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 in Delaware, Florida, Indiana, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, Oregon, Pennsylvania, 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 19-A.

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

A5. Yes. I testified on behalf of NIPSCO in a previous electric rate case, Cause No. 43969, and submitted testimony on behalf of Indianapolis Power & Light in Cause No. 44576.

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 19-B.

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 the class revenue mitigation objectives discussed by NIPSCO Witness Whitehead.

Finally, I discuss NIPSCO's rate design proposals.

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

A8. Yes. I am sponsoring Attachments 19-A through 19-H, all of which were prepared by me or under my supervision and direction.

Q9. Please describe the attachments.

A9. As stated earlier, Attachment 19-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 19-B Summary of Class Cost Allocation and Unit Costs;
Attachment 19-C Asset Functionalization and Classification;
Attachment 19-D External Allocation Factors - Special Studies;
Attachment 19-E Rate Mitigation;
Attachment 19-F Rate Design Schedules;
Attachment 19-G Residential Bill Impacts; and
Attachment 19-H 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. Principles of ACOSS Preparation

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, 2023. 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 543 – Station Power – Renewable. NIPSCO identified a group of customers on Rate 824 that exhibit a different character of service due to the nature of their operations as renewable power stations. These customers were migrated out of Rate 824 – General Service – Large and into the new Rate 543 – Station Power – Renewable.

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 Shikany, the Company's the forecasted revenue requirement for the 12-month period ending December 31, 2023, is $1.820 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 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 $1.798 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 844). Attachment 19-C 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 19-C.

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 19-C.

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 19-D or developed internally in the ACOSS model based on the allocations applied therein.

D. Allocation of Demand-Related Costs

Q36. How have the 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" refers to the demand of a class at the time when the overall system demand is at a peak. "Non-coincident Peak" refers to the highest level of demand that an individual class experienced 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 test 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 test 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 19-D.

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 (2010-2021) were reviewed, and FERC's cost allocation tests for using a 12CP allocator were evaluated. As shown in Table 1 below, 2021 and 2020 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 (2010-2021)

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

A38. 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.

E. Allocation of Customer-Related Costs

Q39. How have the customer-related costs been allocated in the ACOSS?

A39. 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 Attachment 19-D. The general methods used to develop the customer-related allocation factors are discussed below.

Meters: 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.

Service Lines: 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.

Transformers: 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.

F. Allocation of Energy-Related Costs

Q40. How are the energy-related costs allocated in the ACOSS?

A40. 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 Attachment 19-D.

G. Internal Allocations

Q41. How are overhead costs functionalized?

A41. Intangible Plant is allocated based on 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.

H. <u>Allocation of Depreciation Reserve and Expenses</u>

Q42. Please describe the method used to allocate the reserve for depreciation and depreciation expenses.

A42. These items were allocated by account in the same manner as their associated plant accounts.

I. <u>Allocation of O&M Expenses</u>

Q43. How did the ACOSS allocate distribution-related O&M expenses?

A43. 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.

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

Q44. How did the ACOSS allocate Customer Accounting Expenses (FERC Account No. 901 – No. 904)?

A44. 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.

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

Q45. How did the ACOSS allocate Customer Information, Demonstrating, and Selling Expenses (FERC Account Nos. 910 and 912)?

A45. 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 No. 912 was allocated to the rate classes based on customer counts.

L. <u>Allocation of Taxes other than Income Taxes</u>

Q46. How did the ACOSS allocate taxes other than income taxes?

A46. 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, and Property and Public Utility Fee-related taxes were allocated based on total plant.

Q47. How were income taxes allocated to each customer class?

A47. 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

Q48. Have you prepared a summary of NIPSCO's ACOSS results?

A48. Yes. Attachment 19-B presents the summary results of the ACOSS at present rates under the Company's current 800 Series rate classes. 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 811	-0.74%	$ 558,660,009	$ 816,234,331	$ 257,574,322	46.1%
Rate 820	3.25%	$ 947,378	$ 1,118,913	$ 171,535	18.1%
Rate 821	8.94%	$ 263,825,207	$ 257,344,648	$ (6,480,559)	-2.5%
Rate 822	7.92%	$ 954,235	$ 962,239	$ 8,004	0.8%
Rate 823	7.29%	$ 142,567,057	$ 146,856,060	$ 4,289,003	3.0%
Rate 824	7.00%	$ 186,411,680	$ 193,563,700	$ 7,152,019	3.8%
Rate 825	9.18%	$ 8,143,333	$ 7,927,493	$ (215,839)	-2.7%
Rate 826	7.16%	$ 162,182,272	$ 167,063,803	$ 4,881,531	3.0%
Rate 831	5.29%	$ 143,751,315	$ 160,550,075	$ 16,798,760	11.7%
Rate 832	6.45%	$ 14,889,682	$ 15,580,086	$ 690,404	4.6%
Rate 833	5.70%	$ 22,545,784	$ 24,063,569	$ 1,517,785	6.7%
Rate 841	10.27%	$ 4,447,950	$ 4,174,564	$ (273,386)	-6.1%
Rate 842	83.75%	$ 110,666	$ 37,710	$ (72,956)	-65.9%
Rate 543	49.26%	$ 2,448,139	$ 831,693	$ (1,616,447)	-66.0%
Rate 844	3.59%	$ 1,928,481	$ 2,306,323	$ 377,842	19.6%
Rate 850	0.46%	$ 6,698,995	$ 10,253,477	$ 3,554,482	53.1%
Rate 855	13.63%	$ 1,089,334	$ 946,284	$ (143,050)	-13.1%
Rate 860	-3.26%	$ 2,660,168	$ 3,960,282	$ 1,300,113	48.9%
Interdepartmental	-1.54%	$ 4,077,991	$ 6,344,618	$ 2,266,627	55.6%
System Total	**3.43%**	**$ 1,528,339,678**	**$ 1,820,119,869**	**$ 291,780,191**	**19.1%**

Q49. Please describe the results of your ACOSS with respect to classified costs.

A49. 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. <u>Attachment 19-B</u> summarizes the functionalized and classified costs by rate class at equalized rates of return and shows the costs on a unit rate basis. Revenue Allocation and Rate Design Principles

B. <u>Cost Guidelines for Use in Evaluating Class Revenue Levels and Rate Structures</u>

Q50. How can the ACOSS results provide guidelines for rate design?

A50. 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.

Q51. Do the ACOSS results guide in establishing rates within each rate class as well?

A51. 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 19-B summarizes the Company's functionalized revenue requirement per unit of billed demand, annual energy consumption, and customer count for each rate class.

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

Q52. Should other factors be considered that would prevent the Company from simply translating the unit costs into rates for the various tariff services?

A52. 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.

Q53. Please describe other considerations or criteria that should be used in the design of utility rates.

A53. 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 distribution service.

Q54. How are the foregoing guidelines and criteria incorporated into the rate design process?

A54. 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>

Q55. Please describe the approach followed to apportion the current revenue responsibility to the Company's various rate classes.

A55. 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.

Q56. How were the proposed revenue responsibilities for the various rate classes derived?

A56. It was first determined to 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. Second, it was determined that no class should have proposed revenues greater than 1.5 times their cost of service.

Next the Rate 811- Residential increase was set equal to the overall system increase. Fourth, based on settlement agreement discussed by NIPSCO Witness Whitehead, Rate 831's revenues were set equal to its cost of service if the customers in that class were subscribing to a total of 180 MW of demand for Tier 1. (As explained by NIPSCO Witness Whitehead, rates for the Rate 831 class are being designed to recover the costs at 180 MW of Tier 1 among actual Tier 1 commitments of a lower 170 MW of Tier 1 demand). After increasing Rate 811 and Rate 831 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. The remaining increase required was then allocated to all classes based on current revenue for each class, expect Rate 811, Rate 831, those already at 1.5 times the overall system increase, and those set at 1.5 times their cost of services. Attachment 19-E shows each of the steps in the process of calculating the proposed revenue responsibility of each rate class.

B. Resulting Revenues at Proposed Rates by Customer Class

Q57. How does NIPSCO propose to distribute the revenue increase among the rate classes?

A57. 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 811	2.55%	$ 558,660,009	$ 665,315,569	$ 106,655,560	19.1%
Rate 820	9.59%	$ 947,378	$ 1,218,679	$ 271,300	28.6%
Rate 821	12.56%	$ 263,825,207	$ 311,673,363	$ 47,848,156	18.1%
Rate 822	12.12%	$ 954,235	$ 1,135,302	$ 181,067	19.0%
Rate 823	11.81%	$ 142,567,057	$ 172,712,463	$ 30,145,406	21.1%
Rate 824	11.95%	$ 186,411,680	$ 227,371,899	$ 40,960,219	22.0%
Rate 825	13.87%	$ 8,143,333	$ 9,620,233	$ 1,476,900	18.1%
Rate 826	12.47%	$ 162,182,272	$ 196,477,681	$ 34,295,410	21.1%
Rate 831	7.10%	$ 143,751,315	$ 160,550,075	$ 16,798,760	11.7%
Rate 832	12.97%	$ 14,889,682	$ 18,280,525	$ 3,390,843	22.8%
Rate 833	13.05%	$ 22,545,784	$ 28,152,543	$ 5,606,758	24.9%
Rate 841	14.26%	$ 4,447,950	$ 5,254,644	$ 806,694	18.1%
Rate 842	24.05%	$ 110,666	$ 56,566	$ (54,101)	-48.9%
Rate 543	16.27%	$ 2,448,139	$ 1,247,539	$ (1,200,600)	-49.0%
Rate 844	8.94%	$ 1,928,481	$ 2,480,740	$ 552,259	28.6%
Rate 850	4.01%	$ 6,698,995	$ 8,617,384	$ 1,918,390	28.6%
Rate 855	18.36%	$ 1,089,334	$ 1,286,900	$ 197,565	18.1%
Rate 860	2.98%	$ 2,660,168	$ 3,421,960	$ 761,792	28.6%
Interdepartmental	3.01%	$ 4,077,991	$ 5,245,804	$ 1,167,813	28.6%
System Total	**7.10%**	**$ 1,528,339,678**	**$ 1,820,119,869**	**$ 291,780,191**	**19.1%**

Q58. Will a portion of the Proposed Mitigated Revenue shown in Column L of <u>Attachment 19-E</u> be collected through Other Revenue?

A58. 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 <u>Attachment 19-E</u>.

Q59. What is the increase to each rate class with the inclusion of the proposed Variable Cost Tracker?

A59. NIPSCO is proposing a new Rider 594 – Adjustment of Charges for Variable Costs of Coal-Fired Generation (the "Variable Cost Tracker") in this proceeding. NIPSCO Witness Whitehead has described the new adjustment mechanism to reflect changes in variable costs of coal-fired generation. The Variable Cost Tracker is proposed to be recovered from each rate class based on each rate classes energy consumption adjusted for line losses. This is the same method that these variable costs would be allocated if included in the ACOSS study and recovered in base rates. Table below includes the allocation of the proposed Variable Cost Tracker to each rate class and the resulting total revenue increase.

Table 4 - Proposed Revenue Increase with Variable Cost Tracker by Rate Class

Rate	Current Revenue	Proposed Revenue Increase	Variable Cost Tracker	Proposed Total Revenues	Proposed Total Revenue Increase	Proposed Total Percentage Increase
Rate 811	$ 558,660,009	$ 665,315,569	$ 32,158,969	$ 697,474,537	$ 138,814,529	24.8%
Rate 820	$ 947,378	$ 1,218,679	$ 88,019	$ 1,306,697	$ 359,319	37.9%
Rate 821	$ 263,825,207	$ 311,673,363	$ 14,825,220	$ 326,498,583	$ 62,673,376	23.8%
Rate 822	$ 954,235	$ 1,135,302	$ 76,086	$ 1,211,388	$ 257,153	26.9%
Rate 823	$ 142,567,057	$ 172,712,463	$ 9,314,052	$ 182,026,515	$ 39,459,458	27.7%
Rate 824	$ 186,411,680	$ 227,371,899	$ 13,694,404	$ 241,066,303	$ 54,654,623	29.3%
Rate 825	$ 8,143,333	$ 9,620,233	$ 788,461	$ 10,408,694	$ 2,265,361	27.8%
Rate 826	$ 162,182,272	$ 196,477,681	$ 14,207,439	$ 210,685,120	$ 48,502,849	29.9%
Rate 831	$ 143,751,315	$ 160,550,075	$ 11,259,565	$ 171,809,640	$ 28,058,326	19.5%
Rate 832	$ 14,889,682	$ 18,280,525	$ 1,514,815	$ 19,795,340	$ 4,905,658	32.9%
Rate 833	$ 22,545,784	$ 28,152,543	$ 2,463,459	$ 30,616,002	$ 8,070,218	35.8%
Rate 841	$ 4,447,950	$ 5,254,644	$ 307,309	$ 5,561,953	$ 1,114,003	25.0%
Rate 842	$ 110,666	$ 56,566	$ 3,142	$ 59,708	$ (50,958)	-46.0%
Rate 543	$ 2,448,139	$ 1,247,539	$ 36,687	$ 1,284,226	$ (1,163,913)	-47.5%
Rate 844	$ 1,928,481	$ 2,480,740	$ 176,037	$ 2,656,777	$ 728,296	37.8%
Rate 850	$ 6,698,995	$ 8,617,384	$ 314,292	$ 8,931,676	$ 2,232,681	33.3%
Rate 855	$ 1,089,334	$ 1,286,900	$ 67,144	$ 1,354,044	$ 264,709	24.3%
Rate 860	$ 2,660,168	$ 3,421,960	$ 133,360	$ 3,555,320	$ 895,152	33.7%
Interdepartmental	$ 4,077,991	$ 5,245,804	$ 247,511	$ 5,493,315	$ 1,415,325	34.7%
System Total	**$ 1,528,339,678**	**$ 1,820,119,869**	**$ 101,675,971**	**$ 1,921,795,839**	**$ 393,456,162**	**25.7%**

VIII. NIPSCO's Proposed Rate Design

A. Description of NIPSCO's Proposed Rate Design

Q60. How were the proposed rates for each rate schedule calculated?

A60. Detailed calculations for each rate component of each Rate Schedule are included in Attachment 19-F. As the exhibit shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 19-F provides a presentation of the transition of revenues at current rates and existing 800 series rate classes to the proposed revenues at the 500 series rate classes.

Q61. Do the proposed rates include increases to the existing monthly customer charges?

A61. Yes. The proposed rates would increase the Residential monthly customer charge from its current level of $13.50 to the proposed level of $17.00. Similarly, the General Service customer charges are being increased to $34.50 per month from their current level of $30.00. Both of these changes are being made in order to more closely reflect the costs of serving each customer, as indicated by the ACOSS.

Q62. What process did you use in designing the rates?

A62. Using the revenue apportioned to each rate class as described above, I generally followed the following process: First, for Rates 811, 821, 822, and 823, 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 generally 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 existing differences between the blocks on a percentage basis.

Q63. Did you make any changes to the current rate classes?

A63. Yes. As discussed in the testimony of NIPSCO Witnesses Whitehead NIPSCO reached a settlement agreement with the industrial customers taking service on Rate 831 which resulted in a Tier 1 contract demand level of 170 MW across the class rather than the current Tier 1 contract demand level of 176 MW. The updated billing determinants reflecting this new contract demand level are utilized in the rate design for Rate 831. However, as agreed to in the settlement agreement the allocation of demand related production plant in the ACOSS reflects a contract demand level of 180 MW.

Q64. What process was employed to develop rates for the lighting rate classes?

A64. For Rate 560 – Dusk to Dawn lighting I increased each lamp charge and energy charge by an equal percentage as the overall class increase to base rates. Similarly, for Rate 555 – Traffic and Directive Lighting, I increased the service drop charge and energy charge by an equal percentage as the overall class increase to base rates. Rate 550 – Streetlighting contained rates that were set based on the timing of the replacement; reflecting that a portion of the costs associated with these lights initially will be recovered through the TDSIC tracker. However, as the planned replacement lights will be completed prior to the new effective rates resulting from this proceeding and all costs are rolled into the cost of service, it is no longer necessary to reflect this in the rate structure. As such, I consolidated the LED lighting lamp charges to no longer reflect the timing of the replacements and provide one set of LED lighting lamp charges for newly installed LEDs and replacement LEDs. Once this consolidation was completed the lamp charges and energy charges were both increased at an equal percentage as the overall class increase to base rates. A differential was maintained between the newly installed LED lights and replacement LED lights based on the differential established in NIPSCO's last rate case proceeding, reflecting the additional capital requirements of newly installed LED lamps. The calculations supporting the new rates and lamp charges are provided in Attachment 19-F.

Q65. Do the proposed monthly customer charge levels reflect the Company's intention to move to a greater recovery of fixed distribution costs in fixed charges?

A65. Yes. The Company has proposed monthly customer charges at levels that in reflect movement toward their full customer related cost responsibility. The Company utilized the Unit Cost Analysis from the ACOSS (<u>Attachment 19-B</u>) to identify costs related to providing both monthly distribution service to customers (customer related costs) and annual levels of distribution capacity (demand related costs). The level of customer related costs is shown for the Residential class of customers in the Unit Cost Analysis to be $25.55 per customer per month and the combined customer and demand related costs to be $135.82 per customer per month (see <u>Attachment 19-B</u>).

Q66. Why are setting customer charges more in alignment with the fixed cost of service an important outcome of ratemaking?

A66. 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 and convey more appropriate price signals with respect to recovery of fixed distribution costs.

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 customer 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 should easily understand a full customer cost based charge. A full customer cost based charge is easily explained since the rate is based on customer costs. 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.

Q67. Has the IURC offered guidance on moving customer charges closer to a point where they recover 100% of fixed costs of service?

A67. 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 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.[1]

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 811 customer charge makes this movement.

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

Q68. Is the IURC guidance presented in Cause No. 43180 applicable to electric utilities?

A68. 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.[2]

Q69. Does your proposed rate design move fully to SFV pricing for distribution related costs?

A69. No. The proposed rate design makes some movement towards SFV pricing but does not fully move to SFV pricing.

B. <u>Bill Impacts for the Residential Class</u>

Q70. Do you have an attachment that shows how the proposed rates will affect various residential customers?

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

A70. Yes. The typical bill impacts for residential customers are shown on Attachment 19-G, which contains two bill impact analyses, (1) with the base rate increase and the inclusion of the Variable Cost Tracker, and (2) the base rate increase without the Variable Cost Tracker.

C. Updated Tracker Allocations

Q71. Is NIPSCO proposing updates to the tracker allocators in this preceding?

A71. Yes. NIPSCO is proposing to update the tracker allocations based on proposed rate class level revenue allocations, ACOSS results, and energy allocations. Attachment 19-H 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 831 allocation was adjusted to reduce the ACOSS revenue down to the revenue associated with Tier 1. The energy allocators are based on the sales allocator from the ACOSS. The Rate 831 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 831 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. No adjustments were made for Rate 831.

Q72. Does this conclude your prepared direct testimony?

A72. Yes.

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

Dated: September 19, 2022

ATRIUM ECONOMICS
CENTERED ON ENERGY

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

18

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

Canada

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

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 mechanism for a gas utility 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.

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2	**Rate Base**								
3	Plant in Service	$ 8,636,903,069	$ 4,136,494,211	$ 5,199,343	$ 1,221,454,151	$ 4,481,482	$ 654,896,127	$ 832,485,380	$ 29,987,501
4	Accumulated Reserve	(4,315,086,614)	(2,093,440,143)	(1,997,870)	(601,849,232)	(1,724,416)	(329,051,121)	(422,334,977)	(13,892,636)
5	Other Rate Base Items	1,623,865,434	755,607,110	177,775	220,552,288	153,393	137,184,335	177,447,173	5,010,762
6	**Total Rate Base**	**$ 5,945,681,889**	**$ 2,798,661,178**	**$ 3,379,248**	**$ 840,157,207**	**$ 2,910,460**	**$ 463,029,341**	**$ 587,597,576**	**$ 21,105,626**
7	**Revenue at Current Rates**								
8	Retail Sales - Non Fuel	$ 1,039,935,261	$ 393,406,443	$ 511,408	$ 191,464,654	$ 569,972	$ 96,355,294	$ 120,480,221	$ 4,592,967
9	TDSIC Revenue	$ 62,108,337	$ 28,870,347	$ 96,964	$ 10,521,475	$ 97,764	$ 6,605,675	$ 7,464,987	$ 314,362
10	DSM Revenue	$ 11,624,641	$ 3,093,339	$ (14,234)	$ 1,427,600	$ (17,847)	$ 1,935,571	$ 3,299,564	$ 101,055
11	Generation Credit	$ (82,861)	$ (28,330)	$ (51)	$ (14,185)	$ (68)	$ (9,289)	$ (11,652)	$ (409)
12	Retail Sales - Fuel	$ 392,509,634	$ 124,604,472	$ 341,040	$ 57,442,413	$ 294,805	$ 36,088,611	$ 53,014,950	$ 3,055,004
13	Other Revenues	22,244,665	8,713,738	12,251	2,983,250	9,609	1,591,195	2,163,610	80,354
14	**Total Revenue**	**$ 1,528,339,678**	**$ 558,660,009**	**$ 947,378**	**$ 263,825,207**	**$ 954,235**	**$ 142,567,057**	**$ 186,411,680**	**$ 8,143,333**
15	**Expenses at Current Rates**								
16	Operations & Maintenance Expenses	$ 432,440,828	$ 219,296,447	$ 316,751	$ 61,077,641	$ 268,348	$ 32,588,705	$ 40,721,073	$ 1,471,624
17	Depreciation Expense	314,465,223	149,682,526	120,852	43,684,288	105,446	25,157,044	32,112,191	1,015,283
18	Amortization Expense	143,750,842	68,993,149	32,389	19,321,389	28,725	11,343,142	14,840,162	486,519
19	Fuel Expenses	392,509,634	124,604,472	341,040	57,442,413	294,805	36,088,611	53,014,950	3,055,004
20	Taxes Other Than Income	35,531,910	17,334,157	23,302	5,019,492	19,815	2,682,725	3,393,685	121,792
21	Income Taxes	5,875,891	(595,623)	3,168	2,166,028	6,645	972,774	1,186,428	55,864
22	**Total Expenses at Current Rates**	**$ 1,324,574,328**	**$ 579,315,129**	**$ 837,503**	**$ 188,711,250**	**$ 723,785**	**$ 108,833,002**	**$ 145,268,489**	**$ 6,206,086**
23	Current Operating Income	203,765,349	(20,655,120)	109,875	75,113,957	230,451	33,734,055	41,143,192	1,937,246
24	Current Rate of Return	3.43%	-0.74%	3.25%	8.94%	7.92%	7.29%	7.00%	9.18%
25	Revenue to Cost Ratio (Line 12 / Line 46)	0.84	0.68	0.85	1.03	0.99	0.97	0.96	1.03
26	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	0.82	1.01	1.22	1.18	1.16	1.15	1.22
27	**Current Revenue at Equal Rates of Return**								
28	Current Rate of Return	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
29	Current Operating Income at Equal ROR	$ 203,765,349	$ 95,913,334	$ 115,811	$ 28,793,153	$ 99,745	$ 15,868,547	$ 20,137,644	$ 723,314
30	Other Expenses - Equal ROR	1,318,698,437	579,910,752	834,335	186,545,222	717,139	107,860,228	144,082,061	6,150,223
31	Income Taxes - Equal ROR	5,875,891	2,765,810	3,340	830,295	2,876	457,594	580,700	20,858
32	**Total Revenue Requirement at Equal Current ROR**	**$ 1,528,339,678**	**$ 678,589,896**	**$ 953,485**	**$ 216,168,670**	**$ 819,760**	**$ 124,186,370**	**$ 164,800,405**	**$ 6,894,395**
33	Current Subsidy	-	(119,929,887)	(6,107)	47,656,536	134,475	18,380,687	21,611,275	1,248,938

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
1	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
2	**Rate Base**							
3	Plant in Service	$ 8,636,903,069	$ 642,684,094	$ 797,920,744	$ 53,833,359	$ 80,508,483	$ 18,417,345	$ 132,737
4	Accumulated Reserve	(4,315,086,614)	(328,949,687)	(362,317,453)	(29,927,392)	(43,886,092)	(8,849,776)	(67,076)
5	Other Rate Base Items	1,623,865,434	148,499,732	128,557,763	14,889,204	21,406,508	3,164,349	28,179
6	**Total Rate Base**	**$ 5,945,681,889**	**$ 462,234,139**	**$ 564,161,054**	**$ 38,795,171**	**$ 58,028,898**	**$ 12,731,918**	**$ 93,841**
7	**Revenue at Current Rates**							
8	Retail Sales - Non Fuel	$ 1,039,935,261	$ 99,854,682	$ 94,841,338	$ 8,113,309	$ 12,138,197	$ 3,040,637	$ 96,638
9	TDSIC Revenue	$ 62,108,337	$ 4,362,830	$ 2,205,490	$ 271,887	$ 581,721	$ 183,472	$ 1,152
10	DSM Revenue	$ 11,624,641	$ 1,254,056	$ -	$ 477,046	$ 20,933	$ (1,445)	$ -
11	Generation Credit	$ (82,861)	$ (6,795)	$ (8,503)	$ (719)	$ (1,620)	$ (196)	$ (6)
12	Retail Sales - Fuel	$ 392,509,634	$ 55,048,731	$ 42,281,630	$ 5,869,365	$ 9,545,022	$ 1,190,712	$ 12,176
13	Other Revenues	22,244,665	1,668,767	4,431,359	158,794	261,532	34,771	707
14	**Total Revenue**	**$ 1,528,339,678**	**$ 162,182,272**	**$ 143,751,315**	**$ 14,889,682**	**$ 22,545,784**	**$ 4,447,950**	**$ 110,666**
15	**Expenses at Current Rates**							
16	Operations & Maintenance Expenses	$ 432,440,828	$ 32,020,037	$ 30,956,844	$ 2,608,263	$ 3,915,589	$ 908,587	$ 9,288
17	Depreciation Expense	314,465,223	25,613,799	25,645,488	2,320,626	3,365,237	644,045	5,094
18	Amortization Expense	143,750,842	12,815,961	11,090,834	1,292,309	1,989,925	284,244	2,636
19	Fuel Expenses	392,509,634	55,048,731	42,281,630	5,869,365	9,545,022	1,190,712	12,176
20	Taxes Other Than Income	35,531,910	2,641,894	3,068,349	222,701	327,704	74,803	614
21	Income Taxes	5,875,891	954,136	860,698	72,213	95,361	37,714	2,266
22	**Total Expenses at Current Rates**	**$ 1,324,574,328**	**$ 129,094,558**	**$ 113,903,844**	**$ 12,385,476**	**$ 19,238,837**	**$ 3,140,104**	**$ 32,075**
23	Current Operating Income	203,765,349	33,087,713	29,847,470	2,504,206	3,306,947	1,307,846	78,592
24	Current Rate of Return	3.43%	7.16%	5.29%	6.45%	5.70%	10.27%	83.75%
25	Revenue to Cost Ratio (Line 12 / Line 46)	0.84	0.97	0.90	0.96	0.94	1.07	2.93
26	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	1.16	1.07	1.14	1.12	1.27	3.49
27	**Current Revenue at Equal Rates of Return**							
28	Current Rate of Return	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
29	Current Operating Income at Equal ROR	$ 203,765,349	$ 15,841,295	$ 19,334,447	$ 1,329,555	$ 1,988,717	$ 436,337	$ 3,216
30	Other Expenses - Equal ROR	1,318,698,437	128,140,423	113,043,146	12,313,263	19,143,476	3,102,391	29,808
31	Income Taxes - Equal ROR	5,875,891	456,808	557,539	38,340	57,348	12,582	93
32	**Total Revenue Requirement at Equal Current ROR**	**$ 1,528,339,678**	**$ 144,438,526**	**$ 132,935,132**	**$ 13,681,158**	**$ 21,189,541**	**$ 3,551,311**	**$ 33,117**
33	Current Subsidy	-	17,743,746	10,816,182	1,208,524	1,356,244	896,640	77,549

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Line No.	Revenue Requirement Summary	System Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
1	(A)	(B)	(P)	(Q)	(R)	(S)	(T)	(U)
2	**Rate Base**							
3	Plant in Service	$ 8,636,903,069	$ 8,950,713	$ 11,325,185	$ 77,236,426	$ 3,860,879	$ 24,609,746	$ 32,425,163
4	Accumulated Reserve	(4,315,086,614)	(5,361,441)	(4,715,784)	(34,510,933)	(1,887,278)	(14,213,261)	(16,110,047)
5	Other Rate Base Items	1,623,865,434	236,571	1,378,921	2,010,931	579,757	631,101	6,349,582
6	**Total Rate Base**	**$ 5,945,681,889**	**$ 3,825,843**	**$ 7,988,323**	**$ 44,736,423**	**$ 2,553,358**	**$ 11,027,586**	**$ 22,664,698**
7	**Revenue at Current Rates**							
8	Retail Sales - Non Fuel	$ 1,039,935,261	$ 2,296,811	$ 1,160,598	$ 5,362,080	$ 701,070	$ 2,021,222	$ 2,927,720
9	TDSIC Revenue	$ 62,108,337	$ 14,238	$ 35,299	$ 116,137	$ 22,341	$ 81,850	$ 260,347
10	DSM Revenue	$ 11,624,641	$ 15,527	$ 33,476	$ -	$ -	$ -	$ -
11	Generation Credit	$ (82,861)	$ -	$ (121)	$ (441)	$ (51)	$ (145)	$ (280)
12	Retail Sales - Fuel	$ 392,509,634	$ 106,770	$ 682,080	$ 1,187,756	$ 358,964	$ 535,380	$ 849,755
13	Other Revenues	22,244,665	14,793	17,150	33,463	7,011	21,862	40,450
14	**Total Revenue**	**$ 1,528,339,678**	**$ 2,448,139**	**$ 1,928,481**	**$ 6,698,995**	**$ 1,089,334**	**$ 2,660,168**	**$ 4,077,991**
15	**Expenses at Current Rates**							
16	Operations & Maintenance Expenses	$ 432,440,828	$ 153,900	$ 452,166	$ 2,361,778	$ 163,002	$ 1,435,540	$ 1,715,245
17	Depreciation Expense	314,465,223	196,513	326,506	2,410,394	138,545	680,434	1,240,912
18	Amortization Expense	143,750,842	24,941	128,846	256,929	55,824	267,737	495,182
19	Fuel Expenses	392,509,634	106,770	682,080	1,187,756	358,964	535,380	849,755
20	Taxes Other Than Income	35,531,910	27,250	44,043	268,828	14,925	110,871	134,958
21	Income Taxes	5,875,891	54,340	8,264	5,979	10,036	(10,365)	(10,036)
22	**Total Expenses at Current Rates**	**$ 1,324,574,328**	**$ 563,714**	**$ 1,641,904**	**$ 6,491,662**	**$ 741,296**	**$ 3,019,598**	**$ 4,426,015**
23	Current Operating Income	203,765,349	1,884,426	286,577	207,333	348,038	(359,429)	(348,025)
24	Current Rate of Return	3.43%	49.26%	3.59%	0.46%	13.63%	-3.26%	-1.54%
25	Revenue to Cost Ratio (Line 12 / Line 46)	0.84	2.94	0.84	0.65	1.15	0.67	0.64
26	Parity Ratio (Class Rev. to Cost Ratio/System)	1.00	3.51	1.00	0.78	1.37	0.80	0.77
27	**Current Revenue at Equal Rates of Return**							
28	Current Rate of Return	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
29	Current Operating Income at Equal ROR	$ 203,765,349	$ 131,116	$ 273,769	$ 1,533,169	$ 87,507	$ 377,928	$ 776,745
30	Other Expenses - Equal ROR	1,318,698,437	509,373	1,633,640	6,485,683	731,260	3,029,962	4,436,051
31	Income Taxes - Equal ROR	5,875,891	3,781	7,895	44,211	2,523	10,898	22,399
32	**Total Revenue Requirement at Equal Current ROR**	**$ 1,528,339,678**	**$ 644,270**	**$ 1,915,304**	**$ 8,063,063**	**$ 821,290**	**$ 3,418,789**	**$ 5,235,195**
33	Current Subsidy	-	1,803,869	13,178	(1,364,069)	268,044	(758,620)	(1,157,204)

