenue Requirement**	$ 998,622,374		
8	Allocated to Rate 531 - Current Contract Demand	$ 998,622,374	$ 94,871,867	$ 903,750,507
9	Allocated to Rate 531 - New Contract Demand	$ 998,622,374	$ 86,987,467	$ 911,634,907
10	Delta (Line 9-8) - Reduction in Allocation of Prod. Rev. Req. due to Change in CD		$ (7,884,400)	$ 7,884,400
11	Delta Due to Decrease in Legacy Coal Costs	$ (7,884,400)		
12	Delta Due to Decrease in Contract Demand	$ (7,884,400)		
13	Difference (Set to Zero with Goal Seek via Line 4)	$ (0)		

Cause No. 46120

NIPSCO Electric
Change in Legacy Coal Costs Due to Retirements
Revenue Requirement Analysis

Line No.	(A) Production Plant	(B) = (C)-(D) Change in Legacy Coal Due to Retirements	(C) Normalized Twelve Months Ended 12-31-2023	(D) Revenue Requirement Pro Forma at Proposed Rates 12-31-2025
1	Steam Production Gross Plant (310-316)	$ (1,389,021,250)	$ 2,515,944,088	$ 1,126,922,838
2	Steam Production Depreciation Reserve (310-316)	975,168,287	(1,758,619,308)	(783,451,021)
3	Schahfer Units 14, 15, 17 and 18 Retirement Adj.	68,638,138	592,487,087	661,125,225
4	Fuel Inventory Adj.	(49,599,140)	65,267,664	15,668,524
5	Total Rate Base (Sum Lines 1-4)	$ (394,813,965)	$ 1,415,079,531	$ 1,020,265,566
6	**Steam Production Operations**			
7	Supervision & Engineering (500)	$ (2,159,103)	$ 6,484,305	$ 4,325,202
8	Fuel (Non-Trackable) (501)	(11,185,515)	17,913,559	6,728,044
9	Steam Expenses (502)	(8,927,871)	20,499,343	11,571,472
10	Electric Expenses (505)	845,624	5,555,206	6,400,830
11	Miscellaneous Steam Power Expenses (506)	(722,244)	2,161,317	1,439,072
	Steam Production Operations (Sum Lines 9-13)	$ (22,149,109)	$ 52,613,730	$ 30,464,621
	Steam Production Maintenance			
12	Supervision & Engineering (510)	$ (1,244,218)	$ 3,852,917	$ 2,608,699
13	Structures (511)	(6,330,419)	13,207,701	6,877,281
14	Boiler Plant (512)	(7,163,222)	21,649,932	14,486,710
15	Electric Plant (513)	(3,629,662)	7,655,886	4,026,224
16	Miscellaneous Steam Power Expenses (514)	(7,357,116)	16,765,211	9,408,095
17	Steam Production Maintenance (Sume Lines 14-1	$ (25,724,636)	$ 63,131,647	$ 37,407,010
18	**Trackable Fuel Expenses**			
19	Fuel Expense Relating to Legacy Coal (a)	$ (22,533,029)	$ 328,861,915	$ 306,328,886
20	Fuel Expense Relating to Legacy Coal (b)	(46,322)	772,128	725,806
21	Fuel Expenses (Sum Lines 21)	$ (22,579,351)	$ 329,634,043	$ 307,054,692
22	**Steam Depreciation & Amortization Expense**			
23	Steam Production Depreciation Expense (310-316)	$ 2,578,674	118,134,739	120,713,413
24	RMS Unit 14/15/17/18 Amortization Expense	22,724,917	55,054,521	77,779,438
25	Steam Depr. & Amort. Expense (Sum Lines 24-25	$ 25,303,591	$ 173,189,260	$ 198,492,851
26	**REVENUE REQUIREMENT**			
27	Return on Rate Base with Gross Up	$ (37,565,981)	$ 134,642,784	$ 97,076,803
28	O&M with Gross Up	$ (48,166,181)	$ 116,452,406	$ 68,286,225
29	Trackable Fuel Expenses with Gross Up	$ (22,717,277)	$ 331,647,608	$ 308,930,332
30	Depreciation and Amortization with Gross Up	$ 25,458,158	$ 174,247,185	$ 199,705,342
31	**TOTAL REVENUE REQUIREMENT**	**$ (82,991,282)**	**$ 756,989,983**	**$ 673,998,701**

Notes:

(a) This reflects FPP 1-25R - reflecting the retirement of U17/18 and impact across trackable fuel expense.

(b) This reflects the reclass of fuel costs relating to interdepartmental.

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2	**Rate Base**								
3	Plant in Service	$10,736,559,952	$ 4,770,825,404	$ 441,188,705	$ 7,668,826	$ 1,629,469,636	$ 4,687,718	$ 787,729,165	$ 920,750,166
4	Accumulated Reserve	(3,240,408,299)	(1,491,164,237)	(144,056,753)	(2,265,400)	(491,310,945)	(1,353,995)	(228,086,881)	(269,205,977)
5	Other Rate Base Items	1,733,661,788	770,677,043	48,298,528	195,490	264,979,794	128,384	139,357,472	161,826,333
6	**Total Rate Base**	**$ 9,229,813,441**	**$ 4,050,338,209**	**$ 345,430,480**	**$ 5,598,916**	**$ 1,403,138,485**	**$ 3,462,106**	**$ 698,999,756**	**$ 813,370,521**
7	**Revenue at Current Rates**								
8	Retail Sales - Non Fuel	$ 1,381,256,554	$ 471,527,029	$ 59,303,021	$ 833,893	$ 249,767,459	$ 730,039	$ 117,756,153	$ 169,264,316
9	TDSIC Revenue	93,344,310	41,315,349	4,818,982	123,052	14,623,813	104,384	8,153,093	10,606,120
10	DSM Revenue	11,970,888	3,847,798	448,803	6,703	2,905,441	5,479	1,286,412	2,628,610
11	RA Tracker	(6,370,886)	(1,992,450)	(232,397)	(4,275)	(1,209,399)	(5,100)	(695,432)	(765,040)
12	Generation Credit	(4,386,191)	(1,411,527)	(164,639)	(2,673)	(766,933)	(2,659)	(426,779)	(572,486)
13	Retail Sales - Fuel	329,634,043	95,870,856	11,182,284	280,388	49,893,314	221,646	26,725,051	44,006,839
14	Other Revenues	24,150,198	8,743,142	997,310	13,144	3,659,902	8,933	1,662,281	2,156,000
15	**Total Revenue**	**$ 1,829,598,917**	**$ 617,900,197**	**$ 76,353,364**	**$ 1,250,233**	**$ 318,873,596**	**$ 1,062,722**	**$ 154,460,778**	**$ 227,324,359**
16	**Expenses at Current Rates**								
17	Operations & Maintenance Expenses	$ 467,401,861	$ 220,262,525	$ 22,151,336	$ 536,178	$ 71,455,054	$ 236,005	$ 33,328,071	$ 38,013,769
18	Depreciation Expense	389,034,290	173,253,292	13,611,843	179,404	59,102,031	106,382	29,764,536	34,480,140
19	Amortization Expense	182,974,471	84,135,211	7,290,992	47,703	27,184,069	33,234	13,300,127	15,852,762
20	Fuel Expenses	329,634,043	96,148,239	11,214,638	281,199	50,019,525	222,288	26,791,039	43,983,715
21	Taxes Other Than Income	43,310,222	19,567,749	1,864,369	38,131	6,609,207	19,952	3,137,163	3,639,634
22	Income Taxes	33,879,159	1,992,032	1,641,828	13,610	8,485,437	36,122	3,908,833	7,417,741
23	**Total Expenses at Current Rates**	**$ 1,446,234,047**	**$ 595,359,049**	**$ 57,775,006**	**$ 1,096,226**	**$ 222,855,323**	**$ 653,982**	**$ 110,229,770**	**$ 143,387,761**
24	Current Operating Income	$ 383,364,870	$ 22,541,148	$ 18,578,358	$ 154,007	$ 96,018,274	$ 408,740	$ 44,231,009	$ 83,936,599
25	Current Rate of Return	4.15%	0.56%	5.38%	2.75%	6.84%	11.81%	6.33%	10.32%
26	Revenue to Cost Ratio (Line 12 / Line 46)	0.83	0.65	0.89	0.81	0.96	1.19	0.93	1.12
27	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	0.78	1.07	0.97	1.15	1.43	1.12	1.35
28	**Current Revenue at Equal Rates of Return**								
29	Current Rate of Return	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%
30	Current Operating Income at Equal ROR	$ 383,364,870	$ 168,232,802	$ 14,347,626	$ 232,554	$ 58,280,051	$ 143,800	$ 29,033,301	$ 33,783,747
31	Other Expenses - Equal ROR	1,412,354,888	593,367,017	56,133,178	1,082,616	214,369,886	617,861	106,320,936	135,970,020
32	Income Taxes - Equal ROR	33,879,159	14,867,262	1,267,945	20,552	5,150,391	12,708	2,565,764	2,985,576
33	**Total Revenue Requirement at Equal Current ROR**	**$ 1,829,598,917**	**$ 776,467,081**	**$ 71,748,749**	**$ 1,335,721**	**$ 277,800,329**	**$ 774,369**	**$ 137,920,001**	**$ 172,739,343**
34	Current Cross Subsidies (Line 34)	-	(158,566,884)	4,604,615	(85,488)	41,073,268	288,353	16,540,777	54,585,017

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
1	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
2	**Rate Base**								
3	Plant in Service	$10,736,559,952	$ 41,127,423	$ 865,449,658	$ 918,496,196	$ 66,006,051	$ 69,006,423	$ 23,176,620	$ 173,902
4	Accumulated Reserve	(3,240,408,299)	(11,598,725)	(247,222,428)	(240,963,683)	(19,587,123)	(21,003,362)	(7,053,902)	(50,457)
5	Other Rate Base Items	1,733,661,788	6,227,777	170,936,112	126,371,878	15,313,820	16,635,690	2,911,960	30,369
6	**Total Rate Base**	**$ 9,229,813,441**	**$ 35,756,475**	**$ 789,163,343**	**$ 803,904,391**	**$ 61,732,749**	**$ 64,638,750**	**$ 19,034,678**	**$ 153,814**
7	**Revenue at Current Rates**								
8	Retail Sales - Non Fuel	$ 1,381,256,554	$ 5,995,930	$ 142,143,090	$ 111,648,686	$ 11,862,980	$ 17,930,120	$ 4,486,246	$ 56,441
9	TDSIC Revenue	93,344,310	491,084	7,838,993	2,611,056	462,100	747,626	255,555	-
10	DSM Revenue	11,970,888	139,109	470,027	-	187,243	15,399	24,809	-
11	RA Tracker	(6,370,886)	(32,679)	(649,274)	(566,837)	(62,302)	(77,580)	(23,174)	(501)
12	Generation Credit	(4,386,191)	(22,765)	(422,704)	(426,461)	(40,077)	(64,712)	(12,259)	(391)
13	Retail Sales - Fuel	329,634,043	2,681,301	48,524,661	32,107,520	4,947,513	8,429,028	1,165,639	10,696
14	Other Revenues	24,150,198	92,598	2,001,017	4,308,595	174,273	176,805	34,918	535
15	**Total Revenue**	**$ 1,829,598,917**	**$ 9,344,577**	**$ 199,905,810**	**$ 149,682,559**	**$ 17,531,731**	**$ 27,156,687**	**$ 5,931,735**	**$ 66,780**
16	**Expenses at Current Rates**								
17	Operations & Maintenance Expenses	$ 467,401,861	$ 1,695,447	$ 37,089,660	$ 30,444,733	$ 2,695,539	$ 3,040,714	$ 983,838	$ 9,322
18	Depreciation Expense	389,034,290	1,422,644	34,259,601	29,489,799	2,811,500	2,966,706	748,192	6,434
19	Amortization Expense	182,974,471	658,434	16,615,115	12,689,766	1,487,816	1,726,676	336,921	3,426
20	Fuel Expenses	329,634,043	2,671,992	48,459,896	31,764,741	4,899,155	8,342,402	1,168,221	12,016
21	Taxes Other Than Income	43,310,222	161,996	3,451,786	3,507,004	261,345	271,517	92,711	694
22	Income Taxes	33,879,159	221,999	4,874,264	3,392,959	436,548	877,637	211,264	2,833
23	**Total Expenses at Current Rates**	**$ 1,446,234,047**	**$ 6,832,512**	**$ 144,750,322**	**$ 111,289,002**	**$ 12,591,903**	**$ 17,225,652**	**$ 3,541,147**	**$ 34,725**
24	Current Operating Income	$ 383,364,870	$ 2,512,065	$ 55,155,489	$ 38,393,557	$ 4,939,828	$ 9,931,035	$ 2,390,588	$ 32,055
25	Current Rate of Return	4.15%	7.03%	6.99%	4.78%	8.00%	15.36%	12.56%	20.84%
26	Revenue to Cost Ratio (Line 12 / Line 46)	0.83	0.99	0.98	0.85	1.03	1.30	1.22	1.52
27	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	1.19	1.18	1.02	1.24	1.56	1.47	1.83
28	**Current Revenue at Equal Rates of Return**								
29	Current Rate of Return	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%
30	Current Operating Income at Equal ROR	$ 383,364,870	$ 1,485,163	$ 32,778,290	$ 33,390,567	$ 2,564,100	$ 2,684,802	$ 790,615	$ 6,389
31	Other Expenses - Equal ROR	1,412,354,888	6,610,513	139,876,058	107,896,043	12,155,355	16,348,015	3,329,884	31,892
32	Income Taxes - Equal ROR	33,879,159	131,249	2,896,721	2,950,829	226,598	237,264	69,869	565
33	**Total Revenue Requirement at Equal Current ROR**	**$ 1,829,598,917**	**$ 8,226,924**	**$ 175,551,068**	**$ 144,237,439**	**$ 14,946,053**	**$ 19,270,082**	**$ 4,190,367**	**$ 38,845**
34	Current Cross Subsidies (Line 34)	-	1,117,653	24,354,742	5,445,120	2,585,678	7,886,604	1,741,367	27,935

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
1	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
2	**Rate Base**							
3	Plant in Service	$10,736,559,952	$ 13,618,178	$ 22,125,287	$ 94,670,479	$ 5,283,278	$ 29,316,858	$ 25,789,980
4	Accumulated Reserve	(3,240,408,299)	(6,817,296)	(5,615,830)	(29,524,416)	(1,589,751)	(14,396,762)	(7,540,376)
5	Other Rate Base Items	1,733,661,788	1,218,839	1,299,476	2,226,681	624,483	688,416	3,713,244
6	**Total Rate Base**	**$ 9,229,813,441**	**$ 8,019,722**	**$ 17,808,933**	**$ 67,372,744**	**$ 4,318,010**	**$ 15,608,512**	**$ 21,962,848**
7	**Revenue at Current Rates**							
8	Retail Sales - Non Fuel	$ 1,381,256,554	$ 2,583,157	$ 1,081,854	$ 6,398,943	$ 925,722	$ 2,626,819	$ 4,334,654
9	TDSIC Revenue	93,344,310	135,249	195,360	243,822	31,760	122,821	464,091
10	DSM Revenue	11,970,888	5,054	-	-	-	-	-
11	RA Tracker	(6,370,886)	-	(5,187)	(32,143)	(5,010)	(12,105)	-
12	Generation Credit	(4,386,191)	-	(6,466)	(23,867)	(2,979)	(6,054)	(9,759)
13	Retail Sales - Fuel	329,634,043	772,573	350,041	973,509	205,885	430,266	855,034
14	Other Revenues	24,150,198	13,081	15,901	31,758	7,424	24,672	27,909
15	**Total Revenue**	**$ 1,829,598,917**	**$ 3,509,114**	**$ 1,631,503**	**$ 7,592,020**	**$ 1,162,803**	**$ 3,186,419**	**$ 5,671,930**
16	**Expenses at Current Rates**							
17	Operations & Maintenance Expenses	$ 467,401,861	$ 272,299	$ 714,885	$ 1,940,297	$ 168,107	$ 1,208,287	$ 1,155,794
18	Depreciation Expense	389,034,290	398,577	516,288	3,910,507	214,922	892,145	899,346
19	Amortization Expense	182,974,471	146,771	154,543	421,721	70,219	451,039	367,926
20	Fuel Expenses	329,634,043	764,383	346,963	976,326	206,480	431,511	929,316
21	Taxes Other Than Income	43,310,222	47,298	86,409	321,123	19,532	108,494	104,106
22	Income Taxes	33,879,159	152,634	(15,231)	1,790	39,262	7,709	179,888
23	**Total Expenses at Current Rates**	**$ 1,446,234,047**	**$ 1,781,962**	**$ 1,803,857**	**$ 7,571,765**	**$ 718,523**	**$ 3,099,185**	**$ 3,636,376**
24	Current Operating Income	$ 383,364,870	$ 1,727,152	$ (172,354)	$ 20,256	$ 444,280	$ 87,233	$ 2,035,554
25	Current Rate of Return	4.15%	21.54%	-0.97%	0.03%	10.29%	0.56%	9.27%
26	Revenue to Cost Ratio (Line 12 / Line 46)	0.83	1.57	0.48	0.56	1.12	0.72	1.07
27	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	1.89	0.58	0.67	1.35	0.86	1.29
28	**Current Revenue at Equal Rates of Return**							
29	Current Rate of Return	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%
30	Current Operating Income at Equal ROR	$ 383,364,870	$ 333,103	$ 739,703	$ 2,798,360	$ 179,351	$ 648,307	$ 912,238
31	Other Expenses - Equal ROR	1,412,354,888	1,629,328	1,819,088	7,569,975	679,260	3,091,476	3,456,488
32	Income Taxes - Equal ROR	33,879,159	29,437	65,370	247,300	15,850	57,293	80,617
33	**Total Revenue Requirement at Equal Current ROR**	**$ 1,829,598,917**	**$ 1,991,868**	**$ 2,624,161**	**$ 10,615,635**	**$ 874,461**	**$ 3,797,076**	**$ 4,449,343**
34	Current Cross Subsidies (Line 34)	-	1,517,246	(992,658)	(3,023,614)	288,342	(610,658)	1,222,587

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
35	**Revenue Requirement at Equal Rates of Return**								
36	Required Return	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%
37	Required Operating Income	$ 700,542,840	$ 307,420,670	$ 26,218,173	$ 424,958	$ 106,498,211	$ 262,774	$ 53,054,082	$ 61,734,823
38	Operating Income (Deficiency)/Surplus	$ (317,177,971)	$ (284,879,522)	$ (7,639,815)	$ (270,951)	$ (10,479,937)	$ 145,966	$ (8,823,073)	$ 22,201,776
39	Operations & Maintenance Expenses	$ 467,401,861	$ 220,262,525	$ 22,151,336	$ 536,178	$ 71,455,054	$ 236,005	$ 33,328,071	$ 38,013,769
40	Depreciation Expense	389,034,290	173,253,292	13,611,843	179,404	59,102,031	106,382	29,764,536	34,480,140
41	Amortization Expense	182,974,471	84,135,211	7,290,992	47,703	27,184,069	33,234	13,300,127	15,852,762
42	Fuel Expenses	273,878,561	79,885,382	9,317,754	233,636	41,559,044	184,689	22,259,507	36,544,152
43	Taxes Other Than Income	43,310,222	19,567,749	1,864,369	38,131	6,609,207	19,952	3,137,163	3,639,634
44	Income Taxes	33,879,159	14,867,262	1,267,945	20,552	5,150,391	12,708	2,565,764	2,985,576
45	Income Tax Increase	104,999,844	46,077,300	3,929,673	63,694	15,962,329	39,385	7,951,934	9,253,034
46	Bad Debt Expense Increase	1,685,295	1,292,312	242,350	-	83,632	-	4,711	489
47	Public Utility Fee Increase	552,991	245,723	22,724	395	83,927	241	40,572	47,424
48	Total Expenses at Equal Rates of Return	1,497,716,695	639,586,757	59,698,985	1,119,694	227,189,683	632,597	112,352,385	140,816,979
49	**Total Revenue Requirement at Equal Rates of Return**	**$ 2,198,259,535**	**$ 947,007,427**	**$ 85,917,158**	**$ 1,544,651**	**$ 333,687,894**	**$ 895,371**	**$ 165,406,466**	**$ 202,551,802**
50	Revenue (Deficiency)/Surplus	(368,660,619)	(329,107,230)	(9,563,795)	(294,418)	(14,814,298)	167,351	(10,945,688)	24,772,558
51	Total Current Revenues	1,829,598,917	617,900,197	76,353,364	1,250,233	318,873,596	1,062,722	154,460,778	227,324,359
52	Total Revenues at Equal Rates of Return	2,198,259,535	947,007,427	85,917,158	1,544,651	333,687,894	895,371	165,406,466	202,551,802
53	Less Total Other Revenues	24,150,198	8,743,142	997,310	13,144	3,659,902	8,933	1,662,281	2,156,000
54	**Total Base Revenues at Equal Rates of Return**	**$ 2,174,109,337**	**$ 938,264,285**	**$ 84,919,849**	**$ 1,531,507**	**$ 330,027,992**	**$ 886,438**	**$ 163,744,185**	**$ 200,395,801**
55	**Mitigation**								
56	Revenue Apportionment Mitigation	$ 0	$ (204,601,544)	$ -	$ 83,461	$ 58,001,661	$ 360,655	$ 28,095,715	$ 66,121,827
57	Proposed Increase Post Mitigation	$ 368,660,619	$ 124,505,686	$ 9,563,795	$ 377,879	$ 72,815,959	$ 193,304	$ 39,041,403	$ 41,349,270
58	Total Current Revenues	$ 1,829,598,917	$ 617,900,197	$ 76,353,364	$ 1,250,233	$ 318,873,596	$ 1,062,722	$ 154,460,778	$ 227,324,359
59	Total Revenues as Proposed	$ 2,198,259,535	$ 742,405,883	$ 85,917,158	$ 1,628,112	$ 391,689,555	$ 1,256,026	$ 193,502,181	$ 268,673,629
60	Less Total Other Revenues	$ 24,150,198	$ 8,743,142	$ 997,310	$ 13,144	$ 3,659,902	$ 8,933	$ 1,662,281	$ 2,156,000
61	**Total Base Rate Revenue as Proposed**	**$ 2,174,109,337**	**$ 733,662,741**	**$ 84,919,849**	**$ 1,614,968**	**$ 388,029,653**	**$ 1,247,093**	**$ 191,839,900**	**$ 266,517,629**
62	Proposed Income Prior to Taxes	$ 839,421,843	$ 163,763,688	$ 31,415,791	$ 592,664	$ 185,612,593	$ 675,523	$ 91,667,494	$ 140,095,260
63	Income Taxes at Proposed	138,879,003	27,094,050	5,197,618	98,054	30,708,865	111,763	15,166,022	23,178,203
64	Operating Income at Proposed	$ 700,542,840	$ 136,669,637	$ 26,218,173	$ 494,610	$ 154,903,728	$ 563,760	$ 76,501,472	$ 116,917,057
65	Rate of Return at Proposed	7.59%	3.37%	7.59%	8.83%	11.04%	16.28%	10.94%	14.37%
66	Parity Ratio - Revenue to Cost Ratio	1.00	0.78	1.00	1.05	1.17	1.40	1.17	1.33
67	Current Cross Subsidies (Line 34)	$ -	$ (158,566,884)	$ 4,604,615	$ (85,488)	$ 41,073,268	$ 288,353	$ 16,540,777	$ 54,585,017
68	Cross Subsidies at Proposed Rates (Line 59 - Line 52)	$ -	$ (204,601,544)	$ -	$ 83,461	$ 58,001,661	$ 360,655	$ 28,095,715	$ 66,121,827
69	Dollar Value of Change in Cross Subsidies	$ -	$ (46,034,660)	$ (4,604,615)	$ 168,949	$ 16,928,393	$ 72,302	$ 11,554,938	$ 11,536,811
70	Percent Change in Cross Subsidies		29%	-100%	-198%	41%	25%	70%	21%

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
1	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
35	**Revenue Requirement at Equal Rates of Return**								
36	Required Return	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%
37	Required Operating Income	$ 700,542,840	$ 2,713,916	$ 59,897,498	$ 61,016,343	$ 4,685,516	$ 4,906,081	$ 1,444,732	$ 11,674
38	Operating Income (Deficiency)/Surplus	$ (317,177,971)	$ (201,852)	$ (4,742,009)	$ (22,622,787)	$ 254,312	$ 5,024,953	$ 945,855	$ 20,381
39	Operations & Maintenance Expenses	$ 467,401,861	$ 1,695,447	$ 37,089,660	$ 30,444,733	$ 2,695,539	$ 3,040,714	$ 983,838	$ 9,322
40	Depreciation Expense	389,034,290	1,422,644	34,259,601	29,489,799	2,811,500	2,966,706	748,192	6,434
41	Amortization Expense	182,974,471	658,434	16,615,115	12,689,766	1,487,816	1,726,676	336,921	3,426
42	Fuel Expenses	273,878,561	2,220,041	40,263,216	26,391,939	4,070,494	6,931,338	970,624	9,984
43	Taxes Other Than Income	43,310,222	161,996	3,451,786	3,507,004	261,345	271,517	92,711	694
44	Income Taxes	33,879,159	131,249	2,896,721	2,950,829	226,598	237,264	69,869	565
45	Income Tax Increase	104,999,844	406,771	8,977,649	9,145,346	702,282	735,341	216,542	1,750
46	Bad Debt Expense Increase	1,685,295	-	-	-	-	58,875	45	-
47	Public Utility Fee Increase	552,991	2,118	44,575	47,308	3,400	3,554	1,194	9
48	Total Expenses at Equal Rates of Return	1,497,716,695	6,698,701	143,598,323	114,666,724	12,258,974	15,971,986	3,419,936	32,183
49	**Total Revenue Requirement at Equal Rates of Return**	**$ 2,198,259,535**	**$ 9,412,617**	**$ 203,495,820**	**$ 175,683,067**	**$ 16,944,489**	**$ 20,878,068**	**$ 4,864,668**	**$ 43,857**
50	Revenue (Deficiency)/Surplus	(368,660,619)	(68,040)	(3,590,010)	(26,000,508)	587,242	6,278,619	1,067,067	22,923
51	Total Current Revenues	1,829,598,917	9,344,577	199,905,810	149,682,559	17,531,731	27,156,687	5,931,735	66,780
52	Total Revenues at Equal Rates of Return	2,198,259,535	9,412,617	203,495,820	175,683,067	16,944,489	20,878,068	4,864,668	43,857
53	Less Total Other Revenues	24,150,198	92,598	2,001,017	4,308,595	174,273	176,805	34,918	535
54	**Total Base Revenues at Equal Rates of Return**	**$ 2,174,109,337**	**$ 9,320,019**	**$ 201,494,803**	**$ 171,374,472**	**$ 16,770,216**	**$ 20,701,262**	**$ 4,829,749**	**$ 43,323**
55	**Mitigation**								
56	Revenue Apportionment Mitigation	$ 0	$ 1,699,736	$ 36,361,960	$ -	$ 3,776,184	$ 10,439,034	$ 2,146,023	$ 21,929
57	Proposed Increase Post Mitigation	$ 368,660,619	$ 1,767,777	$ 39,951,970	$ 26,000,508	$ 3,188,942	$ 4,160,415	$ 1,078,956	$ (994)
58	Total Current Revenues	$ 1,829,598,917	$ 9,344,577	$ 199,905,810	$ 149,682,559	$ 17,531,731	$ 27,156,687	$ 5,931,735	$ 66,780
59	Total Revenues as Proposed	$ 2,198,259,535	$ 11,112,353	$ 239,857,781	$ 175,683,067	$ 20,720,673	$ 31,317,101	$ 7,010,690	$ 65,786
60	Less Total Other Revenues	$ 24,150,198	$ 92,598	$ 2,001,017	$ 4,308,595	$ 174,273	$ 176,805	$ 34,918	$ 535
61	**Total Base Rate Revenue as Proposed**	**$ 2,174,109,337**	**$ 11,019,755**	**$ 237,856,763**	**$ 171,374,472**	**$ 20,546,400**	**$ 31,140,296**	**$ 6,975,772**	**$ 65,251**
62	Proposed Income Prior to Taxes	$ 839,421,843	$ 4,951,672	$ 108,133,828	$ 73,112,519	$ 9,390,579	$ 16,317,720	$ 3,877,166	$ 35,918
63	Income Taxes at Proposed	138,879,003	819,234	17,890,311	12,096,175	1,553,634	2,699,702	641,462	5,942
64	Operating Income at Proposed	$ 700,542,840	$ 4,132,438	$ 90,243,516	$ 61,016,343	$ 7,836,945	$ 13,618,018	$ 3,235,704	$ 29,975
65	Rate of Return at Proposed	7.59%	11.56%	11.44%	7.59%	12.69%	21.07%	17.00%	19.49%
66	Parity Ratio - Revenue to Cost Ratio	1.00	1.18	1.18	1.00	1.22	1.50	1.44	1.50
67	Current Cross Subsidies (Line 34)	$ -	$ 1,117,653	$ 24,354,742	$ 5,445,120	$ 2,585,678	$ 7,886,604	$ 1,741,367	$ 27,935
68	Cross Subsidies at Proposed Rates (Line 59 - Line 52)	$ -	$ 1,699,736	$ 36,361,960	$ -	$ 3,776,184	$ 10,439,034	$ 2,146,023	$ 21,929
69	Dollar Value of Change in Cross Subsidies	$ -	$ 582,083	$ 12,007,218	$ (5,445,120)	$ 1,190,506	$ 2,552,429	$ 404,655	$ (6,006)
70	Percent Change in Cross Subsidies		52%	49%	-100%	46%	32%	23%	-22%

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
1	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
35	**Revenue Requirement at Equal Rates of Return**							
36	Required Return	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%
37	Required Operating Income	$ 700,542,840	$ 608,697	$ 1,351,698	$ 5,113,591	$ 327,737	$ 1,184,686	$ 1,666,980
38	Operating Income (Deficiency)/Surplus	$ (317,177,971)	$ 1,118,455	$ (1,524,052)	$ (5,093,336)	$ 116,543	$ (1,097,453)	$ 368,573
39	Operations & Maintenance Expenses	$ 467,401,861	$ 272,299	$ 714,885	$ 1,940,297	$ 168,107	$ 1,208,287	$ 1,155,794
40	Depreciation Expense	389,034,290	398,577	516,288	3,910,507	214,922	892,145	899,346
41	Amortization Expense	182,974,471	146,771	154,543	421,721	70,219	451,039	367,926
42	Fuel Expenses	273,878,561	635,092	288,276	811,186	171,556	358,524	772,128
43	Taxes Other Than Income	43,310,222	47,298	86,409	321,123	19,532	108,494	104,106
44	Income Taxes	33,879,159	29,437	65,370	247,300	15,850	57,293	80,617
45	Income Tax Increase	104,999,844	91,234	202,597	766,443	49,122	177,565	249,853
46	Bad Debt Expense Increase	1,685,295	-	-	17	-	2,865	-
47	Public Utility Fee Increase	552,991	701	1,140	4,876	272	1,510	1,328
48	Total Expenses at Equal Rates of Return	1,497,716,695	1,621,410	2,029,508	8,423,471	709,580	3,257,722	3,631,099
49	**Total Revenue Requirement at Equal Rates of Return**	**$ 2,198,259,535**	**$ 2,230,107**	**$ 3,381,206**	**$ 13,537,063**	**$ 1,037,317**	**$ 4,442,408**	**$ 5,298,079**
50	Revenue (Deficiency)/Surplus	(368,660,619)	1,279,007	(1,749,704)	(5,945,042)	125,486	(1,255,989)	373,851
51	Total Current Revenues	1,829,598,917	3,509,114	1,631,503	7,592,020	1,162,803	3,186,419	5,671,930
52	Total Revenues at Equal Rates of Return	2,198,259,535	2,230,107	3,381,206	13,537,063	1,037,317	4,442,408	5,298,079
53	Less Total Other Revenues	24,150,198	13,081	15,901	31,758	7,424	24,672	27,909
54	**Total Base Revenues at Equal Rates of Return**	**$ 2,174,109,337**	**$ 2,217,026**	**$ 3,365,306**	**$ 13,505,305**	**$ 1,029,893**	**$ 4,417,736**	**$ 5,270,169**
55	**Mitigation**							
56	Revenue Apportionment Mitigation	$ 0	$ 1,115,053	$ (1,420,959)	$ (3,650,376)	$ 336,994	$ (292,903)	$ 1,405,549
57	Proposed Increase Post Mitigation	$ 368,660,619	$ (163,954)	$ 328,745	$ 2,294,666	$ 211,509	$ 963,086	$ 1,031,698
58	Total Current Revenues	$ 1,829,598,917	$ 3,509,114	$ 1,631,503	$ 7,592,020	$ 1,162,803	$ 3,186,419	$ 5,671,930
59	Total Revenues as Proposed	$ 2,198,259,535	$ 3,345,160	$ 1,960,247	$ 9,886,687	$ 1,374,311	$ 4,149,505	$ 6,703,628
60	Less Total Other Revenues	$ 24,150,198	$ 13,081	$ 15,901	$ 31,758	$ 7,424	$ 24,672	$ 27,909
61	**Total Base Rate Revenue as Proposed**	**$ 2,174,109,337**	**$ 3,332,079**	**$ 1,944,347**	**$ 9,854,928**	**$ 1,366,887**	**$ 4,124,832**	**$ 6,675,719**
62	Proposed Income Prior to Taxes	$ 839,421,843	$ 1,844,421	$ 198,706	$ 2,476,958	$ 729,703	$ 1,126,641	$ 3,403,000
63	Income Taxes at Proposed	138,879,003	305,152	32,875	409,803	120,727	186,398	563,013
64	Operating Income at Proposed	$ 700,542,840	$ 1,539,269	$ 165,831	$ 2,067,155	$ 608,977	$ 940,242	$ 2,839,987
65	Rate of Return at Proposed	7.59%	19.19%	0.93%	3.07%	14.10%	6.02%	12.93%
66	Parity Ratio - Revenue to Cost Ratio	1.00	1.50	0.58	0.73	1.32	0.93	1.27
67	Current Cross Subsidies (Line 34)	$ -	$ 1,517,246	$ (992,658)	$ (3,023,614)	$ 288,342	$ (610,658)	$ 1,222,587
68	Cross Subsidies at Proposed Rates (Line 59 - Line 52)	$ -	$ 1,115,053	$ (1,420,959)	$ (3,650,376)	$ 336,994	$ (292,903)	$ 1,405,549
69	Dollar Value of Change in Cross Subsidies	$ -	$ (402,192)	$ (428,301)	$ (626,762)	$ 48,653	$ 317,754	$ 182,963
70	Percent Change in Cross Subsidies		-27%	43%	21%	17%	-52%	15%

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**Functional Revenue Requirement**								
2	**Production**								
3	Demand	$ 972,468,005	$ 436,785,625	$ 24,956,249	$ -	$ 148,844,401	$ -	$ 79,192,561	$ 90,804,144
4	Energy	$ 26,154,368	$ 7,630,406	$ 890,003	$ 22,316	$ 3,969,592	$ 17,641	$ 2,126,160	$ 3,490,585
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 998,622,374	$ 444,416,031	$ 25,846,252	$ 22,316	$ 152,813,993	$ 17,641	$ 81,318,720	$ 94,294,729
7	**Transmission**								
8	Demand	$ 314,132,139	$ 91,243,634	$ 6,893,159	$ 213,052	$ 43,584,530	$ 144,864	$ 23,449,833	$ 32,483,232
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 314,132,139	$ 91,243,634	$ 6,893,159	$ 213,052	$ 43,584,530	$ 144,864	$ 23,449,833	$ 32,483,232
12	**Sub-Transmission**								
13	Demand	$ 22,052,290	$ 10,028,037	$ 958,750	$ 36,013	$ 3,273,301	$ 23,504	$ 1,822,148	$ 2,243,569
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 22,052,290	$ 10,028,037	$ 958,750	$ 36,013	$ 3,273,301	$ 23,504	$ 1,822,148	$ 2,243,569
17	**Railroad**								
18	Demand	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	**Dist Primary**								
23	Demand	$ 324,449,352	$ 159,829,808	$ 15,280,835	$ 573,981	$ 51,386,361	$ 374,620	$ 28,923,696	$ 32,964,523
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 324,449,352	$ 159,829,808	$ 15,280,835	$ 573,981	$ 51,386,361	$ 374,620	$ 28,923,696	$ 32,964,523

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
1	**Functional Revenue Requirement**								
2	**Production**								
3	Demand	$ 972,468,005	$ 3,331,275	$ 97,333,060	$ 68,044,814	$ 8,839,627	$ 9,396,094	$ 1,508,533	$ 16,729
4	Energy	$ 26,154,368	$ 212,052	$ 3,845,818	$ 2,520,877	$ 388,801	$ 662,060	$ 92,711	$ 954
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 998,622,374	$ 3,543,327	$ 101,178,879	$ 70,565,691	$ 9,228,428	$ 10,058,154	$ 1,601,244	$ 17,683
7	**Transmission**								
8	Demand	$ 314,132,139	$ 1,515,967	$ 28,842,506	$ 76,649,442	$ 3,325,827	$ 3,442,029	$ 516,273	$ 5,654
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 314,132,139	$ 1,515,967	$ 28,842,506	$ 76,649,442	$ 3,325,827	$ 3,442,029	$ 516,273	$ 5,654
12	**Sub-Transmission**								
13	Demand	$ 22,052,290	$ 167,187	$ 1,984,764	$ 924,359	$ 151,545	$ 80,407	$ 67,786	$ 371
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 22,052,290	$ 167,187	$ 1,984,764	$ 924,359	$ 151,545	$ 80,407	$ 67,786	$ 371
17	**Railroad**								
18	Demand	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	**Dist Primary**								
23	Demand	$ 324,449,352	$ 1,840,308	$ 28,335,317	$ -	$ -	$ (0)	$ 1,080,389	$ 5,909
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 324,449,352	$ 1,840,308	$ 28,335,317	$ -	$ -	$ (0)	$ 1,080,389	$ 5,909

