FILED
October 25, 2023
INDIANA UTILITY
REGULATORY COMMISSION

Northern Indiana Public Service Company LLC

Cause No. 45967

VERIFIED DIRECT TESTIMONY OF JOHN D. TAYLOR

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I. Introduction and Summary of Testimony

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. On whose behalf are you testifying?

A2. I am testifying on behalf of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company").

Q3. Have you prepared an attachment describing your professional qualifications?

A3. Yes. Attachment 16-A to my direct testimony presents my professional qualifications.

Q4. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A4. Yes. I testified on behalf of NIPSCO in two previous electric rate cases, Cause No. 45772 and Cause No. 43969, and I submitted testimony on behalf of Indianapolis Power & Light in Cause No. 44576.

Q5. For what purpose has Atrium been retained by NIPSCO?

A5. Atrium has been retained by NIPSCO as a consultant in the area of utility costing and rate design. Specifically, NIPSCO has requested that we assist the Company in conducting a cost of service study to determine the embedded costs of serving its natural gas retail customers; provide support with the development of its rates; and develop a Sales Reconciliation Adjustment ("SRA") mechanism.

Q6. Please summarize the purpose of your testimony.

A6. In my testimony, I present NIPSCO's allocated cost of service study ("ACOSS") and discuss its results, present the revenue increase apportionment to NIPSCO's rate classes, present the rate design proposals filed by NIPSCO in this proceeding, and present the Company's proposed SRA mechanism. My testimony consists of this introduction and summary section and the following additional sections:

- Purpose and Principles of Cost Allocation
- NIPSCO's ACOSS
- Principles of Sound Rate Design
- Determination of ACOSS's Proposed Class Revenues

- NIPSCO's Rate Design
- NIPSCO's proposed Sales Reconciliation Adjustment ("SRA") mechanism

Q7. Are you sponsoring any attachments to your direct testimony?

A7. Yes. As stated earlier, <u>Attachment 16-A</u> contains background information summarizing my education, presentation of expert testimony, and other industry-related activities. The following is a listing of the remaining attachments I am sponsoring, all of which were prepared by me or under my supervision and direction.

- Attachment 16-B: Cost of Service Study
- Attachment 16-C: Allocation of Pipeline and Storage Demand Costs for Gas Cost Adjustment ("GCA")
- Attachment 16-D: Rate Mitigation & Rate Design
- Attachment 16-E: Residential Customer Bill Comparison Impacts
- Attachment 16-F: Commercial & Industrial Bill Impacts

II. <u>Purpose of an ACOSS</u>

Q8. What is an ACOSS?

A8. 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.

Q9. What is the purpose of an ACOSS?

A9. 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 that is 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.

Q10. Will an electronic copy of the Atrium Model be provided to the Commission?

A10. 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). A description of the Atrium model is provided in <u>Attachment 16-B</u>. NIPSCO is filing 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 the subject to reasonable efforts by Atrium to maintain its secrecy. Therefore, Atrium requests that the Commission allow the Model to be submitted under seal. The Atrium Model will also be provided to the Indiana Office of Utility Consumer Counselor and other parties subject to mutually agreeable nondisclosure agreements.

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

Q11. What is the general purpose and use of an ACOSS in regulatory proceedings?

A11. The purpose of an ACOSS is to allocate the gas distribution utility's overall adjusted going level costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. An ACOSS represents an analysis of which customer or group of customers causes the utility to incur the costs to provide service. The requirement to develop an ACOSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs are costs that are not directly attributable to a specific customer or service but are incurred to maintain and operate the overall gas distribution system.

In addition, utility costs may be fixed or variable in nature. By "fixed costs," I mean costs that do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of mains, service lines, meters, and regulators including labor and related benefit costs.

Finally, the ACOSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the Forward Test Year (the period January 1, 2024 through December 31, 2024). The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and energy developed in the ACOSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q12. Is the preparation of an ACOSS an exact science?

A12. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged to customers by identifying all of the capital and operating costs incurred by the utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the costs to be incurred. The allocation of costs using an ACOSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q13. Is there a guiding principle that supports the appropriate allocation of costs?

A13. Yes. Although there may not be a perfect methodology for allocating costs, there is a fundamental foundational principle, cost causation, which 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 so the analysis results in an appropriate allocation of the utility's total revenue requirement customers' utility service.

Q14. How does the cost analyst establish the cost and utility service relationships?

A14. An important element in the selection and development of a reasonable ACOSS allocation methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. In order to accomplish this, I reviewed NIPSCO's expense and plant accounts, operational data, and usage information, and conducted interviews with NIPSCO employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q15. Please describe NIPSCO's derivation of its total revenue requirement.

A15. The Company's base rates are proposed to recover the revenue requirement, exclusive of the cost of gas and associated taxes. As explained by NIPSCO Witness Weatherford, the Company's revenue requirement is based upon a return equal to the weighted average cost of capital as applied to the Forward Test Year original cost rate base. Because the Company is choosing to propose an overall increase in its gross margin (total revenues less gas costs and associated taxes) of $161.9 million, it has designed base rates to recover $746.3 million of gross margin, with miscellaneous revenues of $9.3 million, for total margin revenue of $755.5 million. I refer to this as the Company's "revenue requirement" throughout my testimony.

Q16. What are the steps to performing an ACOSS?

A16. In order 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 which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system.

Q17. Please describe cost functionalization.

A17. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. NIPSCO's functional cost categories associated with gas service include Underground Storage, Liquified Natural Gas ("LNG") Storage, Transmission, Distribution, Distribution On-Site Customer, and Customer Accounts and Services.