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Line No.	Revenue Requirement Summary	System Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
1	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
34	**Revenue Requirement at Equal Rates of Return**								
35	Required Return	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
36	Required Operating Income	$ 422,143,414	$ 198,704,944	$ 239,927	$ 59,651,162	$ 206,643	$ 32,875,083	$ 41,719,428	$ 1,498,499
37	Operating Income (Deficiency)/Surplus	(218,378,065)	(219,360,064)	(130,052)	15,462,795	23,808	858,972	(576,236)	438,747
38	Operations & Maintenance Expenses	432,440,828	219,296,447	316,751	61,077,641	268,348	32,588,705	40,721,073	1,471,624
39	Depreciation Expense	314,465,223	149,682,526	120,852	43,684,288	105,446	25,157,044	32,112,191	1,015,283
40	Amortization Expense	143,750,842	68,993,149	32,389	19,321,389	28,725	11,343,142	14,840,162	486,519
41	Fuel Expenses	392,509,634	124,604,472	341,040	57,442,413	294,805	36,088,611	53,014,950	3,055,004
42	Taxes Other Than Income	35,531,910	17,334,157	23,302	5,019,492	19,815	2,682,725	3,393,685	121,792
43	Income Taxes	5,875,891	2,765,810	3,340	830,295	2,876	457,594	580,700	20,858
44	Income Tax Increase	72,292,735	34,028,539	41,088	10,215,357	35,388	5,629,911	7,144,519	256,620
45	Bad Debt Expense Increase	737,057	645,963	-	49,955	-	5,011	1,104	-
46	Public Utility Fee Increase	372,335	178,323	224	52,657	193	28,232	35,888	1,293
47	Total Expenses at Equal Rates of Return	1,397,976,455	617,529,387	878,987	197,693,486	755,597	113,980,977	151,844,272	6,428,994
48	**Total Revenue Requirement at Equal Rates of Return**	**$ 1,820,119,869**	**$ 816,234,331**	**$ 1,118,913**	**$ 257,344,648**	**$ 962,239**	**$ 146,856,060**	**$ 193,563,700**	**$ 7,927,493**
49	Revenue (Deficiency)/Surplus	(291,780,191)	(257,574,322)	(171,535)	6,480,559	(8,004)	(4,289,003)	(7,152,019)	215,839
50	Total Current Revenues	1,528,339,678	558,660,009	947,378	263,825,207	954,235	142,567,057	186,411,680	8,143,333
51	Total Revenues at Equal Rates of Return	1,820,119,869	816,234,331	1,118,913	257,344,648	962,239	146,856,060	193,563,700	7,927,493
52	Less Total Other Revenues	22,244,665	8,713,738	12,251	2,983,250	9,609	1,591,195	2,163,610	80,354
53	**Total Base Revenues at Equal Rates of Return**	**$ 1,797,875,204**	**$ 807,520,593**	**$ 1,106,662**	**$ 254,361,397**	**$ 952,631**	**$ 145,264,865**	**$ 191,400,089**	**$ 7,847,140**
54	**Mitigation**								
55	Revenue Apportionment Mitigation	0	(150,918,762)	99,766	54,328,715	173,063	25,856,403	33,808,199	1,692,739
56	Proposed Increase Post Mitigation	291,780,191	106,655,560	271,300	47,848,156	181,067	30,145,406	40,960,219	1,476,900
57	Total Current Revenues	1,528,339,678	558,660,009	947,378	263,825,207	954,235	142,567,057	186,411,680	8,143,333
58	Total Revenues as Proposed	1,820,119,869	665,315,569	1,218,679	311,673,363	1,135,302	172,712,463	227,371,899	9,620,233
59	Less Total Other Revenues	22,244,665	8,713,738	12,251	2,983,250	9,609	1,591,195	2,163,610	80,354
60	**Total Base Rate Revenue as Proposed**	**$ 1,797,875,204**	**$ 656,601,830**	**$ 1,206,427**	**$ 308,690,112**	**$ 1,125,694**	**$ 171,121,268**	**$ 225,208,289**	**$ 9,539,879**
61	Proposed Income Prior to Taxes	500,312,040	84,580,531	384,120	125,025,529	417,970	64,818,991	83,252,846	3,468,717
62	Income Taxes at Proposed	78,168,625	13,214,841	60,015	19,533,957	65,304	10,127,303	13,007,403	541,951
63	Operating Income at Proposed	422,143,414	71,365,690	324,105	105,491,572	352,666	54,691,688	70,245,443	2,926,766
64	Rate of Return at Proposed	7.10%	2.55%	9.59%	12.56%	12.12%	11.81%	11.95%	13.87%
65	Parity Ratio	1.00	0.82	1.09	1.21	1.18	1.18	1.17	1.21

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Line No.	Revenue Requirement Summary	System Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
1	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
34	**Revenue Requirement at Equal Rates of Return**							
35	Required Return	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
36	Required Operating Income	$ 422,143,414	$ 32,818,624	$ 40,055,435	$ 2,754,457	$ 4,120,052	$ 903,966	$ 6,663
37	Operating Income (Deficiency)/Surplus	(218,378,065)	269,090	(10,207,964)	(250,251)	(813,104)	403,880	71,929
38	Operations & Maintenance Expenses	432,440,828	32,020,037	30,956,844	2,608,263	3,915,589	908,587	9,288
39	Depreciation Expense	314,465,223	25,613,799	25,645,488	2,320,626	3,365,237	644,045	5,094
40	Amortization Expense	143,750,842	12,815,961	11,090,834	1,292,309	1,989,925	284,244	2,636
41	Fuel Expenses	392,509,634	55,048,731	42,281,630	5,869,365	9,545,022	1,190,712	12,176
42	Taxes Other Than Income	35,531,910	2,641,894	3,068,349	222,701	327,704	74,803	614
43	Income Taxes	5,875,891	456,808	557,539	38,340	57,348	12,582	93
44	Income Tax Increase	72,292,735	5,620,242	6,859,557	471,705	705,565	154,806	1,141
45	Bad Debt Expense Increase	737,057	-	-	-	33,658	26	-
46	Public Utility Fee Increase	372,335	27,706	34,398	2,321	3,471	794	6
47	Total Expenses at Equal Rates of Return	1,397,976,455	134,245,179	120,494,640	12,825,629	19,943,518	3,270,598	31,048
48	**Total Revenue Requirement at Equal Rates of Return**	**$ 1,820,119,869**	**$ 167,063,803**	**$ 160,550,075**	**$ 15,580,086**	**$ 24,063,569**	**$ 4,174,564**	**$ 37,710**
49	Revenue (Deficiency)/Surplus	(291,780,191)	(4,881,531)	(16,798,760)	(690,404)	(1,517,785)	273,386	72,956
50	Total Current Revenues	1,528,339,678	162,182,272	143,751,315	14,889,682	22,545,784	4,447,950	110,666
51	Total Revenues at Equal Rates of Return	1,820,119,869	167,063,803	160,550,075	15,580,086	24,063,569	4,174,564	37,710
52	Less Total Other Revenues	22,244,665	1,668,767	4,431,359	158,794	261,532	34,771	707
53	**Total Base Revenues at Equal Rates of Return**	**$ 1,797,875,204**	**$ 165,395,035**	**$ 156,118,716**	**$ 15,421,292**	**$ 23,802,037**	**$ 4,139,793**	**$ 37,004**
54	**Mitigation**							
55	Revenue Apportionment Mitigation	0	29,413,879	-	2,700,439	4,088,973	1,080,080	18,855
56	Proposed Increase Post Mitigation	291,780,191	34,295,410	16,798,760	3,390,843	5,606,758	806,694	(54,101)
57	Total Current Revenues	1,528,339,678	162,182,272	143,751,315	14,889,682	22,545,784	4,447,950	110,666
58	Total Revenues as Proposed	1,820,119,869	196,477,681	160,550,075	18,280,525	28,152,543	5,254,644	56,566
59	Less Total Other Revenues	22,244,665	1,668,767	4,431,359	158,794	261,532	34,771	707
60	**Total Base Rate Revenue as Proposed**	**$ 1,797,875,204**	**$ 194,808,914**	**$ 156,118,716**	**$ 18,121,730**	**$ 27,891,010**	**$ 5,219,873**	**$ 55,859**
61	Proposed Income Prior to Taxes	500,312,040	68,309,553	47,472,531	5,964,941	8,971,938	2,151,434	26,752
62	Income Taxes at Proposed	78,168,625	10,672,667	7,417,096	931,961	1,401,773	336,140	4,180
63	Operating Income at Proposed	422,143,414	57,636,886	40,055,435	5,032,980	7,570,165	1,815,295	22,572
64	Rate of Return at Proposed	7.10%	12.47%	7.10%	12.97%	13.05%	14.26%	24.05%
65	Parity Ratio	1.00	1.18	1.00	1.17	1.17	1.26	1.50

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	System Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
1	(A)	(B)	(P)	(Q)	(R)	(S)	(T)	(U)
34	**Revenue Requirement at Equal Rates of Return**							
35	Required Return	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
36	Required Operating Income	$ 422,143,414	$ 271,635	$ 567,171	$ 3,176,286	$ 181,288	$ 782,959	$ 1,609,194
37	Operating Income (Deficiency)/Surplus	(218,378,065)	1,612,791	(280,594)	(2,968,953)	166,750	(1,142,388)	(1,957,218)
38	Operations & Maintenance Expenses	432,440,828	153,900	452,166	2,361,778	163,002	1,435,540	1,715,245
39	Depreciation Expense	314,465,223	196,513	326,506	2,410,394	138,545	680,434	1,240,912
40	Amortization Expense	143,750,842	24,941	128,846	256,929	55,824	267,737	495,182
41	Fuel Expenses	392,509,634	106,770	682,080	1,187,756	358,964	535,380	849,755
42	Taxes Other Than Income	35,531,910	27,250	44,043	268,828	14,925	110,871	134,958
43	Income Taxes	5,875,891	3,781	7,895	44,211	2,523	10,898	22,399
44	Income Tax Increase	72,292,735	46,518	97,129	543,944	31,046	134,083	275,577
45	Bad Debt Expense Increase	737,057	-	-	22	-	1,319	-
46	Public Utility Fee Increase	372,335	386	488	3,330	166	1,061	1,398
47	Total Expenses at Equal Rates of Return	1,397,976,455	560,058	1,739,152	7,077,191	764,996	3,177,323	4,735,425
48	**Total Revenue Requirement at Equal Rates of Return**	**$ 1,820,119,869**	**$ 831,693**	**$ 2,306,323**	**$ 10,253,477**	**$ 946,284**	**$ 3,960,282**	**$ 6,344,618**
49	Revenue (Deficiency)/Surplus	(291,780,191)	1,616,447	(377,842)	(3,554,482)	143,050	(1,300,113)	(2,266,627)
50	Total Current Revenues	1,528,339,678	2,448,139	1,928,481	6,698,995	1,089,334	2,660,168	4,077,991
51	Total Revenues at Equal Rates of Return	1,820,119,869	831,693	2,306,323	10,253,477	946,284	3,960,282	6,344,618
52	Less Total Other Revenues	22,244,665	14,793	17,150	33,463	7,011	21,862	40,450
53	**Total Base Revenues at Equal Rates of Return**	**$ 1,797,875,204**	**$ 816,900**	**$ 2,289,173**	**$ 10,220,014**	**$ 939,273**	**$ 3,938,420**	**$ 6,304,169**
54	**Mitigation**							
55	Revenue Apportionment Mitigation	0	415,846	174,417	(1,636,092)	340,615	(538,321)	(1,098,814)
56	Proposed Increase Post Mitigation	291,780,191	(1,200,600)	552,259	1,918,390	197,565	761,792	1,167,813
57	Total Current Revenues	1,528,339,678	2,448,139	1,928,481	6,698,995	1,089,334	2,660,168	4,077,991
58	Total Revenues as Proposed	1,820,119,869	1,247,539	2,480,740	8,617,384	1,286,900	3,421,960	5,245,804
59	Less Total Other Revenues	22,244,665	14,793	17,150	33,463	7,011	21,862	40,450
60	**Total Base Rate Revenue as Proposed**	**$ 1,797,875,204**	**$ 1,232,747**	**$ 2,463,590**	**$ 8,583,922**	**$ 1,279,889**	**$ 3,400,098**	**$ 5,205,354**
61	Proposed Income Prior to Taxes	500,312,040	737,780	846,612	2,128,349	555,473	389,618	808,355
62	Income Taxes at Proposed	78,168,625	115,271	132,274	332,533	86,787	60,874	126,297
63	Operating Income at Proposed	422,143,414	622,510	714,337	1,795,816	468,686	328,744	682,058
64	Rate of Return at Proposed	7.10%	16.27%	8.94%	4.01%	18.36%	2.98%	3.01%
65	Parity Ratio	1.00	1.50	1.08	0.84	1.36	0.86	0.83

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description		TOTAL	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**Functional Revenue Requirement**									
2	**Production**									
3	Demand	Product_Dem	$ 726,184,245	$ 342,346,578	$ -	$ 97,668,741	$ -	$ 61,970,239	$ 79,726,028	$ 2,025,422
4	Energy	Product_Energy	$ 26,480,528	$ 8,375,494	$ 22,924	$ 3,861,086	$ 19,816	$ 2,425,755	$ 3,566,576	$ 205,347
5	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal		$ 752,664,772	$ 350,722,072	$ 22,924	$ 101,529,827	$ 19,816	$ 64,395,994	$ 83,292,603	$ 2,230,769
7	**Transmission**									
8	Demand	Trans_Dem	$ 221,544,982	$ 67,364,908	$ 146,917	$ 25,892,407	$ 111,000	$ 16,525,058	$ 24,809,973	$ 933,638
9	Energy	Trans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	Trans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal		$ 221,544,982	$ 67,364,908	$ 146,917	$ 25,892,407	$ 111,000	$ 16,525,058	$ 24,809,973	$ 933,638
12	**Sub-Transmission**									
13	Demand	SubTrans_Dem	$ 18,199,151	$ 8,786,516	$ 29,542	$ 2,862,427	$ 25,728	$ 1,554,962	$ 2,063,596	$ 140,658
14	Energy	SubTrans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	SubTrans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal		$ 18,199,151	$ 8,786,516	$ 29,542	$ 2,862,427	$ 25,728	$ 1,554,962	$ 2,063,596	$ 140,658
17	**Railroad**									
18	Demand	RR_Dem	$ 771,134	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Energy	RR_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	RR_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal		$ 771,134	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	**Dist Primary**									
23	Demand	DistPri_Dem	$ 236,930,605	$ 122,934,355	$ 413,335	$ 39,496,927	$ 359,973	$ 21,676,399	$ 26,822,608	$ 1,423,093
24	Energy	DistPri_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	DistPri_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal		$ 236,930,605	$ 122,934,355	$ 413,335	$ 39,496,927	$ 359,973	$ 21,676,399	$ 26,822,608	$ 1,423,093

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)		(B)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Functional Revenue Requirement**								
2	**Production**								
3	Demand	Product_Dem	$ 726,184,245	$ 66,398,995	$ 54,677,137	$ 6,754,363	$ 9,565,927	$ 1,355,514	$ 12,336
4	Energy	Product_Energy	$ 26,480,528	$ 3,700,191	$ 2,932,445	$ 394,519	$ 641,584	$ 80,036	$ 818
5	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal		$ 752,664,772	$ 70,099,185	$ 57,609,582	$ 7,148,882	$ 10,207,511	$ 1,435,550	$ 13,154
7	**Transmission**								
8	Demand	Trans_Dem	$ 221,544,982	$ 18,416,983	$ 59,467,472	$ 2,264,816	$ 3,739,901	$ 374,792	$ 3,725
9	Energy	Trans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	Trans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal		$ 221,544,982	$ 18,416,983	$ 59,467,472	$ 2,264,816	$ 3,739,901	$ 374,792	$ 3,725
12	**Sub-Transmission**								
13	Demand	SubTrans_Dem	$ 18,199,151	$ 1,570,298	$ 594,719	$ 127,592	$ 118,281	$ 56,645	$ 276
14	Energy	SubTrans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	SubTrans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal		$ 18,199,151	$ 1,570,298	$ 594,719	$ 127,592	$ 118,281	$ 56,645	$ 276
17	**Railroad**								
18	Demand	RR_Dem	$ 771,134	$ -	$ -	$ -	$ -	$ -	$ -
19	Energy	RR_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	RR_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal		$ 771,134	$ -	$ -	$ -	$ -	$ -	$ -
22	**Dist Primary**								
23	Demand	DistPri_Dem	$ 236,930,605	$ 19,811,488	$ -	$ 0	$ (0)	$ 792,538	$ 3,865
24	Energy	DistPri_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	DistPri_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal		$ 236,930,605	$ 19,811,488	$ -	$ 0	$ (0)	$ 792,538	$ 3,865

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)		(B)	(P)	(Q)	(R)	(S)	(T)	(U)
1	**Functional Revenue Requirement**								
2	**Production**								
3	Demand	Product_Dem	$ 726,184,245	$ -	$ 533,975	$ -	$ 238,247	$ -	$ 2,910,743
4	Energy	Product_Energy	$ 26,480,528	$ 9,555	$ 45,847	$ 81,854	$ 17,487	$ 34,732	$ 64,462
5	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal		$ 752,664,772	$ 9,555	$ 579,822	$ 81,854	$ 255,734	$ 34,732	$ 2,975,205
7	**Transmission**								
8	Demand	Trans_Dem	$ 221,544,982	$ 700,922	$ 181,522	$ 68,154	$ 71,970	$ 25,858	$ 444,965
9	Energy	Trans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	Trans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal		$ 221,544,982	$ 700,922	$ 181,522	$ 68,154	$ 71,970	$ 25,858	$ 444,965
12	**Sub-Transmission**								
13	Demand	SubTrans_Dem	$ 18,199,151	$ -	$ 39,481	$ 69,334	$ 5,361	$ 25,937	$ 127,798
14	Energy	SubTrans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	SubTrans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal		$ 18,199,151	$ -	$ 39,481	$ 69,334	$ 5,361	$ 25,937	$ 127,798
17	**Railroad**								
18	Demand	RR_Dem	$ 771,134	$ -	$ 771,134	$ -	$ -	$ -	$ -
19	Energy	RR_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	RR_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal		$ 771,134	$ -	$ 771,134	$ -	$ -	$ -	$ -
22	**Dist Primary**								
23	Demand	DistPri_Dem	$ 236,930,605	$ -	$ -	$ 970,073	$ 75,013	$ 362,887	$ 1,788,050
24	Energy	DistPri_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	DistPri_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal		$ 236,930,605	$ -	$ -	$ 970,073	$ 75,013	$ 362,887	$ 1,788,050

NIPSCO
Electric Class Cost of Service Study
Test Year Ended December 31, 2023
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line No.	Description		TOTAL	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
27	**Dist Secondary**									
28	Demand	DistSec_Dem	$ 25,110,906	$ 13,298,110	$ 50,669	$ 5,075,089	$ 40,936	$ 2,912,645	$ 1,924,890	$ 81,756
29	Energy	DistSec_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	DistSec_Cust	$ 35,259,514	$ 31,074,890	$ 9,046	$ 3,678,791	$ 11,183	$ 214,345	$ 16,746	$ 108
31	Subtotal		$ 60,370,420	$ 44,373,001	$ 59,715	$ 8,753,880	$ 52,119	$ 3,126,991	$ 1,941,636	$ 81,864
32	**Customer**									
33	Demand	Cust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	Cust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	Cust_Cust	$ 91,784,810	$ 60,508,359	$ 12,702	$ 15,999,482	$ 33,058	$ 2,918,933	$ 1,010,801	$ 8,253
36	Subtotal		$ 91,784,810	$ 60,508,359	$ 12,702	$ 15,999,482	$ 33,058	$ 2,918,933	$ 1,010,801	$ 8,253
37	**Customer Service**									
38	Demand	CustServ_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	CustServ_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	CustServ_Cust	$ 45,344,360	$ 36,940,648	$ 92,738	$ 5,367,285	$ 65,740	$ 569,112	$ 607,533	$ 54,214
41	Subtotal		$ 45,344,360	$ 36,940,648	$ 92,738	$ 5,367,285	$ 65,740	$ 569,112	$ 607,533	$ 54,214
42	**Fuel Expenses**									
43	Demand	Fuel_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	Fuel_Energy	$ 392,509,634	$ 124,604,472	$ 341,040	$ 57,442,413	$ 294,805	$ 36,088,611	$ 53,014,950	$ 3,055,004
45	Customer	Fuel_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal		$ 392,509,634	$ 124,604,472	$ 341,040	$ 57,442,413	$ 294,805	$ 36,088,611	$ 53,014,950	$ 3,055,004
47	**Total**									
48	Demand		$ 1,228,741,022	$ 554,730,468	$ 640,463	$ 170,995,591	$ 537,638	$ 104,639,303	$ 135,347,095	$ 4,604,567
49	Energy		$ 418,990,162	$ 132,979,966	$ 363,964	$ 61,303,498	$ 314,621	$ 38,514,366	$ 56,581,525	$ 3,260,351
50	Customer		$ 172,388,684	$ 128,523,897	$ 114,486	$ 25,045,558	$ 109,981	$ 3,702,390	$ 1,635,080	$ 62,575
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		$ 1,820,119,869	$ 816,234,331	$ 1,118,913	$ 257,344,648	$ 962,239	$ 146,856,060	$ 193,563,700	$ 7,927,493
52	Demand		67.51%	67.96%	57.24%	66.45%	55.87%	71.25%	69.92%	58.08%
53	Energy		23.02%	16.29%	32.53%	23.82%	32.70%	26.23%	29.23%	41.13%
54	Customer		9.47%	15.75%	10.23%	9.73%	11.43%	2.52%	0.84%	0.79%
55	**Unit Costs**			$ 12,337.26		$ 1,703.41				

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Electric Class Cost of Service Study
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Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)		(B)	(J)	(K)	(L)	(M)	(N)	(O)
27	**Dist Secondary**								
28	Demand	DistSec_Dem	$ 25,110,906	$ 1,296,985	$ -	$ -	$ -	$ 105,396	$ 724
29	Energy	DistSec_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	DistSec_Cust	$ 35,259,514	$ 6,838	$ -	$ -	$ -	$ 26,981	$ 427
31	Subtotal		$ 60,370,420	$ 1,303,823	$ -	$ -	$ -	$ 132,377	$ 1,151
32	**Customer**								
33	Demand	Cust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	Cust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	Cust_Cust	$ 91,784,810	$ 475,892	$ 462,311	$ 36,304	$ 42,196	$ 162,849	$ 144
36	Subtotal		$ 91,784,810	$ 475,892	$ 462,311	$ 36,304	$ 42,196	$ 162,849	$ 144
37	**Customer Service**								
38	Demand	CustServ_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	CustServ_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	CustServ_Cust	$ 45,344,360	$ 337,403	$ 134,361	$ 133,127	$ 410,659	$ 29,101	$ 3,220
41	Subtotal		$ 45,344,360	$ 337,403	$ 134,361	$ 133,127	$ 410,659	$ 29,101	$ 3,220
42	**Fuel Expenses**								
43	Demand	Fuel_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	Fuel_Energy	$ 392,509,634	$ 55,048,731	$ 42,281,630	$ 5,869,365	$ 9,545,022	$ 1,190,712	$ 12,176
45	Customer	Fuel_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal		$ 392,509,634	$ 55,048,731	$ 42,281,630	$ 5,869,365	$ 9,545,022	$ 1,190,712	$ 12,176
47	**Total**								
48	Demand		$ 1,228,741,022	$ 107,494,747	$ 114,739,328	$ 9,146,772	$ 13,424,109	$ 2,684,887	$ 20,926
49	Energy		$ 418,990,162	$ 58,748,922	$ 45,214,076	$ 6,263,884	$ 10,186,606	$ 1,270,747	$ 12,994
50	Customer		$ 172,388,684	$ 820,133	$ 596,672	$ 169,430	$ 452,854	$ 218,931	$ 3,791
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		$ 1,820,119,869	$ 167,063,803	$ 160,550,075	$ 15,580,086	$ 24,063,569	$ 4,174,564	$ 37,710
52	Demand		67.51%	64.34%	71.47%	58.71%	55.79%	64.32%	55.49%
53	Energy		23.02%	35.17%	28.16%	40.20%	42.33%	30.44%	34.46%
54	Customer		9.47%	0.49%	0.37%	1.09%	1.88%	5.24%	10.05%
55	**Unit Costs**								

NIPSCO
Electric Class Cost of Service Study
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Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)		(B)	(P)	(Q)	(R)	(S)	(T)	(U)
27	**Dist Secondary**								
28	Demand	DistSec_Dem	$ 25,110,906	$ -	$ -	$ 163,558	$ 13,990	$ 61,448	$ 84,708
29	Energy	DistSec_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	DistSec_Cust	$ 35,259,514	$ -	$ -	$ 33,281	$ 3,317	$ 180,150	$ 3,410
31	Subtotal		$ 60,370,420	$ -	$ -	$ 196,839	$ 17,308	$ 241,598	$ 88,118
32	**Customer**								
33	Demand	Cust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	Cust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	Cust_Cust	$ 91,784,810	$ 7,627	$ 2,017	$ 7,615,872	$ 153,422	$ 2,301,341	$ 33,249
36	Subtotal		$ 91,784,810	$ 7,627	$ 2,017	$ 7,615,872	$ 153,422	$ 2,301,341	$ 33,249
37	**Customer Service**								
38	Demand	CustServ_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	CustServ_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	CustServ_Cust	$ 45,344,360	$ 6,819	$ 50,267	$ 63,595	$ 8,512	$ 432,548	$ 37,479
41	Subtotal		$ 45,344,360	$ 6,819	$ 50,267	$ 63,595	$ 8,512	$ 432,548	$ 37,479
42	**Fuel Expenses**								
43	Demand	Fuel_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	Fuel_Energy	$ 392,509,634	$ 106,770	$ 682,080	$ 1,187,756	$ 358,964	$ 535,380	$ 849,755
45	Customer	Fuel_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Subtotal		$ 392,509,634	$ 106,770	$ 682,080	$ 1,187,756	$ 358,964	$ 535,380	$ 849,755
47	**Total**								
48	Demand		$ 1,228,741,022	$ 700,922	$ 1,526,112	$ 1,271,120	$ 404,582	$ 476,130	$ 5,356,264
49	Energy		$ 418,990,162	$ 116,325	$ 727,927	$ 1,269,610	$ 376,451	$ 570,113	$ 914,217
50	Customer		$ 172,388,684	$ 14,446	$ 52,284	$ 7,712,747	$ 165,252	$ 2,914,039	$ 74,138
51	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		$ 1,820,119,869	$ 831,693	$ 2,306,323	$ 10,253,477	$ 946,284	$ 3,960,282	$ 6,344,618
52	Demand		67.51%	84.28%	66.17%	12.40%	42.75%	12.02%	84.42%
53	Energy		23.02%	13.99%	31.56%	12.38%	39.78%	14.40%	14.41%
54	Customer		9.47%	1.74%	2.27%	75.22%	17.46%	73.58%	1.17%
55	**Unit Costs**								

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Line No.	Description		TOTAL	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
56	**Production**									
57	Demand	Product_Dem		n/a	n/a	n/a	n/a	$ 22.42	$ 21.65	$ 17.22
58	Energy	Product_Energy	$ 0.002426	$ 0.002426	$ 0.002426	$ 0.002425	$ 0.002426	$ 0.002425	$ 0.002416	$ 0.002411
59	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**									
61	Demand	Trans_Dem		n/a	n/a	n/a	n/a	$ 5.98	$ 6.74	$ 7.94
62	Energy	Trans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	Trans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**									
65	Demand	SubTrans_Dem		n/a	n/a	n/a	n/a	$ 0.56	$ 0.56	$ 1.20
66	Energy	SubTrans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**									
68	Demand	RR_Dem		n/a	n/a	n/a	n/a	$ -	$ -	$ -
69	Energy	RR_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	RR_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**									
72	Demand	DistPri_Dem		n/a	n/a	n/a	n/a	$ 7.84	$ 7.28	$ 12.10
73	Energy	DistPri_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	DistPri_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**									
76	Demand	DistSec_Dem		n/a	n/a	n/a	n/a	$ 1.05	$ 0.52	$ 0.70
77	Energy	DistSec_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	DistSec_Cust	$ 6.02	$ 6.18	$ 6.18	$ 5.85	$ 6.18	$ 5.76	$ 2.63	$ 1.47