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
1	**Functional Revenue Requirement**							
2	**Production**							
3	Demand	$ 972,468,005	$ 548,246	$ 515,024	$ -	$ 321,648	$ -	$ 2,029,974
4	Energy	$ 26,154,368	$ 60,662	$ 27,535	$ 77,482	$ 16,386	$ 34,245	$ 68,083
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 998,622,374	$ 608,908	$ 542,559	$ 77,482	$ 338,034	$ 34,245	$ 2,098,057
7	**Transmission**							
8	Demand	$ 314,132,139	$ 940,127	$ 198,627	$ 109,150	$ 105,563	$ 34,445	$ 434,223
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 314,132,139	$ 940,127	$ 198,627	$ 109,150	$ 105,563	$ 34,445	$ 434,223
12	**Sub-Transmission**							
13	Demand	$ 22,052,290	$ 18,752	$ 30,013	$ 100,560	$ 6,065	$ 27,874	$ 107,284
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 22,052,290	$ 18,752	$ 30,013	$ 100,560	$ 6,065	$ 27,874	$ 107,284
17	**Railroad**							
18	Demand	$ 2,226,445	$ -	$ 2,226,445	$ -	$ -	$ -	$ -
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 2,226,445	$ -	$ 2,226,445	$ -	$ -	$ -	$ -
22	**Dist Primary**							
23	Demand	$ 324,449,352	$ -	$ -	$ 1,602,753	$ 96,673	$ 444,258	$ 1,709,923
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 324,449,352	$ -	$ -	$ 1,602,753	$ 96,673	$ 444,258	$ 1,709,923

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
27	**Dist Secondary**								
28	Demand	$ 31,028,460	$ 14,464,038	$ 1,703,018	$ 55,324	$ 6,753,254	$ 38,544	$ 3,520,963	$ 2,260,471
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 37,965,486	$ 28,149,658	$ 5,278,959	$ 12,740	$ 4,004,979	$ 12,740	$ 209,264	$ 16,844
31	Subtotal	$ 68,993,947	$ 42,613,696	$ 6,981,977	$ 68,064	$ 10,758,233	$ 51,284	$ 3,730,228	$ 2,277,315
32	**Customer**								
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 128,695,333	$ 73,926,312	$ 12,187,394	$ 153,834	$ 22,265,706	$ 41,027	$ 3,250,181	$ 1,202,165
36	Subtotal	$ 128,695,333	$ 73,926,312	$ 12,187,394	$ 153,834	$ 22,265,706	$ 41,027	$ 3,250,181	$ 1,202,165
37	**Customer Service**								
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 65,209,095	$ 45,064,527	$ 8,451,037	$ 243,755	$ 8,046,727	$ 57,741	$ 652,153	$ 542,117
41	Subtotal	$ 65,209,095	$ 45,064,527	$ 8,451,037	$ 243,755	$ 8,046,727	$ 57,741	$ 652,153	$ 542,117
42	**Fuel Expenses**								
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ 273,878,561	$ 79,885,382	$ 9,317,754	$ 233,636	$ 41,559,044	$ 184,689	$ 22,259,507	$ 36,544,152
45	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 273,878,561	$ 79,885,382	$ 9,317,754	$ 233,636	$ 41,559,044	$ 184,689	$ 22,259,507	$ 36,544,152
47	**Total**								
48	Demand	$ 1,666,356,692	$ 712,351,142	$ 49,792,011	$ 878,370	$ 253,841,847	$ 581,533	$ 136,909,201	$ 160,755,938
49	Energy	$ 300,032,930	$ 87,515,788	$ 10,207,757	$ 255,953	$ 45,528,635	$ 202,330	$ 24,385,667	$ 40,034,737
50	Customer	$ 231,869,914	$ 147,140,497	$ 25,917,391	$ 410,329	$ 34,317,412	$ 111,508	$ 4,111,598	$ 1,761,127
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 2,198,259,535	$ 947,007,427	$ 85,917,158	$ 1,544,651	$ 333,687,894	$ 895,371	$ 165,406,466	$ 202,551,802
52	Demand	75.80%	75.22%	57.95%	56.87%	76.07%	64.95%	82.77%	79.37%
53	Energy	13.65%	9.24%	11.88%	16.57%	13.64%	22.60%	14.74%	19.77%
54	Customer	10.55%	15.54%	30.17%	26.56%	10.28%	12.45%	2.49%	0.87%

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
27	**Dist Secondary**								
28	Demand	$ 31,028,460	$ 92,636	$ 1,614,889	$ -	$ -	$ -	$ 124,505	$ 886
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 37,965,486	$ 101	$ 6,934	$ -	$ -	$ -	$ 50,738	$ 699
31	Subtotal	$ 68,993,947	$ 92,738	$ 1,621,823	$ -	$ -	$ -	$ 175,243	$ 1,586
32	**Customer**								
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 128,695,333	$ 12,332	$ 602,836	$ 1,070,237	$ 109,618	$ 59,176	$ 371,866	$ 272
36	Subtotal	$ 128,695,333	$ 12,332	$ 602,836	$ 1,070,237	$ 109,618	$ 59,176	$ 371,866	$ 272
37	**Customer Service**								
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 65,209,095	$ 20,717	$ 666,479	$ 81,398	$ 58,577	$ 306,962	$ 81,244	$ 2,400
41	Subtotal	$ 65,209,095	$ 20,717	$ 666,479	$ 81,398	$ 58,577	$ 306,962	$ 81,244	$ 2,400
42	**Fuel Expenses**								
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ 273,878,561	$ 2,220,041	$ 40,263,216	$ 26,391,939	$ 4,070,494	$ 6,931,338	$ 970,624	$ 9,984
45	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 273,878,561	$ 2,220,041	$ 40,263,216	$ 26,391,939	$ 4,070,494	$ 6,931,338	$ 970,624	$ 9,984
47	**Total**								
48	Demand	$ 1,666,356,692	$ 6,947,374	$ 158,110,537	$ 145,618,615	$ 12,316,999	$ 12,918,531	$ 3,297,485	$ 29,549
49	Energy	$ 300,032,930	$ 2,432,093	$ 44,109,034	$ 28,912,816	$ 4,459,295	$ 7,593,398	$ 1,063,335	$ 10,937
50	Customer	$ 231,869,914	$ 33,150	$ 1,276,249	$ 1,151,636	$ 168,195	$ 366,138	$ 503,847	$ 3,371
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 2,198,259,535	$ 9,412,617	$ 203,495,820	$ 175,683,067	$ 16,944,489	$ 20,878,068	$ 4,864,668	$ 43,857
52	Demand	75.80%	73.81%	77.70%	82.89%	72.69%	61.88%	67.78%	67.38%
53	Energy	13.65%	25.84%	21.68%	16.46%	26.32%	36.37%	21.86%	24.94%
54	Customer	10.55%	0.35%	0.63%	0.66%	0.99%	1.75%	10.36%	7.69%

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
27	**Dist Secondary**							
28	Demand	$ 31,028,460	$ -	$ -	$ 241,953	$ 16,550	$ 69,160	$ 72,268
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 37,965,486	$ -	$ -	$ 27,151	$ 2,719	$ 188,385	$ 3,573
31	Subtotal	$ 68,993,947	$ -	$ -	$ 269,103	$ 19,269	$ 257,546	$ 75,842
32	**Customer**							
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 128,695,333	$ 23,282	$ 15,495	$ 10,473,207	$ 290,333	$ 2,598,687	$ 41,373
36	Subtotal	$ 128,695,333	$ 23,282	$ 15,495	$ 10,473,207	$ 290,333	$ 2,598,687	$ 41,373
37	**Customer Service**							
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 65,209,095	$ 3,945	$ 79,790	$ 93,621	$ 9,823	$ 686,830	$ 59,250
41	Subtotal	$ 65,209,095	$ 3,945	$ 79,790	$ 93,621	$ 9,823	$ 686,830	$ 59,250
42	**Fuel Expenses**							
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ 273,878,561	$ 635,092	$ 288,276	$ 811,186	$ 171,556	$ 358,524	$ 772,128
45	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 273,878,561	$ 635,092	$ 288,276	$ 811,186	$ 171,556	$ 358,524	$ 772,128
47	**Total**							
48	Demand	$ 1,666,356,692	$ 1,507,125	$ 2,970,109	$ 2,054,415	$ 546,499	$ 575,737	$ 4,353,672
49	Energy	$ 300,032,930	$ 695,754	$ 315,811	$ 888,669	$ 187,942	$ 392,769	$ 840,211
50	Customer	$ 231,869,914	$ 27,227	$ 95,286	$ 10,593,979	$ 302,875	$ 3,473,902	$ 104,196
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 2,198,259,535	$ 2,230,107	$ 3,381,206	$ 13,537,063	$ 1,037,317	$ 4,442,408	$ 5,298,079
52	Demand	75.80%	67.58%	87.84%	15.18%	52.68%	12.96%	82.17%
53	Energy	13.65%	31.20%	9.34%	6.56%	18.12%	8.84%	15.86%
54	Customer	10.55%	1.22%	2.82%	78.26%	29.20%	78.20%	1.97%

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
55	**Unit Costs**								
56	**Production**								
57	Demand		n/a	n/a	n/a	n/a	n/a	$ 38.20	$ 23.19
58	Energy	$ 0.002415	$ 0.002456	$ 0.002456	$ 0.002456	$ 0.002455	$ 0.002456	$ 0.002455	$ 0.002446
59	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**								
61	Demand		n/a	n/a	n/a	n/a	n/a	$ 11.31	$ 8.30
62	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**								
65	Demand		n/a	n/a	n/a	n/a	n/a	$ 0.88	$ 0.57
66	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**								
68	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
69	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**								
72	Demand		n/a	n/a	n/a	n/a	n/a	$ 13.95	$ 8.42
73	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**								
76	Demand		n/a	n/a	n/a	n/a	n/a	$ 1.70	$ 0.58
77	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	$ 6.32	$ 6.47	$ 6.47	$ 6.47	$ 6.13	$ 6.47	$ 6.03	$ 2.83

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
55	**Unit Costs**								
56	**Production**								
57	Demand		$ 32.29	$ 32.76	$ 34.58	$ 20.78	$ 18.84	$ 64.26	n/a
58	Energy	$ 0.002415	$ 0.002440	$ 0.002445	$ 0.002123	$ 0.002425	$ 0.002424	$ 0.002454	$ 0.002456
59	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**								
61	Demand		$ 14.70	$ 9.71	$ 38.95	$ 7.82	$ 6.90	$ 21.99	n/a
62	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**								
65	Demand		$ 1.62	$ 0.67	$ 0.47	$ 0.36	$ 0.16	$ 2.89	n/a
66	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**								
68	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
69	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**								
72	Demand		$ 17.84	$ 9.54	$ -	$ -	$ (0.00)	$ 46.02	n/a
73	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**								
76	Demand		$ 0.90	$ 0.54	$ -	$ -	$ -	$ 5.30	n/a
77	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	$ 6.32	$ 1.41	$ 2.22	$ -	$ -	$ -	$ 5.76	$ 6.47

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
55	**Unit Costs**							
56	**Production**							
57	Demand		$ 3.55	$ 14.94	n/a	n/a	n/a	n/a
58	Energy	$ 0.002415	$ 0.002423	$ 0.002427	$ 0.002456	$ 0.002456	$ 0.002456	$ 0.002456
59	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**							
61	Demand		$ 6.08	$ 5.76	n/a	n/a	n/a	n/a
62	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**							
65	Demand		$ 0.12	$ 0.87	n/a	n/a	n/a	n/a
66	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**							
68	Demand		$ -	$ 64.61	n/a	n/a	n/a	n/a
69	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**							
72	Demand		$ -	$ -	n/a	n/a	n/a	n/a
73	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**							
76	Demand		$ -	$ -	n/a	n/a	n/a	n/a
77	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	$ 6.32	$ -	$ -	$ 1.62	$ 1.62	$ 1.62	$ 6.47

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NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
79	**Customer**								
80	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
81	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	$ 21.42	$ 17.00	$ 14.95	$ 78.17	$ 34.09	$ 20.85	$ 93.63	$ 201.98
83	**Customer Service**								
84	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 10.85	$ 10.36	$ 10.36	$ 123.86	$ 12.32	$ 29.34	$ 18.79	$ 91.08
87	**Fuel Expenses**								
88	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
89	Energy	$ 0.025287	$ 0.025712	$ 0.025712	$ 0.025712	$ 0.025703	$ 0.025712	$ 0.025701	$ 0.025612
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**								
92	Demand (per kW)		n/a	n/a	n/a	n/a	n/a	$ 66.04	$ 41.05
93	Energy	$ 0.027701	$ 0.028168	$ 0.028168	$ 0.028168	$ 0.028158	$ 0.028168	$ 0.028156	$ 0.028058
94	Customer (per cust month)	$ 38.58	$ 33.84	$ 31.78	$ 208.50	$ 52.54	$ 56.66	$ 118.45	$ 295.89
95	Demand & Customer Excluding Producti	$ 154.05	$ 97.21	$ 62.24	$ 654.83	$ 213.28	$ 352.15	$ 1,781.18	$ 12,048.54
96	Demand & Customer (per cust month)	$ 315.87	$ 197.66	$ 92.84	$ 654.83	$ 441.15	$ 352.15	$ 4,062.60	$ 27,304.61
97	**BILLING DETERMINANTS**								
98	Billed Demand	12,167,818	0	0	0	0	0	2,072,970	3,915,943
99	Energy	10,831,016,495	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891
100	Customers (Number of Bills)	6,009,505	4,348,440	815,471	1,968	653,202	1,968	34,712	5,952
101	**Unit Cost after Mitigation**								
102	Mitigated percent of COS @ Equal ROR		78.4%	100.0%	105.4%	117.4%	140.3%	117.0%	132.6%
103	Demand (per kW)							$ 77.26	$ 54.45
104	Energy	$ 0.0277	$ 0.0221	$ 0.0282	$ 0.0297	$ 0.0331	$ 0.0395	$ 0.0329	$ 0.0372
105	Customer (per cust month)	$ 38.58	$ 26.53	$ 31.78	$ 219.77	$ 61.67	$ 79.48	$ 138.57	$ 392.48
106	Demand & Customer (per cust month)	$ 315.87	$ 154.95	$ 92.84	$ 690.21	$ 517.83	$ 494.00	$ 4,752.66	$ 36,218.04

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Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
79	**Customer**								
80	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
81	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	$ 21.42	$ 171.28	$ 193.22	$ 12,740.92	$ 1,826.97	$ 1,232.84	$ 42.22	$ 2.51
83	**Customer Service**								
84	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 10.85	$ 287.74	$ 213.62	$ 969.03	$ 976.28	$ 6,395.05	$ 9.22	$ 22.22
87	**Fuel Expenses**								
88	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
89	Energy	$ 0.025287	$ 0.025549	$ 0.025594	$ 0.022223	$ 0.025387	$ 0.025375	$ 0.025695	$ 0.025712
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**								
92	Demand (per kW)		$ 67.34	$ 53.21	$ 73.99	$ 28.95	$ 25.91	$ 140.47	n/a
93	Energy	$ 0.027701	$ 0.027989	$ 0.028039	$ 0.024346	$ 0.027812	$ 0.027799	$ 0.028149	$ 0.028168
94	Customer (per cust month)	$ 38.58	$ 460.42	$ 409.05	$ 13,709.95	$ 2,803.25	$ 7,627.89	$ 57.20	$ 31.21
95	Demand & Customer Excluding Producti	$ 154.05	$ 50,684.01	$ 19,889.01	$ 937,207.58	$ 60,759.45	$ 81,011.99	$ 260.31	$ 149.92
96	Demand & Customer (per cust month)	$ 315.87	$ 96,951.72	$ 51,085.51	$ 1,747,264.89	$ 208,086.57	$ 276,763.95	$ 431.58	$ 304.81
97	**BILLING DETERMINANTS**								
98	Billed Demand	12,167,818	103,162	2,971,245	1,968,000	425,399	498,661	23,475	0
99	Energy	10,831,016,495	86,894,122	1,573,157,210	1,187,580,246	160,336,298	273,158,031	37,775,395	388,291
100	Customers (Number of Bills)	6,009,505	72	3,120	84	60	48	8,808	108
101	**Unit Cost after Mitigation**								
102	Mitigated percent of COS @ Equal ROR		118.1%	117.9%	100.0%	122.3%	150.0%	144.1%	150.0%
103	Demand (per kW)		$ 79.51	$ 62.72	$ 73.99	$ 35.41	$ 38.86	$ 202.43	
104	Energy	$ 0.0277	$ 0.0330	$ 0.0330	$ 0.0243	$ 0.0340	$ 0.0417	$ 0.0406	$ 0.0423
105	Customer (per cust month)	$ 38.58	$ 543.56	$ 482.15	$ 13,709.95	$ 3,427.98	$ 11,441.83	$ 82.44	$ 46.82
106	Demand & Customer (per cust month)	$ 315.87	$ 114,459.33	$ 60,213.80	$ 1,747,264.89	$ 254,459.95	$ 415,145.93	$ 621.97	$ 457.22

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Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
79	**Customer**							
80	Demand		$ -	$ -	n/a	n/a	n/a	n/a
81	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	$ 21.42	$ 323.36	$ 1,291.27	$ 624.30	$ 172.82	$ 22.33	$ 74.95
83	**Customer Service**							
84	Demand		$ -	$ -	n/a	n/a	n/a	n/a
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 10.85	$ 54.79	$ 6,649.19	$ 5.58	$ 5.85	$ 5.90	$ 107.34
87	**Fuel Expenses**							
88	Demand		$ -	$ -	n/a	n/a	n/a	n/a
89	Energy	$ 0.025287	$ 0.025366	$ 0.025412	$ 0.025712	$ 0.025712	$ 0.025712	$ 0.027853
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**							
92	Demand (per kW)		$ 9.75	$ 86.18	n/a	n/a	n/a	n/a
93	Energy	$ 0.027701	$ 0.027789	$ 0.027840	$ 0.028168	$ 0.028168	$ 0.028168	$ 0.030309
94	Customer (per cust month)	$ 38.58	$ 378.16	$ 7,940.47	$ 631.50	$ 180.28	$ 29.84	$ 188.76
95	Demand & Customer Excluding Producti	$ 154.05	$ 13,695.93	$ 212,530.89	$ 753.96	$ 314.12	$ 34.79	$ 4,398.36
96	Demand & Customer (per cust month)	$ 315.87	$ 21,310.45	$ 255,449.57	$ 753.96	$ 505.58	$ 34.79	$ 8,075.85
97	**BILLING DETERMINANTS**							
98	Billed Demand	12,167,818	154,501	34,462	0	0	0	0
99	Energy	10,831,016,495	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
100	Customers (Number of Bills)	6,009,505	72	12	16,776	1,680	116,400	552
101	**Unit Cost after Mitigation**							
102	Mitigated percent of COS @ Equal ROR		150.0%	58.0%	73.0%	132.5%	93.4%	126.5%
103	Demand (per kW)		$ 14.63	$ 49.97				
104	Energy	$ 0.0277	$ 0.0417	$ 0.0161	$ 0.0206	$ 0.0373	$ 0.0263	$ 0.0383
105	Customer (per cust month)	$ 38.58	$ 567.23	$ 4,603.47	$ 461.21	$ 238.85	$ 27.88	$ 238.84
106	Demand & Customer (per cust month)	$ 315.87	$ 31,965.68	$ 148,096.36	$ 550.65	$ 669.83	$ 32.50	$ 10,218.32

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NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2	**Rate Base**								
3	Plant in Service	$10,736,559,952	$ 4,410,404,937	$ 446,290,148	$ 10,927,609	$ 1,696,824,969	$ 6,903,520	$ 828,024,561	$ 1,019,686,072
4	Accumulated Reserve	(3,240,408,299)	(1,382,142,037)	(145,599,869)	(3,251,137)	(511,685,001)	(2,024,244)	(240,275,680)	(299,132,719)
5	Other Rate Base Items	1,733,661,788	628,331,664	50,313,305	1,482,522	291,581,281	1,003,498	155,271,839	200,900,332
6	**Total Rate Base**	**$ 9,229,813,441**	**$ 3,656,594,564**	**$ 351,003,584**	**$ 9,158,995**	**$ 1,476,721,250**	**$ 5,882,773**	**$ 743,020,720**	**$ 921,453,685**
7	**Revenue at Current Rates**								
8	Retail Sales - Non Fuel	$ 1,381,256,554	$ 471,527,029	$ 59,303,021	$ 833,893	$ 249,767,459	$ 730,039	$ 117,756,153	$ 169,264,316
9	TDSIC Revenue	93,344,310	41,315,349	4,818,982	123,052	14,623,813	104,384	8,153,093	10,606,120
10	DSM Revenue	11,970,888	3,847,798	448,803	6,703	2,905,441	5,479	1,286,412	2,628,610
11	RA Tracker	(6,370,886)	(1,992,450)	(232,397)	(4,275)	(1,209,399)	(5,100)	(695,432)	(765,040)
12	Generation Credit	(4,386,191)	(1,411,527)	(164,639)	(2,673)	(766,933)	(2,659)	(426,779)	(572,486)
13	Retail Sales - Fuel	329,634,043	95,870,856	11,182,284	280,388	49,893,314	221,646	26,725,051	44,006,839
14	Other Revenues	24,150,198	8,660,595	998,478	13,891	3,675,328	9,440	1,671,510	2,178,660
15	**Total Revenue**	**$ 1,829,598,917**	**$ 617,817,650**	**$ 76,354,532**	**$ 1,250,979**	**$ 318,889,023**	**$ 1,063,229**	**$ 154,470,007**	**$ 227,347,019**
16	**Expenses at Current Rates**								
17	Operations & Maintenance Expenses	$ 467,401,861	$ 201,795,339	$ 22,412,724	$ 703,152	$ 74,906,199	$ 349,538	$ 35,392,722	$ 43,083,036
18	Depreciation Expense	389,034,290	150,994,717	13,926,894	380,658	63,261,711	243,224	32,253,069	40,590,149
19	Amortization Expense	182,974,471	72,556,000	7,454,886	152,397	29,347,991	104,421	14,594,695	19,031,271
20	Fuel Expenses	329,634,043	96,148,239	11,214,638	281,199	50,019,525	222,288	26,791,039	43,983,715
21	Taxes Other Than Income	43,310,222	18,053,271	1,885,805	51,825	6,892,232	29,263	3,306,483	4,055,360
22	Income Taxes	33,879,159	6,355,333	1,580,069	(25,841)	7,670,024	9,297	3,421,012	6,220,009
23	**Total Expenses at Current Rates**	**$ 1,446,234,047**	**$ 545,902,900**	**$ 58,475,015**	**$ 1,543,390**	**$ 232,097,682**	**$ 958,030**	**$ 115,759,020**	**$ 156,963,541**
24	Current Operating Income	$ 383,364,870	$ 71,914,750	$ 17,879,517	$ (292,410)	$ 86,791,341	$ 105,199	$ 38,710,987	$ 70,383,478
25	Current Rate of Return	4.15%	1.97%	5.09%	-3.19%	5.88%	1.79%	5.21%	7.64%
26	Revenue to Cost Ratio (Line 12 / Line 46)	0.83	0.72	0.88	0.53	0.91	0.74	0.88	1.00
27	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	0.87	1.05	0.64	1.09	0.88	1.06	1.20
28	**Current Revenue at Equal Rates of Return**								
29	Current Rate of Return	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%
30	Current Operating Income at Equal ROR	$ 383,364,870	$ 151,878,465	$ 14,579,108	$ 380,423	$ 61,336,348	$ 244,344	$ 30,861,733	$ 38,273,035
31	Other Expenses - Equal ROR	1,412,354,888	539,547,567	56,894,946	1,569,231	224,427,658	948,733	112,338,009	150,743,531
32	Income Taxes - Equal ROR	33,879,159	13,421,978	1,288,402	33,619	5,420,486	21,593	2,727,348	3,382,308
33	**Total Revenue Requirement at Equal Current ROR**	**$ 1,829,598,917**	**$ 704,848,010**	**$ 72,762,455**	**$ 1,983,274**	**$ 291,184,492**	**$ 1,214,671**	**$ 145,927,091**	**$ 192,398,875**
34	Current Cross Subsidies (Line 34)	-	(87,030,360)	3,592,077	(732,294)	27,704,531	(151,441)	8,542,917	34,948,144

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NIPSCO
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Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
1	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
2	**Rate Base**								
3	Plant in Service	$10,736,559,952	$ 50,922,121	$ 911,314,825	$ 986,228,058	$ 75,966,404	$ 75,985,574	$ 25,008,460	$ 193,128
4	Accumulated Reserve	(3,240,408,299)	(14,561,485)	(261,096,005)	(261,451,633)	(22,599,991)	(23,114,459)	(7,608,008)	(56,273)
5	Other Rate Base Items	1,733,661,788	10,096,120	189,050,218	153,122,073	19,247,587	19,392,054	3,635,431	37,963
6	**Total Rate Base**	**$ 9,229,813,441**	**$ 46,456,756**	**$ 839,269,037**	**$ 877,898,497**	**$ 72,614,000**	**$ 72,263,169**	**$ 21,035,884**	**$ 174,817**
7	**Revenue at Current Rates**								
8	Retail Sales - Non Fuel	$ 1,381,256,554	$ 5,995,930	$ 142,143,090	$ 111,648,686	$ 11,862,980	$ 17,930,120	$ 4,486,246	$ 56,441
9	TDSIC Revenue	93,344,310	491,084	7,838,993	2,611,056	462,100	747,626	255,555	-
10	DSM Revenue	11,970,888	139,109	470,027	-	187,243	15,399	24,809	-
11	RA Tracker	(6,370,886)	(32,679)	(649,274)	(566,837)	(62,302)	(77,580)	(23,174)	(501)
12	Generation Credit	(4,386,191)	(22,765)	(422,704)	(426,461)	(40,077)	(64,712)	(12,259)	(391)
13	Retail Sales - Fuel	329,634,043	2,681,301	48,524,661	32,107,520	4,947,513	8,429,028	1,165,639	10,696
14	Other Revenues	24,150,198	94,841	2,011,522	4,324,108	176,554	178,404	35,338	539
15	**Total Revenue**	**$ 1,829,598,917**	**$ 9,346,820**	**$ 199,916,315**	**$ 149,698,072**	**$ 17,534,012**	**$ 27,158,285**	**$ 5,932,154**	**$ 66,785**
16	**Expenses at Current Rates**								
17	Operations & Maintenance Expenses	$ 467,401,861	$ 2,197,307	$ 39,439,694	$ 33,915,171	$ 3,205,887	$ 3,398,311	$ 1,077,697	$ 10,307
18	Depreciation Expense	389,034,290	2,027,538	37,092,107	33,672,732	3,426,624	3,397,720	861,322	7,621
19	Amortization Expense	182,974,471	973,108	18,088,623	14,865,784	1,807,812	1,950,895	395,773	4,043
20	Fuel Expenses	329,634,043	2,671,992	48,459,896	31,764,741	4,899,155	8,342,402	1,168,221	12,016
21	Taxes Other Than Income	43,310,222	203,153	3,644,510	3,791,611	303,199	300,844	100,409	775
22	Income Taxes	33,879,159	103,423	4,319,014	2,572,988	315,967	793,146	189,087	2,600
23	**Total Expenses at Current Rates**	**$ 1,446,234,047**	**$ 8,176,520**	**$ 151,043,845**	**$ 120,583,028**	**$ 13,958,642**	**$ 18,183,317**	**$ 3,792,509**	**$ 37,363**
24	Current Operating Income	$ 383,364,870	$ 1,170,300	$ 48,872,470	$ 29,115,044	$ 3,575,370	$ 8,974,968	$ 2,139,646	$ 29,422
25	Current Rate of Return	4.15%	2.52%	5.82%	3.32%	4.92%	12.42%	10.17%	16.83%
26	Revenue to Cost Ratio (Line 12 / Line 46)	0.83	0.79	0.93	0.78	0.90	1.20	1.12	1.37
27	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	0.95	1.12	0.93	1.08	1.44	1.34	1.65
28	**Current Revenue at Equal Rates of Return**								
29	Current Rate of Return	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%
30	Current Operating Income at Equal ROR	$ 383,364,870	$ 1,929,604	$ 34,859,455	$ 36,463,949	$ 3,016,058	$ 3,001,486	$ 873,736	$ 7,261
31	Other Expenses - Equal ROR	1,412,354,888	8,073,097	146,724,831	118,010,040	13,642,676	17,390,171	3,603,421	34,763
32	Income Taxes - Equal ROR	33,879,159	170,525	3,080,640	3,222,434	266,539	265,251	77,215	642
33	**Total Revenue Requirement at Equal Current ROR**	**$ 1,829,598,917**	**$ 10,173,226**	**$ 184,664,925**	**$ 157,696,422**	**$ 16,925,273**	**$ 20,656,908**	**$ 4,554,372**	**$ 42,666**
34	Current Cross Subsidies (Line 34)	-	(826,407)	15,251,389	(7,998,351)	608,740	6,501,377	1,377,782	24,119

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NIPSCO
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Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
1	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
2	**Rate Base**							
3	Plant in Service	$10,736,559,952	$ 12,727,817	$ 23,092,820	$ 96,340,010	$ 5,604,786	$ 29,843,721	$ 24,270,410
4	Accumulated Reserve	(3,240,408,299)	(6,547,974)	(5,908,495)	(30,029,426)	(1,687,003)	(14,556,130)	(7,080,727)
5	Other Rate Base Items	1,733,661,788	867,198	1,681,596	2,886,049	751,460	896,496	3,113,101
6	**Total Rate Base**	**$ 9,229,813,441**	**$ 7,047,041**	**$ 18,865,921**	**$ 69,196,634**	**$ 4,669,243**	**$ 16,184,087**	**$ 20,302,784**
7	**Revenue at Current Rates**							
8	Retail Sales - Non Fuel	$ 1,381,256,554	$ 2,583,157	$ 1,081,854	$ 6,398,943	$ 925,722	$ 2,626,819	$ 4,334,654
9	TDSIC Revenue	93,344,310	135,249	195,360	243,822	31,760	122,821	464,091
10	DSM Revenue	11,970,888	5,054	-	-	-	-	-
11	RA Tracker	(6,370,886)	-	(5,187)	(32,143)	(5,010)	(12,105)	-
12	Generation Credit	(4,386,191)	-	(6,466)	(23,867)	(2,979)	(6,054)	(9,759)
13	Retail Sales - Fuel	329,634,043	772,573	350,041	973,509	205,885	430,266	855,034
14	Other Revenues	24,150,198	12,877	16,122	32,140	7,497	24,793	27,561
15	**Total Revenue**	**$ 1,829,598,917**	**$ 3,508,910**	**$ 1,631,724**	**$ 7,592,403**	**$ 1,162,876**	**$ 3,186,540**	**$ 5,671,582**
16	**Expenses at Current Rates**							
17	Operations & Maintenance Expenses	$ 467,401,861	$ 226,679	$ 764,460	$ 2,025,841	$ 184,581	$ 1,235,282	$ 1,077,934
18	Depreciation Expense	389,034,290	343,591	576,040	4,013,613	234,778	924,683	805,501
19	Amortization Expense	182,974,471	118,166	185,627	475,358	80,548	467,966	319,107
20	Fuel Expenses	329,634,043	764,383	346,963	976,326	206,480	431,511	929,316
21	Taxes Other Than Income	43,310,222	43,557	90,474	328,139	20,883	110,708	97,721
22	Income Taxes	33,879,159	163,413	(26,945)	(18,422)	35,370	1,331	198,284
23	**Total Expenses at Current Rates**	**$ 1,446,234,047**	**$ 1,659,788**	**$ 1,936,620**	**$ 7,800,854**	**$ 762,639**	**$ 3,171,480**	**$ 3,427,864**
24	Current Operating Income	$ 383,364,870	$ 1,849,122	$ (304,895)	$ (208,452)	$ 400,237	$ 15,059	$ 2,243,718
25	Current Rate of Return	4.15%	26.24%	-1.62%	-0.30%	8.57%	0.09%	11.05%
26	Revenue to Cost Ratio (Line 12 / Line 46)	0.83	1.75	0.45	0.54	1.04	0.70	1.15
27	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	2.10	0.54	0.65	1.25	0.84	1.39
28	**Current Revenue at Equal Rates of Return**							
29	Current Rate of Return	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%
30	Current Operating Income at Equal ROR	$ 383,364,870	$ 292,702	$ 783,605	$ 2,874,116	$ 193,939	$ 672,214	$ 843,286
31	Other Expenses - Equal ROR	1,412,354,888	1,496,375	1,963,564	7,819,276	727,269	3,170,150	3,229,580
32	Income Taxes - Equal ROR	33,879,159	25,867	69,250	253,995	17,139	59,406	74,524
33	**Total Revenue Requirement at Equal Current ROR**	**$ 1,829,598,917**	**$ 1,814,945**	**$ 2,816,419**	**$ 10,947,387**	**$ 938,348**	**$ 3,901,769**	**$ 4,147,390**
34	Current Cross Subsidies (Line 34)	-	1,693,965	(1,184,695)	(3,354,984)	224,529	(715,230)	1,524,192

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
35	**Revenue Requirement at Equal Rates of Return**								
36	Required Return	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%
37	Required Operating Income	$ 700,542,840	$ 277,535,527	$ 26,641,172	$ 695,168	$ 112,083,143	$ 446,503	$ 56,395,273	$ 69,938,335
38	Operating Income (Deficiency)/Surplus	$ (317,177,971)	$ (205,620,777)	$ (8,761,655)	$ (987,578)	$ (25,291,802)	$ (341,303)	$ (17,684,286)	$ 445,143
39	Operations & Maintenance Expenses	$ 467,401,861	$ 201,795,339	$ 22,412,724	$ 703,152	$ 74,906,199	$ 349,538	$ 35,392,722	$ 43,083,036
40	Depreciation Expense	389,034,290	150,994,717	13,926,894	380,658	63,261,711	243,224	32,253,069	40,590,149
41	Amortization Expense	182,974,471	72,556,000	7,454,886	152,397	29,347,991	104,421	14,594,695	19,031,271
42	Fuel Expenses	273,878,561	79,885,382	9,317,754	233,636	41,559,044	184,689	22,259,507	36,544,152
43	Taxes Other Than Income	43,310,222	18,053,271	1,885,805	51,825	6,892,232	29,263	3,306,483	4,055,360
44	Income Taxes	33,879,159	13,421,978	1,288,402	33,619	5,420,486	21,593	2,727,348	3,382,308
45	Income Tax Increase	104,999,844	41,598,009	3,993,073	104,194	16,799,419	66,923	8,452,723	10,482,606
46	Bad Debt Expense Increase	1,685,295	1,292,312	242,350	-	83,632	-	4,711	489
47	Public Utility Fee Increase	552,991	227,160	22,986	563	87,396	356	42,648	52,519
48	Total Expenses at Equal Rates of Return	1,497,716,695	579,824,168	60,544,873	1,660,044	238,358,109	1,000,007	119,033,907	157,221,891
49	**Total Revenue Requirement at Equal Rates of Return**	**$ 2,198,259,535**	**$ 857,359,695**	**$ 87,186,045**	**$ 2,355,212**	**$ 350,441,252**	**$ 1,446,510**	**$ 175,429,179**	**$ 227,160,225**
50	Revenue (Deficiency)/Surplus	(368,660,619)	(239,542,045)	(10,831,513)	(1,104,232)	(31,552,229)	(383,280)	(20,959,172)	186,793
51	Total Current Revenues	1,829,598,917	617,817,650	76,354,532	1,250,979	318,889,023	1,063,229	154,470,007	227,347,019
52	Total Revenues at Equal Rates of Return	2,198,259,535	857,359,695	87,186,045	2,355,212	350,441,252	1,446,510	175,429,179	227,160,225
53	Less Total Other Revenues	24,150,198	8,660,595	998,478	13,891	3,675,328	9,440	1,671,510	2,178,660
54	**Total Base Revenues at Equal Rates of Return**	**$ 2,174,109,337**	**$ 848,699,100**	**$ 86,187,567**	**$ 2,341,321**	**$ 346,765,923**	**$ 1,437,069**	**$ 173,757,669**	**$ 224,981,566**
55	**Mitigation**								
56	Revenue Apportionment Mitigation	$ 0	$ (115,052,992)	$ -	$ (726,127)	$ 38,110,225	$ (61,922)	$ 18,460,613	$ 27,356,892
57	Proposed Increase Post Mitigation	$ 368,660,619	$ 124,489,053	$ 10,831,513	$ 378,105	$ 69,662,454	$ 321,358	$ 39,419,785	$ 27,170,098
58	Total Current Revenues	$ 1,829,598,917	$ 617,817,650	$ 76,354,532	$ 1,250,979	$ 318,889,023	$ 1,063,229	$ 154,470,007	$ 227,347,019
59	Total Revenues as Proposed	$ 2,198,259,535	$ 742,306,703	$ 87,186,045	$ 1,629,084	$ 388,551,477	$ 1,384,587	$ 193,889,792	$ 254,517,117
60	Less Total Other Revenues	$ 24,150,198	$ 8,660,595	$ 998,478	$ 13,891	$ 3,675,328	$ 9,440	$ 1,671,510	$ 2,178,660
61	**Total Base Rate Revenue as Proposed**	**$ 2,174,109,337**	**$ 733,646,108**	**$ 86,187,567**	**$ 1,615,194**	**$ 384,876,149**	**$ 1,375,147**	**$ 192,218,282**	**$ 252,338,457**
62	Proposed Income Prior to Taxes	$ 839,421,843	$ 217,502,521	$ 31,922,647	$ 106,854	$ 172,413,273	$ 473,097	$ 86,035,957	$ 111,160,140
63	Income Taxes at Proposed	138,879,003	35,984,927	5,281,475	17,679	28,525,090	78,272	14,234,307	18,391,003
64	Operating Income at Proposed	$ 700,542,840	$ 181,517,595	$ 26,641,172	$ 89,175	$ 143,888,183	$ 394,825	$ 71,801,651	$ 92,769,137
65	Rate of Return at Proposed	7.59%	4.96%	7.59%	0.97%	9.74%	6.71%	9.66%	10.07%
66	Parity Ratio - Revenue to Cost Ratio	1.00	0.87	1.00	0.69	1.11	0.96	1.11	1.12
67	Current Cross Subsidies (Line 34)	$ -	$ (87,030,360)	$ 3,592,077	$ (732,294)	$ 27,704,531	$ (151,441)	$ 8,542,917	$ 34,948,144
68	Cross Subsidies at Proposed Rates (Line 59 - Line 52)	$ -	$ (115,052,992)	$ -	$ (726,127)	$ 38,110,225	$ (61,922)	$ 18,460,613	$ 27,356,892
69	Dollar Value of Change in Cross Subsidies	$ -	$ (28,022,632)	$ (3,592,077)	$ 6,167	$ 10,405,695	$ 89,519	$ 9,917,696	$ (7,591,252)
70	Percent Change in Cross Subsidies		32%	-100%	-1%	38%	-59%	116%	-22%

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
1	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
35	**Revenue Requirement at Equal Rates of Return**								
36	Required Return	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%
37	Required Operating Income	$ 700,542,840	$ 3,526,068	$ 63,700,520	$ 66,632,496	$ 5,511,403	$ 5,484,775	$ 1,596,624	$ 13,269
38	Operating Income (Deficiency)/Surplus	$ (317,177,971)	$ (2,355,768)	$ (14,828,050)	$ (37,517,452)	$ (1,936,033)	$ 3,490,194	$ 543,022	$ 16,153
39	Operations & Maintenance Expenses	$ 467,401,861	$ 2,197,307	$ 39,439,694	$ 33,915,171	$ 3,205,887	$ 3,398,311	$ 1,077,697	$ 10,307
40	Depreciation Expense	389,034,290	2,027,538	37,092,107	33,672,732	3,426,624	3,397,720	861,322	7,621
41	Amortization Expense	182,974,471	973,108	18,088,623	14,865,784	1,807,812	1,950,895	395,773	4,043
42	Fuel Expenses	273,878,561	2,220,041	40,263,216	26,391,939	4,070,494	6,931,338	970,624	9,984
43	Taxes Other Than Income	43,310,222	203,153	3,644,510	3,791,611	303,199	300,844	100,409	775
44	Income Taxes	33,879,159	170,525	3,080,640	3,222,434	266,539	265,251	77,215	642
45	Income Tax Increase	104,999,844	528,500	9,547,660	9,987,115	826,069	822,077	239,308	1,989
46	Bad Debt Expense Increase	1,685,295	-	-	-	-	58,875	45	-
47	Public Utility Fee Increase	552,991	2,623	46,938	50,796	3,913	3,914	1,288	10
48	Total Expenses at Equal Rates of Return	1,497,716,695	8,322,794	151,203,388	125,897,583	13,910,535	17,129,224	3,723,679	35,371
49	**Total Revenue Requirement at Equal Rates of Return**	**$ 2,198,259,535**	**$ 11,848,862**	**$ 214,903,908**	**$ 192,530,079**	**$ 19,421,937**	**$ 22,613,999**	**$ 5,320,303**	**$ 48,639**
50	Revenue (Deficiency)/Surplus	(368,660,619)	(2,502,042)	(14,987,593)	(42,832,007)	(1,887,925)	4,544,287	611,851	18,145
51	Total Current Revenues	1,829,598,917	9,346,820	199,916,315	149,698,072	17,534,012	27,158,285	5,932,154	66,785
52	Total Revenues at Equal Rates of Return	2,198,259,535	11,848,862	214,903,908	192,530,079	19,421,937	22,613,999	5,320,303	48,639
53	Less Total Other Revenues	24,150,198	94,841	2,011,522	4,324,108	176,554	178,404	35,338	539
54	**Total Base Revenues at Equal Rates of Return**	**$ 2,174,109,337**	**$ 11,754,021**	**$ 212,892,386**	**$ 188,205,971**	**$ 19,245,383**	**$ 22,435,595**	**$ 5,284,965**	**$ 48,100**
55	**Mitigation**								
56	Revenue Apportionment Mitigation	$ 0	$ 323,007	$ 23,891,872	$ -	$ 2,095,479	$ 7,789,956	$ 1,320,799	$ 24,320
57	Proposed Increase Post Mitigation	$ 368,660,619	$ 2,825,049	$ 38,879,465	$ 42,832,007	$ 3,983,404	$ 3,245,669	$ 708,948	$ 6,175
58	Total Current Revenues	$ 1,829,598,917	$ 9,346,820	$ 199,916,315	$ 149,698,072	$ 17,534,012	$ 27,158,285	$ 5,932,154	$ 66,785
59	Total Revenues as Proposed	$ 2,198,259,535	$ 12,171,869	$ 238,795,780	$ 192,530,079	$ 21,517,416	$ 30,403,955	$ 6,641,102	$ 72,959
60	Less Total Other Revenues	$ 24,150,198	$ 94,841	$ 2,011,522	$ 4,324,108	$ 176,554	$ 178,404	$ 35,338	$ 539
61	**Total Base Rate Revenue as Proposed**	**$ 2,174,109,337**	**$ 12,077,028**	**$ 236,784,258**	**$ 188,205,971**	**$ 21,340,862**	**$ 30,225,551**	**$ 6,605,765**	**$ 72,420**
62	Proposed Income Prior to Taxes	$ 839,421,843	$ 4,548,099	$ 100,220,692	$ 79,842,044	$ 8,699,488	$ 14,362,059	$ 3,233,945	$ 40,219
63	Income Taxes at Proposed	138,879,003	752,465	16,581,115	13,209,548	1,439,296	2,376,145	535,043	6,654
64	Operating Income at Proposed	$ 700,542,840	$ 3,795,635	$ 83,639,577	$ 66,632,496	$ 7,260,193	$ 11,985,913	$ 2,698,902	$ 33,565
65	Rate of Return at Proposed	7.59%	8.17%	9.97%	7.59%	10.00%	16.59%	12.83%	19.20%
66	Parity Ratio - Revenue to Cost Ratio	1.00	1.03	1.11	1.00	1.11	1.34	1.25	1.50
67	Current Cross Subsidies (Line 34)	$ -	$ (826,407)	$ 15,251,389	$ (7,998,351)	$ 608,740	$ 6,501,377	$ 1,377,782	$ 24,119
68	Cross Subsidies at Proposed Rates (Line 59 - Line 52)	$ -	$ 323,007	$ 23,891,872	$ -	$ 2,095,479	$ 7,789,956	$ 1,320,799	$ 24,320
69	Dollar Value of Change in Cross Subsidies	$ -	$ 1,149,413	$ 8,640,483	$ 7,998,351	$ 1,486,739	$ 1,288,579	$ (56,983)	$ 201
70	Percent Change in Cross Subsidies		-139%	57%	-100%	244%	20%	-4%	1%

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
1	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
35	**Revenue Requirement at Equal Rates of Return**							
36	Required Return	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%	7.59%
37	Required Operating Income	$ 700,542,840	$ 534,870	$ 1,431,923	$ 5,252,025	$ 354,396	$ 1,228,372	$ 1,540,981
38	Operating Income (Deficiency)/Surplus	$ (317,177,971)	$ 1,314,252	$ (1,736,819)	$ (5,460,476)	$ 45,841	$ (1,213,313)	$ 702,737
39	Operations & Maintenance Expenses	$ 467,401,861	$ 226,679	$ 764,460	$ 2,025,841	$ 184,581	$ 1,235,282	$ 1,077,934
40	Depreciation Expense	389,034,290	343,591	576,040	4,013,613	234,778	924,683	805,501
41	Amortization Expense	182,974,471	118,166	185,627	475,358	80,548	467,966	319,107
42	Fuel Expenses	273,878,561	635,092	288,276	811,186	171,556	358,524	772,128
43	Taxes Other Than Income	43,310,222	43,557	90,474	328,139	20,883	110,708	97,721
44	Income Taxes	33,879,159	25,867	69,250	253,995	17,139	59,406	74,524
45	Income Tax Increase	104,999,844	80,168	214,622	787,192	53,118	184,113	230,968
46	Bad Debt Expense Increase	1,685,295	-	-	17	-	2,865	-
47	Public Utility Fee Increase	552,991	656	1,189	4,962	289	1,537	1,250
48	Total Expenses at Equal Rates of Return	1,497,716,695	1,473,776	2,189,938	8,700,302	762,890	3,345,083	3,379,133
49	**Total Revenue Requirement at Equal Rates of Return**	**$ 2,198,259,535**	**$ 2,008,646**	**$ 3,621,862**	**$ 13,952,327**	**$ 1,117,286**	**$ 4,573,455**	**$ 4,920,115**
50	Revenue (Deficiency)/Surplus	(368,660,619)	1,500,264	(1,990,138)	(6,359,924)	45,590	(1,386,916)	751,467
51	Total Current Revenues	1,829,598,917	3,508,910	1,631,724	7,592,403	1,162,876	3,186,540	5,671,582
52	Total Revenues at Equal Rates of Return	2,198,259,535	2,008,646	3,621,862	13,952,327	1,117,286	4,573,455	4,920,115
53	Less Total Other Revenues	24,150,198	12,877	16,122	32,140	7,497	24,793	27,561
54	**Total Base Revenues at Equal Rates of Return**	**$ 2,174,109,337**	**$ 1,995,769**	**$ 3,605,740**	**$ 13,920,186**	**$ 1,109,788**	**$ 4,548,662**	**$ 4,892,553**
55	**Mitigation**							
56	Revenue Apportionment Mitigation	$ 0	$ 1,004,323	$ (1,661,348)	$ (4,065,142)	$ 184,565	$ (423,793)	$ 1,429,274
57	Proposed Increase Post Mitigation	$ 368,660,619	$ (495,941)	$ 328,789	$ 2,294,782	$ 138,975	$ 963,122	$ 677,807
58	Total Current Revenues	$ 1,829,598,917	$ 3,508,910	$ 1,631,724	$ 7,592,403	$ 1,162,876	$ 3,186,540	$ 5,671,582
59	Total Revenues as Proposed	$ 2,198,259,535	$ 3,012,969	$ 1,960,514	$ 9,887,184	$ 1,301,851	$ 4,149,662	$ 6,349,389
60	Less Total Other Revenues	$ 24,150,198	$ 12,877	$ 16,122	$ 32,140	$ 7,497	$ 24,793	$ 27,561
61	**Total Base Rate Revenue as Proposed**	**$ 2,174,109,337**	**$ 3,000,093**	**$ 1,944,392**	**$ 9,855,044**	**$ 1,294,353**	**$ 4,124,869**	**$ 6,321,828**
62	Proposed Income Prior to Taxes	$ 839,421,843	$ 1,645,229	$ 54,447	$ 2,228,069	$ 609,218	$ 1,048,097	$ 3,275,747
63	Income Taxes at Proposed	138,879,003	272,197	9,008	368,625	100,793	173,404	541,959
64	Operating Income at Proposed	$ 700,542,840	$ 1,373,032	$ 45,439	$ 1,859,444	$ 508,425	$ 874,694	$ 2,733,788
65	Rate of Return at Proposed	7.59%	19.48%	0.24%	2.69%	10.89%	5.40%	13.47%
66	Parity Ratio - Revenue to Cost Ratio	1.00	1.50	0.54	0.71	1.17	0.91	1.29
67	Current Cross Subsidies (Line 34)	$ -	$ 1,693,965	$ (1,184,695)	$ (3,354,984)	$ 224,529	$ (715,230)	$ 1,524,192
68	Cross Subsidies at Proposed Rates (Line 59 - Line 52)	$ -	$ 1,004,323	$ (1,661,348)	$ (4,065,142)	$ 184,565	$ (423,793)	$ 1,429,274
69	Dollar Value of Change in Cross Subsidies	$ -	$ (689,642)	$ (476,653)	$ (710,158)	$ (39,964)	$ 291,437	$ (94,918)
70	Percent Change in Cross Subsidies		-41%	40%	21%	-18%	-41%	-6%

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**Functional Revenue Requirement**								
2	**Production**								
3	Demand	$ 972,468,005	$ 347,137,894	$ 26,225,136	$ 810,560	$ 165,597,758	$ 551,139	$ 89,215,274	$ 115,412,568
4	Energy	$ 26,154,368	$ 7,630,406	$ 890,003	$ 22,316	$ 3,969,592	$ 17,641	$ 2,126,160	$ 3,490,585
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 998,622,374	$ 354,768,300	$ 27,115,139	$ 832,877	$ 169,567,350	$ 568,780	$ 91,341,433	$ 118,903,153
7	**Transmission**								
8	Demand	$ 314,132,139	$ 91,243,634	$ 6,893,159	$ 213,052	$ 43,584,530	$ 144,864	$ 23,449,833	$ 32,483,232
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 314,132,139	$ 91,243,634	$ 6,893,159	$ 213,052	$ 43,584,530	$ 144,864	$ 23,449,833	$ 32,483,232
12	**Sub-Transmission**								
13	Demand	$ 22,052,290	$ 10,028,037	$ 958,750	$ 36,013	$ 3,273,301	$ 23,504	$ 1,822,148	$ 2,243,569
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 22,052,290	$ 10,028,037	$ 958,750	$ 36,013	$ 3,273,301	$ 23,504	$ 1,822,148	$ 2,243,569
17	**Railroad**								
18	Demand	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	**Dist Primary**								
23	Demand	$ 324,449,352	$ 159,829,808	$ 15,280,835	$ 573,981	$ 51,386,361	$ 374,620	$ 28,923,696	$ 32,964,523
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 324,449,352	$ 159,829,808	$ 15,280,835	$ 573,981	$ 51,386,361	$ 374,620	$ 28,923,696	$ 32,964,523

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
1	**Functional Revenue Requirement**								
2	**Production**								
3	Demand	$ 972,468,005	$ 5,767,520	$ 108,741,148	$ 84,891,825	$ 11,317,075	$ 11,132,025	$ 1,964,169	$ 21,511
4	Energy	$ 26,154,368	$ 212,052	$ 3,845,818	$ 2,520,877	$ 388,801	$ 662,060	$ 92,711	$ 954
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 998,622,374	$ 5,979,572	$ 112,586,966	$ 87,412,702	$ 11,705,876	$ 11,794,085	$ 2,056,880	$ 22,465
7	**Transmission**								
8	Demand	$ 314,132,139	$ 1,515,967	$ 28,842,506	$ 76,649,442	$ 3,325,827	$ 3,442,029	$ 516,273	$ 5,654
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 314,132,139	$ 1,515,967	$ 28,842,506	$ 76,649,442	$ 3,325,827	$ 3,442,029	$ 516,273	$ 5,654
12	**Sub-Transmission**								
13	Demand	$ 22,052,290	$ 167,187	$ 1,984,764	$ 924,359	$ 151,545	$ 80,407	$ 67,786	$ 371
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 22,052,290	$ 167,187	$ 1,984,764	$ 924,359	$ 151,545	$ 80,407	$ 67,786	$ 371
17	**Railroad**								
18	Demand	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 2,226,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	**Dist Primary**								
23	Demand	$ 324,449,352	$ 1,840,308	$ 28,335,317	$ -	$ -	$ (0)	$ 1,080,389	$ 5,909
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 324,449,352	$ 1,840,308	$ 28,335,317	$ -	$ -	$ (0)	$ 1,080,389	$ 5,909

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Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
1	**Functional Revenue Requirement**							
2	**Production**							
3	Demand	$ 972,468,005	$ 326,785	$ 755,680	$ 415,264	$ 401,617	$ 131,047	$ 1,652,010
4	Energy	$ 26,154,368	$ 60,662	$ 27,535	$ 77,482	$ 16,386	$ 34,245	$ 68,083
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 998,622,374	$ 387,447	$ 783,215	$ 492,746	$ 418,003	$ 165,292	$ 1,720,093
7	**Transmission**							
8	Demand	$ 314,132,139	$ 940,127	$ 198,627	$ 109,150	$ 105,563	$ 34,445	$ 434,223
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 314,132,139	$ 940,127	$ 198,627	$ 109,150	$ 105,563	$ 34,445	$ 434,223
12	**Sub-Transmission**							
13	Demand	$ 22,052,290	$ 18,752	$ 30,013	$ 100,560	$ 6,065	$ 27,874	$ 107,284
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 22,052,290	$ 18,752	$ 30,013	$ 100,560	$ 6,065	$ 27,874	$ 107,284
17	**Railroad**							
18	Demand	$ 2,226,445	$ -	$ 2,226,445	$ -	$ -	$ -	$ -
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 2,226,445	$ -	$ 2,226,445	$ -	$ -	$ -	$ -
22	**Dist Primary**							
23	Demand	$ 324,449,352	$ -	$ -	$ 1,602,753	$ 96,673	$ 444,258	$ 1,709,923
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 324,449,352	$ -	$ -	$ 1,602,753	$ 96,673	$ 444,258	$ 1,709,923

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
27	**Dist Secondary**								
28	Demand	$ 31,028,460	$ 14,464,038	$ 1,703,018	$ 55,324	$ 6,753,254	$ 38,544	$ 3,520,963	$ 2,260,471
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 37,965,486	$ 28,149,658	$ 5,278,959	$ 12,740	$ 4,004,979	$ 12,740	$ 209,264	$ 16,844
31	Subtotal	$ 68,993,947	$ 42,613,696	$ 6,981,977	$ 68,064	$ 10,758,233	$ 51,284	$ 3,730,228	$ 2,277,315
32	**Customer**								
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 128,695,333	$ 73,926,312	$ 12,187,394	$ 153,834	$ 22,265,706	$ 41,027	$ 3,250,181	$ 1,202,165
36	Subtotal	$ 128,695,333	$ 73,926,312	$ 12,187,394	$ 153,834	$ 22,265,706	$ 41,027	$ 3,250,181	$ 1,202,165
37	**Customer Service**								
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 65,209,095	$ 45,064,527	$ 8,451,037	$ 243,755	$ 8,046,727	$ 57,741	$ 652,153	$ 542,117
41	Subtotal	$ 65,209,095	$ 45,064,527	$ 8,451,037	$ 243,755	$ 8,046,727	$ 57,741	$ 652,153	$ 542,117
42	**Fuel Expenses**								
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ 273,878,561	$ 79,885,382	$ 9,317,754	$ 233,636	$ 41,559,044	$ 184,689	$ 22,259,507	$ 36,544,152
45	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 273,878,561	$ 79,885,382	$ 9,317,754	$ 233,636	$ 41,559,044	$ 184,689	$ 22,259,507	$ 36,544,152
47	**Total**								
48	Demand	$ 1,666,356,692	$ 622,703,411	$ 51,060,898	$ 1,688,930	$ 270,595,204	$ 1,132,671	$ 146,931,914	$ 185,364,362
49	Energy	$ 300,032,930	$ 87,515,788	$ 10,207,757	$ 255,953	$ 45,528,635	$ 202,330	$ 24,385,667	$ 40,034,737
50	Customer	$ 231,869,914	$ 147,140,497	$ 25,917,391	$ 410,329	$ 34,317,412	$ 111,508	$ 4,111,598	$ 1,761,127
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 2,198,259,535	$ 857,359,695	$ 87,186,045	$ 2,355,212	$ 350,441,252	$ 1,446,510	$ 175,429,179	$ 227,160,225
52	Demand	75.80%	72.63%	58.57%	71.71%	77.22%	78.30%	83.76%	81.60%
53	Energy	13.65%	10.21%	11.71%	10.87%	12.99%	13.99%	13.90%	17.62%
54	Customer	10.55%	17.16%	29.73%	17.42%	9.79%	7.71%	2.34%	0.78%

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Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
27	**Dist Secondary**								
28	Demand	$ 31,028,460	$ 92,636	$ 1,614,889	$ -	$ -	$ -	$ 124,505	$ 886
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 37,965,486	$ 101	$ 6,934	$ -	$ -	$ -	$ 50,738	$ 699
31	Subtotal	$ 68,993,947	$ 92,738	$ 1,621,823	$ -	$ -	$ -	$ 175,243	$ 1,586
32	**Customer**								
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 128,695,333	$ 12,332	$ 602,836	$ 1,070,237	$ 109,618	$ 59,176	$ 371,866	$ 272
36	Subtotal	$ 128,695,333	$ 12,332	$ 602,836	$ 1,070,237	$ 109,618	$ 59,176	$ 371,866	$ 272
37	**Customer Service**								
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 65,209,095	$ 20,717	$ 666,479	$ 81,398	$ 58,577	$ 306,962	$ 81,244	$ 2,400
41	Subtotal	$ 65,209,095	$ 20,717	$ 666,479	$ 81,398	$ 58,577	$ 306,962	$ 81,244	$ 2,400
42	**Fuel Expenses**								
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ 273,878,561	$ 2,220,041	$ 40,263,216	$ 26,391,939	$ 4,070,494	$ 6,931,338	$ 970,624	$ 9,984
45	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 273,878,561	$ 2,220,041	$ 40,263,216	$ 26,391,939	$ 4,070,494	$ 6,931,338	$ 970,624	$ 9,984
47	**Total**								
48	Demand	$ 1,666,356,692	$ 9,383,619	$ 169,518,624	$ 162,465,627	$ 14,794,447	$ 14,654,462	$ 3,753,121	$ 34,331
49	Energy	$ 300,032,930	$ 2,432,093	$ 44,109,034	$ 28,912,816	$ 4,459,295	$ 7,593,398	$ 1,063,335	$ 10,937
50	Customer	$ 231,869,914	$ 33,150	$ 1,276,249	$ 1,151,636	$ 168,195	$ 366,138	$ 503,847	$ 3,371
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 2,198,259,535	$ 11,848,862	$ 214,903,908	$ 192,530,079	$ 19,421,937	$ 22,613,999	$ 5,320,303	$ 48,639
52	Demand	75.80%	79.19%	78.88%	84.38%	76.17%	64.80%	70.54%	70.58%
53	Energy	13.65%	20.53%	20.53%	15.02%	22.96%	33.58%	19.99%	22.49%
54	Customer	10.55%	0.28%	0.59%	0.60%	0.87%	1.62%	9.47%	6.93%

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Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
27	**Dist Secondary**							
28	Demand	$ 31,028,460	$ -	$ -	$ 241,953	$ 16,550	$ 69,160	$ 72,268
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 37,965,486	$ -	$ -	$ 27,151	$ 2,719	$ 188,385	$ 3,573
31	Subtotal	$ 68,993,947	$ -	$ -	$ 269,103	$ 19,269	$ 257,546	$ 75,842
32	**Customer**							
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 128,695,333	$ 23,282	$ 15,495	$ 10,473,207	$ 290,333	$ 2,598,687	$ 41,373
36	Subtotal	$ 128,695,333	$ 23,282	$ 15,495	$ 10,473,207	$ 290,333	$ 2,598,687	$ 41,373
37	**Customer Service**							
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 65,209,095	$ 3,945	$ 79,790	$ 93,621	$ 9,823	$ 686,830	$ 59,250
41	Subtotal	$ 65,209,095	$ 3,945	$ 79,790	$ 93,621	$ 9,823	$ 686,830	$ 59,250
42	**Fuel Expenses**							
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ 273,878,561	$ 635,092	$ 288,276	$ 811,186	$ 171,556	$ 358,524	$ 772,128
45	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 273,878,561	$ 635,092	$ 288,276	$ 811,186	$ 171,556	$ 358,524	$ 772,128
47	**Total**							
48	Demand	$ 1,666,356,692	$ 1,285,665	$ 3,210,765	$ 2,469,679	$ 626,468	$ 706,784	$ 3,975,708
49	Energy	$ 300,032,930	$ 695,754	$ 315,811	$ 888,669	$ 187,942	$ 392,769	$ 840,211
50	Customer	$ 231,869,914	$ 27,227	$ 95,286	$ 10,593,979	$ 302,875	$ 3,473,902	$ 104,196
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 2,198,259,535	$ 2,008,646	$ 3,621,862	$ 13,952,327	$ 1,117,286	$ 4,573,455	$ 4,920,115
52	Demand	75.80%	64.01%	88.65%	17.70%	56.07%	15.45%	80.81%
53	Energy	13.65%	34.64%	8.72%	6.37%	16.82%	8.59%	17.08%
54	Customer	10.55%	1.36%	2.63%	75.93%	27.11%	75.96%	2.12%

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
55	**Unit Costs**								
56	**Production**								
57	Demand		n/a	n/a	n/a	n/a	n/a	$ 43.04	$ 29.47
58	Energy	$ 0.002415	$ 0.002456	$ 0.002456	$ 0.002456	$ 0.002455	$ 0.002456	$ 0.002455	$ 0.002446
59	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**								
61	Demand		n/a	n/a	n/a	n/a	n/a	$ 11.31	$ 8.30
62	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**								
65	Demand		n/a	n/a	n/a	n/a	n/a	$ 0.88	$ 0.57
66	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**								
68	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
69	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**								
72	Demand		n/a	n/a	n/a	n/a	n/a	$ 13.95	$ 8.42
73	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**								
76	Demand		n/a	n/a	n/a	n/a	n/a	$ 1.70	$ 0.58
77	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	$ 6.32	$ 6.47	$ 6.47	$ 6.47	$ 6.13	$ 6.47	$ 6.03	$ 2.83

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Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
55	**Unit Costs**								
56	**Production**								
57	Demand		$ 55.91	$ 36.60	$ 43.14	$ 26.60	$ 22.32	$ 83.67	n/a
58	Energy	$ 0.002415	$ 0.002440	$ 0.002445	$ 0.002123	$ 0.002425	$ 0.002424	$ 0.002454	$ 0.002456
59	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**								
61	Demand		$ 14.70	$ 9.71	$ 38.95	$ 7.82	$ 6.90	$ 21.99	n/a
62	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**								
65	Demand		$ 1.62	$ 0.67	$ 0.47	$ 0.36	$ 0.16	$ 2.89	n/a
66	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**								
68	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
69	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**								
72	Demand		$ 17.84	$ 9.54	$ -	$ -	$ (0.00)	$ 46.02	n/a
73	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**								
76	Demand		$ 0.90	$ 0.54	$ -	$ -	$ -	$ 5.30	n/a
77	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	$ 6.32	$ 1.41	$ 2.22	$ -	$ -	$ -	$ 5.76	$ 6.47

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
55	**Unit Costs**							
56	**Production**							
57	Demand		$ 2.12	$ 21.93	n/a	n/a	n/a	n/a
58	Energy	$ 0.002415	$ 0.002423	$ 0.002427	$ 0.002456	$ 0.002456	$ 0.002456	$ 0.002456
59	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**							
61	Demand		$ 6.08	$ 5.76	n/a	n/a	n/a	n/a
62	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**							
65	Demand		$ 0.12	$ 0.87	n/a	n/a	n/a	n/a
66	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**							
68	Demand		$ -	$ 64.61	n/a	n/a	n/a	n/a
69	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**							
72	Demand		$ -	$ -	n/a	n/a	n/a	n/a
73	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**							
76	Demand		$ -	$ -	n/a	n/a	n/a	n/a
77	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	$ 6.32	$ -	$ -	$ 1.62	$ 1.62	$ 1.62	$ 6.47

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
79	**Customer**								
80	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
81	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	$ 21.42	$ 17.00	$ 14.95	$ 78.17	$ 34.09	$ 20.85	$ 93.63	$ 201.98
83	**Customer Service**								
84	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 10.85	$ 10.36	$ 10.36	$ 123.86	$ 12.32	$ 29.34	$ 18.79	$ 91.08
87	**Fuel Expenses**								
88	Demand		n/a	n/a	n/a	n/a	n/a	$ -	$ -
89	Energy	$ 0.025287	$ 0.025712	$ 0.025712	$ 0.025712	$ 0.025703	$ 0.025712	$ 0.025701	$ 0.025612
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**								
92	Demand (per kW)		n/a	n/a	n/a	n/a	n/a	$ 70.88	$ 47.34
93	Energy	$ 0.027701	$ 0.028168	$ 0.028168	$ 0.028168	$ 0.028158	$ 0.028168	$ 0.028156	$ 0.028058
94	Customer (per cust month)	$ 38.58	$ 33.84	$ 31.78	$ 208.50	$ 52.54	$ 56.66	$ 118.45	$ 295.89
95	Demand & Customer Excluding Product	$ 154.05	$ 97.21	$ 62.24	$ 654.83	$ 213.28	$ 352.15	$ 1,781.18	$ 12,048.54
96	Demand & Customer (per cust month)	$ 315.87	$ 177.04	$ 94.40	$ 1,066.70	$ 466.80	$ 632.20	$ 4,351.33	$ 31,439.09
97	**BILLING DETERMINANTS**								
98	Billed Demand	12,167,818	0	0	0	0	0	2,072,970	3,915,943
99	Energy	10,831,016,495	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891
100	Customers (Number of Bills)	6,009,505	4,348,440	815,471	1,968	653,202	1,968	34,712	5,952
101	**Unit Cost after Mitigation**								
102	Mitigated percent of COS @ Equal ROR		86.6%	100.0%	69.2%	110.9%	95.7%	110.5%	112.0%
103	Demand (per kW)							$ 78.34	$ 53.04
104	Energy	$ 0.0277	$ 0.0244	$ 0.0282	$ 0.0195	$ 0.0312	$ 0.0270	$ 0.0311	$ 0.0314
105	Customer (per cust month)	$ 38.58	$ 29.30	$ 31.78	$ 144.22	$ 58.25	$ 54.24	$ 130.91	$ 331.52
106	Demand & Customer (per cust month)	$ 315.87	$ 153.28	$ 94.40	$ 737.83	$ 517.56	$ 605.14	$ 4,809.23	$ 35,225.30

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
79	**Customer**								
80	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
81	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	$ 21.42	$ 171.28	$ 193.22	$ 12,740.92	$ 1,826.97	$ 1,232.84	$ 42.22	$ 2.51
83	**Customer Service**								
84	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 10.85	$ 287.74	$ 213.62	$ 969.03	$ 976.28	$ 6,395.05	$ 9.22	$ 22.22
87	**Fuel Expenses**								
88	Demand		$ -	$ -	$ -	$ -	$ -	$ -	n/a
89	Energy	$ 0.025287	$ 0.025549	$ 0.025594	$ 0.022223	$ 0.025387	$ 0.025375	$ 0.025695	$ 0.025712
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**								
92	Demand (per kW)		$ 90.96	$ 57.05	$ 82.55	$ 34.78	$ 29.39	$ 159.88	n/a
93	Energy	$ 0.027701	$ 0.027989	$ 0.028039	$ 0.024346	$ 0.027812	$ 0.027799	$ 0.028149	$ 0.028168
94	Customer (per cust month)	$ 38.58	$ 460.42	$ 409.05	$ 13,709.95	$ 2,803.25	$ 7,627.89	$ 57.20	$ 31.21
95	Demand & Customer Excluding Product	$ 154.05	$ 50,684.01	$ 19,889.01	$ 937,207.58	$ 60,759.45	$ 81,011.99	$ 260.31	$ 149.92
96	Demand & Customer (per cust month)	$ 315.87	$ 130,788.46	$ 54,741.95	$ 1,947,824.55	$ 249,377.37	$ 312,929.18	$ 483.31	$ 349.09
97	**BILLING DETERMINANTS**								
98	Billed Demand	12,167,818	103,162	2,971,245	1,968,000	425,399	498,661	23,475	0
99	Energy	10,831,016,495	86,894,122	1,573,157,210	1,187,580,246	160,336,298	273,158,031	37,775,395	388,291
100	Customers (Number of Bills)	6,009,505	72	3,120	84	60	48	8,808	108
101	**Unit Cost after Mitigation**								
102	Mitigated percent of COS @ Equal ROR		102.7%	111.1%	100.0%	110.8%	134.4%	124.8%	150.0%
103	Demand (per kW)		$ 93.44	$ 63.40	$ 82.55	$ 38.53	$ 39.51	$ 199.57	
104	Energy	$ 0.0277	$ 0.0288	$ 0.0312	$ 0.0243	$ 0.0308	$ 0.0374	$ 0.0351	$ 0.0423
105	Customer (per cust month)	$ 38.58	$ 472.97	$ 454.53	$ 13,709.95	$ 3,105.70	$ 10,255.50	$ 71.40	$ 46.82
106	Demand & Customer (per cust month)	$ 315.87	$ 134,353.83	$ 60,827.86	$ 1,947,824.55	$ 276,283.29	$ 420,725.45	$ 603.29	$ 523.64

Cause No. 46120

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2025. Production Demand Allocation: 4 CP (for Generation)
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description	TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(U)
79	**Customer**							
80	Demand		$ -	$ -	n/a	n/a	n/a	n/a
81	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	$ 21.42	$ 323.36	$ 1,291.27	$ 624.30	$ 172.82	$ 22.33	$ 74.95
83	**Customer Service**							
84	Demand		$ -	$ -	n/a	n/a	n/a	n/a
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 10.85	$ 54.79	$ 6,649.19	$ 5.58	$ 5.85	$ 5.90	$ 107.34
87	**Fuel Expenses**							
88	Demand		$ -	$ -	n/a	n/a	n/a	n/a
89	Energy	$ 0.025287	$ 0.025366	$ 0.025412	$ 0.025712	$ 0.025712	$ 0.025712	$ 0.027853
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**							
92	Demand (per kW)		$ 8.32	$ 93.17	n/a	n/a	n/a	n/a
93	Energy	$ 0.027701	$ 0.027789	$ 0.027840	$ 0.028168	$ 0.028168	$ 0.028168	$ 0.030309
94	Customer (per cust month)	$ 38.58	$ 378.16	$ 7,940.47	$ 631.50	$ 180.28	$ 29.84	$ 188.76
95	Demand & Customer Excluding Product	$ 154.05	$ 13,695.93	$ 212,530.89	$ 753.96	$ 314.12	$ 34.79	$ 4,398.36
96	Demand & Customer (per cust month)	$ 315.87	$ 18,234.61	$ 275,504.20	$ 778.71	$ 553.18	$ 35.92	$ 7,391.13
97	**BILLING DETERMINANTS**							
98	Billed Demand	12,167,818	154,501	34,462	0	0	0	0
99	Energy	10,831,016,495	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
100	Customers (Number of Bills)	6,009,505	72	12	16,776	1,680	116,400	552
101	**Unit Cost after Mitigation**							
102	Mitigated percent of COS @ Equal ROR		150.0%	54.1%	70.9%	116.5%	90.7%	129.0%
103	Demand (per kW)		$ 12.48	$ 50.43				
104	Energy	$ 0.0277	$ 0.0417	$ 0.0151	$ 0.0200	$ 0.0328	$ 0.0256	$ 0.0391
105	Customer (per cust month)	$ 38.58	$ 567.23	$ 4,298.18	$ 447.50	$ 210.06	$ 27.08	$ 243.59
106	Demand & Customer (per cust month)	$ 315.87	$ 27,351.92	$ 149,130.41	$ 551.83	$ 644.56	$ 32.59	$ 9,538.22

Northern Indiana Public Service Company
Functional Studies Summary

Line	FERC Account	12/31/2025 Balance	34 kV	RailRoad	Primary	Secondary Demand	Secondary Customer
1	36010 Land	12,037,421	416,039	5,227			
2	36020 Land Rights		50,261	24			
3	36100 Structures and Improvements	20,835,018	2,588,465	1,751,577			
4	36200 Station Equipment	695,847,349	74,010,612	14,782,989			
5	36410 Customers Transformer Station	61,382,976	2,889,788	179,303			
6	36420 Poles, Towers and Fixtures	809,418,849	42,078,304		597,528,045	73,585,149	96,227,351
7	36500 Overhead Conductors, Device	503,607,560	20,562,915		357,231,133	79,922,202	45,891,311
8	36600 Underground Conduit	5,753,946	64,407		4,586,411	292,057	811,070
9	36700 Undergrnd Conductors,Device	719,329,666	2,198,056		578,089,187	36,811,984	102,230,438
10	Poles				77.87%	43.33%	56.67%
11	OH				73.95%	63.52%	36.48%
12	UG				80.61%	26.48%	73.52%
13	Distribution Land						
14	Land and land rights	96.08%	11,565,870				
15	Land and land rights - Sub-trans	3.87%	466,300				
16	Land and land rights - RR	0.04%	5,252				
		100.00%	12,037,421				
17	Distribution Structures						
18	Structures and improvements	79.17%	16,494,975				
19	Structures and improvements - Sub-trans	12.42%	2,588,465				
20	Structures and improvements - RR	8.41%	1,751,577				
		100.00%	20,835,018				
21	Distribution Stations						
22	Station equipment	87.24%	607,053,749				
23	Station equipment - Sub-trans	10.64%	74,010,612				
24	Station equipment - RR	2.12%	14,782,989				
		100.00%	695,847,349				
25	Customer Station Eqpt						
26	Customer stations	95.00%	58,313,885				
27	Customer stations - Sub-trans	4.71%	2,889,788				
28	Customer stations - RR	0.29%	179,303				
		100.00%	61,382,976				
29	Poles, Towers, Fixtures						
30	Poles, Towers and fixtures - Sub-trans	5.20%	42,078,304				
31	Poles, Towers and fixtures - Primary	73.82%	597,528,045				
32	Poles, Towers and fixtures - SEC - Demand	9.09%	73,585,149				
33	Poles, Towers and fixtures - SEC - Customer	11.89%	96,227,351				
		100.00%	809,418,849				
34	OH Conductor						
35	Overhead conductors - Sub-trans	4.08%	20,562,915				
36	Overhead conductors - Primary	70.93%	357,231,133				
37	Overhead conductors - SEC - Demand	15.87%	79,922,202				
38	Overhead conductors - SEC - Customer	9.11%	45,891,311				
		100.00%	503,607,560				
39	UG Conduit						
40	Underground conduit - Sub-trans	1.12%	64,407				
41	Underground conduit - Primary	79.71%	4,586,411				
42	Underground conduit - SEC - Demand	5.08%	292,057				
43	Underground conduit - SEC - Customer	14.10%	811,070				
		100.00%	5,753,946				
44	UG Conductor						
45	Underground conductors - Sub-trans	0.31%	2,198,056				
46	Underground conductors - Primary	80.36%	578,089,187				
47	Underground conductors - SEC - Demand	5.12%	36,811,984				
48	Underground conductors - SEC - Customers	14.21%	102,230,438				
		100.00%	719,329,666				
49	Steam Expense						
50	Steam expenses - fixed	100.00%					
51	Steam expenses - variable	0.00%	-				
		100.00%					
52	Misc. Steam Expense						
53	Miscellaneous steam power expenses - fixed	100.00%					
54	Miscellaneous steam power expenses - variable	0.00%	-				
		100.00%					