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Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)		(B)	(J)	(K)	(L)	(M)	(N)	(O)
56	**Production**								
57	Demand	Product_Dem		$ 23.63	$ 26.80	$ 15.88	$ 19.07	n/a	n/a
58	Energy	Product_Energy	$ 0.002426	$ 0.002415	$ 0.002469	$ 0.002395	$ 0.002394	$ 0.002425	$ 0.002426
59	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**								
61	Demand	Trans_Dem		$ 6.55	$ 29.15	$ 5.33	$ 7.46	n/a	n/a
62	Energy	Trans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	Trans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**								
65	Demand	SubTrans_Dem		$ 0.56	$ 0.29	$ 0.30	$ 0.24	n/a	n/a
66	Energy	SubTrans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**								
68	Demand	RR_Dem		$ -	$ -	$ -	$ -	n/a	n/a
69	Energy	RR_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	RR_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**								
72	Demand	DistPri_Dem		$ 7.05	$ -	$ 0.00	$ (0.00)	n/a	n/a
73	Energy	DistPri_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	DistPri_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**								
76	Demand	DistSec_Dem		$ 0.46	$ -	$ -	$ -	n/a	n/a
77	Energy	DistSec_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	DistSec_Cust	$ 6.02	$ 2.19	$ -	$ -	$ -	$ 5.50	$ 6.18

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Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)		(B)	(P)	(Q)	(R)	(S)	(T)	(U)
56	**Production**								
57	Demand	Product_Dem		$ -	n/a	n/a	n/a	n/a	n/a
58	Energy	Product_Energy	$ 0.002426	$ 0.002393	$ 0.002398	$ 0.002426	$ 0.002426	$ 0.002426	$ 0.002426
59	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	**Transmission**								
61	Demand	Trans_Dem		$ 8.78	n/a	n/a	n/a	n/a	n/a
62	Energy	Trans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Customer	Trans_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	**Sub-Transmission**								
65	Demand	SubTrans_Dem		$ -	n/a	n/a	n/a	n/a	n/a
66	Energy	SubTrans_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	**Railroad**								
68	Demand	RR_Dem		$ -	n/a	n/a	n/a	n/a	n/a
69	Energy	RR_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Customer	RR_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	**Dist Primary**								
72	Demand	DistPri_Dem		$ -	n/a	n/a	n/a	n/a	n/a
73	Energy	DistPri_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Customer	DistPri_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	**Dist Secondary**								
76	Demand	DistSec_Dem		$ -	n/a	n/a	n/a	n/a	n/a
77	Energy	DistSec_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Customer	DistSec_Cust	$ 6.02	$ -	$ -	$ 1.54	$ 1.54	$ 1.54	$ 6.18

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

Line No.	Description		TOTAL	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
79	**Customer**									
80	Demand	Cust_Dem		n/a	n/a	n/a	n/a	$ -	$ -	$ -
81	Energy	Cust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	Cust_Cust	$ 15.67	$ 12.03	$ 8.67	$ 25.43	$ 18.26	$ 78.42	$ 158.81	$ 112.28
83	**Customer Service**									
84	Demand	CustServ_Dem		n/a	n/a	n/a	n/a	$ -	$ -	$ -
85	Energy	CustServ_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	CustServ_Cust	$ 7.74	$ 7.34	$ 63.33	$ 8.53	$ 36.31	$ 15.29	$ 95.45	$ 737.61
87	**Fuel Expenses**									
88	Demand	Fuel_Dem		n/a	n/a	n/a	n/a	$ -	$ -	$ -
89	Energy	Fuel_Energy	$ 0.035964	$ 0.036094	$ 0.036094	$ 0.036081	$ 0.036094	$ 0.036079	$ 0.035919	$ 0.035876
90	Customer	Fuel_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**									
92	Demand (per kW)			n/a	n/a	n/a	n/a	$ 37.85	$ 36.75	$ 39.15
93	Energy		$ 0.038391	$ 0.038520	$ 0.038520	$ 0.038506	$ 0.038520	$ 0.038504	$ 0.038335	$ 0.038287
94	Customer (per cust month)		$ 29.44	$ 25.55	$ 78.18	$ 39.81	$ 60.75	$ 99.47	$ 256.89	$ 851.36
95	Demand & Customer (per cust month)		$ 239.27	$ 135.82	$ 515.54	$ 311.61	$ 357.74	$ 2,910.63	$ 21,521.09	$ 63,498.53
96	**BILLING DETERMINANTS**									
97	Billed Demand	BilledKW	12,421,601	0	0	0	0	2,764,528	3,682,434	117,625
98	Energy	SALES_KWH	10,913,898,510	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988
99	Customers (Number of Bills)	CUST	5,855,971	5,030,650	1,464	629,133	1,810	37,223	6,365	74
100	**Unit Cost after Mitigation**									
101	Mitigated percent of COS @ Equal ROR			81.5%	108.9%	121.1%	118.0%	117.6%	117.5%	121.4%
102	Demand (per kW)							$ 44.51	$ 43.17	$ 47.50
103	Energy		$ 0.0384	$ 0.0314	$ 0.0420	$ 0.0466	$ 0.0454	$ 0.0453	$ 0.0450	$ 0.0465
104	Customer (per cust month)		$ 29.44	$ 20.82	$ 85.15	$ 48.21	$ 71.68	$ 116.98	$ 301.75	$ 1,033.15
105	Demand & Customer (per cust month)		$ 239.27	$ 110.71	$ 561.50	$ 377.39	$ 422.08	$ 3,423.09	$ 25,280.00	$ 77,057.23

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Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Cus

Line No.	Description		TOTAL	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)		(B)	(J)	(K)	(L)	(M)	(N)	(O)
79	**Customer**								
80	Demand	Cust_Dem		$ -	$ -	$ -	$ -	n/a	n/a
81	Energy	Cust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	Cust_Cust	$ 15.67	$ 152.32	$ 5,503.70	$ 605.06	$ 879.08	$ 33.20	$ 2.08
83	**Customer Service**								
84	Demand	CustServ_Dem		$ -	$ -	$ -	$ -	n/a	n/a
85	Energy	CustServ_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	CustServ_Cust	$ 7.74	$ 107.99	$ 1,599.53	$ 2,218.78	$ 8,555.39	$ 5.93	$ 46.54
87	**Fuel Expenses**								
88	Demand	Fuel_Dem		$ -	$ -	$ -	$ -	n/a	n/a
89	Energy	Fuel_Energy	$ 0.035964	$ 0.035930	$ 0.035603	$ 0.035637	$ 0.035618	$ 0.036070	$ 0.036094
90	Customer	Fuel_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**								
92	Demand (per kW)			$ 38.25	$ 56.24	$ 21.51	$ 26.76	n/a	n/a
93	Energy		$ 0.038391	$ 0.038345	$ 0.038072	$ 0.038033	$ 0.038013	$ 0.038494	$ 0.038520
94	Customer (per cust month)		$ 29.44	$ 262.50	$ 7,103.23	$ 2,823.84	$ 9,434.47	$ 44.63	$ 54.79
95	Demand & Customer (per cust month)		$ 239.27	$ 34,668.28	$ 1,373,047.61	$ 155,270.03	$ 289,103.41	$ 591.99	$ 357.26
96	**BILLING DETERMINANTS**								
97	Billed Demand	BilledKW	12,421,601	2,810,181	2,040,000	425,312	501,650	0	0
98	Energy	SALES_KWH	10,913,898,510	1,532,103,352	1,187,580,246	164,697,799	267,979,838	33,011,174	337,325
99	Customers (Number of Bills)	CUST	5,855,971	3,124	84	60	48	4,905	69
100	**Unit Cost after Mitigation**								
101	Mitigated percent of COS @ Equal ROR			117.6%	100.0%	117.3%	117.0%	125.9%	150.0%
102	Demand (per kW)			$ 44.99	$ 56.24	$ 25.23	$ 31.31		
103	Energy		$ 0.0384	$ 0.0451	$ 0.0381	$ 0.0446	$ 0.0445	$ 0.0485	$ 0.0578
104	Customer (per cust month)		$ 29.44	$ 308.72	$ 7,103.23	$ 3,313.29	$ 11,037.61	$ 56.18	$ 82.19
105	Demand & Customer (per cust month)		$ 239.27	$ 40,772.10	$ 1,373,047.61	$ 182,182.42	$ 338,228.96	$ 745.16	$ 535.89

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Line No.	Description		TOTAL	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)		(B)	(P)	(Q)	(R)	(S)	(T)	(U)
79	**Customer**								
80	Demand	Cust_Dem		$ -	n/a	n/a	n/a	n/a	n/a
81	Energy	Cust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Customer	Cust_Cust	$ 15.67	$ 158.89	$ 168.08	$ 353.41	$ 71.42	$ 19.73	$ 60.23
83	**Customer Service**								
84	Demand	CustServ_Dem		$ -	n/a	n/a	n/a	n/a	n/a
85	Energy	CustServ_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	CustServ_Cust	$ 7.74	$ 142.07	$ 4,188.95	$ 2.95	$ 3.96	$ 3.71	$ 67.90
87	**Fuel Expenses**								
88	Demand	Fuel_Dem		$ -	n/a	n/a	n/a	n/a	n/a
89	Energy	Fuel_Energy	$ 0.035964	$ 0.026736	$ 0.035674	$ 0.035205	$ 0.049802	$ 0.037398	$ 0.031982
90	Customer	Fuel_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Total**								
92	Demand (per kW)			$ 8.78	n/a	n/a	n/a	n/a	n/a
93	Energy		$ 0.038391	$ 0.029129	$ 0.038071	$ 0.037631	$ 0.052228	$ 0.039824	$ 0.034408
94	Customer (per cust month)		$ 29.44	$ 300.96	$ 4,357.03	$ 357.90	$ 76.93	$ 24.98	$ 134.31
95	Demand & Customer (per cust month)		$ 239.27	$ 14,903.50	$ 131,532.99	$ 416.89	$ 265.27	$ 29.06	$ 9,837.68
96	**BILLING DETERMINANTS**								
97	Billed Demand	BilledKW	12,421,601	79,870	0	0	0	0	0
98	Energy	SALES_KWH	10,913,898,510	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
99	Customers (Number of Bills)	CUST	5,855,971	48	12	21,550	2,148	116,651	552
100	**Unit Cost after Mitigation**								
101	Mitigated percent of COS @ Equal ROR			150.0%	107.6%	84.0%	136.0%	86.4%	82.7%
102	Demand (per kW)			$ 13.16					
103	Energy		$ 0.0384	$ 0.0437	$ 0.0410	$ 0.0316	$ 0.0710	$ 0.0344	$ 0.0284
104	Customer (per cust month)		$ 29.44	$ 451.44	$ 4,686.53	$ 300.79	$ 104.62	$ 21.59	$ 111.05
105	Demand & Customer (per cust month)		$ 239.27	$ 22,355.25	$ 141,480.26	$ 350.37	$ 360.75	$ 25.11	$ 8,133.91

FERC Account	12/31/2021 Balance	34 kV	RailRoad	Primary	Secondary Demand	Secondary Customer
36010 Land	5,707,254	416,039	11,503			
36020 Land Rights		56,784	-			
36100 Structures and Improvements	16,832,974	2,589,124	742,949			
36200 Station Equipment	552,738,198	69,393,080	5,587,120			
36410 Customers Transformer Station	56,866,138	2,308,531	181,625			
36420 Poles, Towers and Fixtures	615,333,058	33,221,813		445,630,940	55,565,423	80,914,882
36500 Overhead Conductors, Device	387,401,112	17,965,960		249,977,355	60,868,999	58,588,798
36600 Underground Conduit	5,967,003	63,686		4,570,105	425,943	907,269
36700 Undergrnd Conductors,Device	588,030,774	1,884,014		453,770,679	42,292,374	90,083,707
Poles				76.55%	40.71%	59.29%
OH				67.66%	50.95%	49.05%
UG				77.42%	31.95%	68.05%
Distribution Land						
Land and land rights	91.51%	5,222,928				
Land and land rights - Sub-trans	8.28%	472,823				
Land and land rights - RR	0.20%	11,503				
	100.00%	5,707,254	TRUE			
Distribution Structures						
Structures and improvements	80.21%	13,500,901				
Structures and improvements - Sub-trans	15.38%	2,589,124				
Structures and improvements - RR	4.41%	742,949				
	100.00%	16,832,974	TRUE			
Distribution Stations						
Station equipment	86.43%	477,757,998				
Station equipment - Sub-trans	12.55%	69,393,080				
Station equipment - RR	1.01%	5,587,120				
	100.00%	552,738,198	TRUE			
Customer Station Eqpt						
Customer stations	95.62%	54,375,982				
Customer stations - Sub-trans	4.06%	2,308,531				
Customer stations - RR	0.32%	181,625				
	100.00%	56,866,138	TRUE			
Poles, Towers, Fixtures						
Poles, Towers and fixtures - Sub-trans	5.40%	33,221,813				
Poles, Towers and fixtures - Primary	72.42%	445,630,940				
Poles, Towers and fixtures - SEC - Demand	9.03%	55,565,423				
Poles, Towers and fixtures - SEC - Customer	13.15%	80,914,882				
	100.00%	615,333,058	TRUE			
OH Conductor						
Overhead conductors - Sub-trans	4.64%	17,965,960				
Overhead conductors - Primary	64.53%	249,977,355				
Overhead conductors - SEC - Demand	15.71%	60,868,999				
Overhead conductors - SEC - Customer	15.12%	58,588,798				
	100.00%	387,401,112	TRUE			
UG Conduit						
Underground conduit - Sub-trans	1.07%	63,686				
Underground conduit - Primary	76.59%	4,570,105				
Underground conduit - SEC - Demand	7.14%	425,943				
Underground conduit - SEC - Customer	15.20%	907,269				
	100.00%	5,967,003	TRUE			
UG Conductor						
Underground conductors - Sub-trans	0.32%	1,884,014				
Underground conductors - Primary	77.17%	453,770,679				
Underground conductors - SEC - Demand	7.19%	42,292,374				
Underground conductors - SEC - Customers	15.32%	90,083,707				
	100.00%	588,030,774	TRUE			
Steam Expense						
Steam expenses - fixed	100.00%		57.83%	last time		
Steam expenses - variable	0.00%	-	42.17%			
	100.00%	34,967,510				
Misc. Steam Expense						
Miscellaneous steam power expenses - fixed	100.00%		45.63%			
Miscellaneous steam power expenses - variable	0.00%	-	54.37%			
	100.00%	11,583,891				
Taxes Other Than Income Taxes Split						
Property	0					
Payroll	0					
Excise	0					
TY Billing Determinant Totals						
Billed kW	12,421,601					
Total kWh at meter	10,913,898,510					
Customer Count	487,998					

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

Line No.	Pole Account 364			
1	Total Amount of Poles		$	577,208,375
2	Primary Poles	77%	$	441,877,585
3	Secondary Poles	23%	$	135,330,790
4	Total Count of Poles (# of poles)			277,492
5	Primary Poles (# of poles)	77%		213,669
6	Secondary Poles (# of poles)	23%		63,823
7	Secondary Poles (# of poles)			63,823
8	Minimum Cost Plug (Cost of 35 foot pole)		$	1,257
9	Minimum Cost to Provide Secondary (line 7 * line 8)		$	80,233,371
10	Customer - Poles (line 9 / line 3)			59.29%
11	Demand - Poles			40.71%
	Secondary Conductors Overhead - Account 365			
12	Total Feet of Circuits - O/H			21,310,365
	Minimum Size - #4 AL Triplex (14002130)			
13	Minimum Cost Per Foot - O/H			$1.04
14	Total Minimum Cost - O/H		$	22,162,779
15	Total Replacement Cost - O/H		$	45,188,105
16	Customer - O/H			49.0%
17	Demand - O/H			51.0%
	Secondary Conductors Underground - Account 366			
18	Total Feet of Circuits - U/G			4,774,827
	Minimum Size - 4/0 Alum Triplex			
19	Minimum Cost Per Foot - U/G		$	6.68
20	Total Minimum Cost - U/G		$	31,895,847
21	Total Replacement Cost - U/G		$	46,870,265
22	Customer - U/G			68.1%
23	Demand - U/G			31.9%

Northern Indiana Public Service Company
Functional Split Study
Pole Analysis

Development of Ratios for Allocation of Poles carrying Primary and Secondary

Line No.		34 kV	Primary	Secondary	Service	Total
1	Typical Replacement Height (feet)	65	45	35	35	
2	Unit Cost (cost per pole)	$ 8,964	$ 2,039	$ 1,257	$ 1,257	
3	34 kV Pole with Secondary	$ 8,964		$ 1,257		$ 10,221
4	Percent	87.70%		12.30%		100.00%
5	Primary <34 kV Pole w/ Sec		$ 2,039	$ 1,257		$ 3,296
6	Percent		61.86%	38.14%		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	$ 747,754,762	$ 288,314,015	$ 84,797,242	$ 39,970,353	$ 139,039,321	$ 44,041,603	$ 29,853,774	$ 2,533,239	
8	34 kV									
9	Primary		100.00%	61.86%	61.86%	44.78%				
10	Secondary			38.14%		27.61%	100.00%	50.00%		
11	Service				38.14%	27.61%		50.00%	100.00%	
12	34 kV		-	-	-	-	-	-	-	
13	Primary	441,877,585	288,314,015	52,451,407	24,723,696	62,255,561	-	-	-	
14	Secondary	135,330,790	-	32,345,835	-	38,391,880	44,041,603	14,926,887	-	
15	Service		-	-	15,246,657	38,391,880	-	14,926,887	2,533,239	

Line No.		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)	$ 27,843,405	$ 7,277,684	$ 318,830	$ 1,184,949	$ 33,880,797	$ 30,669,067	$ 2,386,573	$ 15,643,911
17	34 kV	100.00%	87.70%	87.70%	78.10%	81.47%	73.12%	73.12%	66.32%
18	Primary					18.53%	16.63%	16.63%	15.08%
19	Secondary		12.30%		10.95%		10.25%		9.30%
20	Service			12.30%	10.95%			10.25%	9.30%
21	34 kV	27,843,405	6,382,602	279,617	925,398	27,603,555	22,424,731	1,745,024	10,374,754
22	Primary	-	-	-	-	6,277,242	5,099,541	396,831	2,359,292
23	Secondary	-	895,082	-	129,776	-	3,144,795	-	1,454,933
24	Service	-	-	39,213	129,776	-	-	244,718	1,454,933

Line No.			Rounded	Total Poles
25	Primary/Secondary Split			
26	**Primary**	76.55%	**77.00%**	213,669
27	**Secondary**	23.45%	**23.00%**	63,823
28	Sub-Total	100.00%	100.00%	277,492

Northern Indiana Public Service Company
Functional Split Study
Conductor Analysis

FUNCTIONAL SPLIT

Line No.	OVERHEAD CIRCUITS	Primary	Secondary
1	Length (Feet)	41,300,003	21,310,365
2	Split (%)		
3	Replacement Cost ($)	$94,560,617	$45,188,105
4	Split (%)	67.7%	32.3%

Line No.	UNDERGROUND CIRCUITS	Primary	Secondary
4	Length (Feet)	13,871,640	4,774,827
5	Split (%)		
5	Replacement Cost ($)	$160,666,123	$46,870,265
6	Split (%)	77.4%	22.6%

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	56,778	6	56,784
3	36100 Structures and Improvements	21,979	2,567,145	2,589,124
4	36200 Station Equipment	80,406	69,312,674	69,393,080
5	36410 Customers Transformer Station	95,686	2,212,845	2,308,531
6	36420 Poles, Towers and Fixtures	33,206,330	15,484	33,221,813
7	36500 Overhead Conductors, Device	17,841,012	124,948	17,965,960
8	36600 Underground Conduit	63,686	-	63,686
9	36700 Undergrnd Conductors,Device	1,883,888	126	1,884,014
10	TOTAL	$ 53,251,767	$ 74,647,265	$ 127,899,032

Northern Indiana Power Service Company
Functional Split Study
Railroad Substation Summary

Line No.	Account	Railroad
1	36010 Land	$ 11,503
2	36020 Land Rights	-
3	36100 Structures and Improvements	742,949
4	36200 Station Equipment	5,587,120
5	36410 Customers Transformer Station	181,625
6	TOTAL	$ 6,523,198

SUBSTATION TOTAL DETAIL

Line No.	Substation Name	36010 Land	36020 Land Rights	36100 Structures and	36200 Station Equipment	36410 Customers Transformer	Total
7	Carroll Substation	$ -	$ -	$ -	$ 15,018	$ 175,637	$ 190,654
8	Columbia Ave Substation	-	-	65,695	291,472	-	357,167
9	Eastport Substation	-	-	6,370	214,097	-	220,468
10	Furnessville Substation	15	-	80,325	176,770	5,989	263,097
11	Grand View Substation	-	-	102,508	2,420,502	-	2,523,010
12	Madison Substation	11,489	-	113,291	1,612,137	-	1,736,917
13	New Carlisle Substation	-	-	160,635	297,550	-	458,185
14	Tee Lake Substation	-	-	162,065	330,779	-	492,845
15	Wickliffe Substation	-	-	52,061	228,795	-	280,856
16	TOTAL	$ 11,503	$ -	$ 742,949	$ 5,587,120	$ 181,625	$ 6,523,198