Northern Indiana Public Service Company
Minimum System Study
Pole and Conductor Minimum System Analysis

Line No.	Pole Account 364			
1	Total Amount of Poles		$	795,187,849
2	Primary Poles	78%	$	619,212,740
3	Secondary Poles	22%	$	175,975,109
4	Total Count of Poles (# of poles)			282,397
5	Primary Poles (# of poles)	78%		220,270
6	Secondary Poles (# of poles)	22%		62,127
7	Secondary Poles (# of poles)			62,127
8	Minimum Cost Plug (Cost of 35 foot pole)		$	1,605
9	Minimum Cost to Provide Secondary (line 7 * line 8)		$	99,719,506
10	Customer - Poles (line 9 / line 3)			56.67%
11	Demand - Poles			43.33%

	Secondary Conductors Overhead - Account 365		
12	Total Feet of Circuits - O/H		15,190,728
	Minimum Size - #4 AL Triplex (14002130)		
13	Minimum Cost Per Foot - O/H		$1.29
14	Total Minimum Cost - O/H	$	19,596,039
15	Total Replacement Cost - O/H	$	53,723,601
19	Customer - O/H		36.5%
20	Demand - O/H		63.5%

	Secondary Conductors Underground - Account 366		
21	Total Feet of Circuits - U/G		4,813,369
	Minimum Size - 4/0 Alum Triplex		
22	Minimum Cost Per Foot - U/G	$	7.42
23	Total Minimum Cost - U/G	$	35,715,201
24	Total Replacement Cost - U/G	$	48,575,827
25	Customer - U/G		73.5%
26	Demand - U/G		26.5%

Northern Indiana Public Service Company
Functional Split Study
Pole Analysis

Line No.	**Development of Ratios for Allocation of Poles carrying Primary and Secondary**	34 kV	Primary	Secondary	Service	Total
1	Typical Replacement Height (feet)	65	45	35	35	
2	Unit Cost (cost per pole)	$ 11,232	$ 2,895	$ 1,605	$ 1,605	
3	34 kV Pole with Secondary	$ 11,232		$ 1,605		$ 12,837
4	Percent	87.50%		12.50%		100.00%
5	Primary <34 kV Pole w/ Sec		$ 2,895	$ 1,605		$ 4,500
6	Percent		64.33%	35.67%		100.00%

Allocation of Pole Costs by Voltage Level

Line No.		Total	Primary Only	Primary & Secondary	Primary & Service	Primary, Secondary & Service	Secondary Only	Secondary & Service	Service Only	*(Continued below)*
7	Total Installed Costs	$1,011,182,773	$ 369,069,372	$ 100,142,031	$ 93,042,668	$ 233,677,855	$ 49,020,551	$ 49,394,670	$ 4,990,380	
8	34 kV									
9	Primary		100.00%	64.33%	64.33%	47.42%				
10	Secondary			35.67%		26.29%	100.00%	50.00%		
11	Service				35.67%	26.29%		50.00%	100.00%	
12	34 kV		-	-	-	-	-	-	-	
13	Primary	619,212,740	369,069,372	64,422,424	59,855,329	110,804,596	-	-	-	
14	Secondary	175,975,109	-	35,719,607	-	61,436,630	49,020,551	24,697,335	-	
15	Service		-	-	33,187,339	61,436,630	-	24,697,335	4,990,380	
			34 kV Only	34 kV & Secondary	34 kV & Service	34 kV, Secondary & Service	34KV & Primary	34KV, Primary, & Secondary	34KV, Primary, & Service	34KV, Primary, Secondary, & Service
16	Total Installed Costs (cont'd)		$ 25,657,913	$ 5,607,051	$ 285,818	$ 639,634	$ 32,825,822	$ 27,356,536	$ 2,863,946	$ 16,608,526
17	34 kV		100.00%	87.50%	87.50%	77.77%	79.51%	71.40%	71.40%	64.79%
18	Primary						20.49%	18.40%	18.40%	16.70%
19	Secondary			12.50%		11.11%		10.20%		9.26%
20	Service				12.50%	11.11%			10.20%	9.26%
21	34 kV		25,657,913	4,905,961	250,080	497,455	26,099,072	19,531,387	2,044,734	10,759,949
22	Primary		-	-	-	-	6,726,750	5,034,001	527,008	2,773,259
23	Secondary		-	701,090	-	71,089	-	2,791,148	-	1,537,659
24	Service		-	-	35,738	71,089	-	-	292,204	1,537,659
25	Primary/Secondary Split		Rounded	Total Poles						
26	**Primary**	77.87%	**78.00%**	220,270						
27	**Secondary**	22.13%	**22.00%**	62,127						
28	Sub-Total	100.00%	100.00%	282,397						

Northern Indiana Public Service Company
Functional Split Study
Conductor Analysis

FUNCTIONAL SPLIT

OVERHEAD CIRCUITS

Line No.		Primary	Secondary
1	Length (Feet)	40,817,916	15,190,728
2	Split (%)		
3	Replacement Cost ($)	$152,541,188	$53,723,601
4	Split (%)	74.0%	26.0%

UNDERGROUND CIRCUITS

Line No.		Primary	Secondary
4	Length (Feet)	14,149,498	4,813,369
5	Split (%)		
5	Replacement Cost ($)	$201,961,097	$48,575,827
6	Split (%)	80.6%	19.4%

Cause No. 46120

Northern Indiana Power Service Company
Functional Split Study
34kV "Subtransmission" System Summary

Line No.	Account	34kV Circuits	34kV Substations	Total 34kV Balance
1	36010 Land	$ 2,002	$ 414,037	$ 416,039
2	36020 Land Rights	50,255	6	50,261
3	36100 Structures and Improvements	21,979	2,566,487	2,588,465
4	36200 Station Equipment	84,638	73,925,974	74,010,612
5	36410 Customers Transformer Station	669,361	2,220,427	2,889,788
6	36420 Poles, Towers and Fixtures	42,062,821	15,484	42,078,304
7	36500 Overhead Conductors, Device	20,449,971	112,943	20,562,915
8	36600 Underground Conduit	64,407	-	64,407
9	36700 Undergrnd Conductors,Device	2,197,930	126	2,198,056
10	TOTAL	$ 65,603,364	$ 79,255,484	$ 144,858,848

Cause No. 46120

Northern Indiana Power Service Company
Functional Split Study
Railroad Substation Summary

Line No.	Account	Railroad
1	36010 Land	$ 5,227
2	36020 Land Rights	24
3	36100 Structures and Improvements	1,751,577
4	36200 Station Equipment	14,782,989
5	36410 Customers Transformer Station	179,303
6	TOTAL	$ 16,719,121

SUBSTATION TOTAL DETAIL

	Substation Name	NICTD or Shared	36010 Land	36020 Land Rights	36100 Structures and Improvements	36200 Station Equipment	36410 Customers Transformer Station	Total
7	Carroll Substation	100% NICTD	$ -	$ -	$ -	$ 15,018	$ 173,315	$ 188,332
8	Columbia Ave Substation	Shared	1,621	6	52,571	1,553,999	-	1,608,198
9	Eastport Substation	100% NICTD	-	16	6,840	254,737	5,989	267,582
10	Furnessville Substation	Shared	-	2	13,572	119,654	-	133,229
11	Grand View Substation	100% NICTD	1,776	-	102,665	2,682,710	-	2,787,151
12	Lyman Substation	Future TY NICTD	-	-	353,140	2,589,691	-	2,942,831
13	Madison Substation	Shared	835	-	8,207	152,918	-	161,960
14	MIller Substation	Future TY NICTD	-	-	51,547	378,011	-	429,558
15	Munster Substation	Future TY NICTD	-	-	406,702	2,982,479	-	3,389,180
16	New Carlisle Substation	100% NICTD	491	-	162,992	375,771	-	539,253
17	Pines Substation	Future TY NICTD	-	-	122,614	899,170	-	1,021,784
18	Sheffield Substation	Future TY NICTD	-	-	295,983	2,170,544	-	2,466,527
19	Tee Lake Substation	100% NICTD	-	-	162,926	335,638	-	498,564
20	Wickliffe Substation	Shared	505	-	11,818	272,650	-	284,973
21	TOTAL		$ 5,227	$ 24	$ 1,751,577	$ 14,782,989	$ 179,303	$ 16,719,121

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	DEMAND ALLOCATORS									
	4 CP (for Generation)									
1		Test Year 4 CP @ Generation		1,082,859	61,870	-	369,008	-	196,331	225,117
2		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
3	GEN_CP	4 CP @ Generation	2,410,898	1,082,859	61,870	-	369,008	-	196,331	225,117
4			100%	44.92%	2.57%	0.00%	15.31%	0.00%	8.14%	9.34%
	12 CP @ Transmission									
5		Test Year 12 CP @ Generation		689,818	52,114	1,611	329,069	1,095	177,285	229,343
6		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7	TRANS_12CP	12 CP @ Transmission	2,336,602	689,818	52,114	1,611	329,069	1,095	177,285	229,343
8			100%	29.52%	2.23%	0.07%	14.08%	0.05%	7.59%	9.82%
	NCPs @ Sub-Transmission									
9		Test Year NCPs @ Sub-Transmission		1,291,823	123,507	4,639	418,164	3,028	233,806	277,652
10		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	SUB_NCP	NCP @ Sub-Transmission	2,808,466	1,291,823	123,507	4,639	418,164	3,028	233,806	277,652
12			100%	46.00%	4.40%	0.17%	14.89%	0.11%	8.33%	9.89%
	NCPs @ Primary									
13		Test Year NCPs @ Primary		1,288,455	123,185	4,627	414,247	3,020	233,166	265,741
14		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	DIST_NCP	NCP @ Primary	2,615,522	1,288,455	123,185	4,627	414,247	3,020	233,166	265,741
16			100%	49.26%	4.71%	0.18%	15.84%	0.12%	8.91%	10.16%
	Avg. of 12 Monthly NCPs @ Secondary									
17		Test Year Avg. Monthly NCPs @ Secondary		670,299	78,922	2,564	312,963	1,786	163,170	104,756
18		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	SEC_NCP12	NCP12 @ Secondary	1,437,936	670,299	78,922	2,564	312,963	1,786	163,170	104,756
20			100%	46.62%	5.49%	0.18%	21.76%	0.12%	11.35%	7.29%
	Customer Stations - Transmission									
21		Customer Count	500,792	362,370	67,956	164	54,434	164	2,893	496
22		Customers Taking at Transmission		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.47%
23	STAT_TRAN	Customer Station - Tran.	29	-	-	-	0	-	-	12
24			100%	0.00%	0.00%	0.00%	1.14%	0.00%	0.00%	42.40%
	Customer Stations - Sub-Transmission									
25		No. of Customers		362,370	67,956	164	54,434	164	2,893	496
26		Customers Taking at Sub-Transmission		0.00%	0.00%	0.00%	0.01%	0.00%	0.03%	2.37%
27	STAT_SBTRN	Customer Station - Sub-Tran.	33	-	-	-	4	-	1	12
28			100%	0.00%	0.00%	0.00%	10.85%	0.00%	2.86%	35.15%
	Direct Assignment of Railroad									
29	RR_DIR	Railroad Direct	1	-	-	-	-	-	-	-
30			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Line No.	Name	Description	Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
	DEMAND ALLOCATORS									
	4 CP (for Generation)									
1		Test Year 4 CP @ Generation		8,259	241,304	168,694	21,915	23,294	3,740	41
2		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
3	GEN_CP	4 CP @ Generation	2,410,898	8,259	241,304	168,694	21,915	23,294	3,740	41
4			100%	0.34%	10.01%	7.00%	0.91%	0.97%	0.16%	0.00%
	12 CP @ Transmission									
5		Test Year 12 CP @ Generation		11,461	216,086	572,846	22,489	22,121	3,903	43
6		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7	TRANS_12CP	12 CP @ Transmission	2,336,602	11,461	216,086	572,846	22,489	22,121	3,903	43
8			100%	0.49%	9.25%	24.52%	0.96%	0.95%	0.17%	0.00%
	NCPs @ Sub-Transmission									
9		Test Year NCPs @ Sub-Transmission		20,570	248,033	117,143	16,622	9,332	8,732	48
10		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	SUB_NCP	NCP @ Sub-Transmission	2,808,466	20,570	248,033	117,143	16,622	9,332	8,732	48
12			100%	0.73%	8.83%	4.17%	0.59%	0.33%	0.31%	0.00%
	NCPs @ Primary									
13		Test Year NCPs @ Primary		14,835	228,423	-	-	(0)	8,709	48
14		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	DIST_NCP	NCP @ Primary	2,615,522	14,835	228,423	-	-	(0)	8,709	48
16			100%	0.57%	8.73%	0.00%	0.00%	0.00%	0.33%	0.00%
	Avg. of 12 Monthly NCPs @ Secondary									
17		Test Year Avg. Monthly NCPs @ Secondary		4,293	74,838	-	-	-	5,770	41
18		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	SEC_NCP12	NCP12 @ Secondary	1,437,936	4,293	74,838	-	-	-	5,770	41
20			100%	0.30%	5.20%	0.00%	0.00%	0.00%	0.40%	0.00%
	Customer Stations - Transmission									
21		Customer Count	500,792	6	260	7	5	4	734	9
22		Customers Taking at Transmission		0.00%	0.57%	71.43%	40.00%	73.47%	0.00%	0.00%
23	STAT_TRAN	Customer Station - Tran.	29	-	1	5	2	3	-	-
24			100%	0.00%	5.14%	17.33%	6.93%	10.19%	0.00%	0.00%
	Customer Stations - Sub-Transmission									
25		No. of Customers		6	260	7	5	4	734	9
26		Customers Taking at Sub-Transmission		16.67%	3.04%	28.57%	60.00%	26.53%	0.00%	0.00%
27	STAT_SBTRN	Customer Station - Sub-Tran.	33	1	8	2	3	1	-	-
28			100%	2.99%	23.65%	5.98%	8.97%	3.17%	0.00%	0.00%
	Direct Assignment of Railroad									
29	RR_DIR	Railroad Direct	1	-	-	-	-	-	-	-
30			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(R)	(S)	(T)	(U)	(V)	(W)
	DEMAND ALLOCATORS								
	4 CP (for Generation)								
1		Test Year 4 CP @ Generation		1,359	1,277	-	797	-	5,033
2		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
3	GEN_CP	4 CP @ Generation	2,410,898	1,359	1,277	-	797	-	5,033
4			100%	0.06%	0.05%	0.00%	0.03%	0.00%	0.21%
	12 CP @ Transmission								
5		Test Year 12 CP @ Generation		649	1,502	825	798	260	3,283
6		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7	TRANS_12CP	12 CP @ Transmission	2,336,602	649	1,502	825	798	260	3,283
8			100%	0.03%	0.06%	0.04%	0.03%	0.01%	0.14%
	NCPs @ Sub-Transmission								
9		Test Year NCPs @ Sub-Transmission		1,318	2,900	12,954	781	3,591	13,820
10		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	SUB_NCP	NCP @ Sub-Transmission	2,808,466	1,318	2,900	12,954	781	3,591	13,820
12			100%	0.05%	0.10%	0.46%	0.03%	0.13%	0.49%
	NCPs @ Primary								
13		Test Year NCPs @ Primary		-	-	12,920	779	3,581	13,784
14		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	DIST_NCP	NCP @ Primary	2,615,522	-	-	12,920	779	3,581	13,784
16			100%	0.00%	0.00%	0.49%	0.03%	0.14%	0.53%
	Avg. of 12 Monthly NCPs @ Secondary								
17		Test Year Avg. Monthly NCPs @ Secondary		-	-	11,213	767	3,205	3,349
18		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	SEC_NCP12	NCP12 @ Secondary	1,437,936	-	-	11,213	767	3,205	3,349
20			100%	0.00%	0.00%	0.78%	0.05%	0.22%	0.23%
	Customer Stations - Transmission								
21		Customer Count	500,792	6	1	1,398	140	9,700	46
22		Customers Taking at Transmission		81.08%	0.00%	0.00%	0.00%	0.00%	0.00%
23	STAT_TRAN	Customer Station - Tran.	29	5	-	-	-	-	-
24			100%	16.86%	0.00%	0.00%	0.00%	0.00%	0.00%
	Customer Stations - Sub-Transmission								
25		No. of Customers		6	1	1,398	140	9,700	46
26		Customers Taking at Sub-Transmission		18.92%	100.00%	0.00%	0.00%	0.00%	0.00%
27	STAT_SBTRN	Customer Station - Sub-Tran.	33	1	1	-	-	-	-
28			100%	3.39%	2.99%	0.00%	0.00%	0.00%	0.00%
	Direct Assignment of Railroad								
29	RR_DIR	Railroad Direct	1	-	1	-	-	-	-
30			100%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%

Cause No. 46120

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	CUSTOMER ALLOCATORS									
	Test Year-End Customer Count									
31	CUST	No. of Customers	500,792	362,370	67,956	164	54,434	164	2,893	496
32			100%	72.36%	13.57%	0.03%	10.87%	0.03%	0.58%	0.10%
	Allocation of Services									
33		Customer Count	500,792	362,370	67,956	164	54,434	164	2,893	496
34		Weighting Factor		1.00	0.63	-	1.36	-	2.76	0.87
35	SERV	Services(Wtd Cust)	500,515	362,370	42,472	-	73,934	-	7,974	432
36			100%	72.40%	8.49%	0.00%	14.77%	0.00%	1.59%	0.09%
	Allocation of Meters									
37	METERS	Meters Replacement Cost	82,480,962	47,842,724	8,972,038	330,106	18,028,063	88,038	2,468,204	1,181,793
38			100%	58.00%	10.88%	0.40%	21.86%	0.11%	2.99%	1.43%
	Allocation of Transformers									
39		Customer Count	500,792	362,370	67,956	164	54,434	164	2,893	496
40		Weighting Factor		1.00	1.00	-	2.16	-	7.10	16.37
41	XFRS	Transformer(Wtd Cust)	584,542	362,370	67,956	-	117,348	-	20,539	8,122
42			100%	61.99%	11.63%	0.00%	20.08%	0.00%	3.51%	1.39%
	Direct Assignment of Dusk-to-Dawn									
43	DSKDWN	Direct to Dusk-to-Dawn	1	-	-	-	-	-	-	-
44			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Direct Assignment of Street and Traffic Lighting (Count of Lights)									
45	STTRLGT	Direct to Street and Traffic Lighting	539,618	-	-	-	-	-	-	-
46			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Gross Write-Offs									
47	GRSWRTOFF	Gross Write Offs	6,816,636	5,227,110	980,250	-	338,272	-	19,053	1,978
48			100%	76.68%	14.38%	0.00%	4.96%	0.00%	0.28%	0.03%
	Meter Reading									
49		Number of Customers	500,792	362,370	67,956	164	54,434	164	2,893	496
50		Weighted		1.00	1.00	77.73	1.48	15.53	5.20	44.85
51	METER_READ	AMR Meter Reading	612,431	362,370	67,956	12,748	80,437	2,547	15,049	22,246
52			100%	59.17%	11.10%	2.08%	13.13%	0.42%	2.46%	3.63%
	Customer Account Supervision									
53		Customer Count	500,792	362,370	67,956	164	54,434	164	2,893	496
54		Weighting Factor		1.00	1.00	0.90	1.38	0.65	1.36	1.36
55	ACCT_901	Customer Account Supervision	517,064	362,370	67,956	147	74,972	106	3,924	673
56			100%	70.08%	13.14%	0.03%	14.50%	0.02%	0.76%	0.13%

Cause No. 46120

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
	CUSTOMER ALLOCATORS									
	Test Year-End Customer Count									
31	CUST	No. of Customers	500,792	6	260	7	5	4	734	9
32			100%	0.00%	0.05%	0.00%	0.00%	0.00%	0.15%	0.00%
	Allocation of Services									
33		Customer Count	500,792	6	260	7	5	4	734	9
34		Weighting Factor		0.13	1.67	1.26	0.16	-	1.55	0.18
35	SERV	Services(Wtd Cust)	500,515	1	434	9	1	-	1,137	2
36			100%	0.00%	0.09%	0.00%	0.00%	0.00%	0.23%	0.00%
	Allocation of Meters									
37	METERS	Meters Replacement Cost	82,480,962	15,670	514,566	2,289,613	234,734	124,326	285,016	-
38			100%	0.02%	0.62%	2.78%	0.28%	0.15%	0.35%	0.00%
	Allocation of Transformers									
39		Customer Count	500,792	6	260	7	5	4	734	9
40		Weighting Factor		10.81	16.77	4.97	0.46	4.04	2.92	0.23
41	XFRS	Transformer(Wtd Cust)	584,542	65	4,361	35	2	16	2,142	2
42			100%	0.01%	0.75%	0.01%	0.00%	0.00%	0.37%	0.00%
	Direct Assignment of Dusk-to-Dawn									
43	DSKDWN	Direct to Dusk-to-Dawn	1	-	-	-	-	-	-	-
44			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Direct Assignment of Street and Traffic Lighting (Count of Lights)									
45	STTRLGT	Direct to Street and Traffic Lighting	539,618	-	-	-	-	-	-	-
46			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Gross Write-Offs									
47	GRSWRTOFF	Gross Write Offs	6,816,636	-	-	-	-	238,137	181	-
48			100%	0.00%	0.00%	0.00%	0.00%	3.49%	0.00%	0.00%
	Meter Reading									
49		Number of Customers	500,792	6	260	7	5	4	734	9
50		Weighted		147.09	102.73	368.14	601.29	322.12	2.44	-
51	METER_READ	AMR Meter Reading	612,431	883	26,709	2,577	3,006	1,288	1,787	-
52			100%	0.14%	4.36%	0.42%	0.49%	0.21%	0.29%	0.00%
	Customer Account Supervision									
53		Customer Count	500,792	6	260	7	5	4	734	9
54		Weighting Factor		0.57	0.57	0.57	0.57	0.57	0.58	0.57
55	ACCT_901	Customer Account Supervision	517,064	3	148	4	3	2	424	5
56			100%	0.00%	0.03%	0.00%	0.00%	0.00%	0.08%	0.00%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(R)	(S)	(T)	(U)	(V)	(W)
	CUSTOMER ALLOCATORS								
	Test Year-End Customer Count								
31	CUST	No. of Customers	500,792	6	1	1,398	140	9,700	46
32			100%	0.00%	0.00%	0.28%	0.03%	1.94%	0.01%
	Allocation of Services								
33		Customer Count	500,792	6	1	1,398	140	9,700	46
34		Weighting Factor		0.26	-	0.86	0.89	1.07	1.33
35	SERV	Services(Wtd Cust)	500,515	2	-	1,205	125	10,358	61
36			100%	0.00%	0.00%	0.24%	0.02%	2.07%	0.01%
	Allocation of Meters								
37	METERS	Meters Replacement Cost	82,480,962	33,569	33,251	-	-	-	39,250
38			100%	0.04%	0.04%	0.00%	0.00%	0.00%	0.05%
	Allocation of Transformers								
39		Customer Count	500,792	6	1	1,398	140	9,700	46
40		Weighting Factor		16.37	-	0.35	0.18	0.08	5.40
41	XFRS	Transformer(Wtd Cust)	584,542	98	-	482	25	730	249
42			100%	0.02%	0.00%	0.08%	0.00%	0.12%	0.04%
	Direct Assignment of Dusk-to-Dawn								
43	DSKDWN	Direct to Dusk-to-Dawn	1	-	-	-	-	1	-
44			100%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
	Direct Assignment of Street and Traffic Lighting (Count of Lights)								
45	STTRLGT	Direct to Street and Traffic Lighting	539,618	-	-	525,405	14,213	-	-
46			100%	0.00%	0.00%	97.37%	2.63%	0.00%	0.00%
	Gross Write-Offs								
47	GRSWRTOFF	Gross Write Offs	6,816,636	-	-	68	-	11,588	-
48			100%	0.00%	0.00%	0.00%	0.00%	0.17%	0.00%
	Meter Reading								
49		Number of Customers	500,792	6	1	1,398	140	9,700	46
50		Weighted		-	7,413.17	-	-	-	117.67
51	METER_READ	AMR Meter Reading	612,431	-	7,413	-	-	-	5,413
52			100%	0.00%	1.21%	0.00%	0.00%	0.00%	0.88%
	Customer Account Supervision								
53		Customer Count	500,792	6	1	1,398	140	9,700	46
54		Weighting Factor		1.31	0.57	0.50	0.57	0.57	0.57
55	ACCT_901	Customer Account Supervision	517,064	8	1	702	80	5,510	26
56			100%	0.00%	0.00%	0.14%	0.02%	1.07%	0.01%

Line No.	Name	Description	Total	Rate 511- Residential	Rate 515- Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522- Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Customer Records and Collecting									
57		Customer Count	500,792	362,370	67,956	164	54,434	164	2,893	496
58		Weighting Factor		1.00	1.00	10.56	1.44	2.39	1.85	7.87
59	ACCT_903	Customer Records & Collections	533,498	362,370	67,956	1,732	78,445	392	5,347	3,904
60			100%	67.92%	12.74%	0.32%	14.70%	0.07%	1.00%	0.73%
	Customer Assistance Expense									
61		Customer Count	500,792	362,370	67,956	164	54,434	164	2,893	496
62		Weighting Factor		1.00	1.00	30.43	1.52	21.93	26.22	198.91
63	ACCT_910	Customer Assistance Expense	899,053	362,370	67,956	4,991	82,716	3,597	75,860	98,659
64			100%	40.31%	7.56%	0.56%	9.20%	0.40%	8.44%	10.97%
	Weighed Secondary Customers (Lighting @ 0.25)									
65		Number of Secondary Customers	497,141	362,358	67,954	164	51,554	164	2,694	217
66		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
67	WEIGHTSNDCST	Secondary Customers w/ Lighting at	488,713	362,358	67,954	164	51,554	164	2,694	217
68			100%	74.15%	13.90%	0.03%	10.55%	0.03%	0.55%	0.04%
	Customer Charge Billing Determinants									
69	CC_BILLDET	Customer Charge Billing Determinan	6,545,123	4,348,440	815,471	1,476	653,202	1,476	-	-
70			100%	66.44%	12.46%	0.02%	9.98%	0.02%	0.00%	0.00%
	Number of Secondary Customers									
71		No. of Customers	500,792	362,370	67,956	164	54,434	164	2,893	496
72		Weighting - Taking at Secondary		1.00	1.00	1.00	0.95	1.00	0.93	0.44
73	SNDCST	No. of Secondary Customers	497,141	362,358	67,954	164	51,554	164	2,694	217
74				72.89%	13.67%	0.03%	10.37%	0.03%	0.54%	0.04%
	ENERGY ALLOCATORS									
	MWh Sales @ Generation									
75		Energy at Source	11,000,452	3,209,327	374,333	9,386	1,669,599	7,420	894,257	1,468,130
76		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
77	ENRGYSRC	Energy at Source	11,000,452	3,209,327	374,333	9,386	1,669,599	7,420	894,257	1,468,130
78			100%	29.17%	3.40%	0.09%	15.18%	0.07%	8.13%	13.35%
	Total Volume of kWh Sales									
79		TRANSMISSION		-	-	-	-	-	-	43,132,070
80		SUB-TRANSMISSION		-	-	-	11,123,587	-	116,016	56,560,799
81		PRIMARY		102,606	11,968	-	74,401,053	-	59,436,948	703,404,579
82		SECONDARY		3,106,827,597	362,377,363	9,086,667	1,531,390,554	7,182,994	806,537,847	623,766,442
83		Total KWh	10683959164	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891
84			1	29.08%	3.39%	0.09%	15.13%	0.07%	8.11%	13.36%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
	Customer Records and Collecting									
57		Customer Count	500,792	6	260	7	5	4	734	9
58		Weighting Factor		26.84	22.36	62.70	27.06	32.60	0.77	0.55
59	ACCT_903	Customer Records & Collections	533,498	161	5,812	439	135	130	564	5
60			100%	0.03%	1.09%	0.08%	0.03%	0.02%	0.11%	0.00%
	Customer Assistance Expense									
61		Customer Count	500,792	6	260	7	5	4	734	9
62		Weighting Factor		499.43	219.69	6,846.16	6,587.90	8,234.63	5.16	333.29
63	ACCT_910	Customer Assistance Expense	899,053	2,997	57,119	47,923	32,940	32,939	3,787	3,000
64			100%	0.33%	6.35%	5.33%	3.66%	3.66%	0.42%	0.33%
	Weighed Secondary Customers (Lighting @ 0.25)									
65		Number of Secondary Customers	497,141	1	89	-	-	-	653	9
66		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
67	WEIGHTSNDCST	Secondary Customers w/ Lighting at	488,713	1	89	-	-	-	653	9
68			100%	0.00%	0.02%	0.00%	0.00%	0.00%	0.13%	0.00%
	Customer Charge Billing Determinants									
69	CC_BILLDET	Customer Charge Billing Determinan	6,545,123	-	-	-	-	-	8,808	108
70			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.13%	0.00%
	Number of Secondary Customers									
71		No. of Customers	500,792	6	260	7	5	4	734	9
72		Weighting - Taking at Secondary		0.22	0.34	-	-	-	0.89	1.00
73	SNDCST	No. of Secondary Customers	497,141	1	89	-	-	-	653	9
74				0.00%	0.02%	0.00%	0.00%	0.00%	0.13%	0.00%
	ENERGY ALLOCATORS									
	MWh Sales @ Generation									
75		Energy at Source	11,000,452	89,188	1,617,540	1,060,274	163,529	278,461	38,994	401
76		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
77	ENRGYSRC	Energy at Source	11,000,452	89,188	1,617,540	1,060,274	163,529	278,461	38,994	401
78			100%	0.81%	14.70%	9.64%	1.49%	2.53%	0.35%	0.00%
	Total Volume of kWh Sales									
79		TRANSMISSION		-	28,738,805	899,856,710	72,184,585	183,730,582	-	-
80		SUB-TRANSMISSION		24,256,799	119,670,341	140,666,206	88,151,713	89,427,449	-	-
81		PRIMARY		43,759,459	884,699,089	-	-	-	4,161,830	-
82		SECONDARY		18,877,864	540,048,975	-	-	-	33,613,566	388,291
83		Total KWh	10683959164	86,894,122	1,573,157,210	1,040,522,916	160,336,298	273,158,031	37,775,395	388,291
84			1	0.81%	14.72%	9.74%	1.50%	2.56%	0.35%	0.00%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(R)	(S)	(T)	(U)	(V)	(W)
	Customer Records and Collecting								
57		Customer Count	500,792	6	1	1,398	140	9,700	46
58		Weighting Factor		8.29	23.67	0.49	0.55	0.54	0.79
59	ACCT_903	Customer Records & Collections	533,498	50	24	679	78	5,239	36
60			100%	0.01%	0.00%	0.13%	0.01%	0.98%	0.01%
	Customer Assistance Expense								
61		Customer Count	500,792	6	1	1,398	140	9,700	46
62		Weighting Factor		203.59	4,189.69	2.78	1.00	1.31	1.00
63	ACCT_910	Customer Assistance Expense	899,053	1,222	4,190	3,885	140	12,718	46
64			100%	0.14%	0.47%	0.43%	0.02%	1.41%	0.01%
	Weighed Secondary Customers (Lighting @ 0.25)								
65		Number of Secondary Customers	497,141	-	-	1,398	140	9,700	46
66		Weighting		1.00	1.00	0.25	0.25	0.25	1.00
67	WEIGHTSNDCST	Secondary Customers w/ Lighting at	488,713	-	-	350	35	2,425	46
68			100%	0.00%	0.00%	0.07%	0.01%	0.50%	0.01%
	Customer Charge Billing Determinants								
69	CC_BILLDET	Customer Charge Billing Determinan	6,545,123	-	12	525,405	14,213	176,512	-
70			100%	0.00%	0.00%	8.03%	0.22%	2.70%	0.00%
	Number of Secondary Customers								
71		No. of Customers	500,792	6	1	1,398	140	9,700	46
72		Weighting - Taking at Secondary		-	-	1.00	1.00	1.00	1.00
73	SNDCST	No. of Secondary Customers	497,141	-	-	1,398	140	9,700	46
74				0.00%	0.00%	0.28%	0.03%	1.95%	0.01%
	ENERGY ALLOCATORS								
	MWh Sales @ Generation								
75		Energy at Source	11,000,452	25,514	11,581	32,589	6,892	14,403	28,635
76		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
77	ENRGYSRC	Energy at Source	11,000,452	25,514	11,581	32,589	6,892	14,403	28,635
78			100%	0.23%	0.11%	0.30%	0.06%	0.13%	0.26%
	Total Volume of kWh Sales								
79		TRANSMISSION		20,792,230	-	-	-	-	-
80		SUB-TRANSMISSION		4,244,884	11,343,950	-	-	-	-
81		PRIMARY		-	-	-	-	-	-
82		SECONDARY		-	-	31,548,942	6,672,200	13,943,820	27,721,784
83		Total KWh	10683959164	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
84			1	0.23%	0.11%	0.30%	0.06%	0.13%	0.26%

Line No.	Name	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	REVENUE ALLOCATORS									
	Direct Assignment of Interdepartmental									
85	INTERDEPT	Interdepartmental	1	-	-	-	-	-	-	-
86			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	MWh Sales @ Generation									
87	REV_ENRGYSRC	Energy at Source	11,000,452	3,209,327	374,333	9,386	1,669,599	7,420	894,257	1,468,130
88			100%	29.17%	3.40%	0.09%	15.18%	0.07%	8.13%	13.35%
	Net Late Charges and Credits									
89	LT_FEES	3-Year Average Late Payments	$ 5,428,612	2,892,626	542,460	-	971,052	-	225,628	309,172
90			100%	53.28%	9.99%	0.00%	17.89%	0.00%	4.16%	5.70%
	Retail Sales without Fuel									
91	RETAIL_SALES	Retail Sales Allocator	$ 1,384,886,162	472,760,787	59,458,188	836,075	250,420,980	731,949	118,064,264	169,707,199
92			100%	34.14%	4.29%	0.06%	18.08%	0.05%	8.53%	12.25%
	Retail Sales without Fuel without Interdepartmental									
93		Retail Sales Allocator	$ 1,384,886,162	472,760,787	59,458,188	836,075	250,420,980	731,949	118,064,264	169,707,199
94		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
95	RETAIL_SALES_wo_INTD		$ 1,380,524,638	472,760,787	59,458,188	836,075	250,420,980	731,949	118,064,264	169,707,199
96			100%	34.25%	4.31%	0.06%	18.14%	0.05%	8.55%	12.29%
	DSM Revenue									
97	DSM	DSM Rider Revenue	$ 11,970,888	3,847,798	448,803	6,703	2,905,441	5,479	1,286,412	2,628,610
98			100%	32.14%	3.75%	0.06%	24.27%	0.05%	10.75%	21.96%
	Rider Revenue									
99	TDSIC	TDSIC Rider Revenue	$ 93,344,310	41,315,349	4,818,982	123,052	14,623,813	104,384	8,153,093	10,606,120
100			100%	44.26%	5.16%	0.13%	15.67%	0.11%	8.73%	11.36%
	Resource Adequacy Tracker									
101	RA	RA Tracker	$ (6,370,886)	(1,992,450)	(232,397)	(4,275)	(1,209,399)	(5,100)	(695,432)	(765,040)
102			100%	31.27%	3.65%	0.07%	18.98%	0.08%	10.92%	12.01%
	Generation Credit									
103	GEN_CREDIT	Generation Credit Revenue	$ (4,386,191)	(1,411,527)	(164,639)	(2,673)	(766,933)	(2,659)	(426,779)	(572,486)
104			100%	32.18%	3.75%	0.06%	17.49%	0.06%	9.73%	13.05%

Line No.	Name	Description	Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
	REVENUE ALLOCATORS									
	Direct Assignment of Interdepartmental									
85	INTERDEPT	Interdepartmental	1	-	-	-	-	-	-	-
86			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	MWh Sales @ Generation									
87	REV_ENRGYSRC	Energy at Source	11,000,452	89,188	1,617,540	1,060,274	163,529	278,461	38,994	401
88			100%	0.81%	14.70%	9.64%	1.49%	2.53%	0.35%	0.00%
	Net Late Charges and Credits									
89	LT_FEES	3-Year Average Late Payments	$ 5,428,612	2,260	272,425	192,831	-	-	283	181
90			100%	0.04%	5.02%	3.55%	0.00%	0.00%	0.01%	0.00%
	Retail Sales without Fuel									
91	RETAIL_SALES	Retail Sales Allocator	$ 1,384,886,162	6,011,619	142,515,010	111,940,817	11,894,020	17,977,035	4,497,985	56,589
92			100%	0.43%	10.29%	8.08%	0.86%	1.30%	0.32%	0.00%
	Retail Sales without Fuel without Interdepartmental									
93		Retail Sales Allocator	$ 1,384,886,162	6,011,619	142,515,010	111,940,817	11,894,020	17,977,035	4,497,985	56,589
94		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
95	RETAIL_SALES_wo_INTD		$ 1,380,524,638	6,011,619	142,515,010	111,940,817	11,894,020	17,977,035	4,497,985	56,589
96			100%	0.44%	10.32%	8.11%	0.86%	1.30%	0.33%	0.00%
	DSM Revenue									
97	DSM	DSM Rider Revenue	$ 11,970,888	139,109	470,027	-	187,243	15,399	24,809	-
98			100%	1.16%	3.93%	0.00%	1.56%	0.13%	0.21%	0.00%
	Rider Revenue									
99	TDSIC	TDSIC Rider Revenue	$ 93,344,310	491,084	7,838,993	2,611,056	462,100	747,626	255,555	-
100			100%	0.53%	8.40%	2.80%	0.50%	0.80%	0.27%	0.00%
	Resource Adequacy Tracker									
101	RA	RA Tracker	$ (6,370,886)	(32,679)	(649,274)	(566,837)	(62,302)	(77,580)	(23,174)	(501)
102			100%	0.51%	10.19%	8.90%	0.98%	1.22%	0.36%	0.01%
	Generation Credit									
103	GEN_CREDIT	Generation Credit Revenue	$ (4,386,191)	(22,765)	(422,704)	(426,461)	(40,077)	(64,712)	(12,259)	(391)
104			100%	0.52%	9.64%	9.72%	0.91%	1.48%	0.28%	0.01%

Line No.	Name	Description		Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)		(C)	(R)	(S)	(T)	(U)	(V)	(W)
	REVENUE ALLOCATORS									
	Direct Assignment of Interdepartmental									
85	INTERDEPT	Interdepartmental		1	-	-	-	-	-	1
86				100%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	MWh Sales @ Generation									
87	REV_ENRGYSRC	Energy at Source		11,000,452	25,514	11,581	32,589	6,892	14,403	28,635
88				100%	0.23%	0.11%	0.30%	0.06%	0.13%	0.26%
	Net Late Charges and Credits									
89	LT_FEES	3-Year Average Late Payments	$	5,428,612	4,056	-	-	223	15,415	-
90				100%	0.07%	0.00%	0.00%	0.00%	0.28%	0.00%
	Retail Sales without Fuel									
91	RETAIL_SALES	Retail Sales Allocator	$	1,384,886,162	2,589,916	1,084,684	6,415,686	928,145	2,633,692	4,361,524
92				100%	0.19%	0.08%	0.46%	0.07%	0.19%	0.31%
	Retail Sales without Fuel without Interdepartmental									
93		Retail Sales Allocator	$	1,384,886,162	2,589,916	1,084,684	6,415,686	928,145	2,633,692	4,361,524
94		Weighting			1.00	1.00	1.00	1.00	1.00	-
95	RETAIL_SALES_wo_INTD		$	1,380,524,638	2,589,916	1,084,684	6,415,686	928,145	2,633,692	-
96				100%	0.19%	0.08%	0.46%	0.07%	0.19%	0.00%
	DSM Revenue									
97	DSM	DSM Rider Revenue	$	11,970,888	5,054	-	-	-	-	-
98				100%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%
	Rider Revenue									
99	TDSIC	TDSIC Rider Revenue	$	93,344,310	135,249	195,360	243,822	31,760	122,821	464,091
100				100%	0.14%	0.21%	0.26%	0.03%	0.13%	0.50%
	Resource Adequacy Tracker									
101	RA	RA Tracker	$	(6,370,886)	-	(5,187)	(32,143)	(5,010)	(12,105)	-
102				100%	0.00%	0.08%	0.50%	0.08%	0.19%	0.00%
	Generation Credit									
103	GEN_CREDIT	Generation Credit Revenue	$	(4,386,191)	-	(6,466)	(23,867)	(2,979)	(6,054)	(9,759)
104				100%	0.00%	0.15%	0.54%	0.07%	0.14%	0.22%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	FUEL ALLOCATORS									
	Fuel Expense - MWh Sales @ Generation excluding Interdepartmental									
105	MWH_GEN_wo_INTD	Fuel Expense	$ 10,971,817	3,209,327	374,333	9,386	1,669,599	7,420	894,257	1,468,130
106			100%	29.25%	3.41%	0.09%	15.22%	0.07%	8.15%	13.38%
	Fuel Sales									
107	FUELREV	Fuel Revenue	$ 359,726,274	104,622,768	12,203,098	305,984	54,448,002	241,880	29,164,742	48,024,160
108			100%	29.08%	3.39%	0.09%	15.14%	0.07%	8.11%	13.35%
	Fuel Sales without Interdepartmental									
109		Fuel Revenue	$ 359,726,274	104,622,768	12,203,098	305,984	54,448,002	241,880	29,164,742	48,024,160
110		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
111	FUELREV_wo_INTD		$ 358,792,770	104,622,768	12,203,098	305,984	54,448,002	241,880	29,164,742	48,024,160
112			100%	29.16%	3.40%	0.09%	15.18%	0.07%	8.13%	13.38%
	UNIT COST BILLING DETERMINANTS									
	Energy at Meter									
113	SALES_KWH	Energy Sales - kWh	10,831,016,495	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891
114			100%	28.69%	3.35%	0.08%	14.93%	0.07%	8.00%	13.17%
	KW Billing Determinants									
115	BILLEDKW	KW Billing Determinants	12,167,818	-	-	-	-	-	2,072,970	3,915,943
116			100%	0.00%	0.00%	0.00%	0.00%	0.00%	17.04%	32.18%
	Revenue at Current Rates									
117		Revenue	$ 1,845,541,443	621,135,175	76,764,433	1,269,142	321,631,303	1,081,033	156,241,732	230,393,603
118			100%	33.66%	4.16%	0.07%	17.43%	0.06%	8.47%	12.48%
	Base Rate Margin at Current Rates									
119		Margin Revenue	$ 1,384,886,162	472,760,787	59,458,188	836,075	250,420,980	731,949	118,064,264	169,707,199
120			100%	34.14%	4.29%	0.06%	18.08%	0.05%	8.53%	12.25%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
	FUEL ALLOCATORS									
	Fuel Expense - MWh Sales @ Generation excluding Interdepartmental									
105	MWH_GEN_wo_INTD	Fuel Expense	$ 10,971,817	89,188	1,617,540	1,060,274	163,529	278,461	38,994	401
106			100%	0.81%	14.74%	9.66%	1.49%	2.54%	0.36%	0.00%
	Fuel Sales									
107	FUELREV	Fuel Revenue	$ 359,726,274	2,926,073	52,954,408	35,038,569	5,399,164	9,198,502	1,272,049	11,672
108			100%	0.81%	14.72%	9.74%	1.50%	2.56%	0.35%	0.00%
	Fuel Sales without Interdepartmental									
109		Fuel Revenue	$ 359,726,274	2,926,073	52,954,408	35,038,569	5,399,164	9,198,502	1,272,049	11,672
110		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
111	FUELREV_wo_INTD		$ 358,792,770	2,926,073	52,954,408	35,038,569	5,399,164	9,198,502	1,272,049	11,672
112			100%	0.82%	14.76%	9.77%	1.50%	2.56%	0.35%	0.00%
	UNIT COST BILLING DETERMINANTS									
	Energy at Meter									
113	SALES_KWH	Energy Sales - kWh	10,831,016,495	86,894,122	1,573,157,210	1,187,580,246	160,336,298	273,158,031	37,775,395	388,291
114			100%	0.80%	14.52%	10.96%	1.48%	2.52%	0.35%	0.00%
	KW Billing Determinants									
115	BILLEDKW	KW Billing Determinants	12,167,818	103,162	2,971,245	1,968,000	425,399	498,661	23,475	-
116			100%	0.85%	24.42%	16.17%	3.50%	4.10%	0.19%	0.00%
	Revenue at Current Rates									
117		Revenue	$ 1,845,541,443	9,545,119	203,355,734	149,163,981	17,902,451	27,873,850	6,038,139	67,870
118			100%	0.52%	11.02%	8.08%	0.97%	1.51%	0.33%	0.00%
	Base Rate Margin at Current Rates									
119		Margin Revenue	$ 1,384,886,162	6,011,619	142,515,010	111,940,817	11,894,020	17,977,035	4,497,985	56,589
120			100%	0.43%	10.29%	8.08%	0.86%	1.30%	0.32%	0.00%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(R)	(S)	(T)	(U)	(V)	(W)
	FUEL ALLOCATORS								
	Fuel Expense - MWh Sales @ Generation excluding Interdepartmental								
105	MWH_GEN_wo_INTD	Fuel Expense	$ 10,971,817	25,514	11,581	32,589	6,892	14,403	
106			100%	0.23%	0.11%	0.30%	0.06%	0.13%	0.00%
	Fuel Sales								
107	FUELREV	Fuel Revenue	$ 359,726,274	843,100	381,996	1,062,379	224,680	469,544	933,503
108			100%	0.23%	0.11%	0.30%	0.06%	0.13%	0.26%
	Fuel Sales without Interdepartmental								
109		Fuel Revenue	$ 359,726,274	843,100	381,996	1,062,379	224,680	469,544	933,503
110		Weighting		1.00	1.00	1.00	1.00	1.00	-
111	FUELREV_wo_INTD		$ 358,792,770	843,100	381,996	1,062,379	224,680	469,544	-
112			100%	0.23%	0.11%	0.30%	0.06%	0.13%	0.00%
	UNIT COST BILLING DETERMINANTS								
	Energy at Meter								
113	SALES_KWH	Energy Sales - kWh	10,831,016,495	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
114			100%	0.23%	0.10%	0.29%	0.06%	0.13%	0.26%
	KW Billing Determinants								
115	BILLEDKW	KW Billing Determinants	12,167,818	154,501	34,462	-	-	-	-
116			100%	1.27%	0.28%	0.00%	0.00%	0.00%	0.00%
	Revenue at Current Rates								
117		Revenue	$ 1,845,541,443	3,573,319	1,655,574	7,698,019	1,181,605	3,220,003	5,749,359
118			100%	0.19%	0.09%	0.42%	0.06%	0.17%	0.31%
	Base Rate Margin at Current Rates								
119		Margin Revenue	$ 1,384,886,162	2,589,916	1,084,684	6,415,686	928,145	2,633,692	4,361,524
120			100%	0.19%	0.08%	0.46%	0.07%	0.19%	0.31%

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large
	(A)	(B)	(C)		(D)	(E)	(F)	(G)	(H)
1	Customer Count @ 12/31/25	500,792	362,370	67,956	164	54,434	164	2,893	496
2	Fixed Charges (Bills/Pumps/Fixtures)	6,545,123	4,348,440	815,471	1,476	653,202	1,476	-	-
3	Energy Sales - kWh	10,683,959,164	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891
4	Billed Demand - kW	12,239,818			-	-	-	2,072,970	3,915,943
5	Margin Revenue @ current	1,384,886,162	472,760,787	59,458,188	836,075	250,420,980	731,949	118,064,264	169,707,199
6	Base Fuel Revenue @ current	359,726,274	104,622,768	12,203,098	305,984	54,448,002	241,880	29,164,742	48,024,160
7	FAC	(30,219,840)	(8,771,414)	(1,023,089)	(25,653)	(4,564,838)	(20,279)	(2,455,406)	(4,024,538)
8	EDR	(3,602,762)	-	-	-	-	-	-	(1,868,525)
9	Revenue credit	(4,386,191)	(1,411,527)	(164,639)	(2,673)	(766,933)	(2,659)	(426,779)	(572,486)
10	RTO	78	-	-	-	-	-	-	-
11	RA	(6,370,886)	(1,992,450)	(232,397)	(4,275)	(1,209,399)	(5,100)	(695,432)	(765,040)
12	TDSIC Revenue	93,344,310	41,315,349	4,818,982	123,052	14,623,813	104,384	8,153,093	10,606,120
13	DSM Revenue	11,970,888	3,847,798	448,803	6,703	2,905,441	5,479	1,286,412	2,628,610
14	ECT	-	-	-	-	-	-	-	-
15	Other Revenues	24,150,198							
16	Total Revenue	1,829,498,232							

Line No.	Description	Total	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping
	(A)	(B)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	Customer Count @ 12/31/25	500,792	6	260	7	5	4	734	9
2	Fixed Charges (Bills/Pumps/Fixtures)	6,545,123	-	-	-	-	-	8,808	108
3	Energy Sales - kWh	10,683,959,164	86,894,122	1,573,157,210	1,040,522,916	160,336,298	273,158,031	37,775,395	388,291
4	Billed Demand - kW	12,239,818	103,162	2,971,245	2,040,000	425,399	498,661	23,475	-
5	Margin Revenue @ current	1,384,886,162	6,011,619	142,515,010	111,940,817	11,894,020	17,977,035	4,497,985	56,589
6	Base Fuel Revenue @ current	359,726,274	2,926,073	52,954,408	35,038,569	5,399,164	9,198,502	1,272,049	11,672
7	FAC	(30,219,840)	(245,317)	(4,439,617)	(2,937,580)	(452,658)	(771,352)	(106,647)	(979)
8	EDR	(3,602,762)	-	(1,071,555)	-	(251,229)	(411,453)	-	-
9	Revenue credit	(4,386,191)	(22,765)	(422,704)	(426,461)	(40,077)	(64,712)	(12,259)	(391)
10	RTO	78	-	-	-	-	-	-	78
11	RA	(6,370,886)	(32,679)	(649,274)	(566,837)	(62,302)	(77,580)	(23,174)	(501)
12	TDSIC Revenue	93,344,310	491,084	7,838,993	2,611,056	462,100	747,626	255,555	-
13	DSM Revenue	11,970,888	139,109	470,027	-	187,243	15,399	24,809	-
14	ECT	-	-	-	-	-	-	-	-
15	Other Revenues	24,150,198							
16	Total Revenue	1,829,498,232							

Cause No. 46120

Northern Indiana Public Service Company
Billing Determinants & Test Year Revenue

Line No.	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)	(T)	(U)
1	Customer Count @ 12/31/25	500,792	6	1	1,398	140	9,700	46
2	Fixed Charges (Bills/Pumps/Fixtures)	6,545,123	-	12	525,405	14,213	176,512	-
3	Energy Sales - kWh	10,683,959,164	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
4	Billed Demand - kW	12,239,818	154,501	34,462	-	-	-	-
5	Margin Revenue @ current	1,384,886,162	2,589,916	1,084,684	6,415,686	928,145	2,633,692	4,361,524
6	Base Fuel Revenue @ current	359,726,274	843,100	381,996	1,062,379	224,680	469,544	933,503
7	FAC	(30,219,840)	(70,684)	(32,026)	(89,068)	(18,837)	(39,366)	(130,492)
8	EDR	(3,602,762)	-	-	-	-	-	-
9	Revenue credit	(4,386,191)	-	(6,466)	(23,867)	(2,979)	(6,054)	(9,759)
10	RTO	78	-	-	-	0	-	-
11	RA	(6,370,886)	-	(5,187)	(32,143)	(5,010)	(12,105)	-
12	TDSIC Revenue	93,344,310	135,249	195,360	243,822	31,760	122,821	464,091
13	DSM Revenue	11,970,888	5,054	-	-	-	-	-
14	ECT	-	-	-	-	-	-	-
15	Other Revenues	24,150,198						
16	Total Revenue	1,829,498,232						

Line No.	ENERGY AND DEMAND LOSS CALCULATIONS	ENERGY LOSS MULTIPLIERS								DEM	
		AGGREGATE MWH LOAD AT VOLTAGE LEVEL	ENERGY % BASIS	ADJUSTMENT FACTOR	%	LOSSES (KWH)	KWH SALES AT VOLTAGE LEVEL	SIMPLE	CUMULATIVE	DEMAND % BASIS	ADJUSTMENT FACTOR
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(C)
1	**VOLTAGE LEVEL (INPUT TO)**										
2	TRANSMISSION	11,000,452,077	1.83%	1.00	1.83%	201,705,673	1,248,434,982	1.0187	1.0187	2.75%	1.00
3	SUB-TRANSMISSION	9,550,311,423	.22%	1.00	.22%	20,953,221	545,561,745	1.0022	1.0209	.26%	1.00
4	PRIMARY	8,983,796,457	.55%	1.00	.55%	49,827,799	1,769,977,532	1.0056	1.0266	.93%	1.00
5	SECONDARY	7,163,991,125	.61%	1.00	.61%	44,006,219	7,119,984,906	1.0062	1.0330	.62%	1.00

Line No.		Total Company	Residential Rate 511	Res, Multi-Family Rate 515	C&GS Heat Pump Rate 520	GS Small Rate 521	Comml SH Rate 522	GS Medium Rate 523	GS Large Rate 524	Metal Melting Rate 525	Off-Peak Serv. Rate 526
6	**INPUT DATA BY SERVICE CLASSIFICATION**										
7	<u>Energy Inputs</u>										
8	Test Year book kWh Sales	10,683,959,164	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891	86,894,122	1,573,157,210
9	Adjustment	0									
10	Test Year Adjusted kWh	10,683,959,164	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891	86,894,122	1,573,157,210
11	<u>Demand Inputs</u>										
12	4 CP (for Generation)	2,308,560	1,034,194	59,090	0	352,562	0	187,587	215,908	7,947	231,613
13	12 CP (for Transmission)	2,244,398	658,817	49,771	1,538	314,403	1,046	169,390	219,961	11,028	207,408
14	NCP12 (Avg. of 12 Monthly NCPs)	2,599,777	666,171	78,436	2,548	328,395	1,775	174,133	238,145	19,638	216,653
15	NCP (Non Coincidental Peak)	3,562,559	1,268,629	121,290	4,556	410,816	2,974	229,707	282,232	20,352	249,294
16	**MWH SALES AT VOLTAGE LEVEL**										
17	DISTRIB. OF KWH SALES BY VOLTAGE LEVEL (%)										
18	TRANSMISSION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0302286	0.0000000	0.0182682
19	SUB-TRANSMISSION	0.0000000	0.0000000	0.0000000	0.0000000	0.0068795	0.0000000	0.0001340	0.0396399	0.2791535	0.0760702
20	PRIMARY	0.0000000	0.0000330	0.0000330	0.0000000	0.0460142	0.0000000	0.0686267	0.4929724	0.5035952	0.5623717
21	SECONDARY	0.0000000	0.9999670	0.9999670	1.0000000	0.9471063	1.0000000	0.9312394	0.4371590	0.2172513	0.3432899
22	TOTAL	-	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000
23	DISTRIB. OF KWH SALES BY VOLTAGE LEVEL										
24	TRANSMISSION	1,248,434,982	0	0	0	0	0	0	43,132,070	0	28,738,805
25	SUB-TRANSMISSION	545,561,745	0	0	0	11,123,587	0	116,016	56,560,799	24,256,799	119,670,341
26	PRIMARY	1,769,977,532	102,606	11,968	0	74,401,053	0	59,436,948	703,404,579	43,759,459	884,699,089
27	SECONDARY	7,119,984,906	3,106,827,597	362,377,363	9,086,667	1,531,390,554	7,182,994	806,537,847	623,766,442	18,877,864	540,048,975
28	TOTAL	10,683,959,164	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891	86,894,122	1,573,157,210
29	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
30	**DISTRIBUTION OF KWH SALES AND LOSSES BY VOLTAGE LEVEL**										
31	<u>MWH SALES</u>										
32	LOAD @ INPUT TO GENERATION	11,000,452,077	3,209,326,682	374,332,757	9,386,142	1,669,598,921	7,419,729	894,256,600	1,468,129,944	89,188,257	1,617,540,145
33	LOSS FACTOR	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
34	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0
35	LOAD @ INPUT TO TRANSMISSION	11,000,452,077	3,209,326,682	374,332,757	9,386,142	1,669,598,921	7,419,729	894,256,600	1,468,129,944	89,188,257	1,617,540,145
36	LOSS FACTOR	0.0000	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187
37	SALES @ TRANSMISSION	1,248,434,982	0	0	0	0	0	0	43,132,070	0	28,738,805
38	LOAD @ INPUT TO SUB-TRANSMISSION	9,550,311,423	3,150,480,064	367,468,944	9,214,036	1,638,984,945	7,283,680	877,859,398	1,398,078,059	87,552,890	1,559,141,920
39	LOSS FACTOR	0.0000	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022
40	SALES @ SUB-TRANSMISSION	545,561,745	0	0	0	11,123,587	0	116,016	56,560,799	24,256,799	119,670,341
41	LOAD @ INPUT TO PRIMARY	8,983,796,457	3,143,567,965	366,662,724	9,193,821	1,624,265,453	7,267,699	875,817,373	1,338,449,900	63,104,002	1,436,050,848
42	LOSS FACTOR	0.0000	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056
43	SALES @ PRIMARY	1,769,977,532	102,606	11,968	0	74,401,053	0	59,436,948	703,404,579	43,759,459	884,699,089
44	LOAD @ INPUT TO SECONDARY	7,163,991,125	3,126,029,848	364,617,095	9,142,828	1,540,855,561	7,227,390	811,522,785	627,621,732	18,994,542	543,386,835
45	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
46	SALES @ SECONDARY	7,119,984,906	3,106,827,597	362,377,363	9,086,667	1,531,390,554	7,182,994	806,537,847	623,766,442	18,877,864	540,048,975
47	TOTAL AT METER	10,683,959,164	3,106,930,204	362,389,331	9,086,667	1,616,915,194	7,182,994	866,090,811	1,426,863,891	86,894,122	1,573,157,210
48	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0

Cause No. 46120

Northern Indiana Public Service Company
Demand and Energy Allocation Factors - Loss Adjustments

Line No.	ENERGY AND DEMAND LOSS CALCULATIONS	IAND LOSS MULTIPLIERS ADJUSTMENT % (J)	SIMPLE (K)	CUMULATIVE (L)
1	**VOLTAGE LEVEL (INPUT TO)**			
2	TRANSMISSION	2.75%	1.0283	1.0283
3	SUB-TRANSMISSION	.26%	1.0026	1.0309
4	PRIMARY	.93%	1.0093	1.0406
5	SECONDARY	.62%	1.0062	1.0471

Line No.		Ind. Pwr Serv. - Large Rate 531	Ind. Pwr Serv. - Small Rate 532	HLF Ind Pwr Serv. Rate 533	Muni. Power Rate 541	Int WW Pumping Rate 542	Renewable Sta. Pwr. Rate 543	Railroad Rate 544	Street Lighting Rate 550	Traffic Lighting Rate 555	Dusk-to-Dawn Rate 560	Interdepartmental
6	**INPUT DATA BY SERVICE CLASSIFICATION**											
7	Energy Inputs											
8	Test Year book kWh Sales	1,040,522,916	160,336,298	273,158,031	37,775,395	388,291	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
9	Adjustment											
10	Test Year Adjusted kWh	1,040,522,916	160,336,298	273,158,031	37,775,395	388,291	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
11	Demand Inputs											
12	4 CP (for Generation)	164,000	21,282	22,635	3,574	40	1,321	1,239	0	762	0	4,806
13	12 CP (for Transmission)	556,908	21,839	21,495	3,730	41	631	1,457	788	762	249	3,135
14	NCP12 (Avg. of 12 Monthly NCPs)	785,252	26,764	27,493	6,444	41	6,952	2,519	11,143	762	3,185	3,328
15	NCP (Non Coincidental Peak)	864,263	30,154	28,431	8,581	47	7,755	2,892	12,722	767	3,526	13,572
16	**MWH SALES AT VOLTAGE LEVEL**											
17	DISTRIB. OF KWH SALES BY VOLTAGE LEVEL (%)											
18	TRANSMISSION	0.8648120	0.4502074	0.6726164	0.0000000	0.0000000	0.8304563	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
19	SUB-TRANSMISSION	0.1351880	0.5497926	0.3273836	0.0000000	0.0000000	0.1695437	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000
20	PRIMARY	0.0000000	0.0000000	0.0000000	0.1101730	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
21	SECONDARY	0.0000000	0.0000000	0.0000000	0.8898270	1.0000000	0.0000000	0.0000000	1.0000000	1.0000000	1.0000000	1.0000000
22	TOTAL	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000
23	DISTRIB. OF KWH SALES BY VOLTAGE LEVEL											
24	TRANSMISSION	899,856,710	72,184,585	183,730,582	0	0	20,792,230	0	0	0	0	0
25	SUB-TRANSMISSION	140,666,206	88,151,713	89,427,449	0	0	4,244,884	11,343,950	0	0	0	0
26	PRIMARY	0	0	0	4,161,830	0	0	0	0	0	0	0
27	SECONDARY	0	0	0	33,613,566	388,291	0	0	31,548,942	6,672,200	13,943,820	27,721,784
28	TOTAL	1,040,522,916	160,336,298	273,158,031	37,775,395	388,291	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
29	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0

Line No.		Rate 531	Rate 532	Rate 533	Rate 541	Rate 542	Rate 543	Rate 544	Rate 550	Rate 555	Rate 560	Interdepartmental
30	**DISTRIBUTION OF KWH SALES AND LOSSES BY VOLTAGE LEVEL**											
31	MWH SALES											
32	LOAD @ INPUT TO GENERATION	1,060,273,522	163,528,608	278,460,552	38,993,976	401,088	25,514,281	11,581,248	32,588,721	6,892,100	14,403,376	28,635,429
33	LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
34	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0	0
35	LOAD @ INPUT TO TRANSMISSION	1,060,273,522	163,528,608	278,460,552	38,993,976	401,088	25,514,281	11,581,248	32,588,721	6,892,100	14,403,376	28,635,429
36	LOSS FACTOR	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187
37	SALES @ TRANSMISSION	899,856,710	72,184,585	183,730,582	0	0	20,792,230	0	0	0	0	0
38	LOAD @ INPUT TO SUB-TRANSMISSION	140,975,504	88,345,542	89,624,083	38,278,978	393,733	4,254,218	11,368,893	31,991,170	6,765,726	14,139,273	28,110,366
39	LOSS FACTOR	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022
40	SALES @ SUB-TRANSMISSION	140,666,206	88,151,713	89,427,449	0	0	4,244,884	11,343,950	0	0	0	0
41	LOAD @ INPUT TO PRIMARY	0	0	0	38,194,994	392,870	0	0	31,920,982	6,750,882	14,108,252	28,048,692
42	LOSS FACTOR	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056
43	SALES @ PRIMARY	0	0	0	4,161,830	0	0	0	0	0	0	0
44	LOAD @ INPUT TO SECONDARY	0	0	0	33,821,320	390,691	0	0	31,743,935	6,713,439	14,030,002	27,893,123
45	LOSS FACTOR	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
46	SALES @ SECONDARY	0	0	0	33,613,566	388,291	0	0	31,548,942	6,672,200	13,943,820	27,721,784
47	TOTAL AT METER	1,040,522,916	160,336,298	273,158,031	37,775,395	388,291	25,037,114	11,343,950	31,548,942	6,672,200	13,943,820	27,721,784
48	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0

		Total Company	Residential Rate 511	Res, Multi-Family Rate 515	C&GS Heat Pump Rate 520	GS Small Rate 521	Comml SH Rate 522	GS Medium Rate 523	GS Large Rate 524	Metal Melting Rate 525	Off-Peak Serv. Rate 526
49	**CLASS CONTRIBUTION TO CONTROL AREA PEAK**										
50	1 COINCIDENT PEAK										
51	KW	0	0	0	0	0	0	0	0	0	0
52	LOAD FACTOR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
53	4 COINCIDENT PEAK										
54	KW	2,308,560	1,034,194	59,090	0	352,562	0	187,587	215,908	7,947	231,613
55	LOAD FACTOR	52.83%	34.29%	70.01%	0.00%	52.35%	0.00%	52.71%	75.44%	124.83%	77.54%
56	12 COINCIDENT PEAK										
57	KW	2,244,398	658,817	49,771	1,538	314,403	1,046	169,390	219,961	11,028	207,408
58	LOAD FACTOR	54.34%	53.83%	83.12%	67.43%	58.71%	78.39%	58.37%	74.05%	89.95%	86.59%
59	**CLASS NON COINCIDENTAL PEAK**										
60	NCP	3,562,559	1,268,629	121,290	4,556	410,816	2,974	229,707	282,232	20,352	249,294
61	LOAD FACTOR	34.23%	27.96%	34.11%	22.77%	44.93%	27.58%	43.04%	57.71%	48.74%	72.04%
62	**CLASS UNDIVERSIFIED KW**										
63	NCP12	2,599,777	666,171	78,436	2,548	328,395	1,775	174,133	238,145	19,638	216,653
64	LOAD FACTOR	46.91%	53.24%	52.74%	40.71%	56.21%	46.19%	56.78%	68.40%	50.51%	82.89%
65	**COINCIDENT KW BY VOLTAGE LEVEL**										
66	4CP FOR GENERATION										
67	PRODUCTION										
68	TRANSMISSION	178,490	0	0	0	0	0	0	6,527	0	4,231
69	SUB-TRANSMISSION	73,591	0	0	0	2,425	0	25	8,559	2,218	17,619
70	PRIMARY	270,217	34	2	0	16,223	0	12,873	106,437	4,002	130,252
71	SECONDARY	1,786,262	1,034,160	59,088	0	333,914	0	174,689	94,386	1,726	79,510
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72	TOTAL	2,308,560	1,034,194	59,090	0	352,562	0	187,587	215,908	7,947	231,613
73	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
74	12 CP FOR TRANSMISSION										
75	PRODUCTION										
76	TRANSMISSION	516,873	0	0	0	0	0	0	6,649	0	3,789
77	SUB-TRANSMISSION	125,656	0	0	0	2,163	0	23	8,719	3,078	15,778
78	PRIMARY	257,155	22	2	0	14,467	0	11,625	108,435	5,553	116,640
79	SECONDARY	1,344,715	658,795	49,770	1,538	297,773	1,046	157,743	96,158	2,396	71,201
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80	TOTAL	2,244,398	658,817	49,771	1,538	314,403	1,046	169,390	219,961	11,028	207,408
81	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
82	**DISTRIBUTION OF COINCIDENT KW**										
83	**AND LOSSES BY VOLTAGE LEVEL**										
84	4CP FOR GENERATION										
85	LOAD @ INPUT TO GENERATION	2,410,898	1,082,859	61,870	0	369,008	0	196,331	225,117	8,259	241,304
86	LOSS FACTOR	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
87	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0
88	LOAD @ INPUT TO TRANSMISSION	2,410,898	1,082,859	61,870	0	369,008	0	196,331	225,117	8,259	241,304
89	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
90	SALES @ TRANSMISSION	178,490	0	0	0	0	0	0	6,527	0	4,231
91	LOAD @ INPUT TO SUB-TRANSMISSION	2,166,158	1,053,102	60,170	0	358,868	0	190,935	212,405	8,032	230,442
92	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
93	SALES @ SUB-TRANSMISSION	73,591	0	0	0	2,425	0	25	8,559	2,218	17,619
94	LOAD @ INPUT TO PRIMARY	2,086,919	1,050,356	60,013	0	355,507	0	190,413	203,292	5,793	212,222
95	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
96	SALES @ PRIMARY	270,217	34	2	0	16,223	0	12,873	106,437	4,002	130,252
97	LOAD @ INPUT TO SECONDARY	1,797,391	1,040,603	59,456	0	335,994	0	175,777	94,974	1,737	80,006
98	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
99	SALES @ SECONDARY	1,786,262	1,034,160	59,088	0	333,914	0	174,689	94,386	1,726	79,510
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100	TOTAL AT METER	2,308,560	1,034,194	59,090	0	352,562	0	187,587	215,908	7,947	231,613
101	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
102	Total Loss Factor		1.04705585	1.04705585	0	1.046646909	0	1.046608993	1.042653111	1.03929354	1.041841086

Northern Indiana Public Service Company
Demand and Energy Allocation Factors - Loss Adjustments

		Ind. Pwr Serv. - Large Rate 531	Ind. Pwr Serv. - Small Rate 532	HLF Ind Pwr Serv. Rate 533	Muni. Power Rate 541	Int WW Pumping Rate 542	Renewable Sta. Pwr. Rate 543	Railroad Rate 544	Street Lighting Rate 550	Traffic Lighting Rate 555	Dusk-to-Dawn Rate 560	Interdepartmental
49	**CLASS CONTRIBUTION TO CONTROL AREA PEAK**											
50	1 COINCIDENT PEAK											
51	KW	0	0	0	0	0	0	0	0	0	0	0
52	LOAD FACTOR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
53	4 COINCIDENT PEAK											
54	KW	164,000	21,282	22,635	3,574	40	1,321	1,239	0	762	0	4,806
55	LOAD FACTOR	72.43%	86.00%	137.76%	120.65%	111.90%	216.32%	104.56%	0.00%	100.01%	0.00%	65.84%
56	12 COINCIDENT PEAK											
57	KW	556,908	21,839	21,495	3,730	41	631	1,457	788	762	249	3,135
58	LOAD FACTOR	21.33%	83.81%	145.07%	115.60%	108.57%	452.77%	88.90%	456.98%	99.93%	640.01%	100.93%
59	**CLASS NON COINCIDENTAL PEAK**											
60	NCP	864,263	30,154	28,431	8,581	47	7,755	2,892	12,722	767	3,526	13,572
61	LOAD FACTOR	13.74%	60.70%	109.68%	50.25%	94.51%	36.86%	44.78%	28.31%	99.26%	45.14%	23.32%
62	**CLASS UNDIVERSIFIED KW**											
63	NCP12	785,252	26,764	27,493	6,444	41	6,952	2,519	11,143	762	3,185	3,328
64	LOAD FACTOR	15.13%	68.39%	113.42%	66.92%	108.57%	41.11%	51.42%	32.32%	99.93%	49.97%	95.08%
65	**COINCIDENT KW BY VOLTAGE LEVEL**											
66	4CP FOR GENERATION											
67	PRODUCTION											
68	TRANSMISSION	141,829	9,581	15,225	0	0	1,097	0	0	0	0	0
69	SUB-TRANSMISSION	22,171	11,701	7,410	0	0	224	1,239	0	0	0	0
70	PRIMARY	0	0	0	394	0	0	0	0	0	0	0
71	SECONDARY	0	0	0	3,180	40	0	0	0	762	0	4,806
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72	TOTAL	164,000	21,282	22,635	3,574	40	1,321	1,239	0	762	0	4,806
73	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
74	12 CP FOR TRANSMISSION											
75	PRODUCTION											
76	TRANSMISSION	481,620	9,832	14,458	0	0	524	0	0	0	0	0
77	SUB-TRANSMISSION	75,287	12,007	7,037	0	0	107	1,457	0	0	0	0
78	PRIMARY	0	0	0	411	0	0	0	0	0	0	0
79	SECONDARY	0	0	0	3,319	41	0	0	788	762	249	3,135
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80	TOTAL	556,908	21,839	21,495	3,730	41	631	1,457	788	762	249	3,135
81	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
82	**DISTRIBUTION OF COINCIDENT KW**											
83	**AND LOSSES BY VOLTAGE LEVEL**											
84	4CP FOR GENERATION											
85	LOAD @ INPUT TO GENERATION	168,694	21,915	23,294	3,740	41	1,359	1,277	0	797	0	5,033
86	LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
87	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0	0
88	LOAD @ INPUT TO TRANSMISSION	168,694	21,915	23,294	3,740	41	1,359	1,277	0	797	0	5,033
89	LOSS FACTOR	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
90	SALES @ TRANSMISSION	141,829	9,581	15,225	0	0	1,097	0	0	0	0	0
91	LOAD @ INPUT TO SUB-TRANSMISSION	22,229	11,731	7,430	3,637	40	225	1,242	0	776	0	4,894
92	LOSS FACTOR	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
93	SALES @ SUB-TRANSMISSION	22,171	11,701	7,410	0	0	224	1,239	0	0	0	0
94	LOAD @ INPUT TO PRIMARY	0	0	0	3,628	40	0	0	0	773	0	4,882
95	LOSS FACTOR	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
96	SALES @ PRIMARY	0	0	0	394	0	0	0	0	0	0	0
97	LOAD @ INPUT TO SECONDARY	0	0	0	3,200	40	0	0	0	766	0	4,836
98	LOSS FACTOR	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
99	SALES @ SECONDARY	0	0	0	3,180	40	0	0	0	762	0	4,806
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100	TOTAL AT METER	164,000	21,282	22,635	3,574	40	1,321	1,239	0	762	0	4,806
101	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
102	Total Loss Factor	1.028619487	1.029734011	1.029136139	1.046341803	1.047056064	1.02871184	1.030944241	0	1.047056064	0	1.047056064