Line No.	Name	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	DEMAND ALLOCATORS									
	4 CP (for Generation)									
1		Test Year 4 CP @ Generation		1,159,173	-	330,703	-	209,829	269,949	6,858
2		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
3	GEN_CP	4 CP @ Generation	2,458,833	1,159,173	-	330,703	-	209,829	269,949	6,858
4			100%	47.14%	0.00%	13.45%	0.00%	8.53%	10.98%	0.28%
	12 CP @ Transmission									
5		Test Year 12 CP @ Generation		755,337	1,647	290,322	1,245	185,289	258,347	10,469
6		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7	TRANS_12CP	12 CP @ Transmission	2,435,327	755,337	1,647	290,322	1,245	185,289	258,347	10,469
8			100%	31.02%	0.07%	11.92%	0.05%	7.61%	10.61%	0.43%
	NCPs @ Sub-Transmission									
9		Test Year NCPs @ Sub-Transmission		1,292,131	4,344	418,454	3,784	227,869	293,021	19,848
10		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	SUB_NCP	NCP @ Sub-Transmission	2,649,182	1,292,131	4,344	418,454	3,784	227,869	293,021	19,848
12			100%	48.77%	0.16%	15.80%	0.14%	8.60%	11.06%	0.75%
	NCPs @ Primary									
13		Test Year NCPs @ Primary		1,288,762	4,333	414,060	3,774	227,241	281,190	14,919
14		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	DIST_NCP	NCP @ Primary	2,483,823	1,288,762	4,333	414,060	3,774	227,241	281,190	14,919
16			100%	51.89%	0.17%	16.67%	0.15%	9.15%	11.32%	0.60%
	Avg. of 12 Monthly NCPs @ Secondary									
17		Test Year Avg. Monthly NCPs @ Secondary		737,155	2,809	281,328	2,269	161,457	106,703	4,532
18		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	SEC_NCP12	NCP12 @ Secondary	1,391,974	737,155	2,809	281,328	2,269	161,457	106,703	4,532
20			100%	52.96%	0.20%	20.21%	0.16%	11.60%	7.67%	0.33%
	Customer Stations - Transmission									
21		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
22		Customers Taking at Transmission		0.00%	0.00%	0.00%	0.00%	0.00%	2.07%	0.00%
23	STAT_TRAN	Customer Station - Tran.	27	-	-	-	-	-	11	-
24			100%	0.00%	0.00%	0.00%	0.00%	0.00%	40.67%	0.00%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)
	DEMAND ALLOCATORS								
	4 CP (for Generation)								
1		Test Year 4 CP @ Generation		224,825	185,135	22,870	32,390	4,590	42
2		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
3	GEN_CP	4 CP @ Generation	2,458,833	224,825	185,135	22,870	32,390	4,590	42
4			100%	9.14%	7.53%	0.93%	1.32%	0.19%	0.00%
	12 CP @ Transmission								
5		Test Year 12 CP @ Generation		202,859	657,824	21,774	36,467	4,202	42
6		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7	TRANS_12CP	12 CP @ Transmission	2,435,327	202,859	657,824	21,774	36,467	4,202	42
8			100%	8.33%	27.01%	0.89%	1.50%	0.17%	0.00%
	NCPs @ Sub-Transmission								
9		Test Year NCPs @ Sub-Transmission		224,108	85,778	16,304	16,591	8,330	41
10		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	SUB_NCP	NCP @ Sub-Transmission	2,649,182	224,108	85,778	16,304	16,591	8,330	41
12			100%	8.46%	3.24%	0.62%	0.63%	0.31%	0.00%
	NCPs @ Primary								
13		Test Year NCPs @ Primary		207,690	-	0	(0)	8,308	41
14		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	DIST_NCP	NCP @ Primary	2,483,823	207,690	-	0	(0)	8,308	41
16			100%	8.36%	0.00%	0.00%	0.00%	0.33%	0.00%
	Avg. of 12 Monthly NCPs @ Secondary								
17		Test Year Avg. Monthly NCPs @ Secondary		71,896	-	-	-	5,842	40
18		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	SEC_NCP12	NCP12 @ Secondary	1,391,974	71,896	-	-	-	5,842	40
20			100%	5.17%	0.00%	0.00%	0.00%	0.42%	0.00%
	Customer Stations - Transmission								
21		Customer Count	487,998	260	7	5	4	409	6
22		Customers Taking at Transmission		0.77%	70.73%	40.00%	75.51%	0.00%	0.00%
23	STAT_TRAN	Customer Station - Tran.	27	2	5	2	3	-	-
24			100%	7.47%	18.38%	7.42%	11.21%	0.00%	0.00%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(Q)	(R)	(S)	(T)	(U)	(V)
	DEMAND ALLOCATORS								
	4 CP (for Generation)								
1		Test Year 4 CP @ Generation		-	1,808	-	807	-	9,856
2		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
3	GEN_CP	4 CP @ Generation	2,458,833	-	1,808	-	807	-	9,856
4			100%	0.00%	0.07%	0.00%	0.03%	0.00%	0.40%
	12 CP @ Transmission								
5		Test Year 12 CP @ Generation		619	2,035	764	807	290	4,989
6		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7	TRANS_12CP	12 CP @ Transmission	2,435,327	619	2,035	764	807	290	4,989
8			100%	0.03%	0.08%	0.03%	0.03%	0.01%	0.20%
	NCPs @ Sub-Transmission								
9		Test Year NCPs @ Sub-Transmission		-	4,986	10,196	788	3,814	18,794
10		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	SUB_NCP	NCP @ Sub-Transmission	2,649,182	-	4,986	10,196	788	3,814	18,794
12			100%	0.00%	0.19%	0.38%	0.03%	0.14%	0.71%
	NCPs @ Primary								
13		Test Year NCPs @ Primary		-	-	10,170	786	3,804	18,745
14		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	DIST_NCP	NCP @ Primary	2,483,823	-	-	10,170	786	3,804	18,745
16			100%	0.00%	0.00%	0.41%	0.03%	0.15%	0.75%
	Avg. of 12 Monthly NCPs @ Secondary								
17		Test Year Avg. Monthly NCPs @ Secondary		-	-	9,067	776	3,406	4,696
18		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	SEC_NCP12	NCP12 @ Secondary	1,391,974	-	-	9,067	776	3,406	4,696
20			100%	0.00%	0.00%	0.65%	0.06%	0.24%	0.34%
	Customer Stations - Transmission								
21		Customer Count	487,998	4	1	1,796	179	9,721	46
22		Customers Taking at Transmission		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	STAT_TRAN	Customer Station - Tran.	27	4	-	-	-	-	-
24			100%	14.85%	0.00%	0.00%	0.00%	0.00%	0.00%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Customer Stations - Sub-Transmission									
25		No. of Customers		419,221	122	52,428	151	3,102	530	6
26		Customers Taking at Sub-Transmission		0.00%	0.00%	0.01%	0.00%	0.03%	2.40%	16.67%
27	STAT_SBTRN	Customer Station - Sub-Tran.	33	-	-	3	-	1	13	1
28			100%	0.00%	0.00%	9.17%	0.00%	2.95%	38.47%	3.08%
	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%
	KW Billing Determinants									
31	BILLEDKW	KW Billing Determinants	12,421,601	-	-	-	-	2,764,528	3,682,434	117,625
32			100%	0.00%	0.00%	0.00%	0.00%	22.26%	29.65%	0.95%
	CUSTOMER ALLOCATORS									
	Test Year-End Customer Count									
33	CUST	No. of Customers	487,998	419,221	122	52,428	151	3,102	530	6
34			100%	85.91%	0.03%	10.74%	0.03%	0.64%	0.11%	0.00%
	Allocation of Services									
35		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
36		Weighting Factor		1.00	-	1.15	-	1.66	0.65	0.07
37	SERV	Services(Wtd Cust)	497,246	419,221	-	60,256	-	5,148	346	0
38			100%	84.31%	0.00%	12.12%	0.00%	1.04%	0.07%	0.00%
	Allocation of Meters									
39		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
40		Weighting Factor		1.00	2.87	2.09	6.05	5.43	9.31	8.21
41	METERS	Meters (Wtd Cust)	570,505	419,221	351	109,818	913	16,829	4,936	50
42			100%	73.48%	0.06%	19.25%	0.16%	2.95%	0.87%	0.01%
	Allocation of Transformers									
43		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
44		Weighting Factor		1.00	-	3.01	-	11.67	27.18	18.52
45	XFRS	Transformer(Wtd Cust)	638,201	419,221	-	157,778	-	36,187	14,417	113
46			100%	65.69%	0.00%	24.72%	0.00%	5.67%	2.26%	0.02%
	Direct Assignment of Dusk-to-Dawn									
47	DSKDWN	Direct to Dusk-to-Dawn	1	-	-	-	-	-	-	-
48			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer Stations - Sub-Transmission								
25		No. of Customers		260	7	5	4	409	6
26		Customers Taking at Sub-Transmission		3.19%	29.27%	60.00%	24.49%	0.00%	0.00%
27	STAT_SBTRN	Customer Station - Sub-Tran.	33	8	2	3	1	-	-
28			100%	25.10%	6.19%	9.06%	2.96%	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%
	KW Billing Determinants								
31	BILLEDKW	KW Billing Determinants	12,421,601	2,810,181	2,040,000	425,312	501,650	-	-
32			100%	22.62%	16.42%	3.42%	4.04%	0.00%	0.00%
	CUSTOMER ALLOCATORS								
	Test Year-End Customer Count								
33	CUST	No. of Customers	487,998	260	7	5	4	409	6
34			100%	0.05%	0.00%	0.00%	0.00%	0.08%	0.00%
	Allocation of Services								
35		Customer Count	487,998	260	7	5	4	409	6
36		Weighting Factor		0.82	1.25	0.14	-	1.26	0.12
37	SERV	Services(Wtd Cust)	497,246	212	9	1	-	516	1
38			100%	0.04%	0.00%	0.00%	0.00%	0.10%	0.00%
	Allocation of Meters								
39		Customer Count	487,998	260	7	5	4	409	6
40		Weighting Factor		7.85	1,808.64	199.44	280.04	2.98	-
41	METERS	Meters (Wtd Cust)	570,505	2,045	12,660	997	1,120	1,218	-
42			100%	0.36%	2.22%	0.17%	0.20%	0.21%	0.00%
	Allocation of Transformers								
43		Customer Count	487,998	260	7	5	4	409	6
44		Weighting Factor		26.58	8.15	0.51	7.16	3.99	0.34
45	XFRS	Transformer(Wtd Cust)	638,201	6,921	57	3	29	1,630	2
46			100%	1.08%	0.01%	0.00%	0.00%	0.26%	0.00%
	Direct Assignment of Dusk-to-Dawn								
47	DSKDWN	Direct to Dusk-to-Dawn	1	-	-	-	-	-	-
48			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(Q)	(R)	(S)	(T)	(U)	(V)
	Customer Stations - Sub-Transmission								
25		No. of Customers		4	1	1,796	179	9,721	46
26		Customers Taking at Sub-Transmission		0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
27	STAT_SBTRN	Customer Station - Sub-Tran.	33	-	1	-	-	-	-
28			100%	0.00%	3.02%	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%
	KW Billing Determinants								
31	BILLEDKW	KW Billing Determinants	12,421,601	79,870	-	-	-	-	-
32			100%	0.64%	0.00%	0.00%	0.00%	0.00%	0.00%
	CUSTOMER ALLOCATORS								
	Test Year-End Customer Count								
33	CUST	No. of Customers	487,998	4	1	1,796	179	9,721	46
34			100%	0.00%	0.00%	0.37%	0.04%	1.99%	0.01%
	Allocation of Services								
35		Customer Count	487,998	4	1	1,796	179	9,721	46
36		Weighting Factor		-	-	0.80	0.93	1.02	1.16
37	SERV	Services(Wtd Cust)	497,246	-	-	1,438	167	9,877	53
38			100%	0.00%	0.00%	0.29%	0.03%	1.99%	0.01%
	Allocation of Meters								
39		Customer Count	487,998	4	1	1,796	179	9,721	46
40		Weighting Factor		10.27	55.68	-	-	-	5.43
41	METERS	Meters (Wtd Cust)	570,505	41	56	-	-	-	250
42			100%	0.01%	0.01%	0.00%	0.00%	0.00%	0.04%
	Allocation of Transformers								
43		Customer Count	487,998	4	1	1,796	179	9,721	46
44		Weighting Factor		27.18	-	0.33	0.20	0.07	8.26
45	XFRS	Transformer(Wtd Cust)	638,201	109	-	598	35	721	380
46			100%	0.02%	0.00%	0.09%	0.01%	0.11%	0.06%
	Direct Assignment of Dusk-to-Dawn								
47	DSKDWN	Direct to Dusk-to-Dawn	1	-	-	-	-	1	-
48			100%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Direct Assignment of Street and Traffic Lighting (Count of Lights)									
49	STTRLGT	Direct to Street and Traffic Lighting	66,251	-	-	-	-	-	-	-
50			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Gross Write-Offs									
51	GRSWRTOFF	Gross Write Offs	15,644,668	13,711,122	-	1,060,336	-	106,371	23,428	-
52			100%	87.64%	0.00%	6.78%	0.00%	0.68%	0.15%	0.00%
	Meter Reading									
53		Number of Customers	487,998	419,221	122	52,428	151	3,102	530	6
54		Weighted		1.00	104.44	1.73	21.23	7.40	69.80	219.53
55	METER_READ	AMR Meter Reading	656,424	419,221	12,746	90,617	3,203	22,944	37,022	1,345
56			100%	63.86%	1.94%	13.80%	0.49%	3.50%	5.64%	0.20%
	Customer Account Supervision									
57		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
58		Weighting Factor		1.00	1.27	1.42	1.93	1.73	1.73	0.50
59	ACCT_901	Customer Account Supervision	505,120	419,221	155	74,314	291	5,360	916	3
60			100%	82.99%	0.03%	14.71%	0.06%	1.06%	0.18%	0.00%
	Customer Records and Collecting									
61		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
62		Weighting Factor		1.00	6.25	1.32	7.24	1.84	14.17	181.79
63	ACCT_903	Customer Records & Collections	519,522	419,221	762	69,402	1,092	5,702	7,515	1,113
64			100%	80.69%	0.15%	13.36%	0.21%	1.10%	1.45%	0.21%
	Customer Assistance Expense									
65		Customer Count	487,998	419,221	122	52,428	151	3,102	530	6
66		Weighting Factor		1.00	32.69	1.86	27.08	38.81	298.78	890.98
67	ACCT_910	Customer Assistance Expense	984,367	419,221	3,989	97,419	4,085	120,373	158,480	5,457
68			100%	42.59%	0.41%	9.90%	0.41%	12.23%	16.10%	0.55%
	Weighed Secondary Customers (Lighting @ 0.25)									
69		Number of Secondary Customers	484,425	419,202	122	49,627	151	2,892	226	1
70		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
71	WEIGHTSNDCST	Secondary Customers w/ Lighting at	475,653	419,202	122	49,627	151	2,892	226	1
72			100%	88.13%	0.03%	10.43%	0.03%	0.61%	0.05%	0.00%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)
	Direct Assignment of Street and Traffic Lighting (Count of Lights)								
49	STTRLGT	Direct to Street and Traffic Lighting	66,251	-	-	-	-	-	-
50			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Gross Write-Offs								
51	GRSWRTOFF	Gross Write Offs	15,644,668	-	-	-	714,410	542	-
52			100%	0.00%	0.00%	0.00%	4.57%	0.00%	0.00%
	Meter Reading								
53		Number of Customers	487,998	260	7	5	4	409	6
54		Weighted		147.63	549.44	897.42	961.52	3.13	-
55	METER_READ	AMR Meter Reading	656,424	38,437	3,846	4,487	3,846	1,281	-
56			100%	5.86%	0.59%	0.68%	0.59%	0.20%	0.00%
	Customer Account Supervision								
57		Customer Count	487,998	260	7	5	4	409	6
58		Weighting Factor		0.34	0.72	0.50	0.50	0.48	0.50
59	ACCT_901	Customer Account Supervision	505,120	88	5	3	2	195	3
60			100%	0.02%	0.00%	0.00%	0.00%	0.04%	0.00%
	Customer Records and Collecting								
61		Customer Count	487,998	260	7	5	4	409	6
62		Weighting Factor		10.16	354.97	476.89	498.84	0.62	0.60
63	ACCT_903	Customer Records & Collections	519,522	2,646	2,485	2,384	1,995	252	3
64			100%	0.51%	0.48%	0.46%	0.38%	0.05%	0.00%
	Customer Assistance Expense								
65		Customer Count	487,998	260	7	5	4	409	6
66		Weighting Factor		294.09	3,591.35	5,026.84	6,283.29	8.13	668.49
67	ACCT_910	Customer Assistance Expense	984,367	76,568	25,139	25,134	25,133	3,325	3,854
68			100%	7.78%	2.55%	2.55%	2.55%	0.34%	0.39%
	Weighed Secondary Customers (Lighting @ 0.25)								
69		Number of Secondary Customers	484,425	92	-	-	-	364	6
70		Weighting		1.00	1.00	1.00	1.00	1.00	1.00
71	WEIGHTSNDCST	Secondary Customers w/ Lighting at	475,653	92	-	-	-	364	6
72			100%	0.02%	0.00%	0.00%	0.00%	0.08%	0.00%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(Q)	(R)	(S)	(T)	(U)	(V)
	Direct Assignment of Street and Traffic Lighting (Count of Lights)								
49	STTRLGT	Direct to Street and Traffic Lighting	66,251	-	-	65,015	1,237	-	-
50			100%	0.00%	0.00%	98.13%	1.87%	0.00%	0.00%
	Gross Write-Offs								
51	GRSWRTOFF	Gross Write Offs	15,644,668	-	-	469	-	27,989	-
52			100%	0.00%	0.00%	0.00%	0.00%	0.18%	0.00%
	Meter Reading								
53		Number of Customers	487,998	4	1	1,796	179	9,721	46
54		Weighted		186.33	8,605.39	-	-	-	175.62
55	METER_READ	AMR Meter Reading	656,424	745	8,605	-	-	-	8,079
56			100%	0.11%	1.31%	0.00%	0.00%	0.00%	1.23%
	Customer Account Supervision								
57		Customer Count	487,998	4	1	1,796	179	9,721	46
58		Weighting Factor		0.97	0.50	0.25	0.50	0.41	0.50
59	ACCT_901	Customer Account Supervision	505,120	4	1	449	90	3,998	23
60			100%	0.00%	0.00%	0.09%	0.02%	0.79%	0.00%
	Customer Records and Collecting								
61		Customer Count	487,998	4	1	1,796	179	9,721	46
62		Weighting Factor		15.01	217.04	0.25	0.51	0.42	0.51
63	ACCT_903	Customer Records & Collections	519,522	60	217	455	91	4,101	23
64			100%	0.01%	0.04%	0.09%	0.02%	0.79%	0.00%
	Customer Assistance Expense								
65		Customer Count	487,998	4	1	1,796	179	9,721	46
66		Weighting Factor		351.66	5,340.66	0.52	1.04	0.85	1.04
67	ACCT_910	Customer Assistance Expense	984,367	1,407	5,341	930	186	8,277	48
68			100%	0.14%	0.54%	0.09%	0.02%	0.84%	0.00%
	Weighed Secondary Customers (Lighting @ 0.25)								
69		Number of Secondary Customers	484,425	-	-	1,796	179	9,721	46
70		Weighting		1.00	1.00	0.25	0.25	0.25	1.00
71	WEIGHTSNDCST	Secondary Customers w/ Lighting at	475,653	-	-	449	45	2,430	46
72			100%	0.00%	0.00%	0.09%	0.01%	0.51%	0.01%

Line No.	Name	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Customer Charge Billing Determinants									
73	CC_BILLDET	Customer Charge Billing Determinar	6,911,416	5,102,724	868	660,968	1,225	-	-	-
74			100%	73.83%	0.01%	9.56%	0.02%	0.00%	0.00%	0.00%
	Number of Secondary Customers									
75		No. of Customers	487,998	419,221	122	52,428	151	3,102	530	6
76		Weighting - Taking at Secondary		1.00	1.00	0.95	1.00	0.93	0.43	0.24
77	SNDCST	No. of Secondary Customers	484,425	419,202	122	49,627	151	2,892	226	1
78				86.54%	0.03%	10.24%	0.03%	0.60%	0.05%	0.00%
	ENERGY ALLOCATORS									
	MWh Sales @ Generation									
79		Energy at Source	11,274,423	3,565,974	9,760	1,643,907	8,437	1,032,796	1,518,515	87,429
80		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
81	ENRGYSRC		11,274,423	3,565,974	9,760	1,643,907	8,437	1,032,796	1,518,515	87,429
82			100%	31.63%	0.09%	14.58%	0.07%	9.16%	13.47%	0.78%
	Total Volume of kWh Sales									
83		TRANSMISSION		-	-	-	-	-	51,088,951	-
84		SUB-TRANSMISSION		-	-	12,793,260	-	150,888	54,589,242	21,159,092
85		PRIMARY		155,279	-	72,253,936	-	67,686,758	741,668,788	43,751,504
86		SECONDARY		3,452,042,871	9,448,602	1,507,001,750	8,167,651	932,423,644	628,616,593	20,244,392
87		Total KWh	10,951,680,176	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988
88			100%	31.52%	0.09%	14.54%	0.07%	9.13%	13.48%	0.78%
	REVENUE ALLOCATORS									
	Direct Assignment of Interdepartmental									
89	INTERDEPT	Interdepartmental	1	-	-	-	-	-	-	-
90			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	MWh Sales @ Generation									
91	REV_ENRGYSRC	Energy at Source	11,274,423	3,565,974	9,760	1,643,907	8,437	1,032,796	1,518,515	87,429
92			100%	31.63%	0.09%	14.58%	0.07%	9.16%	13.47%	0.78%
	Net Late Charges and Credits									
93	LT_FEES	3-Year Average Late Payments	$ 3,361,373	2,270,687	7	591,897	-	143,626	184,906	1,936
94			100%	67.55%	0.00%	17.61%	0.00%	4.27%	5.50%	0.06%
	Retail Sales without Fuel									
95	RETAIL_SALES	Retail Sales Allocator	$ 1,039,935,261	393,406,443	511,408	191,464,654	569,972	96,355,294	120,480,221	4,592,967
96			100%	37.83%	0.05%	18.41%	0.05%	9.27%	11.59%	0.44%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer Charge Billing Determinants								
73	CC_BILLDET	Customer Charge Billing Determinar	6,911,416	-	-	-	-	110,260	96
74			100%	0.00%	0.00%	0.00%	0.00%	1.60%	0.00%
	Number of Secondary Customers								
75		No. of Customers	487,998	260	7	5	4	409	6
76		Weighting - Taking at Secondary		0.35	-	-	-	0.89	1.00
77	SNDCST	No. of Secondary Customers	484,425	92	-	-	-	364	6
78				0.02%	0.00%	0.00%	0.00%	0.08%	0.00%
	ENERGY ALLOCATORS								
	MWh Sales @ Generation								
79		Energy at Source	11,274,423	1,575,403	1,248,526	167,971	273,163	34,076	348
80		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
81	ENRGYSRC		11,274,423	1,575,403	1,248,526	167,971	273,163	34,076	348
82			100%	13.97%	11.07%	1.49%	2.42%	0.30%	0.00%
	Total Volume of kWh Sales								
83		TRANSMISSION		38,860,087	1,102,091,570	76,580,316	188,792,822	-	-
84		SUB-TRANSMISSION		106,932,029	123,270,343	88,117,484	79,187,017	-	-
85		PRIMARY		843,503,725	-	-	-	3,617,149	-
86		SECONDARY		542,807,511	-	-	-	29,394,025	337,325
87		Total KWh	10,951,680,176	1,532,103,352	1,225,361,912	164,697,799	267,979,838	33,011,174	337,325
88			100%	13.99%	11.19%	1.50%	2.45%	0.30%	0.00%
	REVENUE ALLOCATORS								
	Direct Assignment of Interdepartmental								
89	INTERDEPT	Interdepartmental	1	-	-	-	-	-	-
90			100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	MWh Sales @ Generation								
91	REV_ENRGYSRC	Energy at Source	11,274,423	1,575,403	1,248,526	167,971	273,163	34,076	348
92			100%	13.97%	11.07%	1.49%	2.42%	0.30%	0.00%
	Net Late Charges and Credits								
93	LT_FEES	3-Year Average Late Payments	$ 3,361,373	114,682	37,507	-	-	163	291
94			100%	3.41%	1.12%	0.00%	0.00%	0.00%	0.01%
	Retail Sales without Fuel								
95	RETAIL_SALES	Retail Sales Allocator	$ 1,039,935,261	99,854,682	94,841,338	8,113,309	12,138,197	3,040,637	96,638
96			100%	9.60%	9.12%	0.78%	1.17%	0.29%	0.01%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(Q)	(R)	(S)	(T)	(U)	(V)
	Customer Charge Billing Determinants								
73	CC_BILLDET	Customer Charge Billing Determinar	6,911,416	-	54,178	780,175	14,840	186,081	-
74			100%	0.00%	0.78%	11.29%	0.21%	2.69%	0.00%
	Number of Secondary Customers								
75		No. of Customers	487,998	4	1	1,796	179	9,721	46
76		Weighting - Taking at Secondary		-	-	1.00	1.00	1.00	1.00
77	SNDCST	No. of Secondary Customers	484,425	-	-	1,796	179	9,721	46
78				0.00%	0.00%	0.37%	0.04%	2.01%	0.01%
	ENERGY ALLOCATORS								
	MWh Sales @ Generation								
79		Energy at Source	11,274,423	4,068	19,520	34,850	7,445	14,788	27,446
80		Adjustment Factor		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
81	ENRGYSRC		11,274,423	4,068	19,520	34,850	7,445	14,788	27,446
82			100%	0.04%	0.17%	0.31%	0.07%	0.13%	0.24%
	Total Volume of kWh Sales								
83		TRANSMISSION		3,993,490	-	-	-	-	-
84		SUB-TRANSMISSION		-	19,120,033	-	-	-	-
85		PRIMARY		-	-	-	-	-	-
86		SECONDARY		-	-	33,738,540	7,207,774	14,315,916	26,569,822
87		Total KWh	10,951,680,176	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
88			100%	0.04%	0.17%	0.31%	0.07%	0.13%	0.24%
	REVENUE ALLOCATORS								
	Direct Assignment of Interdepartmental								
89	INTERDEPT	Interdepartmental	1	-	-	-	-	-	1
90			100%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	MWh Sales @ Generation								
91	REV_ENRGYSRC	Energy at Source	11,274,423	4,068	19,520	34,850	7,445	14,788	27,446
92			100%	0.04%	0.17%	0.31%	0.07%	0.13%	0.24%
	Net Late Charges and Credits								
93	LT_FEES	3-Year Average Late Payments	$ 3,361,373	5,553	-	-	139	9,980	-
94			100%	0.17%	0.00%	0.00%	0.00%	0.30%	0.00%
	Retail Sales without Fuel								
95	RETAIL_SALES	Retail Sales Allocator	$ 1,039,935,261	2,296,811	1,160,598	5,362,080	701,070	2,021,222	2,927,720
96			100%	0.22%	0.11%	0.52%	0.07%	0.19%	0.28%

Line No.	Name	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Retail Sales without Fuel without Interdepartmental									
97	RETAIL_SALES	Retail Sales Allocator	$ 1,039,935,261	393,406,443	511,408	191,464,654	569,972	96,355,294	120,480,221	4,592,967
98		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
99	RETAIL_SALES_wo_INTD		$ 1,037,007,541	393,406,443	511,408	191,464,654	569,972	96,355,294	120,480,221	4,592,967
100			100%	37.94%	0.05%	18.46%	0.05%	9.29%	11.62%	0.44%
	DSM Revenue									
101	DSM	Retail Sales Allocator	$ 11,624,641	3,093,339	(14,234)	1,427,600	(17,847)	1,935,571	3,299,564	101,055
102			100%	26.61%	-0.12%	12.28%	-0.15%	16.65%	28.38%	0.87%
	Rider Revenue									
103	TDSIC	Retail Sales Allocator	$ 62,108,337	28,870,347	96,964	10,521,475	97,764	6,605,675	7,464,987	314,362
104			100%	46.48%	0.16%	16.94%	0.16%	10.64%	12.02%	0.51%
	Generation Credit									
105	GEN_CREDIT	Retail Sales Allocator	$ (82,861)	(28,330)	(51)	(14,185)	(68)	(9,289)	(11,652)	(409)
106			100%	34.19%	0.06%	17.12%	0.08%	11.21%	14.06%	0.49%
	FUEL ALLOCATORS									
	Fuel Sales									
107	FUELREV	Fuel Revenue	$ 392,509,634	124,604,472	341,040	57,442,413	294,805	36,088,611	53,014,950	3,055,004
108			100%	31.75%	0.09%	14.63%	0.08%	9.19%	13.51%	0.78%
	Fuel Sales without Interdepartmental									
109		Retail Sales Allocator	$ 392,509,634	124,604,472	341,040	57,442,413	294,805	36,088,611	53,014,950	3,055,004
110		Weighting		1.00	1.00	1.00	1.00	1.00	1.00	1.00
111	FUELREV_wo_INTD		$ 391,659,879	124,604,472	341,040	57,442,413	294,805	36,088,611	53,014,950	3,055,004
112			100%	31.81%	0.09%	14.67%	0.08%	9.21%	13.54%	0.78%
	UNIT COST BILLING DETERMINANTS									
	Energy at Meter									
113	SALES_KWH	Energy Sales - kWh	10,913,898,510	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988
114			100%	31.63%	0.09%	14.59%	0.07%	9.17%	13.52%	0.78%
	Revenue at Current Rates									
115		Revenue	$ 1,506,095,013	549,946,271	935,127	260,841,956	944,627	140,975,862	184,248,070	8,062,979
116			100%	36.51%	0.06%	17.32%	0.06%	9.36%	12.23%	0.54%
	Base Rate Margin at Current Rates									
117		Margin Revenue	$ 1,039,935,261	393,406,443	511,408	191,464,654	569,972	96,355,294	120,480,221	4,592,967
118			100%	37.83%	0.05%	18.41%	0.05%	9.27%	11.59%	0.44%

Northern Indiana Public Service Company
Class Allocation Factors

Line No.	Name	Description	Total	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping
	(A)	(B)	(C)	(K)	(L)	(M)	(N)	(O)	(P)
	Retail Sales without Fuel without Interdepartmental								
97	RETAIL_SALES	Retail Sales Allocator	$ 1,039,935,261	99,854,682	94,841,338	8,113,309	12,138,197	3,040,637	96,638
98		Weighting		1.00	1.00	1.00	1.00	1.00	1.00
99	RETAIL_SALES_wo_INTD		$ 1,037,007,541	99,854,682	94,841,338	8,113,309	12,138,197	3,040,637	96,638
100			100%	9.63%	9.15%	0.78%	1.17%	0.29%	0.01%
	DSM Revenue								
101	DSM	Retail Sales Allocator	$ 11,624,641	1,254,056	-	477,046	20,933	(1,445)	-
102			100%	10.79%	0.00%	4.10%	0.18%	-0.01%	0.00%
	Rider Revenue								
103	TDSIC	Retail Sales Allocator	$ 62,108,337	4,362,830	2,205,490	271,887	581,721	183,472	1,152
104			100%	7.02%	3.55%	0.44%	0.94%	0.30%	0.00%
	Generation Credit								
105	GEN_CREDIT	Retail Sales Allocator	$ (82,861)	(6,795)	(8,503)	(719)	(1,620)	(196)	(6)
106			100%	8.20%	10.26%	0.87%	1.96%	0.24%	0.01%
	FUEL ALLOCATORS								
	Fuel Sales								
107	FUELREV	Fuel Revenue	$ 392,509,634	55,048,731	42,281,630	5,869,365	9,545,022	1,190,712	12,176
108			100%	14.02%	10.77%	1.50%	2.43%	0.30%	0.00%
	Fuel Sales without Interdepartmental								
109		Retail Sales Allocator	$ 392,509,634	55,048,731	42,281,630	5,869,365	9,545,022	1,190,712	12,176
110		Weighting		1.00	1.00	1.00	1.00	1.00	1.00
111	FUELREV_wo_INTD		$ 391,659,879	55,048,731	42,281,630	5,869,365	9,545,022	1,190,712	12,176
112			100%	14.06%	10.80%	1.50%	2.44%	0.30%	0.00%
	UNIT COST BILLING DETERMINANTS								
	Energy at Meter								
113	SALES_KWH	Energy Sales - kWh	10,913,898,510	1,532,103,352	1,187,580,246	164,697,799	267,979,838	33,011,174	337,325
114			100%	14.04%	10.88%	1.51%	2.46%	0.30%	0.00%
	Revenue at Current Rates								
115		Revenue	$ 1,506,095,013	160,513,504	139,319,956	14,730,888	22,284,252	4,413,179	109,959
116			100%	10.66%	9.25%	0.98%	1.48%	0.29%	0.01%
	Base Rate Margin at Current Rates								
117		Margin Revenue	$ 1,039,935,261	99,854,682	94,841,338	8,113,309	12,138,197	3,040,637	96,638
118			100%	9.60%	9.12%	0.78%	1.17%	0.29%	0.01%

Line No.	Name	Description	Total	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(C)	(Q)	(R)	(S)	(T)	(U)	(V)
	Retail Sales without Fuel without Interdepartmental								
97	RETAIL_SALES	Retail Sales Allocator	$ 1,039,935,261	2,296,811	1,160,598	5,362,080	701,070	2,021,222	2,927,720
98		Weighting		1.00	1.00	1.00	1.00	1.00	-
99	RETAIL_SALES_wo_INTD		$ 1,037,007,541	2,296,811	1,160,598	5,362,080	701,070	2,021,222	-
100			100%	0.22%	0.11%	0.52%	0.07%	0.19%	0.00%
	DSM Revenue								
101	DSM	Retail Sales Allocator	$ 11,624,641	15,527	33,476	-	-	-	-
102			100%	0.13%	0.29%	0.00%	0.00%	0.00%	0.00%
	Rider Revenue								
103	TDSIC	Retail Sales Allocator	$ 62,108,337	14,238	35,299	116,137	22,341	81,850	260,347
104			100%	0.02%	0.06%	0.19%	0.04%	0.13%	0.42%
	Generation Credit								
105	GEN_CREDIT	Retail Sales Allocator	$ (82,861)	-	(121)	(441)	(51)	(145)	(280)
106			100%	0.00%	0.15%	0.53%	0.06%	0.18%	0.34%
	FUEL ALLOCATORS								
	Fuel Sales								
107	FUELREV	Fuel Revenue	$ 392,509,634	106,770	682,080	1,187,756	358,964	535,380	849,755
108			100%	0.03%	0.17%	0.30%	0.09%	0.14%	0.22%
	Fuel Sales without Interdepartmental								
109		Retail Sales Allocator	$ 392,509,634	106,770	682,080	1,187,756	358,964	535,380	849,755
110		Weighting		1.00	1.00	1.00	1.00	1.00	-
111	FUELREV_wo_INTD		$ 391,659,879	106,770	682,080	1,187,756	358,964	535,380	-
112			100%	0.03%	0.17%	0.30%	0.09%	0.14%	0.00%
	UNIT COST BILLING DETERMINANTS								
	Energy at Meter								
113	SALES_KWH	Energy Sales - kWh	10,913,898,510	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
114			100%	0.04%	0.18%	0.31%	0.07%	0.13%	0.24%
	Revenue at Current Rates								
115		Revenue	$ 1,506,095,013	2,433,347	1,911,332	6,665,532	1,082,323	2,638,307	4,037,541
116			100%	0.16%	0.13%	0.44%	0.07%	0.18%	0.27%
	Base Rate Margin at Current Rates								
117		Margin Revenue	$ 1,039,935,261	2,296,811	1,160,598	5,362,080	701,070	2,021,222	2,927,720
118			100%	0.22%	0.11%	0.52%	0.07%	0.19%	0.28%

Northern Indiana Public Service Company
Billing Determinants & Test Year Revenue

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Customer Count @ 12/31/23	487,998	419,221	122	52,428	151	3,102	530	6	260
2	Fixed Charges (Bills/Pumps/Fixtures	6,911,416	5,102,724	868	660,968	1,225	-	-	-	-
3	Energy Sales - kWh	10,951,680,176	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988	1,532,103,352
4	Billed Demand - kW	12,493,601	-	-	-	-	2,764,528	3,682,434	117,625	2,810,181
5	Fuel Revenue @ current	392,509,634	124,604,472	341,040	57,442,413	294,805	36,088,611	53,014,950	3,055,004	55,048,731
6	Margin Revenue @ current	1,039,935,261	393,406,443	511,408	191,464,654	569,972	96,355,294	120,480,221	4,592,967	99,854,682
7	TDSIC Revenue	62,108,337	28,870,347	96,964	10,521,475	97,764	6,605,675	7,464,987	314,362	4,362,830
8	DSM Revenue	11,624,641	3,093,339	(14,234)	1,427,600	(17,847)	1,935,571	3,299,564	101,055	1,254,056
9	Generation Credit	(82,861)	(28,330)	(51)	(14,185)	(68)	(9,289)	(11,652)	(409)	(6,795)
10	Total Revenue	1,506,095,013	549,946,271	935,127	260,841,956	944,627	140,975,862	184,248,070	8,062,979	160,513,504

Line No.	Description	Total	Rate 831-Ind. Pwr Serv. - Large
	(A)	(B)	(K)
1	Customer Count @ 12/31/23	487,998	7
2	Fixed Charges (Bills/Pumps/Fixtures	6,911,416	-
3	Energy Sales - kWh	10,951,680,176	1,225,361,912
4	Billed Demand - kW	12,493,601	2,112,000
5	Fuel Revenue @ current	392,509,634	42,281,630
6	Margin Revenue @ current	1,039,935,261	94,841,338
7	TDSIC Revenue	62,108,337	2,205,490
8	DSM Revenue	11,624,641	-
9	Generation Credit	(82,861)	(8,503)
10	Total Revenue	1,506,095,013	139,319,956

Northern Indiana Public Service Company
Billing Determinants & Test Year Revenue

Line No.	Description	Total	Rate 832-Small Industrial Service - LLF	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	Customer Count @ 12/31/23	487,998	5	4	409	6	4	1	1,796	179	9,721	46
2	Fixed Charges (Bills/Pumps/Fixtures	6,911,416	-	-	110,260	96	-	54,178	780,175	14,840	186,081	-
3	Energy Sales - kWh	10,951,680,176	164,697,799	267,979,838	33,011,174	337,325	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
4	Billed Demand - kW	12,493,601	425,312	501,650	-	-	79,870	-	-	-	-	-
5	Fuel Revenue @ current	392,509,634	5,869,365	9,545,022	1,190,712	12,176	106,770	682,080	1,187,756	358,964	535,380	849,755
6	Margin Revenue @ current	1,039,935,261	8,113,309	12,138,197	3,040,637	96,638	2,296,811	1,160,598	5,362,080	701,070	2,021,222	2,927,720
7	TDSIC Revenue	62,108,337	271,887	581,721	183,472	1,152	14,238	35,299	116,137	22,341	81,850	260,347
8	DSM Revenue	11,624,641	477,046	20,933	(1,445)	-	15,527	33,476	-	-	-	-
9	Generation Credit	(82,861)	(719)	(1,620)	(196)	(6)	-	(121)	(441)	(51)	(145)	(280)
10	Total Revenue	1,506,095,013	14,730,888	22,284,252	4,413,179	109,959	2,433,347	1,911,332	6,665,532	1,082,323	2,638,307	4,037,541

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

Line No.	ENERGY AND DEMAND LOSS CALCULATIONS	ENERGY LOSS MULTIPLIERS								
		AGGREGATE MWH LOAD AT VOLTAGE LEVEL	ENERGY % BASIS	ADJUSTMENT FACTOR	%	LOSSES (KWH)	KWH SALES AT VOLTAGE LEVEL	SIMPLE	CUMULATIVE	DEMAND % BASIS
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**VOLTAGE LEVEL (INPUT TO)**									
2	TRANSMISSION	11,274,423,117	1.83%	1.00	1.83%	206,729,241	1,461,407,235	1.0187	1.0187	2.75%
3	SUB-TRANSMISSION	9,606,286,641	.22%	1.00	.22%	21,076,030	505,319,387	1.0022	1.0209	.26%
4	PRIMARY	9,079,891,224	.55%	1.00	.55%	50,360,780	1,772,637,139	1.0056	1.0266	.93%
5	SECONDARY	7,256,893,305	.61%	1.00	.61%	44,576,889	7,212,316,416	1.0062	1.0330	.62%

Line No.		Total Company	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824	Metal Melting Rate 825	Off-Peak Serv. Rate 826
6	**INPUT DATA BY SERVICE CLASSIFICATION**									
7	Energy Inputs									
8	Test Year book kWh Sales	10,951,680,176	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988	1,532,103,352
9	Adjustment	0								
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10	Test Year Adjusted kWh	10,951,680,176	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988	1,532,103,352
11	Demand Inputs									
12	4 CP (for Generation)	2,354,893	1,107,078	0	315,968	0	200,483	258,931	6,596	215,786
13	12 CP (for Transmission)	2,340,488	721,391	1,573	277,386	1,189	177,037	247,802	10,069	194,704
14	NCP12 (Avg. of 12 Monthly NCPs)	2,515,992	732,623	2,791	295,364	2,255	172,131	248,982	18,945	201,673
15	NCP (Non Coincidental Peak)	3,446,413	1,268,931	4,266	411,107	3,716	223,872	299,218	19,629	226,855
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	0.0346140	0.0000000	0.0253639
19	SUB-TRANSMISSION	0.0000000	0.0000000	0.0000000	0.0080357	0.0000000	0.0001508	0.0369855	0.2484774	0.0697943
20	PRIMARY	0.0000000	0.0000450	0.0000000	0.0453842	0.0000000	0.0676691	0.5024980	0.5137867	0.5505528
21	SECONDARY	0.0000000	0.9999550	1.0000000	0.9465800	1.0000000	0.9321801	0.4259025	0.2377358	0.3542891
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22	TOTAL	-	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	1,461,407,235	0	0	0	0	0	51,088,951	0	38,860,087
25	SUB-TRANSMISSION	505,319,387	0	0	12,793,260	0	150,888	54,589,242	21,159,092	106,932,029
26	PRIMARY	1,772,637,139	155,279	0	72,253,936	0	67,686,758	741,668,788	43,751,504	843,503,725
27	SECONDARY	7,212,316,416	3,452,042,871	9,448,602	1,507,001,750	8,167,651	932,423,644	628,616,593	20,244,392	542,807,511
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28	TOTAL	10,951,680,176	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988	1,532,103,352
29	ZERO CHECK -->	0	0	0	0	0	0	0	0	0
30	**DISTRIBUTION OF KWH SALES AND LOSSES BY VOLTAGE LEVEL**									
31	MWH SALES									
32	LOAD @ INPUT TO GENERATION	11,274,423,117	3,565,973,516	9,760,006	1,643,906,663	8,436,837	1,032,796,256	1,518,515,165	87,429,150	1,575,403,474
33	LOSS FACTOR	0.0000	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
35	LOAD @ INPUT TO TRANSMISSION	11,274,423,117	3,565,973,516	9,760,006	1,643,906,663	8,436,837	1,032,796,256	1,518,515,165	87,429,150	1,575,403,474
36	LOSS FACTOR	0.0000	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187	1.0187
37	SALES @ TRANSMISSION	1,461,407,235	0	0	0	0	0	51,088,951	0	38,860,087
38	LOAD @ INPUT TO SUB-TRANSMISSION	9,606,286,641	3,500,587,377	9,581,045	1,613,763,783	8,282,139	1,013,858,774	1,439,582,529	85,826,038	1,507,656,591
39	LOSS FACTOR	0.0000	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022
40	SALES @ SUB-TRANSMISSION	505,319,387	0	0	12,793,260	0	150,888	54,589,242	21,159,092	106,932,029
41	LOAD @ INPUT TO PRIMARY	9,079,891,224	3,492,907,148	9,560,024	1,597,429,953	8,263,968	1,011,483,497	1,381,834,867	64,478,645	1,397,416,789
42	LOSS FACTOR	0.0000	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056	1.0056
43	SALES @ PRIMARY	1,772,637,139	155,279	0	72,253,936	0	67,686,758	741,668,788	43,751,504	843,503,725
44	LOAD @ INPUT TO SECONDARY	7,256,893,305	3,473,378,781	9,507,000	1,516,316,018	8,218,132	938,186,639	632,501,859	20,369,516	546,162,420
45	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
46	SALES @ SECONDARY	7,212,316,416	3,452,042,871	9,448,602	1,507,001,750	8,167,651	932,423,644	628,616,593	20,244,392	542,807,511
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47	TOTAL AT METER	10,951,680,176	3,452,198,150	9,448,602	1,592,048,947	8,167,651	1,000,261,290	1,475,963,574	85,154,988	1,532,103,352
48	ZERO CHECK -->	0	0	0	0	0	0	0	0	0

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

Line No.	ENERGY AND DEMAND LOSS CALCULATIONS	DEMAND LOSS MULTIPLIERS			
		ADJUSTMENT FACTOR	ADJUSTMENT %	SIMPLE	CUMULATIVE
		(C)	(J)	(K)	(L)
1	**VOLTAGE LEVEL (INPUT TO)**				
2	TRANSMISSION	1.00	2.75%	1.0283	1.0283
3	SUB-TRANSMISSION	1.00	.26%	1.0026	1.0309
4	PRIMARY	1.00	.93%	1.0093	1.0406
5	SECONDARY	1.00	.62%	1.0062	1.0471

Line No.		Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 832	HLF Ind Pwr Serv. Rate 833	Muni. Power Rate 841	Int WW Pumping Rate 842	Renewable Sta. Pwr. Rate 843	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental
6	**INPUT DATA BY SERVICE CLASSIFICATION**											
7	Energy Inputs											
8	Test Year book kWh Sales	1,225,361,912	164,697,799	267,979,838	33,011,174	337,325	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
9	Adjustment											
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10	Test Year Adjusted kWh	1,225,361,912	164,697,799	267,979,838	33,011,174	337,325	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
11	Demand Inputs											
12	4 CP (for Generation)	180,000	22,211	31,476	4,386	40	0	1,754	0	770	0	9,413
13	12 CP (for Transmission)	639,579	21,146	35,437	4,016	40	602	1,974	730	771	277	4,765
14	NCP12 (Avg. of 12 Monthly NCPs)	741,440	28,284	38,962	6,521	40	3,768	4,379	9,010	771	3,385	4,667
15	NCP (Non Coincidental Peak)	850,453	30,393	56,000	8,186	40	5,785	4,973	10,013	774	3,746	18,456
16	**MWH SALES AT VOLTAGE LEVEL**											
17	DISTRIB. OF KWH SALES BY VOLTAGE LEVEL (%)											
18	TRANSMISSION	0.8994009	0.4649747	0.7045038	0.0000000	0.0000000	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
19	SUB-TRANSMISSION	0.1005991	0.5350253	0.2954962	0.0000000	0.0000000	0.0000000	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000
20	PRIMARY	0.0000000	0.0000000	0.0000000	0.1095735	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
21	SECONDARY	0.0000000	0.0000000	0.0000000	0.8904265	1.0000000	0.0000000	0.0000000	1.0000000	1.0000000	1.0000000	1.0000000
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22	TOTAL	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	1,102,091,570	76,580,316	188,792,822	0	0	3,993,490	0	0	0	0	0
25	SUB-TRANSMISSION	123,270,343	88,117,484	79,187,017	0	0	0	19,120,033	0	0	0	0
26	PRIMARY	0	0	0	3,617,149	0	0	0	0	0	0	0
27	SECONDARY	0	0	0	29,394,025	337,325	0	0	33,738,540	7,207,774	14,315,916	26,569,822
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28	TOTAL	1,225,361,912	164,697,799	267,979,838	33,011,174	337,325	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
29	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0

Line No.		Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 832	HLF Ind Pwr Serv. Rate 833	Muni. Power Rate 841	Int WW Pumping Rate 842	Renewable Sta. Pwr. Rate 843	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental
30	**DISTRIBUTION OF KWH SALES AND LOSSES BY VOLTAGE LEVEL**											
31	MWH SALES											
32	LOAD @ INPUT TO GENERATION	1,248,526,091	167,971,499	273,162,701	34,076,193	348,443	4,068,083	19,519,995	34,850,483	7,445,325	14,787,735	27,445,501
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	1,248,526,091	167,971,499	273,162,701	34,076,193	348,443	4,068,083	19,519,995	34,850,483	7,445,325	14,787,735	27,445,501
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	1,102,091,570	76,580,316	188,792,822	0	0	3,993,490	0	0	0	0	0
38	LOAD @ INPUT TO SUB-TRANSMISSION	123,541,390	88,311,237	79,361,134	33,451,368	342,054	0	19,162,074	34,211,460	7,308,807	14,516,585	26,942,257
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	123,270,343	88,117,484	79,187,017	0	0	0	19,120,033	0	0	0	0
41	LOAD @ INPUT TO PRIMARY	0	0	0	33,377,976	341,303	0	0	34,136,401	7,292,771	14,484,736	26,883,146
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	3,617,149	0	0	0	0	0	0	0
44	LOAD @ INPUT TO SECONDARY	0	0	0	29,575,699	339,410	0	0	33,947,067	7,252,323	14,404,398	26,734,041
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	29,394,025	337,325	0	0	33,738,540	7,207,774	14,315,916	26,569,822
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47	TOTAL AT METER	1,225,361,912	164,697,799	267,979,838	33,011,174	337,325	3,993,490	19,120,033	33,738,540	7,207,774	14,315,916	26,569,822
48	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0

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

		Total Company	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824	Metal Melting Rate 825	Off-Peak Serv. Rate 826
49	**CLASS CONTRIBUTION TO CONTROL AREA PEAK**									
50	1 COINCIDENT PEAK									
51	KW	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%
53	4 COINCIDENT PEAK									
54	KW	2,354,893	1,107,078	0	315,968	0	200,483	258,931	6,596	215,786
55	LOAD FACTOR	53.09%	35.60%	0.00%	57.52%	0.00%	56.95%	65.07%	147.38%	81.05%
56	12 COINCIDENT PEAK									
57	KW	2,340,488	721,391	1,573	277,386	1,189	177,037	247,802	10,069	194,704
58	LOAD FACTOR	53.42%	54.63%	68.56%	65.52%	78.44%	64.50%	67.99%	96.55%	89.83%
59	**CLASS NON COINCIDENTAL PEAK**									
60	NCP	3,446,413	1,268,931	4,266	411,107	3,716	223,872	299,218	19,629	226,855
61	LOAD FACTOR	36.28%	31.06%	25.28%	44.21%	25.09%	51.00%	56.31%	49.52%	77.10%
62	**CLASS UNDIVERSIFIED KW**									
63	NCP12	2,515,992	732,623	2,791	295,364	2,255	172,131	248,982	18,945	201,673
64	LOAD FACTOR	49.69%	53.79%	38.64%	61.53%	41.34%	66.34%	67.67%	51.31%	86.72%
65	**COINCIDENT KW BY VOLTAGE LEVEL**									
66	4CP FOR GENERATION									
67	PRODUCTION									
68	TRANSMISSION	208,830	0	0	0	0	0	8,963	0	5,473
69	SUB-TRANSMISSION	69,891	0	0	2,539	0	30	9,577	1,639	15,061
70	PRIMARY	280,740	50	0	14,340	0	13,567	130,113	3,389	118,802
71	SECONDARY	1,795,432	1,107,029	0	299,089	0	186,887	110,280	1,568	76,451
72	TOTAL	2,354,893	1,107,078	0	315,968	0	200,483	258,931	6,596	215,786
73	ZERO CHECK -->	0	0	0	0	0	0	0	0	0
74	12 CP FOR TRANSMISSION									
75	PRODUCTION									
76	TRANSMISSION	624,153	0	0	0	0	0	8,577	0	4,938
77	SUB-TRANSMISSION	115,613	0	0	2,229	0	27	9,165	2,502	13,589
78	PRIMARY	261,929	32	0	12,589	0	11,980	124,520	5,173	107,195
79	SECONDARY	1,338,792	721,359	1,573	262,568	1,189	165,030	105,540	2,394	68,981
80	TOTAL	2,340,488	721,391	1,573	277,386	1,189	177,037	247,802	10,069	194,704
81	ZERO CHECK -->	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	2,458,833	1,159,173	0	330,703	0	209,829	269,949	6,858	224,825
86	LOSS FACTOR	0.0000	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
88	LOAD @ INPUT TO TRANSMISSION	2,458,833	1,159,173	0	330,703	0	209,829	269,949	6,858	224,825
89	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
90	SALES @ TRANSMISSION	208,830	0	0	0	0	0	8,963	0	5,473
91	LOAD @ INPUT TO SUB-TRANSMISSION	2,182,435	1,127,319	0	321,615	0	204,063	253,569	6,670	213,173
92	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
93	SALES @ SUB-TRANSMISSION	69,891	0	0	2,539	0	30	9,577	1,639	15,061
94	LOAD @ INPUT TO PRIMARY	2,106,854	1,124,380	0	318,238	0	203,501	243,331	5,013	197,557
95	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
96	SALES @ PRIMARY	280,740	50	0	14,340	0	13,567	130,113	3,389	118,802
97	LOAD @ INPUT TO SECONDARY	1,806,618	1,113,926	0	300,953	0	188,051	110,967	1,578	76,927
98	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
99	SALES @ SECONDARY	1,795,432	1,107,029	0	299,089	0	186,887	110,280	1,568	76,451
100	TOTAL AT METER	2,354,893	1,107,078	0	315,968	0	200,483	258,931	6,596	215,786
101	ZERO CHECK -->	0	0	0	0	0	0	0	0	0
102	Total Loss Factor		1.047055773	0	1.046632364	0	1.046614929	1.042551679	1.039721714	1.041885428

		Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 832	HLF Ind Pwr Serv. Rate 833	Muni. Power Rate 841	Int WW Pumping Rate 842	Renewable Sta. Pwr. Rate 843	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	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	180,000	22,211	31,476	4,386	40	0	1,754	0	770	0	9,413
55	LOAD FACTOR	77.71%	84.65%	97.19%	85.91%	96.53%	0.00%	124.46%	0.00%	106.80%	0.00%	32.22%
56	12 COINCIDENT PEAK											
57	KW	639,579	21,146	35,437	4,016	40	602	1,974	730	771	277	4,765
58	LOAD FACTOR	21.87%	88.91%	86.33%	93.83%	96.53%	75.77%	110.56%	527.71%	106.76%	590.18%	63.65%
59	**CLASS NON COINCIDENTAL PEAK**											
60	NCP	850,453	30,393	56,000	8,186	40	5,785	4,973	10,013	774	3,746	18,456
61	LOAD FACTOR	16.45%	61.86%	54.63%	46.03%	96.53%	7.88%	43.89%	38.46%	106.27%	43.63%	16.43%
62	**CLASS UNDIVERSIFIED KW**											
63	NCP12	741,440	28,284	38,962	6,521	40	3,768	4,379	9,010	771	3,385	4,667
64	LOAD FACTOR	18.87%	66.47%	78.51%	57.79%	96.53%	12.10%	49.84%	42.74%	106.76%	48.28%	65.00%
65	**COINCIDENT KW BY VOLTAGE LEVEL**											
66	4CP FOR GENERATION											
67	PRODUCTION											
68	TRANSMISSION	161,892	10,327	22,175	0	0	0	0	0	0	0	0
69	SUB-TRANSMISSION	18,108	11,883	9,301	0	0	0	1,754	0	0	0	0
70	PRIMARY	0	0	0	481	0	0	0	0	0	0	0
71	SECONDARY	0	0	0	3,906	40	0	0	0	770	0	9,413
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72	TOTAL	180,000	22,211	31,476	4,386	40	0	1,754	0	770	0	9,413
73	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
74	12 CP FOR TRANSMISSION											
75	PRODUCTION											
76	TRANSMISSION	575,238	9,833	24,966	0	0	602	0	0	0	0	0
77	SUB-TRANSMISSION	64,341	11,314	10,472	0	0	0	1,974	0	0	0	0
78	PRIMARY	0	0	0	440	0	0	0	0	0	0	0
79	SECONDARY	0	0	0	3,576	40	0	0	730	771	277	4,765
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80	TOTAL	639,579	21,146	35,437	4,016	40	602	1,974	730	771	277	4,765
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	185,135	22,870	32,390	4,590	42	0	1,808	0	807	0	9,856
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	185,135	22,870	32,390	4,590	42	0	1,808	0	807	0	9,856
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	161,892	10,327	22,175	0	0	0	0	0	0	0	0
91	LOAD @ INPUT TO SUB-TRANSMISSION	18,155	11,914	9,325	4,464	41	0	1,758	0	785	0	9,585
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	18,108	11,883	9,301	0	0	0	1,754	0	0	0	0
94	LOAD @ INPUT TO PRIMARY	0	0	0	4,452	41	0	0	0	782	0	9,560
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	481	0	0	0	0	0	0	0
97	LOAD @ INPUT TO SECONDARY	0	0	0	3,930	40	0	0	0	775	0	9,471
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	3,906	40	0	0	0	770	0	9,413
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100	TOTAL AT METER	180,000	22,211	31,476	4,386	40	0	1,754	0	770	0	9,413
101	ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0
102	Total Loss Factor	1.028526506	1.029694314	1.029050421	1.04634569	1.047056064	0	1.030944241	0	1.047056064	0	1.047056064

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

		Total Company	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824	Metal Melting Rate 825	Off-Peak Serv. Rate 826
103	12 CP FOR TRANSMISSION									
104	LOAD @ INPUT TO GENERATION	2,435,327	755,337	1,647	290,322	1,245	185,289	258,347	10,469	202,859
105	LOSS FACTOR	0.0000	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
107	LOAD @ INPUT TO TRANSMISSION	2,435,327	755,337	1,647	290,322	1,245	185,289	258,347	10,469	202,859
108	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
109	SALES @ TRANSMISSION	624,153	0	0	0	0	0	8,577	0	4,938
110	LOAD @ INPUT TO SUB-TRANSMISSION	1,744,252	734,580	1,602	282,344	1,210	180,197	242,670	10,181	192,346
111	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
112	SALES @ SUB-TRANSMISSION	115,613	0	0	2,229	0	27	9,165	2,502	13,589
113	LOAD @ INPUT TO PRIMARY	1,624,091	732,665	1,598	279,378	1,207	179,701	232,872	7,652	178,255
114	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
115	SALES @ PRIMARY	261,929	32	0	12,589	0	11,980	124,520	5,173	107,195
116	LOAD @ INPUT TO SECONDARY	1,347,133	725,853	1,583	264,204	1,196	166,058	106,197	2,409	69,411
117	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
118	SALES @ SECONDARY	1,338,792	721,359	1,573	262,568	1,189	165,030	105,540	2,394	68,981
119	TOTAL AT METER	2,340,488	721,391	1,573	277,386	1,189	177,037	247,802	10,069	194,704
120	ZERO CHECK -->	0	0	0	0	0	0	0	0	0
121	**CLASS KW BY VOLTAGE LEVEL (1-Month Max.)**									
122	NCP									
123	TRANSMISSION	840,378	0	0	0	0	0	10,357	0	5,754
124	SUB-TRANSMISSION	158,451	0	0	3,304	0	34	11,067	4,877	15,833
125	PRIMARY	320,098	57	0	18,658	0	15,149	150,357	10,085	124,896
126	SECONDARY	2,127,486	1,268,874	4,266	389,146	3,716	208,689	127,438	4,667	80,372
127	TOTAL	3,446,413	1,268,931	4,266	411,107	3,716	223,872	299,218	19,629	226,855
128	ZERO CHECK -->	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	3,588,160	1,328,642	4,467	430,278	3,890	234,308	311,951	20,409	236,357
132	LOSS FACTOR	0.0000	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
134	LOAD @ INPUT TO TRANSMISSION	3,588,160	1,328,642	4,467	430,278	3,890	234,308	311,951	20,409	236,357
135	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
136	SALES @ TRANSMISSION	840,378	0	0	0	0	0	10,357	0	5,754
137	LOAD @ INPUT TO SUB-TRANSMISSION	2,649,182	1,292,131	4,344	418,454	3,784	227,869	293,021	19,848	224,108
138	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
139	SALES @ SUB-TRANSMISSION	158,451	0	0	3,304	0	34	11,067	4,877	15,833
140	LOAD @ INPUT TO PRIMARY	2,483,823	1,288,762	4,333	414,060	3,774	227,241	281,190	14,919	207,690
141	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
142	SALES @ PRIMARY	320,098	57	0	18,658	0	15,149	150,357	10,085	124,896
143	LOAD @ INPUT TO SECONDARY	2,140,741	1,276,780	4,293	391,570	3,739	209,989	128,232	4,696	80,873
144	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
145	SALES @ SECONDARY	2,127,486	1,268,874	4,266	389,146	3,716	208,689	127,438	4,667	80,372
146	TOTAL	3,446,413	1,268,931	4,266	411,107	3,716	223,872	299,218	19,629	226,855
147	Zero-Check	0	0	0	0	0	0	0	0	0

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

Line		Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 832	HLF Ind Pwr Serv. Rate 833	Muni. Power Rate 841	Int WW Pumping Rate 842	Renewable Sta. Pwr. Rate 843	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental
103	12 CP FOR TRANSMISSION											
104	LOAD @ INPUT TO GENERATION	657,824	21,774	36,467	4,202	42	619	2,035	764	807	290	4,989
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	657,824	21,774	36,467	4,202	42	619	2,035	764	807	290	4,989
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	575,238	9,833	24,966	0	0	602	0	0	0	0	0
110	LOAD @ INPUT TO SUB-TRANSMISSION	64,509	11,343	10,499	4,087	41	0	1,979	743	785	282	4,852
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	64,341	11,314	10,472	0	0	0	1,974	0	0	0	0
113	LOAD @ INPUT TO PRIMARY	0	0	0	4,076	41	0	0	741	783	281	4,839
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	440	0	0	0	0	0	0	0
116	LOAD @ INPUT TO SECONDARY	0	0	0	3,598	40	0	0	734	776	279	4,795
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	3,576	40	0	0	730	771	277	4,765
119	TOTAL AT METER	639,579	21,146	35,437	4,016	40	602	1,974	730	771	277	4,765
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	764,898	14,132	39,452	0	0	5,785	0	0	0	0	0
124	SUB-TRANSMISSION	85,555	16,261	16,548	0	0	0	4,973	0	0	0	0
125	PRIMARY	0	0	0	897	0	0	0	0	0	0	0
126	SECONDARY	0	0	0	7,289	40	0	0	10,013	774	3,746	18,456
127	TOTAL	850,453	30,393	56,000	8,186	40	5,785	4,973	10,013	774	3,746	18,456
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	874,713	31,295	57,626	8,566	42	5,948	5,127	10,484	811	3,922	19,325
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	874,713	31,295	57,626	8,566	42	5,948	5,127	10,484	811	3,922	19,325
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	764,898	14,132	39,452	0	0	5,785	0	0	0	0	0
137	LOAD @ INPUT TO SUB-TRANSMISSION	85,778	16,304	16,591	8,330	41	0	4,986	10,196	788	3,814	18,794
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	85,555	16,261	16,548	0	0	0	4,973	0	0	0	0
140	LOAD @ INPUT TO PRIMARY	0	0	0	8,308	41	0	0	10,170	786	3,804	18,745
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	897	0	0	0	0	0	0	0
143	LOAD @ INPUT TO SECONDARY	0	0	0	7,335	40	0	0	10,075	779	3,769	18,571
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	7,289	40	0	0	10,013	774	3,746	18,456
146	TOTAL	850,453	30,393	56,000	8,186	40	5,785	4,973	10,013	774	3,746	18,456
147	Zero-Check	0	0	0	0	0	0	0	0	0	0	0

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

No.		Total Company	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824	Metal Melting Rate 825	Off-Peak Serv. Rate 826
	DISTRIBUTION OF CLASS UNDIVERSIFIED KW BY									
148	**VOLTAGE LEVEL**									
149	NCP12									
150	TRANSMISSION	724,954	0	0	0	0	0	8,618	0	5,115
151	SUB-TRANSMISSION	136,005	0	0	2,373	0	26	9,209	4,707	14,076
152	PRIMARY	271,679	33	0	13,405	0	11,648	125,113	9,734	111,032
153	SECONDARY	1,383,355	732,591	2,791	279,586	2,255	160,457	106,042	4,504	71,451
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154	TOTAL	2,515,992	732,623	2,791	295,364	2,255	172,131	248,982	18,945	201,673
155	ZERO CHECK -->	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	2,616,803	767,098	2,923	309,138	2,361	180,155	259,576	19,698	210,121
159	LOSS FACTOR	0.0000	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283	1.0283
160	SALES @ TRANSMISSION	724,954	0	0	0	0	0	8,618	0	5,115
161	LOAD @ INPUT TO SUB-TRANSMISSION	1,819,941	746,018	2,842	300,643	2,296	175,204	243,825	19,156	199,231
162	LOSS FACTOR	0.0000	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
163	SALES @ SUB-TRANSMISSION	136,005	0	0	2,373	0	26	9,209	4,707	14,076
164	LOAD @ INPUT TO PRIMARY	1,679,191	744,073	2,835	297,485	2,290	174,722	233,980	14,399	184,636
165	LOSS FACTOR	0.0000	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
166	SALES @ PRIMARY	271,679	33	0	13,405	0	11,648	125,113	9,734	111,032
167	LOAD @ INPUT TO SECONDARY	1,391,974	737,155	2,809	281,328	2,269	161,457	106,703	4,532	71,896
168	LOSS FACTOR	0.0000	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062	1.0062
169	SALES @ SECONDARY	1,383,355	732,591	2,791	279,586	2,255	160,457	106,042	4,504	71,451
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170	TOTAL	2,515,992	732,623	2,791	295,364	2,255	172,131	248,982	18,945	201,673
		0	0	0	0	0	0	0	0	0
171	**DEVELOPMENT OF ALLOCATION FACTORS**									
172	GENERATION									
173	4CP @ Generation	2,458,833	1,159,173	0	330,703	0	209,829	269,949	6,858	224,825
174	TRANSMISSION SUBSTATIONS									
175	12CP @ Transmission	2,435,327	755,337	1,647	290,322	1,245	185,289	258,347	10,469	202,859
176	TRANSMISSION LINES									
177	12CP @ Transmission	2,435,327	755,337	1,647	290,322	1,245	185,289	258,347	10,469	202,859
178	SUB-TRANSMISSION									
179	NCP @ Sub-Transmission	2,649,182	1,292,131	4,344	418,454	3,784	227,869	293,021	19,848	224,108
180	DISTRIBUTION SUBSTATIONS									
181	NCP @ Primary	2,483,823	1,288,762	4,333	414,060	3,774	227,241	281,190	14,919	207,690
182	PRIMARY LINES									
183	NCP @ Primary Lines	2,483,823	1,288,762	4,333	414,060	3,774	227,241	281,190	14,919	207,690
184	LINE TRANSFORMERS									
185	NCP @ L.Transformers	2,140,741	1,276,780	4,293	391,570	3,739	209,989	128,232	4,696	80,873
186	Percent	100%	59.642%	0.201%	18.291%	0.175%	9.809%	5.990%	0.219%	3.778%
187	NCP12 @ Secondary	1,391,974	737,155	2,809	281,328	2,269	161,457	106,703	4,532	71,896
188	Percent	100%	52.958%	0.202%	20.211%	0.163%	11.599%	7.666%	0.326%	5.165%
189	Average of Percents x 10,000	10000.00	$ 5,630	$ 20	$ 1,925	$ 17	$ 1,070	$ 683	$ 27	$ 447
190	SECONDARY LINES									
191	NCP12 @ Secondary	1,391,974	737,155	2,809	281,328	2,269	161,457	106,703	4,532	71,896