		Total Company	Residential Rate 511	Res, Multi-Family Rate 515	C&GS Heat Pump Rate 520	GS Small Rate 521	Comml SH Rate 522	GS Medium Rate 523	GS Large Rate 524	Metal Melting Rate 525	Off-Peak Serv. Rate 526
103	12 CP FOR TRANSMISSION										
104	LOAD @ INPUT TO GENERATION	2,336,602	689,818	52,114	1,611	329,069	1,095	177,285	229,343	11,461	216,086
105	LOSS FACTOR	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
106	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0
107	LOAD @ INPUT TO TRANSMISSION	2,336,602	689,818	52,114	1,611	329,069	1,095	177,285	229,343	11,461	216,086
108	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
109	SALES @ TRANSMISSION	516,873	0	0	0	0	0	0	6,649	0	3,789
110	LOAD @ INPUT TO SUB-TRANSMISSION	1,755,520	670,862	50,681	1,566	320,026	1,065	172,413	216,392	11,146	206,359
111	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
112	SALES @ SUB-TRANSMISSION	125,656	0	0	0	2,163	0	23	8,719	3,078	15,778
113	LOAD @ INPUT TO PRIMARY	1,625,286	669,113	50,549	1,562	317,029	1,062	171,941	207,108	8,039	190,043
114	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
115	SALES @ PRIMARY	257,155	22	2	0	14,467	0	11,625	108,435	5,553	116,640
116	LOAD @ INPUT TO SECONDARY	1,353,093	662,900	50,080	1,548	299,628	1,052	158,725	96,757	2,411	71,645
117	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
118	SALES @ SECONDARY	1,344,715	658,795	49,770	1,538	297,773	1,046	157,743	96,158	2,396	71,201
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119	TOTAL AT METER	2,244,398	658,817	49,771	1,538	314,403	1,046	169,390	219,961	11,028	207,408
120	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
121	**CLASS KW BY VOLTAGE LEVEL (1-Month Max.)**										
122	NCP										
123	TRANSMISSION	799,650	0	0	0	0	0	0	8,531	0	4,554
124	SUB-TRANSMISSION	185,621	0	0	0	2,826	0	31	11,188	5,681	18,964
125	PRIMARY	325,236	42	4	0	18,903	0	15,764	139,133	10,249	140,196
126	SECONDARY	2,252,052	1,268,587	121,286	4,556	389,086	2,974	213,912	123,380	4,421	85,580
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127	TOTAL	3,562,559	1,268,629	121,290	4,556	410,816	2,974	229,707	282,232	20,352	249,294
128	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
129	**DISTRIBUTION OF CLASS KW AND LOSSES BY VOLTAGE LEVEL**										
130	NCP										
131	LOAD @ INPUT TO GENERATION	3,710,067	1,328,325	126,997	4,770	429,979	3,113	240,413	294,270	21,152	259,725
132	LOSS FACTOR	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
133	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0
134	LOAD @ INPUT TO TRANSMISSION	3,710,067	1,328,325	126,997	4,770	429,979	3,113	240,413	294,270	21,152	259,725
135	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
136	SALES @ TRANSMISSION	799,650	0	0	0	0	0	0	8,531	0	4,554
137	LOAD @ INPUT TO SUB-TRANSMISSION	2,808,466	1,291,823	123,507	4,639	418,164	3,028	233,806	277,652	20,570	248,033
138	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
139	SALES @ SUB-TRANSMISSION	185,621	0	0	0	2,826	0	31	11,188	5,681	18,964
140	LOAD @ INPUT TO PRIMARY	2,615,522	1,288,455	123,185	4,627	414,247	3,020	233,166	265,741	14,835	228,423
141	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
142	SALES @ PRIMARY	325,236	42	4	0	18,903	0	15,764	139,133	10,249	140,196
143	LOAD @ INPUT TO SECONDARY	2,266,083	1,276,491	122,041	4,584	391,510	2,992	215,244	124,149	4,449	86,113
144	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
145	SALES @ SECONDARY	2,252,052	1,268,587	121,286	4,556	389,086	2,974	213,912	123,380	4,421	85,580
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146	TOTAL	3,562,559	1,268,629	121,290	4,556	410,816	2,974	229,707	282,232	20,352	249,294
147	Zero-Check	0	0	0	0	0	0	0	0	0	0

		Ind. Pwr Serv. - Large Rate 531	Ind. Pwr Serv. - Small Rate 532	HLF Ind Pwr Serv. Rate 533	Muni. Power Rate 541	Int WW Pumping Rate 542	Renewable Sta. Pwr. Rate 543	Railroad Rate 544	Street Lighting Rate 550	Traffic Lighting Rate 555	Dusk-to-Dawn Rate 560	Interdepartmental
103	12 CP FOR TRANSMISSION											
104	LOAD @ INPUT TO GENERATION	572,846	22,489	22,121	3,903	43	649	1,502	825	798	260	3,283
105	LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
106	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0	0
107	LOAD @ INPUT TO TRANSMISSION	572,846	22,489	22,121	3,903	43	649	1,502	825	798	260	3,283
108	LOSS FACTOR	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
109	SALES @ TRANSMISSION	481,620	9,832	14,458	0	0	524	0	0	0	0	0
110	LOAD @ INPUT TO SUB-TRANSMISSION	75,484	12,039	7,055	3,796	42	107	1,460	803	776	253	3,193
111	LOSS FACTOR	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
112	SALES @ SUB-TRANSMISSION	75,287	12,007	7,037	0	0	107	1,457	0	0	0	0
113	LOAD @ INPUT TO PRIMARY	0	0	0	3,786	41	0	0	800	774	253	3,184
114	LOSS FACTOR	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
115	SALES @ PRIMARY	0	0	0	411	0	0	0	0	0	0	0
116	LOAD @ INPUT TO SECONDARY	0	0	0	3,340	41	0	0	793	767	250	3,155
117	LOSS FACTOR	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
118	SALES @ SECONDARY	0	0	0	3,319	41	0	0	788	762	249	3,135
119	TOTAL AT METER	556,908	21,839	21,495	3,730	41	631	1,457	788	762	249	3,135
120	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
121	**CLASS KW BY VOLTAGE LEVEL (1-Month Max.)**											
122	NCP											
123	TRANSMISSION	747,425	13,576	19,123	0	0	6,440	0	0	0	0	0
124	SUB-TRANSMISSION	116,838	16,578	9,308	0	0	1,315	2,892	0	0	0	0
125	PRIMARY	0	0	0	945	0	0	0	0	0	0	0
126	SECONDARY	0	0	0	7,636	47	0	0	12,722	767	3,526	13,572
127	TOTAL	864,263	30,154	28,431	8,581	47	7,755	2,892	12,722	767	3,526	13,572
128	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
129	**DISTRIBUTION OF CLASS KW AND LOSSES BY VOLTAGE LEVEL**											
130	NCP											
131	LOAD @ INPUT TO GENERATION	888,998	31,051	29,259	8,979	49	7,978	2,981	13,320	803	3,692	14,211
132	LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
133	SALES @ GENERATION	0	0	0	0	0	0	0	0	0	0	0
134	LOAD @ INPUT TO TRANSMISSION	888,998	31,051	29,259	8,979	49	7,978	2,981	13,320	803	3,692	14,211
135	LOSS FACTOR	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
136	SALES @ TRANSMISSION	747,425	13,576	19,123	0	0	6,440	0	0	0	0	0
137	LOAD @ INPUT TO SUB-TRANSMISSION	117,143	16,622	9,332	8,732	48	1,318	2,900	12,954	781	3,591	13,820
138	LOSS FACTOR	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
139	SALES @ SUB-TRANSMISSION	116,838	16,578	9,308	0	0	1,315	2,892	0	0	0	0
140	LOAD @ INPUT TO PRIMARY	0	0	0	8,709	48	0	0	12,920	779	3,581	13,784
141	LOSS FACTOR	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
142	SALES @ PRIMARY	0	0	0	945	0	0	0	0	0	0	0
143	LOAD @ INPUT TO SECONDARY	0	0	0	7,683	47	0	0	12,801	772	3,548	13,657
144	LOSS FACTOR	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
145	SALES @ SECONDARY	0	0	0	7,636	47	0	0	12,722	767	3,526	13,572
146	TOTAL	864,263	30,154	28,431	8,581	47	7,755	2,892	12,722	767	3,526	13,572
147	Zero-Check	0	0	0	0	0	0	0	0	0	0	0

Cause No. 46120

Northern Indiana Public Service Company
Demand and Energy Allocation Factors - Loss Adjustments

Line	Description	Total Company	Residential Rate 511	Res, Multi-Family Rate 515	C&GS Heat Pump Rate 520	GS Small Rate 521	Comml SH Rate 522	GS Medium Rate 523	GS Large Rate 524	Metal Melting Rate 525	Off-Peak Serv. Rate 526
	DISTRIBUTION OF CLASS UNDIVERSIFIED KW BY										
148	**VOLTAGE LEVEL**										
149	NCP12										
150	TRANSMISSION	726,567	0	0	0	0	0	0	7,199	0	3,958
151	SUB-TRANSMISSION	167,255	0	0	0	2,259	0	23	9,440	5,482	16,481
152	PRIMARY	276,923	22	3	0	15,111	0	11,950	117,399	9,890	121,839
153	SECONDARY	1,429,033	666,149	78,433	2,548	311,025	1,775	162,160	104,107	4,266	74,375
		-----------------	-----------------	-----------------	-----------------	-----------------	-----------------	-----------------	-----------------	-----------------	-----------------
154	TOTAL	2,599,777	666,171	78,436	2,548	328,395	1,775	174,133	238,145	19,638	216,653
155	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION OF CLASS UNDIVERSIFIED KW AND										
156	**LOSSES BY VOLTAGE LEVEL**										
157	NCP12										
158	LOAD @ INPUT TO TRANSMISSION	2,703,963	697,518	82,127	2,668	343,713	1,859	182,250	248,303	20,410	225,717
159	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
160	SALES @ TRANSMISSION	726,567	0	0	0	0	0	0	7,199	0	3,958
161	LOAD @ INPUT TO SUB-TRANSMISSION	1,903,093	678,351	79,870	2,595	334,268	1,808	177,241	234,281	19,849	215,557
162	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
163	SALES @ SUB-TRANSMISSION	167,255	0	0	0	2,259	0	23	9,440	5,482	16,481
164	LOAD @ INPUT TO PRIMARY	1,730,876	676,582	79,662	2,588	331,138	1,803	176,756	224,230	14,315	198,514
165	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
166	SALES @ PRIMARY	276,923	22	3	0	15,111	0	11,950	117,399	9,890	121,839
167	LOAD @ INPUT TO SECONDARY	1,437,936	670,299	78,922	2,564	312,963	1,786	163,170	104,756	4,293	74,838
168	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
169	SALES @ SECONDARY	1,429,033	666,149	78,433	2,548	311,025	1,775	162,160	104,107	4,266	74,375
		-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
170	TOTAL	2,599,777	666,171	78,436	2,548	328,395	1,775	174,133	238,145	19,638	216,653
		0	0	0	0	0	0	0	0	0	0
171	**DEVELOPMENT OF ALLOCATION FACTORS**										
172	GENERATION										
173	4 CP (for Generation)	2,410,898	1,082,859	61,870	0	369,008	0	196,331	225,117	8,259	241,304
174	TRANSMISSION SUBSTATIONS										
175	12CP @ Transmission	2,336,602	689,818	52,114	1,611	329,069	1,095	177,285	229,343	11,461	216,086
176	TRANSMISSION LINES										
177	12CP @ Transmission	2,336,602	689,818	52,114	1,611	329,069	1,095	177,285	229,343	11,461	216,086
178	SUB-TRANSMISSION										
179	NCP @ Sub-Transmission	2,808,466	1,291,823	123,507	4,639	418,164	3,028	233,806	277,652	20,570	248,033
180	DISTRIBUTION SUBSTATIONS										
181	NCP @ Primary	2,615,522	1,288,455	123,185	4,627	414,247	3,020	233,166	265,741	14,835	228,423
182	PRIMARY LINES										
183	NCP @ Primary Lines	2,615,522	1,288,455	123,185	4,627	414,247	3,020	233,166	265,741	14,835	228,423
184	LINE TRANSFORMERS										
185	NCP @ L.Transformers	2,266,083	1,276,491	122,041	4,584	391,510	2,992	215,244	124,149	4,449	86,113
186	Percent	100%	56.330%	5.386%	0.202%	17.277%	0.132%	9.499%	5.479%	0.196%	3.800%
187	NCP12 @ Secondary	1,437,936	670,299	78,922	2,564	312,963	1,786	163,170	104,756	4,293	74,838
188	Percent	100%	46.615%	5.489%	0.178%	21.765%	0.124%	11.348%	7.285%	0.299%	5.205%
189	Average of Percents x 10,000	10000.00	5,147	544	19	1,952	13	1,042	638	25	450
190	SECONDARY LINES										
191	NCP12 @ Secondary	1,437,936	670,299	78,922	2,564	312,963	1,786	163,170	104,756	4,293	74,838

Line	Description	Ind. Pwr Serv. - Large Rate 531	Ind. Pwr Serv. - Small Rate 532	HLF Ind Pwr Serv. Rate 533	Muni. Power Rate 541	Int WW Pumping Rate 542	Renewable Sta. Pwr. Rate 543	Railroad Rate 544	Street Lighting Rate 550	Traffic Lighting Rate 555	Dusk-to-Dawn Rate 560	Interdepartmental
148	**DISTRIBUTION OF CLASS UNDIVERSIFIED KW BY VOLTAGE LEVEL**											
149	NCP12											
150	TRANSMISSION	679,095	12,050	18,492	0	0	5,773	0	0	0	0	0
151	SUB-TRANSMISSION	106,157	14,715	9,001	0	0	1,179	2,519	0	0	0	0
152	PRIMARY	0	0	0	710	0	0	0	0	0	0	0
153	SECONDARY	0	0	0	5,734	41	0	0	11,143	762	3,185	3,328
154	TOTAL	785,252	26,764	27,493	6,444	41	6,952	2,519	11,143	762	3,185	3,328
155	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
156	**DISTRIBUTION OF CLASS UNDIVERSIFIED KW AND LOSSES BY VOLTAGE LEVEL**											
157	NCP12											
158	LOAD @ INPUT TO TRANSMISSION	807,725	27,560	28,294	6,743	43	7,151	2,596	11,668	798	3,335	3,485
159	LOSS FACTOR	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
160	SALES @ TRANSMISSION	679,095	12,050	18,492	0	0	5,773	0	0	0	0	0
161	LOAD @ INPUT TO SUB-TRANSMISSION	106,434	14,753	9,024	6,557	42	1,182	2,525	11,347	776	3,243	3,389
162	LOSS FACTOR	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
163	SALES @ SUB-TRANSMISSION	106,157	14,715	9,001	0	0	1,179	2,519	0	0	0	0
164	LOAD @ INPUT TO PRIMARY	0	0	0	6,540	41	0	0	11,317	774	3,235	3,380
165	LOSS FACTOR	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
166	SALES @ PRIMARY	0	0	0	710	0	0	0	0	0	0	0
167	LOAD @ INPUT TO SECONDARY	0	0	0	5,770	41	0	0	11,213	767	3,205	3,349
168	LOSS FACTOR	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
169	SALES @ SECONDARY	0	0	0	5,734	41	0	0	11,143	762	3,185	3,328
170	TOTAL	785,252	26,764	27,493	6,444	41	6,952	2,519	11,143	762	3,185	3,328
		0	0	0	0	0	0	0	0	0	0	0
171	**DEVELOPMENT OF ALLOCATION FACTORS**											
172	GENERATION											
173	4 CP (for Generation)	168,694	21,915	23,294	3,740	41	1,359	1,277	0	797	0	5,033
174	TRANSMISSION SUBSTATIONS											
175	12CP @ Transmission	572,846	22,489	22,121	3,903	43	649	1,502	825	798	260	3,283
176	TRANSMISSION LINES											
177	12CP @ Transmission	572,846	22,489	22,121	3,903	43	649	1,502	825	798	260	3,283
178	SUB-TRANSMISSION											
179	NCP @ Sub-Transmission	117,143	16,622	9,332	8,732	48	1,318	2,900	12,954	781	3,591	13,820
180	DISTRIBUTION SUBSTATIONS											
181	NCP @ Primary	0	0	0	8,709	48	0	0	12,920	779	3,581	13,784
182	PRIMARY LINES											
183	NCP @ Primary Lines	0	0	0	8,709	48	0	0	12,920	779	3,581	13,784
184	LINE TRANSFORMERS											
185	NCP @ L.Transformers	0	0	0	7,683	47	0	0	12,801	772	3,548	13,657
186	Percent	0.000%	0.000%	0.000%	0.339%	0.002%	0.000%	0.000%	0.565%	0.034%	0.157%	0.603%
187	NCP12 @ Secondary	0	0	0	5,770	41	0	0	11,213	767	3,205	3,349
188	Percent	0.000%	0.000%	0.000%	0.401%	0.003%	0.000%	0.000%	0.780%	0.053%	0.223%	0.233%
189	Average of Percents x 10,000	-	-	(0)	37	0	-	-	67	4	19	42
190	SECONDARY LINES											
191	NCP12 @ Secondary	0	0	0	5,770	41	0	0	11,213	767	3,205	3,349

Northern Indiana Public Service Company
Transformers

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Transformer Replacement Costs	$ 761,157,560	$559,990,888	**new rate**	$ -	$152,147,300	$ -	$ 27,688,521	$ 10,779,578	$ 84,129	$ 5,653,055	$ 45,079
2	2023 Customer Count	502,514	431,840		104	54,425	144	3,007	508	6	260	7
3	Cost per Customer		$ 1,296.76		$ -	$ 2,795.56	$ -	$ 9,207.51	$ 21,233.57	$ 14,021.50	$ 21,749.49	$ 6,439.91
4	Weighting Factor		1.00	1.00	-	2.16	-	7.10	16.37	10.81	16.77	4.97

Northern Indiana Public Service Company
Transformers

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Transformer Replacement Costs	$ 761,157,560	$ 2,972	$ 20,935	$ 2,733,108	$ 2,742		$ -	$ 707,325	$ 32,941	$ 946,621	$ 322,366
2	2023 Customer Count	502,514	5	4	722	9	6	1	1,581	140	9,700	46
3	Cost per Customer		$ 594.33	$ 5,233.75	$ 3,783.72	$ 304.64		$ -	$ 447.44	$ 235.29	$ 98	$ 7,007.95
4	Weighting Factor		0.46	4.04	2.92	0.23	16.37	-	0.35	0.18	0.08	5.40

Northern Indiana Public Service Company
Transformers

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Transformer Replacement Costs	$ 761,157,560	$559,990,888	**new rate**	$ -	$152,147,300	$ -	$ 27,688,521	$10,779,578	$ 84,129	$ 5,653,055	$ 45,079
2	2023 Customer Count	502,514	431,840		104	54,425	144	3,007	508	6	260	7
3	Cost per Customer		$ 1,296.76		$ -	$ 2,795.56	$ -	$ 9,207.51	$ 21,233.57	$ 14,021.50	$ 21,749.49	$ 6,439.91
4	Weighting Factor		1.00	1.00	-	2.16	-	7.10	16.37	10.81	16.77	4.97

Northern Indiana Public Service Company
Transformers

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Transformer Replacement Costs	$ 761,157,560	$ 2,972	$ 20,935	$ 2,733,108	$ 2,742		$ -	$ 707,325	$ 32,941	$ 946,621	$ 322,366
2	2023 Customer Count	502,514	5	4	722	9	6	1	1,581	140	9,700	46
3	Cost per Customer		$ 594.33	$ 5,233.75	$ 3,783.72	$ 304.64		$ -	$ 447.44	$ 235.29	$ 98	$ 7,007.95
4	Weighting Factor		0.46	4.04	2.92	0.23	16.37	-	0.35	0.18	0.08	5.40

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Service Replacement Costs	$ 191,762,137	$168,236,918	**new rate**	$ -	$21,558,324	$ -	$1,134,416	$ 15,460	$ 122	$ 21,247	$ 571
2	Count of Services with Prices		369,962		-	34,904	-	905	39	2	28	1
3	Cost per Service		$ 455		$ -	$ 618	$ -	$ 1,253	$ 396	$ 61	$ 759	$ 571
4	Weighting		1.00	0.625	0.00	1.36	0.00	2.76	0.87	0.13	1.67	1.26

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Service Replacement Costs	$ 191,762,137	$ 73	$ -	$ 352,093	$ 84	$ 118	$ -	$126,225	$ 5,679	$278,240	$ 32,566
2	Count of Services with Prices		1	-	500	1	1	-	322	14	573	54
3	Cost per Service		$ 73	$ -	$ 704	$ 84	$ 118	$ -	$ 392	$ 406	$ 486	$ 603
4	Weighting		0.16	0.00	1.55	0.18	0.26	0.00	0.86	0.89	1.07	1.33

Summary of Engineering Estimate of Single Family vs Multi-Family Service Line costs

Summary Assumptions

1) Use Multiple of 2.5x in total cost per service
2) Max 6 customers vs. 1 Single family - assume averge of 4 customers?
3) Therefore 2.5 times costs divided by 4 customers equals .625 the cost of a Residential Service (.625 weighting factor)

weighting factor = 0.625

Details

Service Line Cost - No Meter (135 feet)

		100/200 Amp 1 ph (234164)	320/400 Amp 1 ph (234182)	100/200 Amp 1 ph-Network (234139)	100/200 Amp 3 ph/3 wire (234139)
	Overhead Service				
	4/0 Aluminum Triplex				
	Underground Service - from Overhead System				
Single	#4/0 Aluminum Triplex	$4,081	$0	$4,077	$4,077
Multi	500 KCM Aluminum Triplex	$8,111	$8,111	$8,108	$8,108
	Multiple - 500 KCM Aluminum Triplex	**1.99**		**1.99**	**1.99**
Multi-High Demand	500 KCM Copper Triplex	$12,679	$12,679	$12,676	$12,676
	Multiple - 500 KCM Copper Triplex	**3.11**		**3.11**	**3.11**
	Underground Service - from Underground System				
Single	#4/0 Aluminum Triplex	$3,759	$0	$3,755	$3,755
Multi	500 KCM Aluminum Triplex	$7,106	$7,106	$7,103	$7,103
	Multiple - 500 KCM Aluminum Triplex	**1.89**		**1.89**	**1.89**
Multi-High Demand	500 KCM Copper Triplex	$7,549	$10,719	$10,716	$10,716
	Multiple - 500 KCM Copper Triplex	**2.01**		**2.85**	**2.85**

EXCESS SERVICE

Overhead Service

4/0 Aluminum Triplex

	Underground Service		**Cost Multiple**
Single	#4/0 Aluminum Triplex	$19.59	
Multi	500 KCM Aluminum Triplex	$45.36	**2.32**
Multi-High Demand	500 KCM Copper Triplex	$75.44	**3.85**

Northern Indiana Public Service Company
Meters Analysis Summary

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Meter Replacement Costs	$ 79,515,720	$56,814,762	**new rate**	$ 330,106	$18,028,063	$ 88,038	$2,468,204	$ 889,204	$ 15,670	$ 491,169	$ 13,500
2	Large Industrial Meter Replacement Cost	$ 2,925,991	$ -		$ -	$ -	$ -	$ -	$ 292,589	$ -	$ 23,398	$ 2,276,113
3	Total Meter Replacement Costs	$ 82,480,962	$47,842,724	8,972,038	$ 330,106	$18,028,063	$ 88,038	$2,468,204	$1,181,793	$ 15,670	$ 514,566	$ 2,289,613

	Rate 511-Residential	Rate 515-Residential Multi-Family
511-515 Customer Split	84.21%	15.79%

Northern Indiana Public Service Company
Meters Analysis Summary

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Meter Replacement Costs	$ 79,515,720	$ 18,192	$ 6,976	$ 285,016	$ -	$ 33,569	$ 33,251	$ -	$ -	$ -	$ -
2	Large Industrial Meter Replacement Cost	$ 2,925,991	$ 216,542	$ 117,350	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Total Meter Replacement Costs	$ 82,480,962	$ 234,734	$ 124,326	$ 285,016	$ -	$ 33,569	$ 33,251				$ 39,250

511-515 Customer Split

Northern Indiana Public Service Company
Account 902 - Meter Reading Expense

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	**Meter Department Reading Expense**	$ 260,625										
2	Manual Reads by Meter Dept.	783	-		68	205	17	79	149	6	181	6
3	Manual Read - Avg. Time in Minutes		-		20	20	20	25	25	25	25	73
4	Class Manual Read Time Percentage	100.0%	-		6.9%	20.8%	1.7%	10.0%	18.9%	0.8%	23.0%	2.2%
5	Allocation of Meter Dept. Reading	$ 260,625	$ -		$ 17,994	$ 54,247	$ 4,499	$ 26,131	$ 49,286	$ 1,985	$ 59,870	$ 5,795
6	*Cost per manual read (per month)*	*$ 27.74*			*$22.05*	*$22.05*	*$22.05*	*$27.56*	*$27.56*	*$27.56*	*$27.56*	*$80.49*
7	**Meter Readers Expense**	$ 1,111,401										
8	Manual Reads by Meter Readers	424	215		1	123	5	52	23	-	-	
9	Manual Read Hours (5 min./read)	424										
10	Manual Read Cost (assumed $51/hr)	$ 21,624	$ 10,965		$ 51	$ 6,273	$ 255	$ 2,652	$ 1,173	$ -	$ -	
11	Customers Minus Manual Reads	489,883	431,625		35	54,097	122	2,876	336	-	79	
12	AMI Read Cost	$ 1,089,777	$ 960,178		$ 77	$ 120,342	$ 271	$ 6,398	$ 747	$ -	$ 176	
13	Allocation of Meter Readers	$ 1,111,197	$ 971,143		$ 128	$ 126,615	$ 526	$ 9,050	$ 1,920	$ -	$ 176	
14	*Cost per AMI read (per month)*	*$ 0.19*										
15	*Cost per manual read (per month)*	*$ 4.25*										
16	Total Meter Reading Allocation	$ 1,371,822	$ 971,143	**new rate**	$ 18,122	$ 180,862	$ 5,025	$ 35,181	$ 51,205	$ 1,985	$ 60,046	$ 5,795
17	2023 Customer Count	502,514	431,840		104	54,425	144	3,007	508	6	260	7
18	Cost per Customer		$ 2.25	$ 2.25	$ 174.81	$ 3.32	$ 34.93	$ 11.70	$ 100.86	$ 330.78	$ 231.02	$ 827.88
19	Weighting Factor		1.00	1.00	77.73	1.48	15.53	5.20	44.85	147.09	102.73	368.14

Northern Indiana Public Service Company
Account 902 - Meter Reading Expense

Line No.	Description	Total	Rate 532- Small Industrial Service - LLF	Rate 533- Small Industrial Service - HLF	Rate 541- Muni. Power	Rate 542- Int WW Pumping	Rate 543- Sta. Pwr. Renewable	Rate 544- Railroad	Rate 550- Street Lighting	Rate 555- Traffic Lighting	Rate 560- Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	**Meter Department Reading Expense**	$ 260,625										
2	Manual Reads by Meter Dept.	783	7	3	7	-	-	9	-	-	-	46
3	Manual Read - Avg. Time in Minutes		73	73	25	-	-	140	-	-	-	20
4	Class Manual Read Time Percentage	100.0%	2.6%	1.1%	0.9%		0.0%	6.4%				4.7%
5	Allocation of Meter Dept. Reading	$ 260,625	$ 6,761	$ 2,898	$ 2,315		$ -	$ 16,671				$ 12,173
6	*Cost per manual read (per month)*	*$ 27.74*	*$80.49*	*$80.49*	*$27.56*		*#DIV/0!*	*$154.36*				*$22.05*
7	**Meter Readers Expense**	$ 1,111,401										
8	Manual Reads by Meter Readers	424			1		-					4
9	Manual Read Hours (5 min./read)	424										
10	Manual Read Cost (assumed $51/hr)	$ 21,624			$ 51		$ -					
11	Customers Minus Manual Reads	489,883			714		-					
12	AMI Read Cost	$ 1,089,777			$ 1,589		$ -					
13	Allocation of Meter Readers	$ 1,111,197			$ 1,640		$ -					
14	*Cost per AMI read (per month)*	*$ 0.19*										
15	*Cost per manual read (per month)*	*$ 4.25*										
16	Total Meter Reading Allocation	$ 1,371,822	$ 6,761	$ 2,898	$ 3,956	$ -	$ -	$ 16,671	$ -	$ -	$ -	$ 12,173
17	2023 Customer Count	502,514	5	4	722	9	6	1	1,581	140	9,700	46
18	Cost per Customer		$ 1,352.21	$ 724.40	$ 5.48	$ -	$ -	$16,671.09	$ -	$ -	$ -	$ 264.62
19	Weighting Factor		601.29	322.12	2.44	-	-	7,413.17	-	-	-	117.67

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	3-Year Average Write-Offs	6,816,636	5,227,110	980,250	-	338,272	-	19,053	1,978	-	-	-
2	Allocation Percentage	100.00%	76.68%	14.38%	0.00%	4.96%	0.00%	0.28%	0.03%	0.00%	0.00%	0.00%
3	2023 Write-offs	6,547,715	6,219,823	**new rate**	-	301,412	-	10,947	-	-	-	-
4	2022 Write-offs	5,791,738	5,477,907		-	298,724	-	1,462	1,429	-	-	-
5	2021 Write-offs	8,110,454	6,924,350		-	414,678	-	44,751	4,503	-	-	-
6	Residential Split											
7	Customer Counts		362,370	67,956								
8	Allocation percentage		84.21%	15.79%								

Northern Indiana Public Service Company
Write-Offs

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	3-Year Average Write-Offs	6,816,636	-	238,137	181	-	-	-	68	-	11,588	-
2	Allocation Percentage	100.00%	0.00%	3.49%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	0.00%
3	2023 Write-offs	6,547,715	-	-	-	-	-	-	203	-	15,330	-
4	2022 Write-offs	5,791,738	-	-	-	-	-	-	-	-	12,216	-
5	2021 Write-offs	8,110,454	-	714,410	542	-	-	-	-	-	7,219	-
6	Residential Split											
7	Customer Counts											
8	Allocation percentage											

Cause No. 46120

Northern Indiana Public Service Company
Late Payments

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	3-Year Average Late Payments	5,428,612	2,892,626	542,460	-	971,052	-	225,628	309,172	2,260	272,425	192,831
2	Allocation Percentage	100.00%	53.28%	9.99%	0.00%	17.89%	0.00%	4.16%	5.70%	0.04%	5.02%	3.55%
3	2023 Late Payments	5,177,979	3,433,870	**new rate**	-	999,827	-	214,387	311,017	972	243,534	(22,364)
4	2022 Late Payments	5,885,278	3,528,519		-	971,998	-	221,417	287,333	-	349,907	488,337
5	2021 Late Payments	5,217,842	3,342,867		-	941,331	-	241,082	329,166	5,807	223,835	112,520
6	Residential Split											
7	Customer Counts		362,370	67,956								
8	Allocation percentage		84.21%	15.79%								

Northern Indiana Public Service Company
Late Payments

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	3-Year Average Late Payments	5,428,612	-	-	283	181	4,056	-	-	223	15,415	-
2	Allocation Percentage	100.00%	0.00%	0.00%	0.01%	0.00%	0.07%	0.00%	0.00%	0.00%	0.28%	0.00%
3	2023 Late Payments	5,177,979	(4,736)	(16,623)	252	-	1,669	-	-	176	15,997	-
4	2022 Late Payments	5,885,278	-	16,623	412	207	4,945	-	-	121	15,459	-
5	2021 Late Payments	5,217,842	-	-	185	335	5,553	-	-	371	14,790	-
6	Residential Split											
7	Customer Counts											
8	Allocation percentage											

Northern Indiana Public Service Company
Allocation of Customer Accounts (Accts. 901, 903, 910, 913)

Line No.	Description	Total	Rate 511-Residential	Rate 515-Residential Multi-Family	Rate 520-C&GS Heat Pump	Rate 521-GS Small	Rate 522-Comml SH	Rate 523-GS Medium	Rate 524-GS Large	Rate 525-Metal Melting	Rate 526-Off-Peak Serv.	Rate 531-Ind. Pwr Serv. - Large
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Acct 901 - Customer Account Supervision	$ 1,218,781	$ 1,014,653	**new rate**	$ 219	$ 176,126	$ 219	$ 9,585	$ 1,532	$ 8	$ 347	$ 9
2	Allocations	100%	83.25%		0.02%	14.45%	0.02%	0.79%	0.13%	0.00%	0.03%	0.00%
3	Customer Count (2023)	502,514	431,840		104	54,425	144	3,007	508	6	260	7
4	Acct 901 / Customer		$ 2.35		$ 2.11	$ 3.24	$ 1.52	$ 3.19	$ 3.19	$ 1.33	$ 1.34	$ 1.33
5	Weighting Factor		1.00	1.00	0.90	1.38	0.65	1.36	1.36	0.57	0.57	0.57
6	Acct 903 - Customer Records & Collections	$ 8,652,945	$ 6,988,442	**new rate**	$ 17,719	$1,269,270	$ 5,561	$ 89,957	$ 64,657	$ 2,606	$ 94,031	$ 7,102
7	Allocations	100%	80.76%		0.20%	14.67%	0.06%	1.04%	0.75%	0.03%	1.09%	0.08%
8	Customer Count (2023)	502,514	431,840		104	54,425	144	3,007	508	6	260	7
9	Acct 903 / Customer		$ 16.18		$ 170.92	$ 23.32	$ 38.65	$ 29.91	$ 127.36	$ 434.37	$ 361.77	$ 1,014.61
10	Weighting Factor		1.00	1.00	10.56	1.44	2.39	1.85	7.87	26.84	22.36	62.70
11	Acct 910 - Customer Assistance Expense	$ 539,112	$ 257,525	**new rate**	$ 1,881	$ 49,319	$ 1,881	$ 47,029	$ 60,219	$ 1,787	$ 34,051	$ 28,579
12	Allocations	100%	47.77%		0.35%	9.15%	0.35%	8.72%	11.17%	0.33%	6.32%	5.30%
13	Customer Count (2023)	502,514	431,840		104	54,425	144	3,007	508	6	260	7
14	Acct 910 / Customer		$ 0.60		$ 18.15	$ 0.91	$ 13.08	$ 15.64	$ 118.62	$ 297.83	$ 131.01	$ 4,082.67
15	Weighting Factor		1.00	1.00	30.43	1.52	21.93	26.22	198.91	499.43	219.69	6,846.16

Northern Indiana Public Service Company
Allocation of Customer Accounts (Accts. 901, 903, 910, 913)

Line No.	Description	Total	Rate 532-Small Industrial Service - LLF	Rate 533-Small Industrial Service - HLF	Rate 541-Muni. Power	Rate 542-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 544-Railroad	Rate 550-Street Lighting	Rate 555-Traffic Lighting	Rate 560-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Acct 901 - Customer Account Supervision	$ 1,218,781	$ 7	$ 5	$ 980	$ 12	$ 19	$ 1	$ 1,866	$ 187	$ 12,946	$ 61
2	Allocations	100%	0.00%	0.00%	0.08%	0.00%	0.00%	0.00%	0.15%	0.02%	1.06%	0.01%
3	Customer Count (2023)	502,514	5	4	722	9	6	1	1,581	140	9,700	46
4	Acct 901 / Customer		$ 1.33	$ 1.33	$ 1.36	$ 1.33	$ 3.09	$ 1.33	$ 1.18	$ 1.33	$ 1.33	$ 1.33
5	Weighting Factor		0.57	0.57	0.58	0.57	1.31	0.57	0.50	0.57	0.57	0.57
6	Acct 903 - Customer Records & Collections	$ 8,652,945	$ 2,190	$ 2,110	$ 8,978	$ 81	$ 805	$ 383	$ 12,428	$ 1,257	$ 84,784	$ 585
7	Allocations	100%	0.03%	0.02%	0.10%	0.00%	0.01%	0.00%	0.14%	0.01%	0.98%	0.01%
8	Customer Count (2023)	502,514	5	4	722	9	6	1	1,581	140	9,700	46
9	Acct 903 / Customer		$ 437.95	$ 527.56	$ 12.43	$ 8.96	$ 134.15	$ 383.12	$ 7.86	$ 8.98	$ 8.74	$ 12.71
10	Weighting Factor		27.06	32.60	0.77	0.55	8.29	23.67	0.49	0.55	0.54	0.79
11	Acct 910 - Customer Assistance Expense	$ 539,112	$ 19,643	$ 19,643	$ 2,222	$ 1,789	$ 728	$ 2,498	$ 2,619	$ 84	$ 7,585	$ 28
12	Allocations	100%	3.64%	3.64%	0.41%	0.33%	0.14%	0.46%	0.49%	0.02%	1.41%	0.01%
13	Customer Count (2023)	502,514	5	4	722	9	6	1	1,581	140	9,700	46
14	Acct 910 / Customer		$ 3,928.66	$ 4,910.67	$ 3.08	$ 198.75	$ 121.41	$ 2,498.49	$ 1.66	$ 0.60	$ 0.78	$ 0.60
15	Weighting Factor		6,587.90	8,234.63	5.16	333.29	203.59	4,189.69	2.78	1.00	1.31	1.00

Northern Indiana Public Service Company
Test Year Ended December 31, 2025
Proposed Mitigation of Rate Increases