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

No.		Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 832	HLF Ind Pwr Serv. Rate 833	Muni. Power Rate 841	Int WW Pumping Rate 842	Renewable Sta. Pwr. Rate 843	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental
148	**DISTRIBUTION OF CLASS UNDIVERSIFIED KW BY VOLTAGE LEVEL**											
149	NCP12											
150	TRANSMISSION	666,852	13,151	27,449	0	0	3,768	0	0	0	0	0
151	SUB-TRANSMISSION	74,588	15,133	11,513	0	0	0	4,379	0	0	0	0
152	PRIMARY	0	0	0	715	0	0	0	0	0	0	0
153	SECONDARY	0	0	0	5,806	40	0	0	9,010	771	3,385	4,667
154	TOTAL	741,440	28,284	38,962	6,521	40	3,768	4,379	9,010	771	3,385	4,667
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	762,591	29,124	40,094	6,823	42	3,874	4,515	9,434	807	3,544	4,886
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	666,852	13,151	27,449	0	0	3,768	0	0	0	0	0
161	LOAD @ INPUT TO SUB-TRANSMISSION	74,783	15,172	11,543	6,635	41	0	4,391	9,175	785	3,447	4,752
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	74,588	15,133	11,513	0	0	0	4,379	0	0	0	0
164	LOAD @ INPUT TO PRIMARY	0	0	0	6,618	41	0	0	9,151	783	3,438	4,739
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	715	0	0	0	0	0	0	0
167	LOAD @ INPUT TO SECONDARY	0	0	0	5,842	40	0	0	9,067	776	3,406	4,696
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	5,806	40	0	0	9,010	771	3,385	4,667
170	TOTAL	741,440	28,284	38,962	6,521	40	3,768	4,379	9,010	771	3,385	4,667
		0	0	0	0	0	0	0	0	0	0	0
171	**DEVELOPMENT OF ALLOCATION FACTORS**											
172	GENERATION											
173	4CP @ Generation	185,135	22,870	32,390	4,590	42	0	1,808	0	807	0	9,856
174	TRANSMISSION SUBSTATIONS											
175	12CP @ Transmission	657,824	21,774	36,467	4,202	42	619	2,035	764	807	290	4,989
176	TRANSMISSION LINES											
177	12CP @ Transmission	657,824	21,774	36,467	4,202	42	619	2,035	764	807	290	4,989
178	SUB-TRANSMISSION											
179	NCP @ Sub-Transmission	85,778	16,304	16,591	8,330	41	0	4,986	10,196	788	3,814	18,794
180	DISTRIBUTION SUBSTATIONS											
181	NCP @ Primary	0	0	0	8,308	41	0	0	10,170	786	3,804	18,745
182	PRIMARY LINES											
183	NCP @ Primary Lines	0	0	0	8,308	41	0	0	10,170	786	3,804	18,745
184	LINE TRANSFORMERS											
185	NCP @ L.Transformers	0	0	0	7,335	40	0	0	10,075	779	3,769	18,571
186	Percent	0.000%	0.000%	0.000%	0.343%	0.002%	0.000%	0.000%	0.471%	0.036%	0.176%	0.868%
187	NCP12 @ Secondary	0	0	0	5,842	40	0	0	9,067	776	3,406	4,696
188	Percent	0.000%	0.000%	0.000%	0.420%	0.003%	0.000%	0.000%	0.651%	0.056%	0.245%	0.337%
189	Average of Percents x 10,000	$ -	$ 0	$ (0)	$ 38	$ 0	$ -	$ -	$ 56	$ 5	$ 21	$ 60
190	SECONDARY LINES											
191	NCP12 @ Secondary	0	0	0	5,842	40	0	0	9,067	776	3,406	4,696

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Transformer Replacement Costs	$ 411,142,530	$ 268,344,651	$ -	$ 102,689,403	$ -	$ 23,409,803	$ 9,070,380	$ 69,586	$ 4,543,934	$ 35,735	$ 1,592
2	2021 Customer Count	500,195	428,590	127	54,499	157	3,205	533	6	273	7	5
3	Cost per Customer		$ 626.11	$ -	$ 1,884.24	$ -	$ 7,304.15	$ 17,017.60	$ 11,597.63	$ 16,644.45	$ 5,105.06	$ 318.46
4	Weighting Factor		1.00	-	3.01	-	11.67	27.18	18.52	26.58	8.15	0.51

Northern Indiana Public Service Company
Transformers

Line No.	Description	Total	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	Transformer Replacement Costs	$ 411,142,530	$ 17,934	$ 1,865,255	$ 1,679		$ -	$ 369,451	$ 17,152	$ 468,085	$ 237,890
2	2021 Customer Count	500,195	4	747	8		1	1,773	140	10,074	46
3	Cost per Customer		$ 4,483.53	$ 2,496.99	$ 209.90		$ -	$ 208.38	$ 122.51	$ 46.46	$ 5,171.51
4	Weighting Factor		7.16	3.99	0.34	27.18	-	0.33	0.20	0.07	8.26

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Service Replacement Costs	$ 402,233,582	$ 360,177,919	$ -	$ 39,005,088	$ -	$ 1,559,524	$ 28,210	$ 146	$ 22,426	$ 1,229	$ 136
2	Count of Services with Prices		366,846	0	34,566	0	957	44	2	28	1	1
3	Cost per Service		$ 982	$ -	$ 1,128	$ -	$ 1,630	$ 641	$ 73	$ 801	$ 1,229	$ 136
4	Weighting		1.00	0.00	1.15	0.00	1.66	0.65	0.07	0.82	1.25	0.14

Northern Indiana Public Service Company
Services

Line No.	Description	Total	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 843-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	Service Replacement Costs	$ 402,233,582	$ -	$ 618,858	$ 114	$ -	$ -	$ 242,895	$ 11,921	$ 520,750	$ 44,366
2	Count of Services with Prices		-	499	1	0	0	309	13	522	39
3	Cost per Service		$ -	$ 1,240	$ 114	$ -	$ -	$ 786	$ 917	$ 998	$ 1,138
4	Weighting		0.00	1.26	0.12	0.00	0.00	0.80	0.93	1.02	1.16

Northern Indiana Public Service Company
Meters Analysis Summary

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Meter Replacement Costs	$ 68,691,515	$51,686,574	$ 44,007	$13,766,866	$ 114,529	$ 2,096,993	$ 427,944	$ 5,943	$ 243,055	$ 15,779	$ 4,952
2	Large Industrial Meter Replacement Cost	$ 1,942,464	$ -	$ -	$ -	$ -	$ -	$ 170,239	$ -	$ 15,533	$ 1,511,032	$ 115,307
3	Total Meter Replacement Costs	$ 70,633,979	$51,686,574	$ 44,007	$13,766,866	$ 114,529	$ 2,096,993	$ 598,184	$ 5,943	$ 258,588	$ 1,526,811	$ 120,259
4	2021 Customer Count	500,199	428,590	127	54,499	157	3,205	533	6	273	7	5
5	Replacement Cost per Customer		$ 120.60	$ 346.51	$ 252.61	$ 729.49	$ 654.29	$ 1,122.30	$ 990.44	$ 947.21	$218,115.83	$ 24,051.81
6	Weighting Factor		1.00	2.87	2.09	6.05	5.43	9.31	8.21	7.85	1,808.64	199.44

Northern Indiana Public Service Company
Meters Analysis Summary

Line No.	Description	Total	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	Meter Replacement Costs	$ 68,691,515	$ 4,734	$ 268,474	$ -	$ 4,952	$ 6,714	$ -	$ -	$ -	
2	Large Industrial Meter Replacement Cost	$ 1,942,464	$ 130,353	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Total Meter Replacement Costs	$ 70,633,979	$ 135,086	$ 268,474	$ -	$ 4,952	$ 6,714				$ -
4	2021 Customer Count	500,199	4	747	8	4	1	1,773	140	10,074	46
5	Replacement Cost per Customer		$ 33,771.55	$ 359.40	$ -	$ 1,238.04	$ 6,714.38	$ -	$ -	$ -	$ -
6	Weighting Factor		280.04	2.98	-	10.27	55.68	-	-	-	5.43

Northern Indiana Public Service Company
Account 902 - Meter Reading Expense

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	**Meter Department Reading Expense**	$ 294,157										
2	Manual Reads by Meter Dept.	814	-	75	206	17	82	163	6	183	6	7
3	Manual Read - Avg. Time in Minutes		-	20	20	20	25	25	25	25	73	73
4	Class Manual Read Time Percentage	100.0%	-	7.4%	20.2%	1.7%	10.1%	20.0%	0.7%	22.5%	2.2%	2.5%
5	Allocation of Meter Dept. Reading	$ 294,157	$ -	$ 21,686	$ 59,563	$ 4,915	$ 29,637	$ 58,912	$ 2,169	$ 66,141	$ 6,332	$ 7,388
6	*Cost per manual read (per month)*	*$ 30.11*		*$24.10*	*$24.10*	*$24.10*	*$30.12*	*$30.12*	*$30.12*	*$30.12*	*$87.95*	*$87.95*
7	**Meter Readers Expense**	$ 815,290										
8	Manual Reads by Meter Readers	508	285	1	124	5	63	25	-	1		
9	Manual Read Hours (5 min./read)	711										
10	Manual Read Cost (assumed $51/hr)	$ 36,271	$ 20,349	$ 71	$ 8,854	$ 357	$ 4,498	$ 1,785	$ -	$ 71		
11	Customers Minus Manual Reads	486,892	428,305	51	54,169	135	3,060	345	-	89		
12	AMI Read Cost	$ 779,019	$ 685,281	$ 82	$ 86,669	$ 216	$ 4,896	$ 552	$ -	$ 142		
13	Allocation of Meter Readers	$ 815,290	$ 705,630	$ 153	$ 95,523	$ 573	$ 9,394	$ 2,337	$ -	$ 214		
14	*Cost per AMI read (per month)*	*$ 0.13*										
15	*Cost per manual read (per month)*	*$ 5.95*										
16	Total Meter Reading Allocation	$ 1,109,447	$ 705,630	$ 21,839	$ 155,086	$ 5,488	$ 39,031	$ 61,249	$ 2,169	$ 66,355	$ 6,332	$ 7,388
17	2021 Customer Count	500,199	428,590	127	54,499	157	3,205	533	6	273	7	5
18	Cost per Customer		$ 1.65	$ 171.96	$ 2.85	$ 34.96	$ 12.18	$ 114.91	$ 361.43	$ 243.06	$ 904.60	$ 1,477.51
19	Weighting Factor		1.00	104.44	1.73	21.23	7.40	69.80	219.53	147.63	549.44	897.42

Northern Indiana Public Service Company
Account 902 - Meter Reading Expense

Line No.	Description	Total	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	**Meter Department Reading Expense**	$ 294,157									
2	Manual Reads by Meter Dept.	814	6	7	-	3	7	-	-	-	46
3	Manual Read - Avg. Time in Minutes		73	25	-	25	140	-	-	-	20
4	Class Manual Read Time Percentage	100.0%	2.2%	0.9%		0.4%	4.8%				4.5%
5	Allocation of Meter Dept. Reading	$ 294,157	$ 6,332	$ 2,530		$ 1,084	$ 14,168				$ 13,300
6	*Cost per manual read (per month)*	*$ 30.11*	*$87.95*	*$30.12*		*$30.12*	*$168.67*				*$24.10*
7	**Meter Readers Expense**	$ 815,290									
8	Manual Reads by Meter Readers	508		2		2					
9	Manual Read Hours (5 min./read)	711									
10	Manual Read Cost (assumed $51/hr)	$ 36,271		$ 143		$ 143					
11	Customers Minus Manual Reads	486,892		738		-					
12	AMI Read Cost	$ 779,019		$ 1,181		$ -					
13	Allocation of Meter Readers	$ 815,290		$ 1,324		$ 143					
14	*Cost per AMI read (per month)*	*$ 0.13*									
15	*Cost per manual read (per month)*	*$ 5.95*									
16	Total Meter Reading Allocation	$ 1,109,447	$ 6,332	$ 3,854	$ -	$ 1,227	$ 14,168	$ -	$ -	$ -	$ 13,300
17	2021 Customer Count	500,199	4	747	8	4	1	1,773	140	10,074	46
18	Cost per Customer		$ 1,583.05	$ 5.16	$ -	$ 306.77	$ 14,167.89	$ -	$ -	$ -	$ 289.14
19	Weighting Factor		961.52	3.13	-	186.33	8,605.39	-	-	-	175.62

Northern Indiana Public Service Company
Write-Offs

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	3-Year Average Write-Offs	15,644,668	13,711,122	-	1,060,336	-	106,371	23,428	-	-	-	-
2	Allocation Percentage		87.64%	0.00%	6.78%	0.00%	0.68%	0.15%	0.00%	0.00%	0.00%	0.00%
3	2021 Write-offs	8,110,454	6,924,350	-	414,678	-	44,751	4,503	-	-	-	-
4	2020 Write-offs	2,904,561	2,587,224	-	266,650	-	35,408	6,992	-	-	-	-
5	2019 Write-offs	4,629,653	4,199,548	-	379,008	-	26,213	11,933	-	-	-	-

Northern Indiana Public Service Company
Write-Offs

Line No.	Description	Total	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	3-Year Average Write-Offs	15,644,668	714,410	542	-	-	-	469	-	27,989	-
2	Allocation Percentage		4.57%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.18%	0.00%
3	2021 Write-offs	8,110,454	714,410	542	-	-	-	-	-	7,219	-
4	2020 Write-offs	2,904,561	-	-	-	-	-	7	-	8,280	-
5	2019 Write-offs	4,629,653	-	-	-	-	-	462	-	12,489	-

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	3-Year Average Late Paymen	3,361,373	2,270,687	7	591,897	-	143,626	184,906	1,936	114,682	37,507	-
2	Allocation Percentage		67.55%	0.00%	17.61%	0.00%	4.27%	5.50%	0.06%	3.41%	1.12%	0.00%
3	2021 Late Payments	5,217,842	3,342,867	-	941,331	-	241,082	329,166	5,807	223,835	112,520	-
4	2020 Late Payments	986,510	703,443	-	179,486	-	41,968	44,501	-	13,445	-	-
5	2019 Late Payments	3,868,661	2,765,751	22	654,876	-	147,827	181,053	-	106,765	-	-

Northern Indiana Public Service Company
Late Payments

Line No.	Description	Total	Rate 833-Small Industrial Service - HLF	Rate 841-Muni. Power	Rate 842-Int WW Pumping	Rate 543-Sta. Pwr. Renewable	Rate 844-Railroad	Rate 850-Street Lighting	Rate 855-Traffic Lighting	Rate 860-Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	3-Year Average Late Paymen	3,361,373	-	163	291	5,553	-	-	139	9,980	-
2	Allocation Percentage		0.00%	0.00%	0.01%	0.17%	0.00%	0.00%	0.00%	0.30%	0.00%
3	2021 Late Payments	5,217,842	-	185	335	5,553	-	-	371	14,790	-
4	2020 Late Payments	986,510	-	96	175		-	-	16	3,381	-
5	2019 Late Payments	3,868,661	-	207	362		-	-	28	11,770	-

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

Line No.	Description	Total	Rate 811-Residential	Rate 820-C&GS Heat Pump	Rate 821-GS Small	Rate 822-Comml SH	Rate 823-GS Medium	Rate 824-GS Large	Rate 825-Metal Melting	Rate 826-Off-Peak Serv.	Rate 831-Ind. Pwr Serv. - Large	Rate 832-Small Industrial Service - LLF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Acct 901 - Customer Account Supervision	$ 1,276,374	$ 1,056,761	$ 397	$ 190,473	$ 747	$ 13,654	$ 1,645	$ 7	$ 228	$ 12	$ 6
2	Allocations	100%	82.79%	0.03%	14.92%	0.06%	1.07%	0.13%	0.00%	0.02%	0.00%	0.00%
3	Customer Count	500,199	428,590	127	54,499	157	3,205	533	6	273	7	5
4	Acct 901 / Customer		$ 2.47	$ 3.13	$ 3.49	$ 4.76	$ 4.26	$ 4.26	$ 1.24	$ 0.83	$ 1.77	$ 1.24
5	Weighting Factor		1.00	1.27	1.42	1.93	1.73	1.73	0.50	0.34	0.72	0.50
6	Acct 903 - Customer Records & Collections	$ 8,481,007	$ 6,827,685	$ 12,641	$ 1,149,291	$ 18,110	$ 93,861	$ 120,306	$ 17,377	$ 44,197	$ 39,584	$ 37,985
7	Allocations	100%	80.51%	0.15%	13.55%	0.21%	1.11%	1.42%	0.20%	0.52%	0.47%	0.45%
8	Customer Count	500,199	428,590	127	54,499	157	3,205	533	6	273	7	5
9	Acct 903 / Customer		$ 15.93	$ 99.54	$ 21.09	$ 115.35	$ 29.29	$ 225.71	$ 2,896.10	$ 161.89	$ 5,654.82	$ 7,597.05
10	Weighting Factor		1.00	6.25	1.32	7.24	1.84	14.17	181.79	10.16	354.97	476.89
11	Acct 910 - Customer Assistance Expense	$ 446,809	$ 189,455	$ 1,835	$ 44,765	$ 1,879	$ 54,979	$ 70,396	$ 2,363	$ 35,490	$ 11,113	$ 11,110
12	Allocations	100%	42.40%	0.41%	10.02%	0.42%	12.30%	15.76%	0.53%	7.94%	2.49%	2.49%
13	Customer Count	500,199	428,590	127	54,499	157	3,205	533	6	273	7	5
14	Acct 910 / Customer		$ 0.44	$ 14.45	$ 0.82	$ 11.97	$ 17.15	$ 132.07	$ 393.85	$ 130.00	$ 1,587.53	$ 2,222.08
15	Weighting Factor		1.00	32.69	1.86	27.08	38.81	298.78	890.98	294.09	3,591.35	5,026.84

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

Line No.	Description	Total	Rate 833- Small Industrial Service - HLF	Rate 841- Muni. Power	Rate 842-Int WW Pumping	Rate 543- Sta. Pwr. Renewable	Rate 844- Railroad	Rate 850- Street Lighting	Rate 855- Traffic Lighting	Rate 860- Dusk-to-Dawn	Interdepartmental
	(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
1	Acct 901 - Customer Account Supervision	$ 1,276,374	$ 5	$ 877	$ 10	$ 10	$ 1	$ 1,093	$ 173	$ 10,216	$ 57
2	Allocations	100%	0.00%	0.07%	0.00%	0.00%	0.00%	0.09%	0.01%	0.80%	0.00%
3	Customer Count	500,199	4	747	8	4	1	1,773	140	10,074	46
4	Acct 901 / Customer		$ 1.24	$ 1.17	$ 1.23	$ 2.40	$ 1.24	$ 0.62	$ 1.24	$ 1.01	$ 1.24
5	Weighting Factor		0.50	0.48	0.50	0.97	0.50	0.25	0.50	0.41	0.50
6	Acct 903 - Customer Records & Collections	$ 8,481,007	$ 31,787	$ 7,331	$ 76	$ 957	$ 3,458	$ 7,150	$ 1,138	$ 67,702	$ 372
7	Allocations	100%	0.37%	0.09%	0.00%	0.01%	0.04%	0.08%	0.01%	0.80%	0.00%
8	Customer Count	500,199	4	747	8	4	1	1,773	140	10,074	46
9	Acct 903 / Customer		$ 7,946.87	$ 9.81	$ 9.55	$ 239.17	$ 3,457.62	$ 4.03	$ 8.13	$ 6.72	$ 8.09
10	Weighting Factor		498.84	0.62	0.60	15.01	217.04	0.25	0.51	0.42	0.51
11	Acct 910 - Customer Assistance Expense	$ 446,809	$ 11,110	$ 2,686	$ 2,364	$ 622	$ 2,361	$ 406	$ 64	$ 3,792	$ 21
12	Allocations	100%	2.49%	0.60%	0.53%	0.14%	0.53%	0.09%	0.01%	0.85%	0.00%
13	Customer Count	500,199	4	747	8	4	1	1,773	140	10,074	46
14	Acct 910 / Customer		$ 2,777.48	$ 3.60	$ 295.50	$ 155.45	$ 2,360.80	$ 0.23	$ 0.46	$ 0.38	$ 0.46
15	Weighting Factor		6,283.29	8.13	668.49	351.66	5,340.66	0.52	1.04	0.85	1.04

Northern Indiana Public Service Company
Test Year Ended December 31, 2023
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**	**Res. at System Increase, 831 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 Revenue**
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
1	Rate 811-Residential	425,341,799	124,604,472	8,713,738	558,660,009	106,655,560			106,655,560	19.09%	656,601,830	665,315,569
2	Rate 820-C&GS Heat Pump	594,087	341,040	12,251	947,378		271,300		271,300	28.64%	1,206,427	1,218,679
3	Rate 821-GS Small	203,399,544	57,442,413	2,983,250	263,825,207		-	47,848,156	47,848,156	18.14%	308,690,112	311,673,363
4	Rate 822-Comml SH	649,822	294,805	9,609	954,235		8,004	173,063	181,067	18.98%	1,125,694	1,135,302
5	Rate 823-GS Medium	104,887,251	36,088,611	1,591,195	142,567,057		4,289,003	25,856,403	30,145,406	21.14%	171,121,268	172,712,463
6	Rate 824-GS Large	131,233,120	53,014,950	2,163,610	186,411,680		7,152,019	33,808,199	40,960,219	21.97%	225,208,289	227,371,899
7	Rate 825-Metal Melting	5,007,975	3,055,004	80,354	8,143,333		-	1,476,900	1,476,900	18.14%	9,539,879	9,620,233
8	Rate 826-Off-Peak Serv.	105,464,773	55,048,731	1,668,767	162,182,272		4,881,531	29,413,879	34,295,410	21.15%	194,808,914	196,477,681
9	Rate 831-Ind. Pwr Serv. - Large	97,038,325	42,281,630	4,431,359	143,751,315	16,798,760			16,798,760	11.69%	156,118,716	160,550,075
10	Rate 832-Small Industrial Service - LLI	8,861,523	5,869,365	158,794	14,889,682		690,404	2,700,439	3,390,843	22.77%	18,121,730	18,280,525
11	Rate 833-Small Industrial Service - HL	12,739,231	9,545,022	261,532	22,545,784		1,517,785	4,088,973	5,606,758	24.87%	27,891,010	28,152,543
12	Rate 841-Muni. Power	3,222,468	1,190,712	34,771	4,447,950		-	806,694	806,694	18.14%	5,219,873	5,254,644
13	Rate 842-Int WW Pumping	97,784	12,176	707	110,666	(54,101)			(54,101)	-48.89%	55,859	56,566
14	Rate 543-Sta. Pwr. Renewable	2,326,577	106,770	14,793	2,448,139	(1,200,600)			(1,200,600)	-49.04%	1,232,747	1,247,539
15	Rate 844-Railroad	1,229,252	682,080	17,150	1,928,481		552,259		552,259	28.64%	2,463,590	2,480,740
16	Rate 850-Street Lighting	5,477,777	1,187,756	33,463	6,698,995		1,918,390		1,918,390	28.64%	8,583,922	8,617,384
17	Rate 855-Traffic Lighting	723,360	358,964	7,011	1,089,334		-	197,565	197,565	18.14%	1,279,889	1,286,900
18	Rate 860-Dusk-to-Dawn	2,102,927	535,380	21,862	2,660,168		761,792		761,792	28.64%	3,400,098	3,421,960
19	Interdepartmental	3,187,786	849,755	40,450	4,077,991		1,167,813		1,167,813	28.64%	5,205,354	5,245,804
20	**System Total**	**1,113,585,378**	**392,509,634**	**22,244,665**	**$ 1,528,339,678**	**$ 122,199,620**	**$ 23,210,300**	**$ 146,370,271**	**$ 291,780,191**	**19.09%**	**$ 1,797,875,204**	**$ 1,820,119,869**

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Residential Service
Rate 811

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Customer Charge			
1	Customer Charge	5,102,724	$ 13.50	$ 68,886,778
2	Total	5,102,724		$ 68,886,778
	Billed kwh			
3	For all kWh used	3,406,828,673	$ 0.122116	$ 416,028,290
4	Total kWh	3,406,828,673		$ 416,028,290
5	DSM Proforma	45,369,477		
6	Total Adj kWh	3,452,198,150		
7	Residential Service (Rate 811)			$ 484,915,069
	Contract Riders			
8	DSMA		Rider 883	$ 3,093,339
9	TDSIC		Rider 888	$ 28,870,347
10	Total Rider			$ 31,963,685
	Other Adjustments			
11	Generation Credit			$ (28,330)
12	Difference in Fuel Calculation			$ 33,095,846
13	Total Other Adjustments			$ 33,067,516
14	Grand Total			$ 549,946,271

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Residential Service
Rate 511

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Customer Charge			
1	Customer Charge	5,102,724	$ 17.00	$ 86,746,313
2	Total	5,102,724		$ 86,746,313
	Billed kWh			
3	For all kWh used	3,452,198,150	$ 0.165070	$ 569,854,349
4	Total kWh	3,452,198,150		$ 569,854,349
5				
6				
7	Residential Service (Rate 511)			$ 656,600,662
			Propopsed Revenue Target	$ 656,601,830
			Difference Due to Rounding	$ (1,168)
	Contract Riders			
8	DSMA		Rider 583	$ -
9	TDSIC		Rider 588	$ -
10	Total Rider			$ -
	Other Adjustments			
11	Generation Credit			$ -
12	Difference in Fuel Calculation			$ -
13	Total Other Adjustments			$ -
14	Grand Total			$ 656,600,662

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Commercial and General Service - Heat Pump
Rate 820

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Customer Charge			
1	Customer Charge	868	$ 30.00	$ 26,044
2	Total	868		$ 26,044
	Billed kwh			
3	For all kWh used	9,448,602	$ 0.080037	$ 756,238
4	Total kWh	9,448,602		$ 756,238
5	Commercial and General Service - Heat Pump (Rate 820)			$ 782,282
	Contract Riders			
6	DSMA		Rider 883	$ (14,234)
7	TDSIC		Rider 888	$ 96,964
8	Total Rider			$ 82,730
	Other Adjustments			
9	Generation Credit			$ (51)
10	Difference in Fuel Calculation			$ 90,583
11	Total Other Adjustments			$ 90,532
12	Grand Total			$ 955,543

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Commercial and General Service - Heat Pump
Rate 520

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Customer Charge			
1	Customer Charge	868	$ 34.50	$ 29,950
2	Total	868		$ 29,950
	Billed kWh			
3	All kWh	9,448,602	$ 0.124513	$ 1,176,474
4	Total kWh	9,448,602		$ 1,176,474
5	Commercial and General Service - Heat Pump (Rate 520)			$ 1,206,424
			Propopsed Revenue Target	$ 1,206,427
			Difference Due to Rounding	$ (3)
	Contract Riders			
6	DSMA		Rider 583	$ -
7	TDSIC		Rider 588	$ -
8	Total Rider			$ -
	Other Adjustments			
9	Generation Credit			$ -
10	Difference in Fuel Calculation			$ -
11	Total Other Adjustments			$ -
12	Grand Total			$ 1,206,424

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
General Service - Small
Rate 821

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Customer Charge			
1	Customer Charge	654,238	$ 30.00	$ 19,627,150
2	Total	654,238		$ 19,627,150
	Minimum Charge - Three Phase Service			
3	General Service - Small	6,730	$ 44.00	$ 296,116
4	Total	6,730		$ 296,116
	Billed kwh			
5	For all kWh used	1,549,576,346	$ 0.137771	$ 213,486,683
6	Total kWh	1,549,576,346		$ 213,486,683
7	DSM Proforma	42,472,601		
8	Total Adj kWh	1,592,048,947		
9	General Service - Small (Rate 821)			$ 233,409,948
	Contract Riders			
10	DSMA		Rider 883	$ 1,427,600
11	TDSIC		Rider 888	$ 10,521,475
12	Total Rider			$ 11,949,074
	Other Adjustments			
13	Generation Credit			$ (14,185)
14	Difference in Fuel Calculation			$ 15,257,119
15	Guaranteed Revenue			$ 240,000
16	Total Other Adjustments			$ 15,482,934
17	Grand Total			$ 260,841,956

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
General Service - Small
Rate 521

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Customer Charge			
1	Customer Charge	654,238	$ 34.50	$ 22,571,222
2	Total	654,238		$ 22,571,222
	Minimum Charge - Three Phase Service			
3	General Service - Small	6,730	$ 50.50	$ 339,860
4	Total	6,730		$ 339,860
	Billed kWh			
5	All kWh	1,592,048,947	$ 0.179504	$ 285,779,154
6	Total kWh	1,592,048,947		$ 285,779,154
7	General Service - Small (Rate 521)			$ 308,690,236
			Propopsed Revenue Target	$ 308,690,112
	Contract Riders			
8	DSMA		Rider 583	$ -
9	TDSIC		Rider 588	$ -
10	Total Rider			$ -
	Other Adjustments			
11	Generation Credit			$ -
12	Difference in Fuel Calculation			$ -
13	Guaranteed Revenue			$ -
14	Total Other Adjustments			$ -
15	Grand Total			$ 308,690,236

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Commercial Spaceheating
Rate 822

Line No.	Description	Annualized Billing Determinants (kWh, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(C)	(D)	(E)
	Customer Charge			
1	Customer Charge	1,225	$ 30.00	$ 36,758
2	Total	1,225		$ 36,758
	Billed kwh			
3	For all kWh used	8,167,651	$ 0.094326	$ 770,422
4	Total kWh	8,167,651		$ 770,422
5	Commercial Spaceheating (Rate 822)			$ 807,180
	Contract Riders			
6	DSMA		Rider 883	$ (17,847)
7	TDSIC		Rider 888	$ 97,764
8	Total Rider			$ 79,917
	Other Adjustments			
9	Generation Credit			$ (68)
10	Difference in Fuel Calculation			$ 78,302
11	Total Other Adjustments			$ 78,235
12	Grand Total			$ 965,332

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Commercial Spaceheating
Rate 522

Line No.	Description	Annualized Billing Determinants (kWh, Bill Counts)	Proposed Rate	Revenue
	(J)	(K)	(L)	(M)
	Customer Charge			
1	Customer Charge	1,225	$ 34.50	$ 42,272
2		1,225		$ 42,272
	Billed kWh			
3	For all kWh used	8,167,651	$ 0.132648	$ 1,083,423
4	Total kWh	8,167,651		$ 1,083,423
5	Commercial Spaceheating (Rate 522)			$ 1,125,694
			Propopsed Revenue Target	$ 1,125,694
			Difference Due to Rounding	$ 0
	Contract Riders			
6	DSMA		Rider 583	$ -
7	TDSIC		Rider 588	$ -
8	Total Rider			$ -
	Other Adjustments			
9	Generation Credit			$ -
10	Difference in Fuel Calculation			$ -
11	Total Other Adjustments			$ -
12	Grand Total			$ 1,125,694

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
General Service - Medium
Rate 823

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	First 10 kW	390,393	$ 24.93	$ 9,732,491
2	Over 10 kW	2,366,084	$ 11.38	$ 26,926,030
3	Total kW	2,756,476		$ 36,658,521
4	DSM Proforma	4,310		
5	Total Adj kWh	2,760,786		
	Minimum Charge - Billed kW			
6	First 10 kW	465	$ 24.93	$ 11,599
7	Over 10 kW	7,587	$ 11.38	$ 86,337
8	Total kW	8,052		$ 97,936
	Billed kWh			
9	All kWh	973,282,202	$ 0.088489	$ 86,124,769
10	Total kWh	973,282,202		$ 86,124,769
11	DSM Proforma	26,613,109		
12	Total Adj kWh	999,895,310		
	Thermal Storage - Billed kWh			
13	All kWh	365,979	$ 0.071937	$ 26,327
14	Total kWh	365,979		$ 26,327
15	General Service - Medium (Rate 823)			$ 122,907,553
	Contract Riders			
16	DSMA		Rider 883	$ 1,935,571
17	TDSIC		Rider 888	$ 6,605,675
18	Total Rider			$ 8,541,246
	Other Adjustments			
19	Generation Credit			$ (9,289)
20	Difference in Fuel Calculation			$ 9,585,395
21	Total Other Adjustments			$ 9,576,107
22	Grand Total			$ 141,024,906

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
General Service - Medium
Rate 523

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Proposed Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	First 10 kW	390,393	$ 34.71	$ 13,550,532
2	Over 10 kW	2,370,393	$ 15.84	$ 37,547,027
3	Total kW	2,760,786		$ 51,097,559
	Minimum Charge - Billed kW			
4	First 10 kW	465	$ 34.71	$ 16,149
5	Over 10 kW	7,587	$ 15.84	$ 120,174
6	Total kW	8,052		$ 136,323
	Billed kWh			
7	All kWh	999,895,310	$ 0.119863	$ 119,850,452
8	Total kWh	999,895,310		$ 119,850,452
	Thermal Storage - Billed kWh			
9	All kWh	365,979	$ 0.100156	$ 36,655
10	Total kWh			$ 36,655
11	General Service - Medium (Rate 523)			$ 171,120,989
			Propopsed Revenue Target	$ 171,121,268
			Difference Due to Rounding	$ (280)
	Contract Riders			
12	DSMA		Rider 583	$ -
13	TDSIC		Rider 588	$ -
14	Total Rider			$ -
	Other Adjustments			
15	Generation Credit			$ -
16	Difference in Fuel Calculation			$ -
17	Total Other Adjustments			$ -
18	Grand Total			$ 171,120,989

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
General Service - Large
Rate 824

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	First 50 kW	291,991	$ 19.91	$ 5,813,547
2	Next 1,950 kW	3,133,536	$ 13.02	$ 40,798,633
3	Over 2,000 kW	243,844	$ 12.50	$ 3,048,054
4	Total kW	3,669,371		$ 49,660,235
5	DSM Proforma	4,302		
6	Total Adj kWh	3,673,674		
7	*Minimum Charge - Billed kW*			
8	First 50 kW	617	$ 19.91	$ 12,288
9	Next 1,950 kW	8,144	$ 13.02	$ 106,031
10	Over 2,000 kW	-	$ 12.50	$ -
11	Over 3,000 kW	-	$ 12.96	$ -
11	Total kW	8,761		$ 118,319
	Billed kWh			
12	First 30,000 kWh	168,674,591	$ 0.085252	$ 14,379,846
13	Next 70,000 kWh	327,355,755	$ 0.077552	$ 25,387,093
14	Next 900,000 kWh	859,111,325	$ 0.074002	$ 63,575,956
15	Over 1,000,000 kWh	93,780,963	$ 0.070402	$ 6,602,367
16	Total kWh	1,448,922,634		$ 109,945,263
	DSM Proforma	26,562,973		
	Total Adj kWh	1,475,485,607		

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
General Service - Large
Rate 524

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	First 50 kW	291,991	$ 28.13	$ 8,213,715
2	Next 1,950 kW	3,133,536	$ 18.40	$ 57,657,055
3	Over 2,000 kW	248,147	$ 17.66	$ 4,382,270
4	Total kW	3,673,674		$ 70,253,040
5	*Minimum Charge - Billed kW*			
6	First 50 kW	617	$ 28.13	$ 17,362
7	Next 1,950 kW	8,144	$ 18.40	$ 149,844
8	Over 2,000 kW	-	$ 17.66	$ -
9	Over 3,000 kW	-	$ 18.31	$ -
9	Total kW	8,761		$ 167,206
	Billed kWh			
10	First 30,000 kWh	168,674,591	$ 0.118364	$ 19,964,999
11	Next 70,000 kWh	327,355,755	$ 0.107673	$ 35,247,376
12	Next 900,000 kWh	859,111,325	$ 0.102744	$ 88,268,534
13	Over 1,000,000 kWh	120,343,936	$ 0.097746	$ 11,763,138
14	Total kWh	1,475,485,607		$ 155,244,048

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
General Service - Large
Rate 824

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Per kWh Usage Charge Ratios			
17	Block 2 / Block 1		90.97%	
18	Block 3 / Block 1		86.80%	
19	Block 4 / Block 1		82.58%	
	Thermal Storage - Billed kWh			
20	All kWh	477,967	$ 0.071937	$ 34,383
21	Total kWh	477,967		$ 34,383
	Discounts - Billed kW			
22	Primary Service	482,689	$ (0.72)	$ (347,536)
23	Transmission Service	9,836	$ (0.90)	$ (8,853)
24	Total kW	492,526		$ (356,389)
25	General Service - Large (Rate 824)			$ 159,401,812
	Contract Riders			
26	DSMA		Rider 883	$ 3,299,564
27	TDSIC		Rider 888	$ 7,464,987
28	Total Rider			$ 10,764,551
	Other Adjustments			
29	Generation Credit			$ (11,652)
30	Difference in Fuel Calculation			$ 14,093,359
31	Total Other Adjustments			$ 14,081,707
32	Grand Total			$ 184,248,070

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
General Service - Large
Rate 524

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Per kWh Usage Charge Ratios			
15	Block 2 / Block 1		90.97%	
16	Block 3 / Block 1		86.80%	
17	Block 4 / Block 1		82.58%	
	Thermal Storage - Billed kWh			
18	All kWh	477,967	$ 0.100156	$ 47,871
19	Total kWh			$ 47,871
	Discounts - Billed kW			
20	Primary Service	482,689	$ (1.02)	$ (492,343)
21	Transmission Service	9,836	$ (1.27)	$ (12,492)
22	Total kW	492,526		$ (504,835)
23	General Service - Large (Rate 524)			$ 225,207,330
			Propopsed Revenue Target	$ 225,208,289
			Difference Due to Rounding	$ (959)
24	*Contract Riders*			
25	DSMA		Rider 583	$ -
26	TDSIC		Rider 588	$ -
27	Total Rider			$ -
	Other Adjustments			
28	Generation Credit			$ -
29	Difference in Fuel Calculation			$ -
30	Total Other Adjustments			$ -
31	Grand Total			$ 225,207,330

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Metal Melting Service
Rate 825

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	First 500 kW	42,309	$ 23.16	$ 979,867
2	Over 500 kW	75,317	$ 22.12	$ 1,666,004
3	Total kW	117,625		$ 2,645,871
	Billed kWh			
4	All kWh	85,154,988	$ 0.049557	$ 4,220,026
5	Total kWh	85,154,988		$ 4,220,026
6	Metal Melting Service (Rate 825)			$ 6,865,897
	Contract Riders			
7	DSMA		Rider 883	$ 101,055
8	TDSIC		Rider 888	$ 314,362
9	Total Rider			$ 415,417
	Other Adjustments			
10	Generation Credit			$ (409)
11	Difference in Fuel Calculation			$ 811,431
12	Total Other Adjustments			$ 811,022
13	Grand Total			$ 8,092,336

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Metal Melting Service
Rate 525

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	First 500 kW	42,309	$ 32.18	$ 1,361,490
2	Over 500 kW	75,317	$ 30.73	$ 2,314,481
3	Total kW	117,625		$ 3,675,971
			Target	$ 3,675,971
			Difference	$ -
	Billed kWh			
4	All kWh	85,154,988	$ 0.068862	$ 5,863,943
5	Total kWh	85,154,988		$ 5,863,943
			Target	$ 5,863,908
			Difference	$ 35
6	Metal Melting Service (Rate 525)			$ 9,539,914
			Propopsed Revenue Target	$ 9,539,879
			Difference Due to Rounding	$ 35
	Contract Riders			
7	DSMA		Rider 583	$ -
8	TDSIC		Rider 588	$ -
9	Total Rider			$ -
	Other Adjustments			
10	Generation Credit			$ -
11	Difference in Fuel Calculation			$ -
12	Total Other Adjustments			$ -
13	Grand Total			$ 9,539,914

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Off-Peak Service
Rate 826

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	First 200 kW	944,167	$ 27.42	$ 25,889,047
2	Next 500 kW	1,016,993	$ 26.38	$ 26,828,268
3	Next 1,300 kW	609,692	$ 25.34	$ 15,449,584
4	Over 2,000 kW	235,268	$ 24.82	$ 5,839,349
5	Total kW	2,806,119		$ 74,006,249
6	DSM Proforma	4,062		
7	Total Adj kWh	2,810,181		
	Billed kWh			
8	All kWh	1,507,259,590	$ 0.044264	$ 66,717,339
9	Total kWh	1,507,259,590		$ 66,717,339
10	DSM Proforma	24,843,761		
11	Total Adj kWh	1,532,103,352		
	Discounts - Billed kW			
12	Primary Service	445,800	$ (0.72)	$ (320,976)
13	Transmission Service	133,932	$ (0.90)	$ (120,539)
14	Total kW	579,732		$ (441,515)
15	Off-Peak Service (Rate 826)			$ 140,282,073
	Contract Riders			
16	DSMA		Rider 883	$ 1,254,056
17	TDSIC		Rider 888	$ 4,362,830
18	Total Rider			$ 5,616,886
	Other Adjustments			
19	Generation Credit			$ (6,795)
20	Difference in Fuel Calculation			$ 14,621,340
21	Total Other Adjustments			$ 14,614,545
22	Grand Total			$ 160,513,504

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Off-Peak Service
Rate 526

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	First 200 kW	944,167	$ 38.08	$ 35,953,863
2	Next 500 kW	1,016,993	$ 36.63	$ 37,252,444
3	Next 1,300 kW	609,692	$ 35.19	$ 21,455,046
4	Over 2,000 kW	239,330	$ 34.47	$ 8,249,708
5	Total kW	2,810,181		$ 102,911,061
	Billed kWh			
6	All kWh	1,532,103,352	$ 0.060389	$ 92,522,189
7	Total kWh	1,532,103,352		$ 92,522,189
	Discounts - Billed kW			
8	Primary Service	445,800	$ (1.02)	$ (454,716)
9	Transmission Service	133,932	$ (1.27)	$ (170,093)
10	Total kW	579,732		$ (624,809)
11	Off-Peak Service (Rate 526)			$ 194,808,441
			Propopsed Revenue Target	$ 194,808,914
			Difference Due to Rounding	$ (473)
	Contract Riders			
12	DSMA		Rider 583	$ -
13	TDSIC		Rider 588	$ -
14	Total Rider			$ -
	Other Adjustments			
15	Generation Credit			$ -
16	Difference in Fuel Calculation			$ -
17	Total Other Adjustments			$ -
18	Grand Total			$ 194,808,441

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Large Industrial Power Service
Rate 831

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	*Tier 1 Annual Billing Determinants (kW)*	2,112,000	$ 25.24	$ 53,306,880
2	Total	2,112,000		$ 53,306,880
	Billed kWh			
3	Tier 1 Energy Billing Determinant (kWh)	1,225,361,912	$ 0.028201	$ 34,556,431
4	All kWh	1,225,361,912		$ 34,556,431
5	*Transmission Charge Billed kWh*			
6	Transmission Charge - Tier 1	1,225,361,912	$ 0.008525	$ 10,446,210
7	Transmission Charge - Tier 2	1,960,305,203	$ 0.008525	$ 16,711,602
8	Transmission Charge - Tier 3	985,257,330	$ 0.008525	$ 8,399,319
9	Adj. Facility Transmission Charge	1,117,265,000	$ 0.002557	$ 2,856,847
		5,288,189,445		$ 38,413,977
10	Discounts - Billed kW			
11	Lagging RKVA Discount	$ (1,201,956)	$ 0.32	$ (384,626)
12	Total Discount			$ (384,626)
13	Large Industrial Power Service (Rate 831)			$ 125,892,663
	Contract Riders			
14	DSMA		Rider 883	$ -
15	TDSIC		Rider 888	$ 2,205,490
16	Total Rider			$ 2,205,490
	Other Adjustments			
17	Generation Credit			$ (8,503)
18	Difference in Fuel Calculation			$ 11,230,306
19	Total Other Adjustments			$ 11,221,803
20	Grand Total			$ 139,319,956

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Large Industrial Power Service
Rate 531

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	Tier 1 Annual Billing Determinants (kW)	2,040,000	$ 27.28	$ 55,658,435
2	Total	2,040,000		$ 55,658,435
	Billed kWh			
3	Tier 1 Energy Billing Determinant (kWh)	1,187,580,246	$ 0.038072	$ 45,214,076
4	Total	1,187,580,246		$ 45,214,076
4	*Transmission Charge Billed kWh*			
5	Transmission Charge - Tier 1	1,187,580,246	$ 0.012362	$ 14,680,867
5	Transmission Charge - Tier 2	1,976,186,869	$ 0.012362	$ 24,429,622
5	Transmission Charge - Tier 3	998,397,330	$ 0.012362	$ 12,342,188
6	Adj. Facility Transmission Charge	1,126,025,000	$ 0.003709	$ 4,176,427
7	Total kWh	5,288,189,445		$ 55,629,104
	Discounts - Billed kW			
	Lagging RKVA Discount	$ (1,201,956)	$ 0.32	$ (384,626)
	Total Discount			$ (384,626)
8	Large Industrial Power Service (Rate 531)			$ 156,116,988
			Propopsed Revenue Target	$ 156,118,716
			Difference Due to Rounding	$ (1,728)
	Contract Riders			
9	DSMA		Rider 583	$ -
10	TDSIC		Rider 588	$ -
11	Total Rider			$ -
	Other Adjustments			
12	Generation Credit			$ -
13	Difference in Fuel Calculation			$ -
14	Total Other Adjustments			$ -
15	Grand Total			$ 156,116,988

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Small Industrial Power Service
Rate 832

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	*Billed kW*	425,312	$ 10.57	$ 4,495,552
	Total	425,312		$ 4,495,552
2	*Billed kWh*			
3	First 450 hours x kW	162,750,754	$ 0.047737	$ 7,769,233
	Next 50 hours x kW	1,678,833	$ 0.097398	$ 163,515
	Over 500 hours x kW	268,212	$ 0.172903	$ 46,375
4	All kWh	164,697,799		$ 7,979,122
	Discounts - Billed kW			
5	Lagging RKVA Discount	41,604	$ 0.32	$ 13,313
6	Total Discount			$ 13,313
7	Small Industrial Power Service (Rate 832)			$ 12,487,987
8				
	Contract Riders			
9	DSMA		Rider 883	$ 477,046
10	TDSIC		Rider 888	$ 271,887
11	Total Rider			$ 748,933
	Other Adjustments			
12	Generation Credit			$ (719)
13	Difference in Fuel Calculation			$ 1,558,946
14	Total Other Adjustments			$ 1,558,226
15	Grand Total			$ 14,795,147

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Small Industrial Power Service
Rate 532

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	*Billed kW*	425,312	$ 15.34	$ 6,524,292
	Total	425,312		$ 6,524,292
2	*Billed kWh*			
3	First 450 hours x kW	162,750,754	$ 0.069306	$ 11,279,604
	Next 50 hours x kW	1,678,833	$ 0.141337	$ 237,281
	Over 500 hours x kW	268,212	$ 0.250905	$ 67,296
4	All kWh	164,697,799		$ 11,584,181
	Discounts - Billed kW			
5	Lagging RKVA Discount	41,604	$ 0.32	$ 13,313
6	Total Discount			$ 13,313
7	Small Industrial Power Service (Rate 532)			$ 18,121,786
8			Propopsed Revenue Target	$ 18,121,730
			Difference Due to Rounding	$ 55
	Contract Riders			
9	DSMA		Rider 583	$ -
10	TDSIC		Rider 588	$ -
11	Total Rider			$ -
	Other Adjustments			
12	Generation Credit			$ -
13	Difference in Fuel Calculation			$ -
14	Total Other Adjustments			$ -
15	Grand Total			$ 18,121,786

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Small Industrial Power Service - HLF
Rate 833

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	*Billed kW*	501,650	$ 16.35	$ 8,201,978
	Total	501,650		$ 8,201,978
2	*Billed kWh*			
3	600 hours x kW	267,979,838	$ 0.040792	$ 10,931,434
	Next 60 hours x kW	-	$ 0.037691	$ -
	Over 660 hours x kW	-	$ 0.036657	$ -
4	All kWh	267,979,838		$ 10,931,434
	Discounts - Billed kW			
5	Lagging RKVA Discount	$ 45,564	$ 0.32	$ 14,580
6	Total Discount			$ 14,580
7	Small Industrial Power Service - HLF (Rate 833)			$ 19,147,992
8				
	Contract Riders			
9	DSMA		Rider 883	$ 20,933
10	TDSIC		Rider 888	$ 581,721
11	Total Rider			$ 602,654
	Other Adjustments			
12	Generation Credit			$ (1,620)
13	Difference in Fuel Calculation			$ 2,535,227
14	Total Other Adjustments			$ 2,533,606
15	Grand Total			$ 22,284,252

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Small Industrial Power Service - HLF
Rate 533

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	*Billed kW*	501,650	$ 23.82	$ 11,949,303
	Total	501,650		$ 11,949,303
2	*Billed kWh*			
3	600 hours x kW	267,979,838	$ 0.059434	$ 15,927,114
	Next 60 hours x kW	-	$ 0.054901	$ -
	Over 660 hours x kW	-	$ 0.053395	$ -
4	All kWh	267,979,838		$ 15,927,114
	Discounts - Billed kW			
5	Lagging RKVA Discount	45,564	$ 0.32	$ 14,580
6	Total Discount			$ 14,580
7	Small Industrial Power Service - HLF (Rate 533)			$ 27,890,997
			Propopsed Revenue Target	$ 27,891,010
8			Difference Due to Rounding	$ (13)
	Contract Riders			
9	DSMA		Rider 583	$ -
10	TDSIC		Rider 588	$ -
11	Total Rider			$ -
	Other Adjustments			
12	Generation Credit			
13	Difference in Fuel Calculation			
14	Total Other Adjustments			$ -
15	Grand Total			$ 27,890,997

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Municipal Power
Rate 841

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate		Annualized Revenue
	(A)	(B)	(C)		(D)
	Minimum Charge - Billed kW				
1	Minimum Charge	146	$ 7.61	$	1,113
2	Three Phase	523	$ 31.13	$	16,277
3	Warning Signal	132	$ 7.61	$	1,005
4	First 25 horsepower of the connected load	21,559	$ 2.41	$	51,957
5	Next 475 horsepower of the connected loa	53,841	$ 1.17	$	62,994
6	Over 500 horsepower of the connected loa	34,059	$ 0.58	$	19,754
7	Total	110,260		$	153,100
	Billed kWh				
8	All kWh	32,198,980	$ 0.116838	$	3,762,064
9	Total kWh	32,198,980		$	3,762,064
	DSM Proforma	812,194			
	Total Adj kWh	33,011,174			
10	Municipal Power (Rate 841)			$	3,915,164
	Contract Riders				
11	DSMA		Rider 883	$	(1,445)
12	TDSIC		Rider 888	$	183,472
13	Total Rider			$	182,027
	Other Adjustments				
14	Generation Credit			$	(196)
15	Difference in Fuel Calculation			$	316,262
16	Total Other Adjustments			$	316,065
17	Grand Total			$	4,413,256

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Municipal Power
Rate 541

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate		Revenue
	(E)	(F)	(G)		(H)
	Minimum Charge - Billed kW				
1	Minimum Charge	146	$ 10.15	$	1,484
2	Three Phase	523	$ 41.50	$	21,699
3	Warning Signal	132	$ 10.15	$	1,340
4	First 25 horsepower of the connected load	21,559	$ 3.21	$	69,204
5	Next 475 horsepower of the connected loa	53,841	$ 1.56	$	83,992
6	Over 500 horsepower of the connected loa	34,059	$ 0.77	$	26,225
7	Total	110,260		$	203,945
	Billed kWh				
8	All kWh	33,011,174	$ 0.151946	$	5,015,916
9	Total kWh	33,011,174		$	5,015,916
10	Municipal Power (Rate 541)			$	5,219,861
			Propopsed Revenue Target	$	5,219,873
			Difference Due to Rounding	$	(13)
	Contract Riders				
11	DSMA		Rider 583	$	-
12	TDSIC		Rider 588	$	-
13	Total Rider			$	-
	Other Adjustments				
14	Generation Credit			$	-
15	Difference in Fuel Calculation			$	-
16	Total Other Adjustments			$	-
17	Grand Total			$	5,219,861

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Intermittent Wastewater Pumping
Rate 842

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Customer Charge			
1	Intermittent Wastewater Pumping	96	$ 50.00	$ 4,800
2	Total	96		$ 4,800
	Pump Charge			
3	Residential	39,789	$ 2.39	$ 95,096
4	Commercial	2,001	$ 2.84	$ 5,683
5	Total	41,790		$ 100,780
	Pump Charge Ratios			
6	Commercial / Residential		118.83%	
7	Intermittent Wastewater Pumping (Rate 842)			$ 105,580
	Contract Riders			
8	DSMA		Rider 883	$ -
9	TDSIC		Rider 888	$ 1,152
10	Total Rider			$ 1,152
	Other Adjustments			
11	Generation Credit			$ (6)
12	Difference in Fuel Calculation			$ 3,234
13	Total Other Adjustments			$ 3,228
14	Grand Total			$ 109,959

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Intermittent Wastewater Pumping
Rate 542

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Customer Charge			
1	Intermittent Wastewater Pumping	96	$ 60.00	$ 5,760
2	Total	96		$ 5,760
			Target	$ 5,760
			Difference	$ -
	Pump Charge			
3	Residential	39,789	$ 1.19	$ 47,349
4	Commercial	2,001	$ 1.41	$ 2,822
5	Total	41,790		$ 50,171
			Target	$ 50,099
			Difference	$ 72
	Pump Charge Ratios			
6	Commercial / Residential		118.49%	
7	Intermittent Wastewater Pumping (Rate 542)			$ 55,931
			Propopsed Revenue Target	$ 55,859
			Difference Due to Rounding	$ 72
	Contract Riders			
8	DSMA		Rider 583	$ -
9	TDSIC		Rider 588	$ -
10	Total Rider			$ -
	Other Adjustments			
11	Generation Credit			$ -
12	Difference in Fuel Calculation			$ -
13	Total Other Adjustments			$ -
14	Grand Total			$ 55,931

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
General Service - Large
Rate 824

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate		Annualized Revenue	
	(A)	(B)	(C)		(D)	
	Billed kW - Power Factor Adjusted Rate 824					
1	First 50 kW	2,000	$	19.91	$	39,820
2	Next 1,950 kW	61,850	$	13.02	$	805,284
3	Over 2,000 kW	67,400	$	12.50	$	842,500
4	Total kW	131,250			$	1,687,604
	Minimum Charge - Billed kW - Power Factor Adjusted Rate 824					
5	First 50 kW	500	$	19.91	$	9,955
6	Next 1,950 kW	17,618	$	13.02	$	229,388
7	Over 2,000 kW	23,388	$	12.50	$	292,350
8	Total kW	41,506			$	531,692
	Billed kWh					
9	First 30,000 kWh	1,067,699	$	0.085252	$	91,023
10	Next 70,000 kWh	1,175,021	$	0.077552	$	91,125
11	Next 900,000 kWh	1,676,850	$	0.074002	$	124,090
12	Over 1,000,000 kWh	73,920	$	0.070402	$	5,204
13	Total kWh	3,993,490			$	311,443
	Thermal Storage - Billed kWh					
14	All kWh		$	0.071937	$	-
15	Total kWh				$	-

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Station Power For Renewable Wholesale Generation Equipment
Rate 543

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate		Revenue	
	(E)	(F)	(G)		(H)	
	Billed kW					
1	All kW	79,870	$	12.50	$	998,375
2	Total kW	79,870			$	998,375
	Minimum Charge - Billed kW					
3	All kW	-	$	12.50	$	-
4	Total kW	-			$	-
	Billed kWh					
5	Total kWh	3,993,490	$	0.058688	$	234,370
6	Total kWh	3,993,490			$	234,370

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
General Service - Large
Rate 824

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Discounts - Billed kW			
16	Primary Service		$ (0.72)	$ -
17	Transmission Service	141,287	$ (0.90)	$ (127,158)
18	Total kW	141,287		$ (127,158)
19	General Service - Large (Rate 824)			$ 2,403,581
	Contract Riders			
20	DSMA		Rider 883	$ 15,527
21	TDSIC		Rider 888	$ 14,238
22	Total Rider			$ 29,766
	Other Adjustments			
23	Generation Credit			$ -
24	Difference in Fuel Calculation			$ -
25	Total Other Adjustments			$ -
26	Grand Total			$ 2,433,347

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Station Power For Renewable Wholesale Generation Equipment
Rate 543

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
7	Station Power For Renewable Wholesale Generation Equipment (Rate 543)			$ 1,232,745
8	Propopsed Revenue Target			$ 1,232,747
9	Difference Due to Rounding			$ (2)
	Contract Riders			
10	DSMA		Rider 583	$ -
11	TDSIC		Rider 588	$ -
12	Total Rider			$ -
	Other Adjustments			
13	Generation Credit			$ -
14	Difference in Fuel Calculation			$ -
15	Total Other Adjustments			$ -
16	Grand Total			$ 1,232,745

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Railroad Power Service
Rate 844

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kW			
1	All kW	54,178	$ 16.85	$ 912,907
2	Total kW	54,178		$ 912,907
	Billed kWh			
3	First 660 hours x kW	19,120,033	$ 0.040024	$ 765,260
4	Over 660 hours x kW	-	$ 0.037774	$ -
5	Total kWh	19,120,033		$ 765,260
	Per kWh Usage Charge Ratios			
6	Block 2 / Block 1		94.38%	
	Adjustments - Billed kWh			
7	Load Factor Adjustment	4,693,350	$ 0.0010	$ 4,693
8	Total kWh	4,693,350		$ 4,693
9	Railroad Power Service (Rate 844)			$ 1,682,860
	Contract Riders			
10	DSMA		Rider 883	$ 33,476
11	TDSIC		Rider 888	$ 35,299
12	Total Rider			$ 68,775
	Other Adjustments			
13	Generation Credit			$ (121)
14	Difference in Fuel Calculation			$ 181,165
15	Total Other Adjustments			$ 181,045
16	Grand Total			$ 1,932,679

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Railroad Power Service
Rate 544

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kW			
1	All kW	54,178	$ 24.67	$ 1,336,582
2	Total kW	54,178		$ 1,336,582
			Target	$ 1,336,582
			Difference	$ -
	Billed kWh			
3	First 660 hours x kW	19,120,033	$ 0.058584	$ 1,120,128
4	Over 660 hours x kW	-	$ 0.055291	$ -
5	Total kWh	19,120,033		$ 1,120,128
	Per kWh Usage Charge Ratios			
6	Block 2 / Block 1		94.38%	
	Adjustments - Billed kWh			
7	Load Factor Adjustment	4,693,350	$ 0.001464	$ 6,871
8	Total kWh	4,693,350		$ 6,871
9	Railroad Power Service (Rate 544)			$ 2,463,581
			Propopsed Revenue Target	$ 2,463,590
			Difference Due to Rounding	$ (9)
	Contract Riders			
10	DSMA		Rider 583	$ -
11	TDSIC		Rider 588	$ -
12	Total Rider			$ -
	Other Adjustments			
13	Generation Credit			$ -
14	Difference in Fuel Calculation			$ -
15	Total Other Adjustments			$ -
16	Grand Total			$ 2,463,581

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Street Lighting
Rate 850

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate		Annualized Revenue
	(A)	(B)	(C)		(D)
	Lamp Charges				
1	Cust Own, Cust Maint Street Lts	255,396	4.08	$	1,042,016
2	Cust Own, Co Maint Street Lts	-	-	$	-
3	LC - 250 WATT - HPS	732	5.77	$	4,224
4	LC - 400 WATT - HPS	228	6.65	$	1,516
5	Co Own & Maint Street Lights				
6	LC - 100 WATT - HPS	26,718	13.56	$	362,296
7	LC - 150 WATT - HPS	28,286	14.36	$	406,193
8	LC - 175 WATT - MV	228	13.80	$	3,146
9	LC - 250 WATT - HPS	2,748	14.79	$	40,643
10	LC - 400 WATT - HPS	2,172	16.33	$	35,469
11	LC - 400 WATT - MV	480	15.76	$	7,565
12	LC - UP TO 50 WATT LED - NEW	2,316	14.12	$	32,702
13	LC - UP TO 50 WATT LED - RPL	-	9.92	$	-
14	LC - 70 TO 90 WATT LED - NEW	756	15.14	$	11,446
15	LC - 70 TO 90 WATT LED - RPL	-	10.90	$	-
16	LC - 91 TO 115 WATT LED - NEW	1,164	16.38	$	19,066
17	LC - 91 TO 115 WATT LED - RPL	-	12.08	$	-
18	LC - 170 TO 210 WATT LED - NEW	204	19.72	$	4,023
19	LC - 170 TO 210 WATT LED - RPL	-	15.29	$	-
20	Co Own/Maint St Lite TDSIC Prior to 1/1/20				
21	LC - UP TO 50 WATT LED - RPL	162,756	7.27	$	1,183,236
22	LC - 70 TO 90 WATT LED - RPL	97,104	7.64	$	741,875
23	LC - 91 TO 115 WATT LED - RPL	8,364	8.13	$	67,999
24	LC - 170 TO 210 WATT LED - RPL	11,376	9.98	$	113,532
25	Co Own/Maint St Lite TDSIC After 1/1/20				
26	LC - UP TO 50 WATT LED - RPL	151,174	6.85	$	1,035,539
27	LC - 70 TO 90 WATT LED - RPL	26,917	7.41	$	199,456
28	LC - 91 TO 115 WATT LED - RPL	672	8.11	$	5,450
29	LC - 170 TO 210 WATT LED - RPL	384	9.96	$	3,825
30	Total Lamps	780,175		$	5,321,217