		Current Revenues				Proposed Revenues						
Line No.	**Rate Description**	**Retail Sales (Non-Fuel), TDSIC & DSM**	**Retail Sales - Fuel**	**Other Revenues**	**Total Revenue**	**511 at System Increase,515 and 531 at Parity, Max 1.5x Cost to Serve**	**Increase to Parity with No Reductions - Cap at 1.5x System Avg.**	**Balance to Other Classes on Revenue**	**Proposed Increase**	**% Increase**	**Rate Schedule Revenue**	**Total Proposed Revenue**
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
1	Rate 511-Residential	513,286,199	95,870,856	8,743,142	617,900,197	124,505,686			124,505,686	20.15%	733,662,741	742,405,883
2	Rate 515-Residential Multi-Family	64,173,770	11,182,284	997,310	76,353,364	9,563,795			9,563,795	12.53%	84,919,849	85,917,158
3	Rate 520-C&GS Heat Pump	956,701	280,388	13,144	1,250,233		294,418	83,461	377,879	30.22%	1,614,968	1,628,112
4	Rate 521-GS Small	265,320,381	49,893,314	3,659,902	318,873,596		14,814,298	58,001,661	72,815,959	22.84%	388,029,653	391,689,555
5	Rate 522-Comml SH	832,143	221,646	8,933	1,062,722			193,304	193,304	18.19%	1,247,093	1,256,026
6	Rate 523-GS Medium	126,073,447	26,725,051	1,662,281	154,460,778		10,945,688	28,095,715	39,041,403	25.28%	191,839,900	193,502,181
7	Rate 524-GS Large	181,161,520	44,006,839	2,156,000	227,324,359			41,349,270	41,349,270	18.19%	266,517,629	268,673,629
8	Rate 525-Metal Melting	6,570,678	2,681,301	92,598	9,344,577		68,040	1,699,736	1,767,777	18.92%	11,019,755	11,112,353
9	Rate 526-Off-Peak Serv.	149,380,132	48,524,661	2,001,017	199,905,810		3,590,010	36,361,960	39,951,970	19.99%	237,856,763	239,857,781
10	Rate 531-Ind. Pwr Serv. - Large	113,266,445	32,107,520	4,308,595	149,682,559	26,000,508			26,000,508	17.37%	171,374,472	175,683,067
11	Rate 532-Small Industrial Service - LL	12,409,945	4,947,513	174,273	17,531,731			3,188,942	3,188,942	18.19%	20,546,400	20,720,673
12	Rate 533-Small Industrial Service - HI	18,550,853	8,429,028	176,805	27,156,687			4,160,415	4,160,415	15.32%	31,140,296	31,317,101
13	Rate 541-Muni. Power	4,731,177	1,165,639	34,918	5,931,735			1,078,956	1,078,956	18.19%	6,975,772	7,010,690
14	Rate 542-Int WW Pumping	55,549	10,696	535	66,780	(994)			(994)	-1.49%	65,251	65,786
15	Rate 543-Sta. Pwr. Renewable	2,723,461	772,573	13,081	3,509,114	(163,954)			(163,954)	-4.67%	3,332,079	3,345,160
16	Rate 544-Railroad	1,265,561	350,041	15,901	1,631,503	328,745			328,745	20.15%	1,944,347	1,960,247
17	Rate 550-Street Lighting	6,586,754	973,509	31,758	7,592,020		2,294,666		2,294,666	30.22%	9,854,928	9,886,687
18	Rate 555-Traffic Lighting	949,494	205,885	7,424	1,162,803			211,509	211,509	18.19%	1,366,887	1,374,311
19	Rate 560-Dusk-to-Dawn	2,731,481	430,266	24,672	3,186,419		963,086		963,086	30.22%	4,124,832	4,149,505
20	Interdepartmental	4,788,986	855,034	27,909	5,671,930			1,031,698	1,031,698	18.19%	6,675,719	6,703,628
21	**System Total**	**1,475,814,675**	**329,634,043**	**24,150,198**	**$ 1,829,598,917**	**$ 160,233,785**	**$ 32,970,207**	**$ 175,456,627**	**$ 368,660,619**	**20.15%**	**$ 2,174,109,337**	**$ 2,198,259,535**

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Residential Service
Rate 511

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Customer Charge*			
2	Customer Charge	4,348,440	$ 14.00	$ 60,878,157
3	Total	4,348,440		$ 60,878,157
4	*Billed kwh*			
5	For all kWh used	3,106,930,204	$ 0.166243	$ 516,505,398
6	Total kWh	3,106,930,204		$ 516,505,398
7	DSM Proforma	39,780,432		
8	Total Adj kWh	3,146,710,635		
9	Residential Service (Rate 511)			$ 577,383,555
10	*Contract Riders*			
11	RA		Rider 574	$ (1,992,450)
12	EDR		Rider 577	$ -
13	DSMA		Rider 583	$ 3,847,798
14	TDSIC		Rider 588	$ 41,315,349
15	Total Rider			$ 43,170,698
16	*Other Adjustments*			
17	Generation Credit			$ (1,411,527)
18	Difference in Fuel Calculation			$ (8,771,414)
19	Total Other Adjustments			$ (10,182,941)
20	Grand Total			$ 610,371,312

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Residential Service
Rate 611

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Customer Charge*			
2	Customer Charge	4,348,440	$ 25.00	$ 108,710,994
3	Total	4,348,440		$ 108,710,994
4	*Billed kWh*			
5	For all kWh used	3,146,710,635	$ 0.198605	$ 624,952,466
6	Total kWh	3,146,710,635		$ 624,952,466
7	Residential Service (Rate 611)			$ 733,663,460
			Propopsed Revenue Target	$ 733,662,741
			Difference Due to Rounding	$ 719
8	*Contract Riders*			
9	RA		Rider 674	$ -
10	EDR		Rider 677	$ -
11	DSMA		Rider 683	$ -
12	TDSIC		Rider 688	$ -
13	Total Rider			$ -
14	*Other Adjustments*			
15	Generation Credit			$ -
16	Difference in Fuel Calculation			$ -
17	Total Other Adjustments			$ -
18	Grand Total			$ 733,663,460

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Residential Multi-Family
Rate 511

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Customer Charge*			
2	Customer Charge	815,471	$ 14.00	$ 11,416,597
3	Total	815,471		$ 11,416,597
4	*Billed kwh*			
5	For all kWh used	362,389,331	$ 0.166243	$ 60,244,689
6	Total kWh	362,389,331		$ 60,244,689
7	DSM Proforma	4,639,951		
8	Total Adj kWh	367,029,282		
9	Residential Multi-Family (Rate 511)			$ 71,661,287
10	*Contract Riders*			
11	RA		Rider 574	$ (232,397)
12	EDR		Rider 577	$ -
13	DSMA		Rider 583	$ 448,803
14	TDSIC		Rider 588	$ 4,818,982
15	Total Rider			$ 5,035,388
16	*Other Adjustments*			
17	Generation Credit			$ (164,639)
18	Difference in Fuel Calculation			$ (1,023,089)
19	Total Other Adjustments			$ (1,187,728)
20	Grand Total			$ 75,508,947

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Residential Multi-Family
Rate 615

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Customer Charge*			
2	Customer Charge	815,471	$ 25.00	$ 20,386,781
3	Total	815,471		$ 20,386,781
4	*Billed kWh*			
5	For all kWh used	367,029,282	$ 0.175825	$ 64,532,923
6	Total kWh	367,029,282		$ 64,532,923
7	Residential Multi-Family (Rate 615)			$ 84,919,704
			Propopsed Revenue Target	$ 84,919,849
			Difference Due to Rounding	$ (144)
8	*Contract Riders*			
9	RA		Rider 674	$ -
10	EDR		Rider 677	$ -
11	DSMA		Rider 683	$ -
12	TDSIC		Rider 688	$ -
13	Total Rider			$ -
14	*Other Adjustments*			
15	Generation Credit			$ -
16	Difference in Fuel Calculation			$ -
17	Total Other Adjustments			$ -
18	Grand Total			$ 84,919,704

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Commercial and General Service - Heat Pump
Rate 520

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Customer Charge*			
2	Customer Charge	1,476	$ 32.50	$ 47,970
3	Total	1,476		$ 47,970
4	*Billed kwh*			
5	For all kWh used	9,086,667	$ 0.120406	$ 1,094,089
6	Total kWh	9,086,667		$ 1,094,089
7	Commercial and General Service - Heat Pump (Rate 520)			$ 1,142,059
8	*Contract Riders*			
9	RA		Rider 574	$ (4,275)
10	EDR		Rider 577	$ -
11	DSMA		Rider 583	$ 6,703
12	TDSIC		Rider 588	$ 123,052
13	Total Rider			$ 125,481
14	*Other Adjustments*			
15	Generation Credit			$ (2,673)
16	Difference in Fuel Calculation			$ (25,653)
17	Total Other Adjustments			$ (28,326)
18	Grand Total			$ 1,239,214

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Commercial and General Service - Heat Pump
Rate 620

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Customer Charge*			
2	Customer Charge	1,476	$ 41.40	$ 61,106
3	Total	1,476		$ 61,106
4	*Billed kWh*			
5	All kWh	9,086,667	$ 0.171005	$ 1,553,865
6	Total kWh	9,086,667		$ 1,553,865
7	Commercial and General Service - Heat Pump (Rate 620)			$ 1,614,972
			Propopsed Revenue Target	$ 1,614,968
			Difference Due to Rounding	$ 4
8	*Contract Riders*			
9	RA		Rider 674	$ -
10	EDR		Rider 677	$ -
11	DSMA		Rider 683	$ -
12	TDSIC		Rider 688	$ -
13	Total Rider			$ -
14	*Other Adjustments*			
15	Generation Credit			$ -
16	Difference in Fuel Calculation			$ -
17	Total Other Adjustments			$ -
18	Grand Total			$ 1,614,972

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
General Service - Small
Rate 521

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Customer Charge*			
2	Customer Charge	667,878	$ 32.50	$ 21,706,035
3	Total	667,878		$ 21,706,035
4	*Minimum Charge - Three Phase Service*			
5	General Service - Small	9,049	$ 48.50	$ 438,857
6	Total	9,049		$ 438,857
7	*Billed kwh*			
8	For all kWh used	1,616,915,194	$ 0.174854	$ 282,724,089
9	Total kWh	1,616,915,194		$ 282,724,089
10	DSM Proforma	38,812,935		
11	Total Adj kWh	1,655,728,129		
12	General Service - Small (Rate 521)			$ 304,868,982
13	*Contract Riders*			
14	RA		Rider 574	$ (1,209,399)
15	EDR		Rider 577	$ -
16	DSMA		Rider 583	$ 2,905,441
17	TDSIC		Rider 588	$ 14,623,813
18	Total Rider			$ 16,319,855
19	*Other Adjustments*			
20	Generation Credit			$ (766,933)
21	Difference in Fuel Calculation			$ (4,564,838)
22	Guaranteed Revenue			$ -
23	Total Other Adjustments			$ (5,331,770)
24	Grand Total			$ 315,857,066

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
General Service - Small
Rate 621

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Customer Charge*			
2	Customer Charge	667,878	$ 41.40	$ 27,650,149
3	Total	667,878		$ 27,650,149
4	*Minimum Charge - Three Phase Service*			
5	General Service - Small	9,049	$ 63.40	$ 573,682
6	Total	9,049		$ 573,682
7	*Billed kWh*			
8	All kWh	1,655,728,129	$ 0.217310	$ 359,806,280
9	Total kWh	1,655,728,129		$ 359,806,280
10	General Service - Small (Rate 621)			$ 388,030,111
			Propopsed Revenue Target	$ 388,029,653
11	*Contract Riders*			
12	RA		Rider 674	$ -
13	EDR		Rider 677	$ -
14	DSMA		Rider 683	$ -
15	TDSIC		Rider 688	$ -
16	Total Rider			$ -
17	*Other Adjustments*			
18	Generation Credit			$ -
19	Difference in Fuel Calculation			$ -
20	Guaranteed Revenue			$ -
21	Total Other Adjustments			$ -
22	Grand Total			$ 388,030,111

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Commercial Spaceheating
Rate 522

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(C)	(D)	(E)
1	*Customer Charge*			
2	Customer Charge	1,476	$ 32.50	$ 47,970
3	Total	1,476		$ 47,970
4	*Billed kwh*			
5	For all kWh used	7,182,994	$ 0.128896	$ 925,859
6	Total kWh	7,182,994		$ 925,859
7	Commercial Spaceheating (Rate 522)			$ 973,829
8	*Contract Riders*			
9	RA		Rider 574	$ (5,100)
10	EDR		Rider 577	$ -
11	DSMA		Rider 583	$ 5,479
12	TDSIC		Rider 588	$ 104,384
13	Total Rider			$ 104,763
14	*Other Adjustments*			
15	Generation Credit			$ (2,659)
16	Difference in Fuel Calculation			$ (20,279)
17	Total Other Adjustments			$ (22,938)
18	Grand Total			$ 1,055,654

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Commercial Spaceheating
Rate 622

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(J)	(K)	(L)	(M)
1	*Customer Charge*			
2	Customer Charge	1,476	$ 41.40	$ 61,106
		1,476		$ 61,106
3	*Billed kWh*			
4	For all kWh used	7,182,994	$ 0.165110	$ 1,185,984
5	Total kWh	7,182,994		$ 1,185,984
6	Commercial Spaceheating (Rate 622)			$ 1,247,091
			Propopsed Revenue Target	$ 1,247,093
			Difference Due to Rounding	$ (3)
7	*Contract Riders*			
8	RA		Rider 674	$ -
9	EDR		Rider 677	$ -
10	DSMA		Rider 683	$ -
11	TDSIC		Rider 688	$ -
12	Total Rider			$ -
13	*Other Adjustments*			
14	Generation Credit			$ -
15	Difference in Fuel Calculation			$ -
16	Total Other Adjustments			$ -
17	Grand Total			$ 1,247,091

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
General Service - Medium
Rate 523

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	First 10 kW	350,147	$ 33.54	$ 11,743,931
3	Over 10 kW	2,228,447	$ 15.31	$ 34,117,528
4	Total kW	2,578,594		$ 45,861,459
5	DSM Proforma	4,936		
6	Total Adj kWh	2,583,530		
7	*Minimum Charge - Billed kW*			
8	First 10 kW	2,397	$ 33.54	$ 80,407
9	Over 10 kW	24,490	$ 15.31	$ 374,946
10	Total kW	26,888		$ 455,353
11	*Billed kWh*			
12	All kWh	865,757,650	$ 0.116522	$ 100,879,813
13	Total kWh	865,757,650		$ 100,879,813
14	DSM Proforma	21,332,906		
15	Total Adj kWh	887,090,556		
16	Thermal Storage - Billed kWh			
17	All kWh	333,161	$ 0.097195	$ 32,382
18	Total kWh	333,161		$ 32,382
19	General Service - Medium (Rate 523)			$ 147,229,006
20	*Contract Riders*			
21	RA		Rider 574	$ (695,432)
22	EDR		Rider 577	$ -
23	DSMA		Rider 583	$ 1,286,412
24	TDSIC		Rider 588	$ 8,153,093
25	Total Rider			$ 8,744,072
	Other Adjustments			
26	Generation Credit			$ (426,779)
27	Difference in Fuel Calculation			$ (2,455,406)
28	Total Other Adjustments			$ (2,882,185)
29	Grand Total			$ 153,090,894

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
General Service - Medium
Rate 623

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Proposed Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	First 10 kW	350,147	$ 43.70	$ 15,301,425
3	Over 10 kW	2,233,383	$ 19.95	$ 44,555,996
4	Total kW	2,583,530		$ 59,857,421
5	*Minimum Charge - Billed kW*			
6	First 10 kW	2,397	$ 43.70	$ 104,764
7	Over 10 kW	24,490	$ 19.95	$ 488,581
8	Total kW	26,888		$ 593,344
9	*Billed kWh*			
10	All kWh	887,090,556	$ 0.148065	$ 131,347,063
11	Total kWh	887,090,556		$ 131,347,063
12	Thermal Storage - Billed kWh			
13	All kWh	333,161	$ 0.126645	$ 42,193
14	Total kWh	333,161		$ 42,193
15	General Service - Medium (Rate 623)			$ 191,840,022
			Propopsed Revenue Target	$ 191,839,900
			Difference Due to Rounding	$ 122
16	*Contract Riders*			
17	RA		Rider 674	$ -
18	EDR		Rider 677	$ -
19	DSMA		Rider 683	$ -
20	TDSIC		Rider 688	$ -
21	Total Rider			$ -
	Other Adjustments			
22	Generation Credit			$ -
23	Difference in Fuel Calculation			$ -
24	Total Other Adjustments			$ -
25	Grand Total			$ 191,840,022

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
General Service - Large
Rate 524

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	First 50 kW	304,756	$ 27.16	$ 8,277,180
3	Next 1,950 kW	3,143,451	$ 17.76	$ 55,827,692
4	Over 2,000 kW	448,672	$ 17.05	$ 7,649,860
5	Total kW	3,896,880		$ 71,754,732
6	DSM Proforma	5,238		
7	Total Adj kWh	3,902,117		
8	*Minimum Charge - Billed kW*			
9	First 50 kW	69	$ 27.16	$ 1,884
10	Next 1,950 kW	3,144	$ 17.76	$ 55,840
11	Over 2,000 kW	15,850	$ 17.05	$ 270,244
12	Over 3,000 kW	-	$ 17.68	$ -
13	Total kW	19,064		$ 327,968
14	*Billed kWh*			
15	First 30,000 kWh	190,221,498	$ 0.115008	$ 21,876,994
16	Next 70,000 kWh	330,778,467	$ 0.104620	$ 34,606,043
17	Next 900,000 kWh	811,955,698	$ 0.099831	$ 81,058,349
18	Over 1,000,000 kWh	92,579,575	$ 0.094975	$ 8,792,745
19	Total kWh	1,425,535,237		$ 146,334,132
20	DSM Proforma	22,536,595		
21	Total Adj kWh	1,448,071,832		
22	Per kWh Usage Charge Ratios			
23	Block 2 / Block 1		90.97%	
24	Block 3 / Block 1		86.80%	
25	Block 4 / Block 1		82.58%	

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
General Service - Large
Rate 624

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	First 50 kW	304,756	$ 33.25	$ 10,133,146
3	Next 1,950 kW	3,143,451	$ 21.74	$ 68,338,627
4	Over 2,000 kW	453,910	$ 20.87	$ 9,473,104
5	Total kW	3,902,117		$ 87,944,877
6	*Minimum Charge - Billed kW*			
7	First 50 kW	69	$ 33.25	$ 2,306
8	Next 1,950 kW	3,144	$ 21.74	$ 68,354
9	Over 2,000 kW	15,850	$ 20.87	$ 330,792
10	Over 3,000 kW	-	$ 21.64	$ -
11	Total kW	19,064		$ 401,452
12	*Billed kWh*			
13	First 30,000 kWh	190,221,498	$ 0.138658	$ 26,375,732
14	Next 70,000 kWh	330,778,467	$ 0.126134	$ 41,722,411
15	Next 900,000 kWh	811,955,698	$ 0.120360	$ 97,726,988
16	Over 1,000,000 kWh	115,116,170	$ 0.114505	$ 13,181,377
17	Total kWh	1,448,071,832		$ 179,006,508
18	Per kWh Usage Charge Ratios			
19	Block 2 / Block 1		90.97%	
20	Block 3 / Block 1		86.80%	
21	Block 4 / Block 1		82.58%	

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
General Service - Large
Rate 524

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
26	Thermal Storage - Billed kWh			
27	All kWh	614,317	$ 0.097195	$ 59,709
28	Total kWh	614,317		$ 59,709
29	Discounts - Billed kW			
30	Primary Service	648,103	$ (1.02)	$ (661,065)
31	Transmission Service	66,234	$ (1.27)	$ (84,117)
32	Total kW	714,337		$ (745,182)
33	General Service - Large (Rate 524)			$ 217,731,359
34	*Contract Riders*			
35	RA		Rider 574	$ (765,040)
36	EDR		Rider 577	$ (1,868,525)
37	DSMA		Rider 583	$ 2,628,610
38	TDSIC		Rider 588	$ 10,606,120
39	Total Rider			$ 10,601,164
40	*Other Adjustments*			
41	Generation Credit			$ (572,486)
42	Difference in Fuel Calculation			$ (4,024,538)
43	Total Other Adjustments			$ (4,597,024)
44	Grand Total			$ 223,735,499

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
General Service - Large
Rate 624

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
22	Thermal Storage - Billed kWh			
23	All kWh	614,317	$ 0.126645	$ 77,800
24	Total kWh	614,317		$ 77,800
25	Discounts - Billed kW			
26	Primary Service	648,103	$ (1.25)	$ (810,129)
27	Transmission Service	66,234	$ (1.55)	$ (102,662)
28	Total kW	714,337		$ (912,791)
29	General Service - Large (Rate 624)			$ 266,517,846
			Propopsed Revenue Target	$ 266,517,629
			Difference Due to Rounding	$ 218
30	*Contract Riders*			
31	RA		Rider 674	$ -
32	EDR		Rider 677	$ -
33	DSMA		Rider 683	$ -
34	TDSIC		Rider 688	$ -
35	Total Rider			$ -
36	*Other Adjustments*			
37	Generation Credit			$ -
38	Difference in Fuel Calculation			$ -
39	Total Other Adjustments			$ -
40	Grand Total			$ 266,517,846

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Metal Melting Service
Rate 525

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	First 500 kW	37,795	$ 31.10	$ 1,175,425
3	Over 500 kW	65,367	$ 29.70	$ 1,941,391
4	Total kW	103,162		$ 3,116,816
5	DSM Proforma	478		
6	Total Adj kW	103,640		
7	*Billed kWh*			
8	All kWh	86,894,122	$ 0.066988	$ 5,820,863
9	Total kWh	86,894,122		$ 5,820,863
10	DSM Proforma	2,055,210		
11	Total Adj kWh	88,949,332		
12	Metal Melting Service (Rate 525)			$ 8,937,680
13	*Contract Riders*			
14	RA		Rider 574	$ (32,679)
15	EDR		Rider 577	$ -
16	DSMA		Rider 583	$ 139,109
17	TDSIC		Rider 588	$ 491,084
18	Total Rider			$ 597,513
19	*Other Adjustments*			
20	Generation Credit			$ (22,765)
21	Difference in Fuel Calculation			$ (245,317)
22	Total Other Adjustments			$ (268,083)
23	Grand Total			$ 9,267,110

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Metal Melting Service
Rate 625

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	First 500 kW	37,795	$ 38.34	$ 1,449,061
3	Over 500 kW	65,845	$ 36.62	$ 2,411,237
4	Total kW	103,640		$ 3,860,298
5	*Billed kWh*			
6	All kWh	88,949,332	$ 0.080489	$ 7,159,443
7	Total kWh	88,949,332		$ 7,159,443
8	Metal Melting Service (Rate 625)			$ 11,019,740
			Propopsed Revenue Target	$ 11,019,755
			Difference Due to Rounding	$ (15)
9	*Contract Riders*			
10	RA		Rider 674	$ -
11	EDR		Rider 677	$ -
12	DSMA		Rider 683	$ -
13	TDSIC		Rider 688	$ -
14	Total Rider			$ -
15	*Other Adjustments*			
16	Generation Credit			$ -
17	Difference in Fuel Calculation			$ -
18	Total Other Adjustments			$ -
19	Grand Total			$ 11,019,740

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Off-Peak Service
Rate 526

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	First 200 kW	603,643	$ 40.87	$ 24,670,904
3	Next 500 kW	859,215	$ 39.32	$ 33,784,336
4	Next 1,300 kW	854,162	$ 37.77	$ 32,261,695
5	Over 2,000 kW	654,225	$ 36.99	$ 24,199,779
6	Total kW	2,971,245		$ 114,916,714
7	DSM Proforma	2,833		
8	Total Adj kW	2,974,079		
9	*Billed kWh*			
10	All kWh	1,572,560,658	$ 0.051637	$ 81,202,315
11	Total kWh	1,572,560,658		$ 81,202,315
12	DSM Proforma	12,195,054		
13	Total Adj kWh	1,584,755,712		
14	Discounts - Billed kW			
15	Primary Service	432,045	$ (1.02)	$ (440,686)
16	Transmission Service	164,508	$ (1.27)	$ (208,925)
17	Total kW	596,553		$ (649,611)
18	Off-Peak Service (Rate 526)			$ 195,469,418
19	*Contract Riders*			
20	RA		Rider 574	$ (649,274)
21	EDR		Rider 577	$ (1,071,555)
22	DSMA		Rider 583	$ 470,027
23	TDSIC		Rider 588	$ 7,838,993
24	Total Rider			$ 6,588,190
25	*Other Adjustments*			
26	Generation Credit			$ (422,704)
27	Difference in Fuel Calculation			$ (4,439,617)
28	Total Other Adjustments			$ (4,862,321)
29	Grand Total			$ 197,195,287

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Off-Peak Service
Rate 626

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	First 200 kW	603,643	$ 49.73	$ 30,019,184
3	Next 500 kW	859,215	$ 47.85	$ 41,113,440
4	Next 1,300 kW	854,162	$ 45.96	$ 39,257,281
5	Over 2,000 kW	657,058	$ 45.01	$ 29,574,193
6	Total kW	2,974,079		$ 139,964,098
7	*Billed kWh*			
8	All kWh	1,584,755,712	$ 0.062273	$ 98,687,492
9	Total kWh	1,584,755,712		$ 98,687,492
10	Discounts - Billed kW			
11	Primary Service	432,045	$ (1.25)	$ (540,056)
12	Transmission Service	164,508	$ (1.55)	$ (254,987)
13	Total kW	596,553		$ (795,043)
14	Off-Peak Service (Rate 626)			$ 237,856,547
			Propopsed Revenue Target	$ 237,856,763
			Difference Due to Rounding	$ (216)
15	*Contract Riders*			
16	RA		Rider 674	$ -
17	EDR		Rider 677	$ -
18	DSMA		Rider 683	$ -
19	TDSIC		Rider 688	$ -
20	Total Rider			$ -
21	*Other Adjustments*			
22	Generation Credit			$ -
23	Difference in Fuel Calculation			$ -
24	Total Other Adjustments			$ -
25	Grand Total			$ 237,856,547

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Large Industrial Power Service
Rate 531

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	*Tier 1 Annual Billing Determinants (kW)*	2,040,000	$ 27.45	$ 55,998,000
3	Total	2,040,000		$ 55,998,000
4	*Billed kWh*			
5	Tier 1 Energy Billing Determinant (kWh)	1,040,522,916	$ 0.037151	$ 38,656,467
6	All kWh	1,040,522,916		$ 38,656,467
7	*Transmission Charge Billed kWh*			
8	Transmission Charge - Tier 1	1,040,522,916	$ 0.011493	$ 11,958,730
9	Transmission Charge - Tier 2	1,193,697,083	$ 0.011493	$ 13,719,161
10	Transmission Charge - Tier 3	1,972,499,406	$ 0.011493	$ 22,669,936
11	Adj. Facility Transmission Charge	1,229,701,253	$ 0.003448	$ 4,240,010
		5,436,420,657		$ 52,587,836
12	Discounts - Billed kW			
13	Lagging RKVA Discount	(821,616)	$ 0.32	$ (262,917)
14	Total Discount			$ (262,917)
15	Large Industrial Power Service (Rate 531)			$ 146,979,386
16	*Contract Riders*			
17	RA		Rider 574	$ (566,837)
18	EDR		Rider 577	$ -
19	DSMA		Rider 583	$ -
20	TDSIC		Rider 588	$ 2,611,056
21	Total Rider			$ 2,044,219
22	*Other Adjustments*			
23	Generation Credit			$ (426,461)
24	Difference in Fuel Calculation			$ (2,937,580)
25	Total Other Adjustments			$ (3,364,041)
26	Grand Total			$ 145,659,564

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Large Industrial Power Service
Rate 631

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	Tier 1 Annual Billing Determinants (kW)	1,968,000	$ 35.29	$ 69,459,367
3	Total	1,968,000		$ 69,459,367
4	*Billed kWh*			
5	Tier 1 Energy Billing Determinant (kWh)	1,003,798,578	$ 0.028803	$ 28,912,816
6	Total	1,003,798,578		$ 28,912,816
7	*Transmission Charge Billed kWh*			
8	Transmission Charge - Tier 1	1,003,798,578	$ 0.016012	$ 16,072,823
9	Transmission Charge - Tier 2	1,230,421,421	$ 0.016012	$ 19,701,508
10	Transmission Charge - Tier 3	1,972,499,406	$ 0.016012	$ 31,583,660
11	Adj. Facility Transmission Charge	1,229,701,253	$ 0.004804	$ 5,907,485
		5,436,420,657		$ 73,265,476
12	Discounts - Billed kW			
13	Lagging RKVA Discount	(821,616)	$ 0.32	$ (262,917)
14	Total Discount			$ (262,917)
15	Large Industrial Power Service (Rate 631)			$ 171,374,742
			Propopsed Revenue Target	$ 171,374,472
			Difference Due to Rounding	$ 270
16	*Contract Riders*			
17	RA		Rider 674	$ -
18	EDR		Rider 677	$ -
19	DSMA		Rider 683	$ -
20	TDSIC		Rider 688	$ -
21	Total Rider			$ -
22	*Other Adjustments*			
23	Generation Credit			$ -
24	Difference in Fuel Calculation			$ -
25	Total Other Adjustments			$ -
26	Grand Total			$ 171,374,742

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Small Industrial Power Service
Rate 532

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	*Billed kW*	425,399	$ 14.87	$ 6,325,676
3	Total	425,399		$ 6,325,676
4	*Billed kWh*			
5	First 450 hours x kW	157,576,677	$ 0.067079	$ 10,570,086
6	Next 50 hours x kW	2,491,884	$ 0.137571	$ 342,811
7	Over 500 hours x kW	267,737	$ 0.244220	$ 65,387
8	All kWh	160,336,298		$ 10,978,284
9	Discounts - Billed kW			
10	Lagging RKVA Discount	(33,672)	$ 0.32	$ (10,775)
11	Total Discount			$ (10,775)
12	Small Industrial Power Service (Rate 532)			$ 17,293,184
13	*Contract Riders*			
14	RA		Rider 574	$ (62,302)
15	EDR		Rider 577	$ (251,229)
16	DSMA		Rider 583	$ 187,243
17	TDSIC		Rider 588	$ 462,100
18	Total Rider			$ 335,812
19	*Other Adjustments*			
20	Generation Credit			$ (40,077)
21	Difference in Fuel Calculation			$ (452,658)
22	Total Other Adjustments			$ (492,734)
23	Grand Total			$ 17,136,262

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Small Industrial Power Service
Rate 632

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	*Billed kW*	425,399	$ 17.67	$ 7,516,791
3	Total	425,399		$ 7,516,791
4	*Billed kWh*			
5	First 450 hours x kW	157,576,677	$ 0.079678	$ 12,555,394
6	Next 50 hours x kW	2,491,884	$ 0.163451	$ 407,301
7	Over 500 hours x kW	267,737	$ 0.290163	$ 77,687
8	All kWh	160,336,298		$ 13,040,383
9	Discounts - Billed kW			
10	Lagging RKVA Discount	(33,672)	$ 0.32	$ (10,775)
11	Total Discount			$ (10,775)
12	Small Industrial Power Service (Rate 632)			$ 20,546,399
			Propopsed Revenue Target	$ 20,546,400
			Difference Due to Rounding	$ (1)
13	*Contract Riders*			
14	RA		Rider 674	$ -
15	EDR		Rider 677	$ -
16	DSMA		Rider 683	$ -
17	TDSIC		Rider 688	$ -
18	Total Rider			$ -
19	*Other Adjustments*			
20	Generation Credit			$ -
21	Difference in Fuel Calculation			$ -
22	Total Other Adjustments			$ -
23	Grand Total			$ 20,546,399

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Small Industrial Power Service - HLF
Rate 533

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	*Billed kW*	498,661	$ 22.92	$ 11,429,310
3	Total	498,661		$ 11,429,310
4	*Billed kWh*			
5	600 hours x kW	273,158,031	$ 0.057644	$ 15,745,922
6	Next 60 hours x kW	-	$ 0.053068	$ -
7	Over 660 hours x kW	-	$ 0.051612	$ -
8	All kWh	273,158,031		$ 15,745,922
9	Discounts - Billed kW			
10	Lagging RKVA Discount	396	$ 0.32	$ 127
11	Total Discount			$ 127
12	Small Industrial Power Service - HLF (Rate 533)			$ 27,175,358
13	*Contract Riders*			
14	RA		Rider 574	$ (77,580)
15	EDR		Rider 577	$ (411,453)
16	DSMA		Rider 583	$ 15,399
17	TDSIC		Rider 588	$ 747,626
18	Total Rider			$ 273,993
19	*Other Adjustments*			
20	Generation Credit			$ (64,712)
21	Difference in Fuel Calculation			$ (771,352)
22	Total Other Adjustments			$ (836,064)
23	Grand Total			$ 26,613,287

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Small Industrial Power Service - HLF
Rate 633

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	*Billed kW*	498,661	$ 26.26	$ 13,094,838
3	Total	498,661		$ 13,094,838
4	*Billed kWh*			
5	600 hours x kW	273,158,031	$ 0.066062	$ 18,045,366
6	Next 60 hours x kW	-	$ 0.060811	$ -
7	Over 660 hours x kW	-	$ 0.059142	$ -
8	All kWh	273,158,031		$ 18,045,366
9	Discounts - Billed kW			
10	Lagging RKVA Discount	396	$ 0.32	$ 127
11	Total Discount			$ 127
12	Small Industrial Power Service - HLF (Rate 633)			$ 31,140,330
			Propopsed Revenue Target	$ 31,140,296
			Difference Due to Rounding	$ 34
13	*Contract Riders*			
14	RA		Rider 674	$ -
15	EDR		Rider 677	$ -
16	DSMA		Rider 683	$ -
17	TDSIC		Rider 688	$ -
18	Total Rider			$ -
19	*Other Adjustments*			
20	Generation Credit			
21	Difference in Fuel Calculation			
22	Total Other Adjustments			$ -
23	Grand Total			$ 31,140,330

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Municipal Power
Rate 541

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Minimum Charge - Billed kW*			
2	Minimum Charge	280	$ 9.80	$ 2,744
3	Three Phase	840	$ 40.07	$ 33,650
4	Warning Signal	128	$ 9.80	$ 1,253
5	First 25 horsepower of the connected load	21,905	$ 3.10	$ 67,906
6	Next 475 horsepower of the connected loa	49,952	$ 1.51	$ 75,428
7	Over 500 horsepower of the connected loa	31,170	$ 0.75	$ 23,378
8	Total	104,275		$ 204,358
9	*Billed kWh*			
10	All kWh	37,775,395	$ 0.147336	$ 5,565,676
11	Total kWh	37,775,395		$ 5,565,676
12	DSM Proforma	657,356		
13	Total Adj kWh	38,432,751		
14	Municipal Power (Rate 541)			$ 5,770,033
15	*Contract Riders*			
16	RA		Rider 574	$ (23,174)
17	EDR		Rider 577	$ -
18	DSMA		Rider 583	$ 24,809
19	TDSIC		Rider 588	$ 255,555
20	Total Rider			$ 257,190
21	*Other Adjustments*			
22	Generation Credit			$ (12,259)
23	Difference in Fuel Calculation			$ (106,647)
24	Total Other Adjustments			$ (118,906)
25	Grand Total			$ 5,908,318

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Municipal Power
Rate 641

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Minimum Charge - Billed kW*			
2	Minimum Charge	280	$ 11.85	$ 3,318
3	Three Phase	840	$ 48.44	$ 40,679
4	Warning Signal	128	$ 11.85	$ 1,515
5	First 25 horsepower of the connected load	21,905	$ 3.75	$ 82,144
6	Next 475 horsepower of the connected loa	49,952	$ 1.83	$ 91,412
7	Over 500 horsepower of the connected loa	31,170	$ 0.91	$ 28,365
8	Total	104,275		$ 247,433
9	*Billed kWh*			
10	All kWh	38,432,751	$ 0.175068	$ 6,728,345
11	Total kWh	38,432,751		$ 6,728,345
12	Municipal Power (Rate 641)			$ 6,975,778
			Propopsed Revenue Target	$ 6,975,772
			Difference Due to Rounding	$ 6
13	*Contract Riders*			
14	RA		Rider 674	$ -
15	EDR		Rider 677	$ -
16	DSMA		Rider 683	$ -
17	TDSIC		Rider 688	$ -
18	Total Rider			$ -
19	*Other Adjustments*			
20	Generation Credit			$ -
21	Difference in Fuel Calculation			$ -
22	Total Other Adjustments			$ -
23	Grand Total			$ 6,975,778

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Intermittent Wastewater Pumping
Rate 542

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Customer Charge*			
2	Intermittent Wastewater Pumping	108	$ 60.00	$ 6,480
3	Total	108		$ 6,480
4	*Pump Charge*			
5	Residential	39,245	$ 1.19	$ 46,702
6	Commercial	2,417	$ 1.41	$ 3,408
7	Total	41,662		$ 50,109
8	Fuel	346,629	$ 0.033674	$ 11,672
9	Pump Charge Ratios			
10	Commercial / Residential		118.49%	
11	Intermittent Wastewater Pumping (Rate 542)			$ 68,261
12	*Contract Riders*			
13	RTO		Rider 571	$ 78
14	RA		Rider 574	$ (501)
15	EDR		Rider 577	$ -
16	DSMA		Rider 583	$ -
17	TDSIC		Rider 588	$ -
18	Total Rider			$ (423)
19	*Other Adjustments*			
20	Generation Credit			$ (391)
21	Difference in Fuel Calculation			$ (979)
22	Total Other Adjustments			$ (1,370)
23	Grand Total			$ 66,469

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Intermittent Wastewater Pumping
Rate 642