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Street Lighting
Rate 550

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate		Revenue
	(E)	(F)	(G)		(H)
	Lamp Charges				
1	*Cust Own, Cust Maint Street Lts*	255,396	5.56	$	1,420,002
2	*Cust Own, Co Maint Street Lts*	-	-	$	-
3	*LC - 250 WATT - HPS*	732	7.86	$	5,754
4	*LC - 400 WATT - HPS*	228	9.06	$	2,066
5	*Co Own & Maint Street Lights*				
6	*LC - 100 WATT - HPS*	26,718	18.47	$	493,481
7	*LC - 150 WATT - HPS*	28,286	19.56	$	553,282
8	*LC - 175 WATT - MV*	228	18.80	$	4,286
9	*LC - 250 WATT - HPS*	2,748	20.15	$	55,372
10	*LC - 400 WATT - HPS*	2,172	22.25	$	48,327
11	*LC - 400 WATT - MV*	480	21.47	$	10,306
12	*LC - UP TO 50 WATT LED - NEW*	2,316	15.63	$	36,199
13	*LC - UP TO 50 WATT LED - RPL*	313,930	9.91	$	3,111,042
14	*LC - 70 TO 90 WATT LED - NEW*	756	16.19	$	12,240
15	*LC - 70 TO 90 WATT LED - RPL*	124,021	10.41	$	1,291,061
16	*LC - 91 TO 115 WATT LED - NEW*	1,164	16.94	$	19,718
17	*LC - 91 TO 115 WATT LED - RPL*	9,036	11.08	$	100,119
18	*LC - 170 TO 210 WATT LED - NEW*	204	19.64	$	4,007
19	*LC - 170 TO 210 WATT LED - RPL*	11,760	13.60	$	159,936
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30	Total Lamps	780,175		$	7,327,197

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Street Lighting
Rate 850

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kWh			
31	Cust Own, Cust Maint Street Lts	20,210,848	$ 0.026829	$ 542,237
32	Cust Own, Co Maint Street Lts	120,054	$ 0.026829	$ 3,221
33	Co Own & Maint Street Lights	4,188,622	$ 0.026829	$ 112,377
34	Co Own/Maint St Lite TDSIC Prior to 1/1/2(	6,223,188	$ 0.026829	$ 166,962
35	Co Own/Maint St Lite TDSIC After 1/1/20	2,995,829	$ 0.026829	$ 80,375
36	Total kWh	33,738,540		$ 905,171
37				
38				
39				
40	Street Lighting (Rate 850)			$ 6,226,388
	Contract Riders			
41	DSMA		Rider 883	$ -
42	TDSIC		Rider 888	$ 116,137
43	Total Rider			$ 116,137
	Other Adjustments			
44	Generation Credit			$ (441)
45	Difference in Fuel Calculation			$ 323,448
46	Total Other Adjustments			$ 323,007
47	Grand Total			$ 6,665,532

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Street Lighting
Rate 550

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kWh			
31	Cust Own, Cust Maint Street Lts	20,210,848	$ 0.037249	$ 752,834
32	Cust Own, Co Maint Street Lts	120,054	$ 0.037249	$ 4,472
33	Co Own & Maint Street Lights	13,407,638	$ 0.037249	$ 499,421
34				
35				
36	Total kWh	33,738,540		$ 1,256,727
37	Street Lighting (Rate 550)			$ 8,583,924
			Target	$ 8,583,922
			Difference	$ 2
	Contract Riders			
38	DSMA		Rider 583	$ -
39	TDSIC		Rider 588	$ -
40	Total Rider			$ -
	Other Adjustments			
41	Generation Credit			$ -
42	Difference in Fuel Calculation			$ -
43	Total Other Adjustments			$ -
44	Grand Total			$ 8,583,924

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Traffic and Directive Lighting
Rate 855

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Service Drop			
1	Service Drop Charge	14,840	$ 14.76	$ 219,038
2	Total kW	14,840		$ 219,038
	Adjustments			
	Billed kWh			
3	All kWh	7,207,774	$ 0.107092	$ 771,895
4	Total kWh	7,207,774		$ 771,895
	Adjustments			
5	Traffic and Directive Lighting (Rate 855)			$ 990,933
	Contract Riders			
6	DSMA		Rider 883	$ -
7	TDSIC		Rider 888	$ 22,341
8	Total Rider			$ 22,341
	Other Adjustments			
9	Generation Credit			$ (51)
10	Difference in Fuel Calculation			$ 69,100
11	Total Other Adjustments			$ 69,049
12	Grand Total			$ 1,082,323

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Traffic and Directive Lighting
Rate 555

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Service Drop			
1	Service Drop Charge	14,840	$ 19.06	$ 282,850
2	Total kW	14,840		$ 282,850
			Target	$ 282,850
			Difference	$ -
	Billed kWh			
3	All kWh	7,207,774	$ 0.138328	$ 997,037
4	Total kWh	7,207,774		$ 997,037
			Target	$ 997,037
			Difference	$ -
5	Traffic and Directive Lighting (Rate 555)			$ 1,279,887
			Propopsed Revenue Target	$ 1,279,889
			Difference Due to Rounding	$ (1)
	Contract Riders			
6	DSMA		Rider 583	$ -
7	TDSIC		Rider 588	$ -
8	Total Rider			$ -
	Other Adjustments			
9	Generation Credit			$ -
10	Difference in Fuel Calculation			$ -
11	Total Other Adjustments			$ -
12	Grand Total			$ 1,279,887

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Dusk to Dawn Area Lighting
Rate 860

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate		Annualized Revenue
	(A)	(B)	(C)		(D)
	Lamps Charges				
1	LC - 100 WATT - HPS	61,358	11.22	$	688,437
2	LC - 131 - 169 WATT - LED	229	16.39	$	3,753
3	LC - 131 - 169 WATT - LED FL	209	23.42	$	4,906
4	LC - 150 WATT - HPS, FLOOD	5,469	12.85	$	70,280
5	LC - 175 WATT - MV	16,335	11.55	$	188,672
6	LC - 250 WATT - HPS	16,499	12.84	$	211,852
7	LC - 250 WATT - HPS, FLOOD	9,860	13.56	$	133,708
8	LC - 30'POLE & SPAN - HPS	12,402	4.96	$	61,514
9	LC - 30'POLE & SPAN - MV	6,558	4.96	$	32,530
10	LC - 35'POLE & SPAN - HPS	7,355	5.23	$	38,465
11	LC - 35'POLE & SPAN - MV	3,446	5.23	$	18,023
12	LC - 400 WATT - HPS	11,101	14.19	$	157,526
13	LC - 400 WATT - HPS, FLOOD	22,740	14.79	$	336,330
14	LC - 400 WATT - MV	4,189	14.16	$	59,319
15	LC - 40'POLE & SPAN - HPS	2,068	5.72	$	11,829
16	LC - 40'POLE & SPAN - MV	144	5.72	$	824
17	LC - 51 - 130 WATT - LED	209	15.36	$	3,215
18	LC - 91 - 130 WATT - LED FL	59	22.43	$	1,326
19	LC - EXTRA SPAN - HPS	2,125	1.60	$	3,400
20	LC - EXTRA SPAN - MV	1,650	1.60	$	2,640
21	LC - GUY & ANCHOR SET - HPS	1,384	1.11	$	1,536
22	LC - GUY & ANCHOR SET - MV	362	1.11	$	402
23	LC - UPTO 50 WATT - LED	300	14.01	$	4,208
24	LC - UPTO 90 WATT - LED FL	27	21.98	$	582
25	Total Lamps	186,081		$	2,035,275

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Dusk to Dawn Area Lighting
Rate 560

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate		Revenue
	(E)	(F)	(G)		(H)
	Lamps Charges				
1	*LC - 100 WATT - HPS*	61,358	15.77	$	967,615
2	*LC - 131 - 169 WATT - LED*	229	23.03	$	5,273
3	*LC - 131 - 169 WATT - LED FL*	209	32.91	$	6,894
4	*LC - 150 WATT - HPS, FLOOD*	5,469	18.06	$	98,775
5	*LC - 175 WATT - MV*	16,335	16.23	$	265,121
6	*LC - 250 WATT - HPS*	16,499	18.04	$	297,648
7	*LC - 250 WATT - HPS, FLOOD*	9,860	19.06	$	187,940
8	*LC - 30'POLE & SPAN - HPS*	12,402	6.97	$	86,442
9	*LC - 30'POLE & SPAN - MV*	6,558	6.97	$	45,712
10	*LC - 35'POLE & SPAN - HPS*	7,355	7.35	$	54,057
11	*LC - 35'POLE & SPAN - MV*	3,446	7.35	$	25,328
12	*LC - 400 WATT - HPS*	11,101	19.94	$	221,357
13	*LC - 400 WATT - HPS, FLOOD*	22,740	20.79	$	472,772
14	*LC - 400 WATT - MV*	4,189	19.90	$	83,365
15	*LC - 40'POLE & SPAN - HPS*	2,068	8.04	$	16,627
16	*LC - 40'POLE & SPAN - MV*	144	8.04	$	1,158
17	*LC - 51 - 130 WATT - LED*	209	21.59	$	4,519
18	*LC - 91 - 130 WATT - LED FL*	59	31.52	$	1,863
19	*LC - EXTRA SPAN - HPS*	2,125	2.25	$	4,782
20	*LC - EXTRA SPAN - MV*	1,650	2.25	$	3,713
21	*LC - GUY & ANCHOR SET - HPS*	1,384	1.56	$	2,159
22	*LC - GUY & ANCHOR SET - MV*	362	1.56	$	564
23	*LC - UPTO 50 WATT - LED*	300	19.69	$	5,914
24	*LC - UPTO 90 WATT - LED FL*	27	30.89	$	819
25	Total Lamps	186,081		$	2,860,418

Northern Indiana Public Service Company LLC
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Dusk to Dawn Area Lighting
Rate 860

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kWh			
26	All kWh	14,315,916	$ 0.026829	$ 384,082
27	Total kWh	14,315,916		$ 384,082
28	Dusk to Dawn Area Lighting (Rate 860)			$ 2,419,357
	Contract Riders			
29	DSMA		Rider 883	$ -
30	Adjustment of TDSIC		Rider 888	$ 81,850
31	Total Rider			$ 81,850
	Other Adjustments			
32	Generation Credit			$ (145)
33	Difference in Fuel Calculation			$ 137,245
34	Total Other Adjustments			$ 137,100
35	Grand Total			$ 2,638,307

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Dusk to Dawn Area Lighting
Rate 560

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kWh			
26	All kWh	14,315,916	$ 0.037698	$ 539,681
27	Total kWh	14,315,916		$ 539,681
28	Dusk to Dawn Area Lighting (Rate 560)			$ 3,400,099
			Propopsed Revenue Target	$ 3,400,098
			Difference Due to Rounding	$ 1
	Contract Riders			
29	DSMA		Rider 583	$ -
30	TDSIC		Rider 588	$ -
31	Total Rider			$ -
	Other Adjustments			
32	Generation Credit			$ -
33	Difference in Fuel Calculation			$ -
34	Total Other Adjustments			$ -
35	Grand Total			$ 3,400,099

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Interdepartmental
Interdepartmental

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Current Rate	Annualized Revenue
	(A)	(B)	(C)	(D)
	Billed kWh			
1	All kWh	26,569,822	$ 0.133677	$ 3,551,774
2	Total kWh	26,569,822		$ 3,551,774
3	Interdepartmental			$ 3,551,774
	Contract Riders			
4	DSMA		Rider 883	$ -
5	TDSIC		Rider 888	$ 260,347
6	Total Rider			$ 260,347
	Other Adjustments			
7	Generation Credit			$ (280)
8	Difference in Fuel Calculation			$ 225,701
9	Total Other Adjustments			$ 225,420
10	Grand Total			$ 4,037,541

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Interdepartmental
Interdepartmental

Line No.	Description	Annualized Billing Determinants (kWh, kW, Bill Counts)	Proposed Rate	Revenue
	(E)	(F)	(G)	(H)
	Billed kWh			
1	All kWh	26,569,822	$ 0.195912	$ 5,205,347
2	Total kWh	26,569,822		$ 5,205,347
			Target	$ 5,205,354
			Difference	$ (7)
3	Interdepartmental			$ 5,205,347
			Target	$ 5,205,354
			Difference Due to Rounding	$ (7)
	Contract Riders			
4	DSMA		Rider 583	$ -
5	TDSIC		Rider 588	$ -
6	Total Rider			$ -
	Other Adjustments			
7	Generation Credit			$ -
8	Difference in Fuel Calculation			$ -
9	Total Other Adjustments			$ -
10	Grand Total			$ 5,205,347

Northern Indiana Public Service Company
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2023
Back-Up, Maintenance and Temporary
Rate 832, 833 / Rider 876

Line No.	Description (A)	Current Rate (B)
	Back-up Service - Rate 832, 833 / Rider 876	
1	Demand Charge per Daily kW	Applicable Rate 831, 832, 833 charge, divided by number of days in month.
2	Energy - Fuel per kWh	Real-Time LMP
3	Energy - Non-Fuel per kWh	$ 0.003131
	Maintenance Service - Rate 832, 833 / Rider 876	
	Demand Charge per Daily kW	
4	-- January, May, December	$ 0.46
5	-- February, March, April, October, November	$ 0.26
6	Energy per kWh	Applicable Energy Charge for Rate 831
7	Transmission per kWh	N/A
	Temporary Service - Rate 832, 833	
	Demand Charge per Daily kW	
8	-- 1st 30 days	$ 0.58
9	-- 2nd 30 days	$ 0.87
10	-- 3rd 30 days	$ 1.17
11	-- In excess of 90 days	$ 2.33
12	Energy per kWh	Applicable Energy Charge for Rate 832 and 833
	Buy-Through Temporary Service - Rate 832, 833	
13	Demand Charge per Daily kW	$ -
14	Energy - Fuel per kWh	Real-Time LMP
15	Energy - Non-Fuel per kWh	$ 0.003131

Northern Indiana Public Service Company
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2023
Back-Up, Maintenance and Temporary
Rate 532, 533 / Rider 576

Line No.	Description (F)	Proposed Rate (G)
	Back-up Service - Rate 532, 533 / Rider 576	
1	Demand Charge per Daily kW	Applicable Rate 531, 532, 533 charge, divided by number of days in month.
2	Energy - Fuel per kWh	Real-Time LMP
3	Energy - Non-Fuel per kWh	$ 0.002426
	Maintenance Service - Rate 532, 533 / Rider 576	
	Demand Charge per Daily kW	
4	-- January, May, December	$ 0.55
5	-- February, March, April, October, November	$ 0.31
6	Energy per kWh	Applicable Energy Charge for Rate 831
7	Transmission per kWh	N/A
	Temporary Service - Rate 532, 533	
	Demand Charge per Daily kW	
8	-- 1st 30 days	$ 0.69
9	-- 2nd 30 days	$ 1.04
10	-- 3rd 30 days	$ 1.39
11	-- In excess of 90 days	$ 2.77
12	Energy per kWh	Applicable Energy Charge for Rate 532 and 533
	Buy-Through Temporary Service - Rate 532, 533	
13	Demand Charge per Daily kW	$ -
14	Energy - Fuel per kWh	Real-Time LMP
15	Energy - Non-Fuel per kWh	$ 0.002426

NORTHERN INDIANA PUBLIC SERVICE COMPANY
TYPICAL BILL COMPARISON
RATE 511

	Current Rates	Proposed Rates
Customer Charge	$ 13.50	$ 17.00
Energy Charge		
Energy Charge	$ 0.122116	$ 0.165070
Riders		
DSMA	$ 0.000908	n/a
TDSIC	$ 0.008474	n/a
Increase in Fuel Cost	$ 0.009706	n/a
Variable Cost Tracker	$ -	$ 0.009316
Total Energy	$ 0.141204	$ 0.174386

Line No.	Monthly kWh (A)	Monthly Total Bill: Current Rates (B)	Monthly Total Bill: Proposed Rates (C)	Increase / Decrease: Amount (D) (C) - (B)	Increase / Decrease: Percent (E) (D) / (B)	Increase / Decrease: Proposed ¢ / kWh (F) 100 x (C) / (A)
1	75	$ 24.09	$ 30.08	$ 5.99	24.86%	40.11
2	200	$ 41.74	$ 51.88	$ 10.14	24.28%	25.94
3	400	$ 69.98	$ 86.75	$ 16.77	23.97%	21.69
4	500	$ 84.10	$ 104.19	$ 20.09	23.89%	20.84
5	600	$ 98.22	$ 121.63	$ 23.41	23.83%	20.27
6	700	$ 112.34	$ 139.07	$ 26.73	23.79%	19.87
7	800	$ 126.46	$ 156.51	$ 30.04	23.76%	19.56
8	900	$ 140.58	$ 173.95	$ 33.36	23.73%	19.33
9	1,000	$ 154.70	$ 191.39	$ 36.68	23.71%	19.14
10	2,500	$ 366.51	$ 452.96	$ 86.45	23.59%	18.12
11	5,000	$ 719.52	$ 888.93	$ 169.41	23.54%	17.78
Avg. Bill	668	$ 107.78	$ 133.43	$ 25.65	23.80%	19.98

NORTHERN INDIANA PUBLIC SERVICE COMPANY
TYPICAL BILL COMPARISON
RATE 511 (without Variable Cost Tracker)

	Current Rates	Proposed Rates
Customer Charge	$ 13.50	$ 17.00
Energy Charge		
Energy Charge	$ 0.122116	$ 0.165070
Riders		
DSMA	$ 0.000908	n/a
TDSIC	$ 0.008474	n/a
Increase in Fuel Cost	$ 0.009706	n/a
Variable Cost Tracker	$ -	$ -
Total Energy	$ 0.141204	$ 0.165070

Line No.	Monthly kWh (A)	Monthly Total Bill: Current Rates (B)	Monthly Total Bill: Proposed Rates (C)	Increase / Decrease: Amount (D) (C) - (B)	Increase / Decrease: Percent (E) (D) / (B)	Increase / Decrease: Proposed ¢ / kWh (F) 100 x (C) / (A)
1	75	$ 24.09	$ 29.38	$ 5.29	21.96%	39.17
2	200	$ 41.74	$ 50.01	$ 8.27	19.82%	25.01
3	400	$ 69.98	$ 83.03	$ 13.05	18.64%	20.76
4	500	$ 84.10	$ 99.54	$ 15.43	18.35%	19.91
5	600	$ 98.22	$ 116.04	$ 17.82	18.14%	19.34
6	700	$ 112.34	$ 132.55	$ 20.21	17.99%	18.94
7	800	$ 126.46	$ 149.06	$ 22.59	17.86%	18.63
8	900	$ 140.58	$ 165.56	$ 24.98	17.77%	18.40
9	1,000	$ 154.70	$ 182.07	$ 27.37	17.69%	18.21
10	2,500	$ 366.51	$ 429.68	$ 63.16	17.23%	17.19
11	5,000	$ 719.52	$ 842.35	$ 122.83	17.07%	16.85
Avg. Bill	668	$ 107.78	$ 127.21	$ 19.43	18.03%	19.05

Northern Indiana Public Service Company
Tracker Allocators
2022 Electric Rate Case
Demand Allocation

Line	Description	Rate Class	Demand Allocators - Total Revenue /1	Resulting % Allocation on Revenue
1	Residential	Rate 511	$ 665,315,569	37.39%
2	C&GS Heat Pump	Rate 520	$ 1,218,679	0.07%
3	GS Small	Rate 521	$ 311,673,363	17.52%
4	Comml SH	Rate 522	$ 1,135,302	0.06%
5	GS Medium	Rate 523	$ 172,712,463	9.71%
6	GS Large	Rate 524	$ 227,371,899	12.78%
7	Metal Melting	Rate 525	$ 9,620,233	0.54%
8	Off-Peak Serv.	Rate 526	$ 196,477,681	11.04%
9	Industrial Power Service - Large	Rate 531	$ 119,601,839	6.72%
10	Small Industrial Service - LLF	Rate 532	$ 18,280,525	1.03%
11	Small Industrial Service - HLF	Rate 533	$ 28,152,543	1.58%
12	Muni. Power	Rate 541	$ 5,254,644	0.30%
13	Int WW Pumping	Rate 542	$ 56,566	0.00%
14	Station Power - Renewable	Rate 543	$ 1,247,539	0.07%
15	Railroad	Rate 544	$ 2,480,740	0.14%
16	Street Lighting	Rate 550	$ 8,617,384	0.48%
17	Traffic Lighting	Rate 555	$ 1,286,900	0.07%
18	Dusk to Dawn Lighting	Rate 560	$ 3,421,960	0.19%
19		Interdepartmental	$ 5,245,804	0.29%
20	System Total		$ 1,779,171,632	100.00%

/1 Source: Attachment 19-E. Rate 531 revenue is Tier 1 only; Attachment 19-F.

Northern Indiana Public Service Company
Tracker Allocators
2022 Electric Rate Case
Energy Allocation

Line	Description	Rate Class	MWH at the Source /1	% Allocation on Sales
1	Residential	Rate 511	3,565,974	31.74%
2	C&GS Heat Pump	Rate 520	9,760	0.09%
3	GS Small	Rate 521	1,643,907	14.63%
4	Comml SH	Rate 522	8,437	0.08%
5	GS Medium	Rate 523	1,032,796	9.19%
6	GS Large	Rate 524	1,518,515	13.51%
7	Metal Melting	Rate 525	87,429	0.78%
8	Off-Peak Serv.	Rate 526	1,575,403	14.02%
9	Industrial Power Service - Large	Rate 531 Tier 1	1,210,030	10.77%
10	Small Industrial Service - LLF	Rate 532	167,971	1.49%
11	Small Industrial Service - HLF	Rate 533	273,163	2.43%
12	Muni. Power	Rate 541	34,076	0.30%
13	Int WW Pumping	Rate 542	348	0.00%
14	Station Power - Renewable	Rate 543	4,068	0.04%
15	Railroad	Rate 544	19,520	0.17%
16	Street Lighting	Rate 550	34,850	0.31%
17	Traffic Lighting	Rate 555	7,445	0.07%
18	Dusk to Dawn Lighting	Rate 560	14,788	0.13%
19		Interdepartmental	27,446	0.24%
20	System Total		11,235,927	100%

21	Description	Rate Class	MWH at the Source /1	% Allocation on Sales
22	Residential	Rate 511	3,565,974	26.91%
23	C&GS Heat Pump	Rate 520	9,760	0.07%
24	GS Small	Rate 521	1,643,907	12.41%
25	Comml SH	Rate 522	8,437	0.06%
26	GS Medium	Rate 523	1,032,796	7.79%
27	GS Large	Rate 524	1,518,515	11.46%
28	Metal Melting	Rate 525	87,429	0.66%
29	Off-Peak Serv.	Rate 526	1,575,403	11.89%
30	Industrial Power Service - Large	Rate 531 Tier 1	1,210,030	9.13%
31		Rate 531 Tier 2	2,013,545	15.20%
32	Small Industrial Service - LLF	Rate 532	167,971	1.27%
33	Small Industrial Service - HLF	Rate 533	273,163	2.06%
34	Muni. Power	Rate 541	34,076	0.26%
35	Int WW Pumping	Rate 542	348	0.00%
36	Station Power - Renewable	Rate 543	4,068	0.03%
37	Railroad	Rate 544	19,520	0.15%
38	Street Lighting	Rate 550	34,850	0.26%
39	Traffic Lighting	Rate 555	7,445	0.06%
40	Dusk to Dawn Lighting	Rate 560	14,788	0.11%
41		Interdepartmental	27,446	0.21%
42	System Total		13,249,472	100%

/1 Source: Attachment 19-D

Northern Indiana Public Service Company
Tracker Allocators
2022 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 511	39.27%	56.28%
2	C&GS Heat Pump	Rate 520	0.09%	0.16%
3	GS Small	Rate 521	14.83%	16.23%
4	Comml SH	Rate 522	0.07%	0.14%
5	GS Medium	Rate 523	9.32%	8.34%
6	GS Large	Rate 524	13.86%	9.68%
7	Metal Melting	Rate 525	0.55%	0.51%
8	Off-Peak Serv.	Rate 526	10.31%	7.10%
9	Industrial Power Service - Large	Rate 531	6.95%	0.00%
10	Small Industrial Service - LLF	Rate 532	1.23%	0.00%
11	Small Industrial Service - HLF	Rate 533	1.99%	0.00%
12	Muni. Power	Rate 541	0.22%	0.31%
13	Int WW Pumping	Rate 542	0.00%	0.00%
14	Station Power - Renewable	Rate 543	0.36%	0.00%
15	Railroad	Rate 544	0.51%	0.00%
16	Street Lighting	Rate 550	0.07%	0.39%
17	Traffic Lighting	Rate 555	0.04%	0.03%
18	Dusk to Dawn Lighting	Rate 560	0.03%	0.20%
		Interdepartmental	0.30%	0.63%
19	System Total		100.00%	100.00%

Northern Indiana Public Service Company
Tracker Allocators
2022 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 511	$ 67,364,908	$ 8,786,516	$ 76,151,424		$ 76,151,424	39.27%
2	Rate 520	$ 146,917	$ 29,542	$ 176,460		$ 176,460	0.09%
3	Rate 521	$ 25,892,407	$ 2,862,427	$ 28,754,834		$ 28,754,834	14.83%
4	Rate 522	$ 111,000	$ 25,728	$ 136,728		$ 136,728	0.07%
5	Rate 523	$ 16,525,058	$ 1,554,962	$ 18,080,020		$ 18,080,020	9.32%
6	Rate 524	$ 24,809,973	$ 2,063,596	$ 26,873,569		$ 26,873,569	13.86%
7	Rate 525	$ 933,638	$ 140,658	$ 1,074,296		$ 1,074,296	0.55%
8	Rate 526	$ 18,416,983	$ 1,570,298	$ 19,987,280		$ 19,987,280	10.31%
9	Rate 531	$ 59,467,472	$ 594,719	$ 60,062,191	$ (46,573,893)	$ 13,488,297	6.95%
10	Rate 532	$ 2,264,816	$ 127,592	$ 2,392,408		$ 2,392,408	1.23%
11	Rate 533	$ 3,739,901	$ 118,281	$ 3,858,182		$ 3,858,182	1.99%
12	Rate 541	$ 374,792	$ 56,645	$ 431,437		$ 431,437	0.22%
13	Rate 542	$ 3,725	$ 276	$ 4,001		$ 4,001	0.00%
14	Rate 543	$ 700,922	$ -	$ 700,922		$ 700,922	0.36%
15	Rate 544	$ 181,522	$ 810,614	$ 992,137		$ 992,137	0.51%
16	Rate 550	$ 68,154	$ 69,334	$ 137,488		$ 137,488	0.07%
17	Rate 555	$ 71,970	$ 5,361	$ 77,332		$ 77,332	0.04%
18	Rate 560	$ 25,858	$ 25,937	$ 51,794		$ 51,794	0.03%
19	Interdepartmental	$ 444,965	$ 127,798	$ 572,763		$ 572,763	0.30%
20	Total	$ 221,544,982	$ 18,970,285	$ 240,515,267	$ (46,573,893)	$ 193,941,374	100.00%
21	Tier 1 Transmission Volumes			1,187,580,246	22.46%		
22	Total Transmission Volumes			5,288,189,445			

23	Rate	Dist Primary /1	Dist Secondary /1	Total	831 Tier 1 Adj	Adj. Total	Distribution Rev. Req. Allocation Factor
24	Rate 511	$ 122,934,355	$ 44,373,001	$ 167,307,356		$ 167,307,356	56.28%
25	Rate 520	$ 413,335	$ 59,715	$ 473,050		$ 473,050	0.16%
26	Rate 521	$ 39,496,927	$ 8,753,880	$ 48,250,807		$ 48,250,807	16.23%
27	Rate 522	$ 359,973	$ 52,119	$ 412,092		$ 412,092	0.14%
28	Rate 523	$ 21,676,399	$ 3,126,991	$ 24,803,390		$ 24,803,390	8.34%
29	Rate 524	$ 26,822,608	$ 1,941,636	$ 28,764,244		$ 28,764,244	9.68%
30	Rate 525	$ 1,423,093	$ 81,864	$ 1,504,957		$ 1,504,957	0.51%
31	Rate 526	$ 19,811,488	$ 1,303,823	$ 21,115,310		$ 21,115,310	7.10%
32	Rate 531	$ -	$ -	$ -		$ -	0.00%
33	Rate 532	$ 0	$ -	$ 0		$ 0	0.00%
34	Rate 533	$ (0)	$ -	$ (0)		$ (0)	0.00%
35	Rate 541	$ 792,538	$ 132,377	$ 924,916		$ 924,916	0.31%
36	Rate 542	$ 3,865	$ 1,151	$ 5,016		$ 5,016	0.00%
37	Rate 543	$ -	$ -	$ -		$ -	0.00%
38	Rate 544	$ -	$ -	$ -		$ -	0.00%
39	Rate 550	$ 970,073	$ 196,839	$ 1,166,912		$ 1,166,912	0.39%
40	Rate 555	$ 75,013	$ 17,308	$ 92,321		$ 92,321	0.03%
41	Rate 560	$ 362,887	$ 241,598	$ 604,486		$ 604,486	0.20%
42	Interdepartmental	$ 1,788,050	$ 88,118	$ 1,876,167		$ 1,876,167	0.63%
43	Total	$ 236,930,605	$ 60,370,420	$ 297,301,025	$ -	$ 297,301,025	100.00%

/1 Source: Attachment 19-B