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Customer Charge*			
2	Intermittent Wastewater Pumping	108	$ 60.00	$ 6,480
3	Total	108		$ 6,480
4	*Pump Charge*			
5	Residential	39,245	$ 1.18	$ 46,309
6	Commercial	2,417	$ 1.40	$ 3,383
7	Total	41,662		$ 49,692
8	Fuel	346,629	$ 0.025635	$ 8,886
9	Pump Charge Ratios			
10	Commercial / Residential		118.64%	
11	Intermittent Wastewater Pumping (Rate 642)			$ 65,058
			Propopsed Revenue Target	$ 65,251
			Difference Due to Rounding	$ (193)
12	*Contract Riders*			
13	RTO		Rider 671	$ -
14	RA		Rider 674	$ -
15	EDR		Rider 677	$ -
16	DSMA		Rider 683	$ -
17	TDSIC		Rider 688	$ -
18	Total Rider			$ -
19	*Other Adjustments*			
20	Generation Credit			$ -
21	Difference in Fuel Calculation			$ -
22	Total Other Adjustments			$ -
23	Grand Total			$ 65,058

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Station Power For Renewable Wholesale Generation Equipment
Rate 543

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	All kW	154,501	$ 12.50	$ 1,931,265
3	Total kW	154,501		$ 1,931,265
4	DSM Proforma	71		
5	Total Adj kW	154,573		
6	*Minimum Charge - Billed kW*			
7	All kW	-	$ 12.50	$ -
8	Total kW	-		$ -
9	*Billed kWh*			
10	Total kWh	25,037,114	$ 0.059981	$ 1,501,751
11	Total kWh	25,037,114		$ 1,501,751
12	DSM Proforma	306,768		
13	Total Adj kWh	25,343,882		
14	Station Power For Renewable Wholesale Generation Equipment (Rate 543)			$ 3,433,016
15	*Contract Riders*			
16	RA		Rider 574	$ -
17	EDR		Rider 577	$ -
18	DSMA		Rider 583	$ 5,054
19	TDSIC		Rider 588	$ 135,249
20	Total Rider			$ 140,303
21	*Other Adjustments*			
22	Generation Credit			$ -
23	Difference in Fuel Calculation			$ (70,684)
24	Total Other Adjustments			$ (70,684)
25	Grand Total			$ 3,502,635

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Station Power For Renewable Wholesale Generation Equipment
Rate 643

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	All kW	154,573	$ 12.50	$ 1,932,157
3	Total kW	154,573		$ 1,932,157
4	*Minimum Charge - Billed kW*			
5	All kW	-	$ 12.50	$ -
6	Total kW	-		$ -
7	*Billed kWh*			
8	Total kWh	25,343,882	$ 0.055237	$ 1,399,920
9	Total kWh	25,343,882		$ 1,399,920
10	Station Power For Renewable Wholesale Generation Equipment (Rate 643)			$ 3,332,077
			Propopsed Revenue Target	$ 3,332,079
			Difference Due to Rounding	$ (2)
11	*Contract Riders*			
12	RA		Rider 674	$ -
13	EDR		Rider 677	$ -
14	DSMA		Rider 683	$ -
15	TDSIC		Rider 688	$ -
16	Total Rider			$ -
17	*Other Adjustments*			
18	Generation Credit			$ -
19	Difference in Fuel Calculation			$ -
20	Total Other Adjustments			$ -
21	Grand Total			$ 3,332,077

Cause No. 46120

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Railroad Power Service
Rate 544

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kW*			
2	All kW	34,462	$ 24.06	$ 829,162
3	Total kW	34,462		$ 829,162
4	*Billed kWh*			
5	First 660 hours x kW	11,343,950	$ 0.056199	$ 637,519
6	Over 660 hours x kW	-	$ 0.053040	$ -
7	Total kWh	11,343,950		$ 637,519
8	Per kWh Usage Charge Ratios			
9	Block 2 / Block 1		94.38%	
10	Adjustments - Billed kWh			
11	Load Factor Adjustment	-	$ 0.001434	$ -
12	Total kWh	-		$ -
13	Railroad Power Service (Rate 544)			$ 1,466,680
14	*Contract Riders*			
15	RA	Rider 574		$ (5,187)
16	EDR	Rider 577		$ -
17	DSMA	Rider 583		$ -
18	TDSIC	Rider 588		$ 195,360
19	Total Rider			$ 190,173
20	*Other Adjustments*			
21	Generation Credit			$ (6,466)
22	Difference in Fuel Calculation			$ (32,026)
23	Total Other Adjustments			$ (38,492)
24	Grand Total			$ 1,618,362

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Railroad Power Service
Rate 644

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kW*			
2	All kW	34,462	$ 31.90	$ 1,099,346
3	Total kW	34,462		$ 1,099,346
4	*Billed kWh*			
5	First 660 hours x kW	11,343,950	$ 0.074489	$ 844,999
6	Over 660 hours x kW	-	$ 0.070302	$ -
7	Total kWh	11,343,950		$ 844,999
8	Per kWh Usage Charge Ratios			
9	Block 2 / Block 1		94.38%	
10	Adjustments - Billed kWh			
11	Load Factor Adjustment	-	$ 0.001901	$ -
12	Total kWh	-		$ -
13	Railroad Power Service (Rate 644)			$ 1,944,345
			Propopsed Revenue Target	$ 1,944,347
			Difference Due to Rounding	$ (2)
14	*Contract Riders*			
15	RA		Rider 674	$ -
16	EDR		Rider 677	$ -
17	DSMA		Rider 683	$ -
18	TDSIC		Rider 688	$ -
19	Total Rider			$ -
20	*Other Adjustments*			
21	Generation Credit			$ -
22	Difference in Fuel Calculation			$ -
23	Total Other Adjustments			$ -
24	Grand Total			$ 1,944,345

Cause No. 46120

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Street Lighting
Rate 550

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Lamp Charges*			
2	Customer Owned & Maintained Street Lights			
3	Lamps	259,084	$ 5.04	$ 1,305,783
4	Customer Owned, Co Maintained Street Lts			
5	250 Watt HPS (Cust Own/Co Maint)	611	$ 7.13	$ 4,356
6	400 Watt HPS (Cust Own/Co Maint)	-	$ 8.22	$ -
7	Company Owned & Maintained Street Lights			
8	175 Watt Mercury Vapor	160	$ 17.05	$ 2,728
9	400 Watt Mercury Vapor	456	$ 19.47	$ 8,878
10	Up to 50 Watt LED Replacement	332,488	$ 8.98	$ 2,985,743
11	70 to 90 Watt LED Replacement	136,875	$ 9.45	$ 1,293,472
12	91 to 115 Watt LED Replacement	11,492	$ 10.05	$ 115,496
13	170 to 210 Watt LED Replacement	11,141	$ 12.34	$ 137,479
14	Up to 50 Watt LED New Install	4,543	$ 14.18	$ 64,413
15	70 to 90 Watt LED New Install	1,408	$ 14.69	$ 20,689
16	91 to 115 Watt LED New Install	1,911	$ 15.36	$ 29,356
17	170 to 210 Watt LED New Install	523	$ 17.82	$ 9,326
18	100 Watt High Pressure Sodium	11,729	$ 16.76	$ 196,570
19	150 Watt High Pressure Sodium	9,266	$ 17.75	$ 164,475
20	250 Watt High Pressure Sodium	1,261	$ 18.28	$ 23,051
21	400 Watt High Pressure Sodium	1,540	$ 20.19	$ 31,093
22	Total Lamps	784,488		$ 6,392,907

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Street Lighting
Rate 650

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	Lamp Charges			
2	Customer Owned & Maintained Street Lights			
3	Lamps	259,084	$ 6.64	$ 1,720,317
4	Customer Owned, Co Maintained Street Lts			
5	250 Watt HPS (Cust Own/Co Maint)	611	$ 9.40	$ 5,743
6	400 Watt HPS (Cust Own/Co Maint)	-	$ 10.83	$ -
7	Company Owned & Maintained Street Lights			
8	175 Watt Mercury Vapor	160	$ 22.47	$ 3,595
9	400 Watt Mercury Vapor	456	$ 25.66	$ 11,701
10	Up to 50 Watt LED Replacement	332,488	$ 11.83	$ 3,933,334
11	70 to 90 Watt LED Replacement	136,875	$ 12.45	$ 1,704,097
12	91 to 115 Watt LED Replacement	11,492	$ 13.24	$ 152,155
13	170 to 210 Watt LED Replacement	11,141	$ 16.26	$ 181,151
14	Up to 50 Watt LED New Install	4,543	$ 18.69	$ 84,899
15	70 to 90 Watt LED New Install	1,408	$ 19.36	$ 27,267
16	91 to 115 Watt LED New Install	1,911	$ 20.24	$ 38,683
17	170 to 210 Watt LED New Install	523	$ 23.48	$ 12,287
18	100 Watt High Pressure Sodium	11,729	$ 22.09	$ 259,083
19	150 Watt High Pressure Sodium	9,266	$ 23.39	$ 216,736
20	250 Watt High Pressure Sodium	1,261	$ 24.09	$ 30,377
21	400 Watt High Pressure Sodium	1,540	$ 26.61	$ 40,979
22	Total Lamps	784,488		$ 8,422,408

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Street Lighting
Rate 550

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
23	*Billed kWh*			
24	Cust Own, Cust Maint Street Lts	31,548,942	$ 0.034396	$ 1,085,157
25	Total kWh	31,548,942		$ 1,085,157
26	Street Lighting (Rate 550)			$ 7,478,065
27	*Contract Riders*			
28	RA		Rider 574	$ (32,143)
29	EDR		Rider 577	$ -
30	DSMA		Rider 583	$ -
31	TDSIC		Rider 588	$ 243,822
32	Total Rider			$ 211,678
33	*Other Adjustments*			
34	Generation Credit			$ (23,867)
35	Difference in Fuel Calculation			$ (89,068)
36	Total Other Adjustments			$ (112,936)
37	Grand Total			$ 7,576,807

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Street Lighting
Rate 650

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
23	*Billed kWh*			
24	Cust Own, Cust Maint Street Lts	31,548,942	$ 0.045406	$ 1,432,511
25	Total kWh	31,548,942		$ 1,432,511
26	Street Lighting (Rate 650)			$ 9,854,919
			Target	$ 9,854,928
			Difference	$ (10)
27	*Contract Riders*			
28	RA		Rider 674	$ -
29	EDR		Rider 677	$ -
30	DSMA		Rider 683	$ -
31	TDSIC		Rider 688	$ -
32	Total Rider			$ -
33	*Other Adjustments*			
34	Generation Credit			$ -
35	Difference in Fuel Calculation			$ -
36	Total Other Adjustments			$ -
37	Grand Total			$ 9,854,919

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Traffic and Directive Lighting
Rate 555

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Service Drop*			
2	Service Drop Charge	14,213	$ 18.33	$ 260,524
3	Total kW	14,213		$ 260,524
4	Adjustments			
5	*Billed kWh*			
6	All kWh	6,672,200	$ 0.133734	$ 892,300
7	Total kWh	6,672,200		$ 892,300
8	Adjustments			
9	Traffic and Directive Lighting (Rate 555)			$ 1,152,824
10	*Contract Riders*			
11	RA		Rider 574	$ (5,010)
12	EDR		Rider 577	$ -
13	DSMA		Rider 583	$ -
14	TDSIC		Rider 588	$ 31,760
15	Total Rider			$ 26,751
16	*Other Adjustments*			
17	Generation Credit			$ (2,979)
18	Difference in Fuel Calculation			$ (18,837)
19	Total Other Adjustments			$ (21,816)
20	Grand Total			$ 1,157,759

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Traffic and Directive Lighting
Rate 655

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Service Drop*			
2	Service Drop Charge	14,213	$ 21.73	$ 308,848
3	Total kW	14,213		$ 308,848
4	*Billed kWh*			
5	All kWh	6,672,200	$ 0.158574	$ 1,058,037
6	Total kWh	6,672,200		$ 1,058,037
			Target	$ 1,058,037
			Difference	$ -
7	Traffic and Directive Lighting (Rate 655)			$ 1,366,886
			Propopsed Revenue Target	$ 1,366,887
			Difference Due to Rounding	$ (1)
8	*Contract Riders*			
9	RA		Rider 674	$ -
10	EDR		Rider 677	$ -
11	DSMA		Rider 683	$ -
12	TDSIC		Rider 688	$ -
13	Total Rider			$ -
14	*Other Adjustments*			
15	Generation Credit			$ -
16	Difference in Fuel Calculation			$ -
17	Total Other Adjustments			$ -
18	Grand Total			$ 1,366,886

Cause No. 46120

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Dusk to Dawn Area Lighting
Rate 560

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Dusk to Dawn Area Lighting
Rate 660

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Lamps Charges*			
2	175 Watt Mercury Vapor	15,131	$ 15.84	$ 239,677
3	400 Watt Mercury Vapor	3,924	$ 19.42	$ 76,212
4	100 Watt HPS Dusk to Dawn	59,421	$ 15.39	$ 914,481
5	250 Watt HPS Dusk to Dawn	15,911	$ 17.61	$ 280,186
6	400 Watt HPS Dusk to Dawn	9,378	$ 19.46	$ 182,492
7	Up to 50 Watt LED	-	$ 19.21	$ -
8	51 to 130 Watt LED	-	$ 21.06	$ -
9	131 to 169 Watt LED	-	$ 22.48	$ -
10	150 Watt HPS Floodlight	5,584	$ 17.62	$ 98,390
11	250 Watt HPS Floodlight	10,420	$ 18.59	$ 193,700
12	400 Watt HPS Floodlight	20,195	$ 20.28	$ 409,549
13	Up to 90 Watt LED Floodlight	-	$ 30.14	$ -
14	91 to 130 Watt LED Floodlight	-	$ 30.76	$ -
15	131 to 169 Watt LED Floodlight	-	$ 32.12	$ -
16	30 ft. wood pole and span	19,324	$ 6.80	$ 131,405
17	35 ft. wood pole and span	10,222	$ 7.17	$ 73,294
18	40 ft. wood pole and span	1,743	$ 7.84	$ 13,666
19	Guy and anchor set	1,413	$ 1.52	$ 2,148
20	Extra span of Secondary Line	3,847	$ 2.19	$ 8,425
21	Total Lamps	176,512		$ 2,623,624

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Lamps Charges*			
2	*175 Watt Mercury Vapor*	15,131	$ 21.05	$ 318,510
3	*400 Watt Mercury Vapor*	3,924	$ 25.81	$ 101,289
4	*100 Watt HPS Dusk to Dawn*	59,421	$ 20.46	$ 1,215,743
5	*250 Watt HPS Dusk to Dawn*	15,911	$ 23.41	$ 372,467
6	*400 Watt HPS Dusk to Dawn*	9,378	$ 25.87	$ 242,604
7	*Up to 50 Watt LED*	-	$ 25.53	$ -
8	*51 to 130 Watt LED*	-	$ 27.99	$ -
9	*131 to 169 Watt LED*	-	$ 29.88	$ -
10	*150 Watt HPS Floodlight*	5,584	$ 23.42	$ 130,777
11	*250 Watt HPS Floodlight*	10,420	$ 24.71	$ 257,468
12	*400 Watt HPS Floodlight*	20,195	$ 26.96	$ 544,449
13	*Up to 90 Watt LED Floodlight*	-	$ 40.06	$ -
14	*91 to 130 Watt LED Floodlight*	-	$ 40.89	$ -
15	*131 to 169 Watt LED Floodlight*	-	$ 42.69	$ -
16	*30 ft. wood pole and span*	19,324	$ 9.04	$ 174,692
17	*35 ft. wood pole and span*	10,222	$ 9.53	$ 97,419
18	*40 ft. wood pole and span*	1,743	$ 10.42	$ 18,163
19	*Guy and anchor set*	1,413	$ 2.02	$ 2,854
20	*Extra span of Secondary Line*	3,847	$ 2.91	$ 11,195
21	Total Lamps	176,512		$ 3,487,630

Cause No. 46120

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Dusk to Dawn Area Lighting
Rate 560

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
22	*Billed kWh*			
23	All kWh	13,943,820	$ 0.034396	$ 479,612
24	Total kWh	13,943,820		$ 479,612
25	Dusk to Dawn Area Lighting (Rate 560)			$ 3,103,236
26	*Contract Riders*			
27	RA		Rider 574	$ (12,105)
28	EDR		Rider 577	$ -
29	DSMA		Rider 583	$ -
30	TDSIC		Rider 588	$ 122,821
31	Total Rider			$ 110,716
32	*Other Adjustments*			
33	Generation Credit			$ (6,054)
34	Difference in Fuel Calculation			$ (39,366)
35	Total Other Adjustments			$ (45,420)
36	Grand Total			$ 3,168,532

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Dusk to Dawn Area Lighting
Rate 660

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
22	*Billed kWh*			
23	All kWh	13,943,820	$ 0.045698	$ 637,205
24	Total kWh	13,943,820		$ 637,205
25	Dusk to Dawn Area Lighting (Rate 660)			$ 4,124,834
			Propopsed Revenue Target	$ 4,124,832
			Difference Due to Rounding	$ 2
26	*Contract Riders*			
27	RA		Rider 674	$ -
28	EDR		Rider 677	$ -
29	DSMA		Rider 683	$ -
30	TDSIC		Rider 688	$ -
31	Total Rider			$ -
32	*Other Adjustments*			
33	Generation Credit			$ -
34	Difference in Fuel Calculation			$ -
35	Total Other Adjustments			$ -
36	Grand Total			$ 4,124,834

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Interdepartmental
Interdepartmental

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
1	*Billed kWh*			
2	All kWh	27,721,784	$ 0.191006	$ 5,295,027
3	Total kWh	27,721,784		$ 5,295,027
4	Interdepartmental			$ 5,295,027
5	*Contract Riders*			
6	RA		Rider 574	$ -
7	EDR		Rider 577	$ -
8	DSMA		Rider 583	$ -
9	TDSIC		Rider 588	$ 464,091
10	Total Rider			$ 464,091
11	*Other Adjustments*			
12	Generation Credit			$ (9,759)
13	Difference in Fuel Calculation			$ (130,492)
14	Total Other Adjustments			$ (140,252)
15	Grand Total			$ 5,618,867

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Interdepartmental
Interdepartmental

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
1	*Billed kWh*			
2	All kWh	27,721,784	$ 0.240811	$ 6,675,711
3	Total kWh	27,721,784		$ 6,675,711
4	Interdepartmental			$ 6,675,711
			Target	$ 6,675,719
			Difference Due to Rounding	$ (8)
5	*Contract Riders*			
6	RA		Rider 674	$ -
7	EDR		Rider 677	$ -
8	DSMA		Rider 683	$ -
9	TDSIC		Rider 688	$ -
10	Total Rider			$ -
11	*Other Adjustments*			
12	Generation Credit			$ -
13	Difference in Fuel Calculation			$ -
14	Total Other Adjustments			$ -
15	Grand Total			$ 6,675,711

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2025
Back-Up, Maintenance and Temporary
Rate 532, 533 / Rider 576

Line No.	Description	Current Rate
	(A)	(B)
1	**Back-up Service - Rate 532, 533 / Rider 576**	
2	Demand Charge per Daily kW	Applicable Rate 531, 532, 533 charge, divided by number of days in month.
3	Energy - Fuel per kWh	Real-Time LMP
4	Energy - Non-Fuel per kWh	$ 0.003217
5	**Maintenance Service - Rate 532, 533 / Rider 576**	
6	Demand Charge per Daily kW	
7	-- January, May, December	$ 0.54
8	-- February, March, April, October, November	$ 0.31
9	Energy per kWh	Applicable Energy Charge for Rate 531
10	Transmission per kWh	N/A
11	**Temporary Service - Rate 532, 533**	
12	Demand Charge per Daily kW	
13	-- 1st 30 days	$ 0.68
14	-- 2nd 30 days	$ 1.02
15	-- 3rd 30 days	$ 1.37
16	-- In excess of 90 days	$ 2.74
17	Energy per kWh	Applicable Energy Charge for Rate 532 and 533
18	**Buy-Through Temporary Service - Rate 532, 533**	
19	Demand Charge per Daily kW	$ -
20	Energy - Fuel per kWh	Real-Time LMP
21	Energy - Non-Fuel per kWh	$ 0.003217

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2025
Back-Up, Maintenance and Temporary
Rate 632, 633 / Rider 676

Line No.	Description	Proposed Rate
	(F)	(G)
1	**Back-up Service - Rate 632, 633 / Rider 676**	
2	Demand Charge per Daily kW	Applicable Rate 631, 632, 633 charge, divided by number of days in month.
3	Energy - Fuel per kWh	Real-Time LMP
4	Energy - Non-Fuel per kWh	$ 0.002415
5	**Maintenance Service - Rate 632, 633 / Rider 676**	
6	Demand Charge per Daily kW	
7	-- January, May, December	$ 0.65
8	-- February, March, April, October, November	$ 0.37
9	Energy per kWh	Applicable Energy Charge for Rate 631
10	Transmission per kWh	N/A
11	**Temporary Service - Rate 632, 633**	
12	Demand Charge per Daily kW	
13	-- 1st 30 days	$ 0.82
14	-- 2nd 30 days	$ 1.23
15	-- 3rd 30 days	$ 1.65
16	-- In excess of 90 days	$ 3.29
17	Energy per kWh	Applicable Energy Charge for Rate 632 and 633
18	**Buy-Through Temporary Service - Rate 632, 633**	
19	Demand Charge per Daily kW	$ -
20	Energy - Fuel per kWh	Real-Time LMP
21	Energy - Non-Fuel per kWh	$ 0.002415

NORTHERN INDIANA PUBLIC SERVICE COMPANY
TYPICAL BILL COMPARISON
RATE 611

	Current Rates	Proposed Rates
Customer Charge	$ 14.00	$ 25.00
Energy Charge		
Energy Charge	$ 0.166243	$ 0.198605
Riders		
DSMA	$ 0.001238	n/a
TDSIC	$ 0.013298	n/a
RA	$ (0.000641)	n/a
Change in Fuel Cost	$ (0.003277)	n/a
Total Energy	$ 0.176860	$ 0.198605

		Monthly Total Bill		Increase / Decrease	
	Monthly kWh	Current Rates	Proposed Rates	Amount	Percent
Line No.	(A)	(B)	(C)	(D)	(E)
				(C) - (B)	(D) / (B)
1	75	$ 27.26	$ 39.90	$ 12.63	46.33%
2	200	$ 49.37	$ 64.72	$ 15.35	31.09%
3	400	$ 84.74	$ 104.44	$ 19.70	23.24%
4	500	$ 102.43	$ 124.30	$ 21.87	21.35%
5	600	$ 120.12	$ 144.16	$ 24.05	20.02%
6	700	$ 137.80	$ 164.02	$ 26.22	19.03%
7	800	$ 155.49	$ 183.88	$ 28.40	18.26%
8	900	$ 173.17	$ 203.74	$ 30.57	17.65%
9	1,000	$ 190.86	$ 223.61	$ 32.74	17.16%
10	2,500	$ 456.15	$ 521.51	$ 65.36	14.33%
11	5,000	$ 898.30	$ 1,018.03	$ 119.72	13.33%
Avg. Bill	714	$ 140.37	$ 166.90	$ 26.54	18.91%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
TYPICAL BILL COMPARISON
RATE 615

	Current Rates	Proposed Rates
Customer Charge	$ 14.00	$ 25.00
Energy Charge		
Energy Charge	$ 0.166243	$ 0.175825
Riders		
DSMA	$ 0.001238	n/a
TDSIC	$ 0.013298	n/a
RA	$ (0.000641)	n/a
Change in Fuel Cost	$ (0.003277)	n/a
Total Energy	$ 0.176860	$ 0.175825

		Monthly Total Bill		Increase / Decrease	
	Monthly kWh	Current Rate 511	Proposed Rate 615	Amount	Percent
Line No.	(A)	(B)	(C)	(D)	(E)
				(C) - (B)	(D) / (B)
1	75	$ 27.26	$ 38.19	$ 10.92	40.06%
2	200	$ 49.37	$ 60.17	$ 10.79	21.86%
3	400	$ 84.74	$ 95.33	$ 10.59	12.49%
4	500	$ 102.43	$ 112.91	$ 10.48	10.23%
5	600	$ 120.12	$ 130.50	$ 10.38	8.64%
6	700	$ 137.80	$ 148.08	$ 10.28	7.46%
7	800	$ 155.49	$ 165.66	$ 10.17	6.54%
8	900	$ 173.17	$ 183.24	$ 10.07	5.81%
9	1,000	$ 190.86	$ 200.83	$ 9.96	5.22%
10	2,500	$ 456.15	$ 464.56	$ 8.41	1.84%
11	5,000	$ 898.30	$ 904.13	$ 5.82	0.65%
Avg. Bill	444	$ 92.60	$ 103.14	$ 10.54	11.38%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
TYPICAL BILL COMPARISON
RATE 611 VS. RATE 615

	Rate 611	Rate 615
Customer Charge	$ 25.00	$ 25.00
Energy Charge		
Energy Charge	$ 0.198605	$ 0.175825
Riders		
DSMA	n/a	n/a
TDSIC	n/a	n/a
RA	n/a	n/a
Change in Fuel Cost	n/a	n/a
Total Energy	$ 0.198605	$ 0.175825

		Monthly Total Bill		Increase / Decrease	
	Monthly kWh	Rate 611	Rate 615	Amount	Percent
Line No.	(A)	(B)	(C)	(D)	(E)
				(C) - (B)	(D) / (B)
1	75	$ 39.90	$ 38.19	$ (1.71)	-4.28%
2	200	$ 64.72	$ 60.17	$ (4.56)	-7.04%
3	400	$ 104.44	$ 95.33	$ (9.11)	-8.72%
4	500	$ 124.30	$ 112.91	$ (11.39)	-9.16%
5	600	$ 144.16	$ 130.50	$ (13.67)	-9.48%
6	700	$ 164.02	$ 148.08	$ (15.95)	-9.72%
7	800	$ 183.88	$ 165.66	$ (18.22)	-9.91%
8	900	$ 203.74	$ 183.24	$ (20.50)	-10.06%
9	1,000	$ 223.61	$ 200.83	$ (22.78)	-10.19%
10	2,500	$ 521.51	$ 464.56	$ (56.95)	-10.92%
11	5,000	$ 1,018.03	$ 904.13	$ (113.90)	-11.19%
Avg. Bill	444	$ 113.26	$ 103.14	$ (10.12)	-8.94%

Cause No. 46120

Northern Indiana Public Service Company
Tracker Allocators
2024 Electric Rate Case
Demand Allocation

Line	Description	Rate Class	Demand Allocators - Total Revenue /1	Resulting % Allocation on Revenue
1	Residential	Rate 611	$ 742,405,883	34.67%
2	Residential Multi-Family	Rate 615	$ 85,917,158	4.01%
3	C&GS Heat Pump	Rate 620	$ 1,628,112	0.08%
4	GS Small	Rate 621	$ 391,689,555	18.29%
5	Comml SH	Rate 622	$ 1,256,026	0.06%
6	GS Medium	Rate 623	$ 193,502,181	9.04%
7	GS Large	Rate 624	$ 268,673,629	12.55%
8	Metal Melting	Rate 625	$ 11,112,353	0.52%
9	Off-Peak Serv.	Rate 626	$ 239,857,781	11.20%
10	Industrial Power Service - Large	Rate 631	$ 118,490,414	5.53%
11	Small Industrial Service - LLF	Rate 632	$ 20,720,673	0.97%
12	Small Industrial Service - HLF	Rate 633	$ 31,317,101	1.46%
13	Muni. Power	Rate 641	$ 7,010,690	0.33%
14	Int WW Pumping	Rate 642	$ 65,786	0.00%
15	Station Power - Renewable	Rate 643	$ 3,345,160	0.16%
16	Railroad	Rate 644	$ 1,960,247	0.09%
17	Street Lighting	Rate 650	$ 9,886,687	0.46%
18	Traffic Lighting	Rate 655	$ 1,374,311	0.06%
19	Dusk to Dawn Lighting	Rate 660	$ 4,149,505	0.19%
20		Interdepartmental	$ 6,703,628	0.31%
21	System Total		$ 2,141,066,882	100.00%

/1 Source: Attachment 19-G. Rate 631 revenue is Tier 1 only; Attachment 19-H.

Northern Indiana Public Service Company
Tracker Allocators
2024 Electric Rate Case
Energy Allocation

Line	Description	Rate Class	MWH at the Source /1	% Allocation on Sales
1	Residential	Rate 611	3,209,327	29.27%
2	Residential Multi-Family	Rate 615	374,333	3.41%
3	C&GS Heat Pump	Rate 620	9,386	0.09%
4	GS Small	Rate 621	1,669,599	15.23%
5	Comml SH	Rate 622	7,420	0.07%
6	GS Medium	Rate 623	894,257	8.16%
7	GS Large	Rate 624	1,468,130	13.39%
8	Metal Melting	Rate 625	89,188	0.81%
9	Off-Peak Serv.	Rate 626	1,617,540	14.75%
10	Industrial Power Service - Large	Rate 631 Tier 1	1,022,852	9.33%
11	Small Industrial Service - LLF	Rate 632	163,529	1.49%
12	Small Industrial Service - HLF	Rate 633	278,461	2.54%
13	Muni. Power	Rate 641	38,994	0.36%
14	Int WW Pumping	Rate 642	401	0.00%
15	Station Power - Renewable	Rate 643	25,514	0.23%
16	Railroad	Rate 644	11,581	0.11%
17	Street Lighting	Rate 650	32,589	0.30%
18	Traffic Lighting	Rate 655	6,892	0.06%
19	Dusk to Dawn Lighting	Rate 660	14,403	0.13%
20		Interdepartmental	28,635	0.26%
21	System Total		10,963,031	100%

22	Description	Rate Class	MWH at the Source /1	% Allocation on Sales
23	Residential	Rate 611	3,209,327	26.27%
24	Residential Multi-Family	Rate 615	374,333	3.06%
25	C&GS Heat Pump	Rate 620	9,386	0.08%
26	GS Small	Rate 621	1,669,599	13.67%
27	Comml SH	Rate 622	7,420	0.06%
28	GS Medium	Rate 623	894,257	7.32%
29	GS Large	Rate 624	1,468,130	12.02%
30	Metal Melting	Rate 625	89,188	0.73%
31	Off-Peak Serv.	Rate 626	1,617,540	13.24%
32	Industrial Power Service - Large	Rate 631 Tier 1	1,022,852	8.37%
33		Rate 631 Tier 2	1,253,777	10.26%
34	Small Industrial Service - LLF	Rate 632	163,529	1.34%
35	Small Industrial Service - HLF	Rate 633	278,461	2.28%
36	Muni. Power	Rate 641	38,994	0.32%
37	Int WW Pumping	Rate 642	401	0.00%
38	Station Power - Renewable	Rate 643	25,514	0.21%
39	Railroad	Rate 644	11,581	0.09%
40	Street Lighting	Rate 650	32,589	0.27%
41	Traffic Lighting	Rate 655	6,892	0.06%
42	Dusk to Dawn Lighting	Rate 660	14,403	0.12%
43		Interdepartmental	28,635	0.23%
44	System Total		12,216,807	100%

/1 Source: Attachment 19-F

Northern Indiana Public Service Company
Tracker Allocators
2024 Electric Rate Case
TDSIC Allocation

Transmission and Distribution
Revenue Requirement Allocation

*For purposes of recovering approved capital TDSIC expenditures and costs pursuant to I.C. 8-1-39-9(a), the following class allocation factor percentages shall be applied to the respective distribution- or transmission-related revenue requirement and then the resulting TDSIC charge factors (per kWh) applied to each customer's firm (or non-interruptible) load within that class:

Line	Description	Rate Class	Transmission Rev. Req. Allocation Factor %	Distribution Rev. Req. Allocation Factor %
1	Residential	Rate 611	36.80%	49.03%
2	Residential Multi-Family	Rate 615	2.85%	4.78%
3	C&GS Heat Pump	Rate 620	0.09%	0.18%
4	GS Small	Rate 621	17.03%	16.36%
5	Comml SH	Rate 622	0.06%	0.12%
6	GS Medium	Rate 623	9.18%	9.13%
7	GS Large	Rate 624	12.62%	9.91%
8	Metal Melting	Rate 625	0.61%	0.54%
9	Off-Peak Serv.	Rate 626	11.20%	8.43%
10	Industrial Power Service - Large	Rate 631	5.21%	0.00%
11	Small Industrial Service - LLF	Rate 632	1.26%	0.00%
12	Small Industrial Service - HLF	Rate 633	1.28%	0.00%
13	Muni. Power	Rate 641	0.21%	0.34%
14	Int WW Pumping	Rate 642	0.00%	0.00%
15	Station Power - Renewable	Rate 643	0.35%	0.00%
16	Railroad	Rate 644	0.89%	0.00%
17	Street Lighting	Rate 650	0.08%	0.52%
18	Traffic Lighting	Rate 655	0.04%	0.03%
19	Dusk to Dawn Lighting	Rate 660	0.02%	0.14%
		Interdepartmental	0.20%	0.50%
20	System Total		100.00%	100.00%

Northern Indiana Public Service Company
Tracker Allocators
2024 Electric Rate Case
TDSIC Allocation Support

TDISC Allocators

Line	Rate	Trans /1	Sub Trans /1	Total	831 Tier 1 Adj	Adj. Total	Transmission Rev. Req. Allocation Factor
1	Rate 611	$ 91,243,634	$ 10,028,037	$ 101,271,671		$ 101,271,671	36.80%
2	Rate 615	$ 6,893,159	$ 958,750	$ 7,851,909		$ 7,851,909	2.85%
3	Rate 620	$ 213,052	$ 36,013	$ 249,065		$ 249,065	0.09%
4	Rate 621	$ 43,584,530	$ 3,273,301	$ 46,857,831		$ 46,857,831	17.03%
5	Rate 622	$ 144,864	$ 23,504	$ 168,369		$ 168,369	0.06%
6	Rate 623	$ 23,449,833	$ 1,822,148	$ 25,271,981		$ 25,271,981	9.18%
7	Rate 624	$ 32,483,232	$ 2,243,569	$ 34,726,800		$ 34,726,800	12.62%
8	Rate 625	$ 1,515,967	$ 167,187	$ 1,683,154		$ 1,683,154	0.61%
9	Rate 626	$ 28,842,506	$ 1,984,764	$ 30,827,270		$ 30,827,270	11.20%
10	Rate 631	$ 76,649,442	$ 924,359	$ 77,573,801	$ (63,250,320)	$ 14,323,482	5.21%
11	Rate 632	$ 3,325,827	$ 151,545	$ 3,477,372		$ 3,477,372	1.26%
12	Rate 633	$ 3,442,029	$ 80,407	$ 3,522,437		$ 3,522,437	1.28%
13	Rate 641	$ 516,273	$ 67,786	$ 584,059		$ 584,059	0.21%
14	Rate 642	$ 5,654	$ 371	$ 6,025		$ 6,025	0.00%
15	Rate 643	$ 940,127	$ 18,752	$ 958,880		$ 958,880	0.35%
16	Rate 644	$ 198,627	$ 2,256,458	$ 2,455,085		$ 2,455,085	0.89%
17	Rate 650	$ 109,150	$ 100,560	$ 209,710		$ 209,710	0.08%
18	Rate 655	$ 105,563	$ 6,065	$ 111,629		$ 111,629	0.04%
19	Rate 660	$ 34,445	$ 27,874	$ 62,319		$ 62,319	0.02%
20	Interdepartmental	$ 434,223	$ 107,284	$ 541,507		$ 541,507	0.20%
21	Total	$ 314,132,139	$ 24,278,735	$ 338,410,873	$ (63,250,320)	$ 275,160,554	100.00%
22	Tier 1 Transmission Volumes			1,003,798,578	18.46%		
23	Total Transmission Volumes			5,436,420,657			

24	Rate	Dist Primary /1	Dist Secondary /1	Total	831 Tier 1 Adj	Adj. Total	Distribution Rev. Req. Allocation Factor
25	Rate 611	$ 159,829,808	$ 14,464,038	$ 174,293,846		$ 174,293,846	49.03%
26	Rate 615	$ 15,280,835	$ 1,703,018	$ 16,983,853		$ 16,983,853	4.78%
27	Rate 620	$ 573,981	$ 55,324	$ 629,305		$ 629,305	0.18%
28	Rate 621	$ 51,386,361	$ 6,753,254	$ 58,139,615		$ 58,139,615	16.36%
29	Rate 622	$ 374,620	$ 38,544	$ 413,164		$ 413,164	0.12%
30	Rate 623	$ 28,923,696	$ 3,520,963	$ 32,444,659		$ 32,444,659	9.13%
31	Rate 624	$ 32,964,523	$ 2,260,471	$ 35,224,994		$ 35,224,994	9.91%
32	Rate 625	$ 1,840,308	$ 92,636	$ 1,932,944		$ 1,932,944	0.54%
33	Rate 626	$ 28,335,317	$ 1,614,889	$ 29,950,207		$ 29,950,207	8.43%
34	Rate 631	$ -	$ -	$ -		$ -	0.00%
35	Rate 632	$ -	$ -	$ -		$ -	0.00%
36	Rate 633	$ (0)	$ -	$ (0)		$ (0)	0.00%
37	Rate 641	$ 1,080,389	$ 124,505	$ 1,204,893		$ 1,204,893	0.34%
38	Rate 642	$ 5,909	$ 886	$ 6,795		$ 6,795	0.00%
39	Rate 643	$ -	$ -	$ -		$ -	0.00%
40	Rate 644	$ -	$ -	$ -		$ -	0.00%
41	Rate 650	$ 1,602,753	$ 241,953	$ 1,844,705		$ 1,844,705	0.52%
42	Rate 655	$ 96,673	$ 16,550	$ 113,223		$ 113,223	0.03%
43	Rate 660	$ 444,258	$ 69,160	$ 513,418		$ 513,418	0.14%
44	Interdepartmental	$ 1,709,923	$ 72,268	$ 1,782,191		$ 1,782,191	0.50%
45	Total	$ 324,449,352	$ 31,028,460	$ 355,477,813	$ -	$ 355,477,813	100.00%

/1 Source: Attachment 19-B