Q18. Please describe cost classification.

A18. The second step, classification of costs, further separates the functionalized plant and expenses into the three cost defining characteristics of (1) customer related; (2) demand or capacity related; and (3) commodity related.

Q19. Please describe the types of costs contained in the customer cost, demand cost and commodity cost categories.

A19. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by the Company for its customers.

Q20. Please describe cost allocation.

A20. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, and commodity allocation factors.

Q21. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A21. Yes. The factors which can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q22. Why are these considerations relevant to conducting NIPSCO's ACOSS?

A22. 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 provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of Indiana as it pertains to cost of service studies and gas ratemaking issues.

Q23. Please explain why the physical configuration of the system is an important consideration.

A23. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure or a single-pressure based operation.

Q24. What are the specific physical characteristics of the NIPSCO system?

A24. As discussed by NIPSCO Witness Robles, the physical configuration of the NIPSCO system is a dispersed / multiple city-gate, integrated transmission / distribution and multiple-pressure based system.

Q25. How does the availability of data influence an ACOSS?

A25. 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, segregation of data by operating unit or geographic region and the types of load data available. NIPSCO maintains detailed plant accounting records for many of its distribution-related facilities.

Q26. How do state regulatory policies affect a utility's ACOSS?

A26. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedent sets forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

IV. NIPSCO's ACOSS

Q27. Please describe the process of performing NIPSCO's ACOSS presented in the Company's filing.

A27. The detailed process description of NIPSCO's ACOSS analysis is presented in Attachment 16-B. The exhibit provides a full scope of the process including the development of allocation factors that supports various cost of service studies presented in this proceeding as discussed below.

Q28. Please discuss the contents of Attachment 16-B.

A28. Attachment 16-B consists of three sections detailing the process of developing NIPSCO's ACOSS. The first section includes an introduction, the general purpose, and the process of the cost of service study, as well as an overview of the Excel-based ACOSS model presented in this proceeding. The second section presents the ACOSS development process specific to the Company including Functionalization, Classification, and Allocation. The Allocation section specifically describes the development of internal and external allocation factors and processes used in the ACOSS. The third section depicts the results of the cost of service studies including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates. The following is the list of Schedules included in Attachment 16-B that provides the results of the ACOSS:

- Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates
- Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 3 - Cost of Service Allocation Study Detail by Account
- Schedule 4 - Account Balances and Allocation Methods
- Schedule 5 - External Allocation Factors
- Schedule 6 - Internal Allocation Factors Summary
- Schedule 7 - Alternative COSS – Design Day Allocation of Transmission Plant

Q29. How are the NIPSCO rate classes structured for purposes on conducting its ACOSS?

A29. For NIPSCO's ACOSS, I included the following rate classes:

- Residential – Rate 211

- Multi-Family – Rate 215
- Small General – Rate 221
- Large General – Rate 225
- Large Transport – Rate 228 DP
- Large Transport – Rate 228 HP
- Interruptible – Rate 234
- General Transport – Rate 238

Q30. What was the source of the cost data analyzed in the Company's ACOSS?

A30. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and schedules contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

A. <u>Description of Method used to Allocate NIPSCO's Distribution Mains Costs</u>

Q31. How are Distribution Mains classified and allocated in the ACOSS you developed?

A31. The ACOSS was performed utilizing a peak allocation methodology with distribution mains classified as demand and customer related. The customer-related portion of the distribution mains investment was then allocated to the rate classes based on the number of customers on NIPSCO's system. The demand-related portion was allocated to the rate classes based on their respective contribution to the Company's peak day demand under system design and weather conditions.

B. <u>Rationale for Classification of a Portion of Distribution Mains Investment as Customer Related</u>

Q32. Please discuss the rationale for the classification of a portion of the investment in distribution mains as customer related.

A32. It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the local distribution company's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers. There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the utility's gas system by its customers. Second, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demand and the number of customers served by the utility.

Q33. Is the method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A33. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities are: (1) the zero-intercept approach; and (2) the most commonly installed, minimum-sized unit of plant investment approach. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, (1) Electric Utility Cost Allocation Manual, by John J. Doran et al., National Association of Regulatory Utility Commissioners (NARUC), and (2) Gas Rate Fundamentals, American Gas Association ("AGA"), both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution main facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q34. Please describe the zero-intercept method for determining a customer component of distribution mains costs.

A34. Under the zero-intercept approach, which is the method utilized in NIPSCO's ACOSS, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the utility's gas system against the actual size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the utility's distribution system, regardless of the customer's peak or annual gas consumption.

Q35. Please describe the minimum-sized unit approach.

A35. The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. This method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. While the zero-intercept method, with reliable data, estimates the customer costs associated with a zero-size pipe diameter, the minimum-size method may include some capacity costs since any minimum size pipe considered will, in fact, be capable of actually delivering some gas.

Q36. What method was employed in developing an appropriate classification for NIPSCO's distribution mains?

A36. Two separate weighted regression analyses were conducted for the Company's investment in distribution mains: one for plastic distribution mains and one for steel distribution mains. The "zero-intercept" regression results, which were \$9.48 per foot for plastic mains and \$26.77 per foot for steel mains, applied to the Company's total footage of distribution mains results in an investment amount equivalent to 41% of the total investment in distribution mains, on a current cost (year 2022) basis. The regressions' intercept values of $9.48 and $26.77 per foot represent cost components exclusively related to the fact that NIPSCO incurs cost to install a main, regardless of its size (i.e., the installation is unrelated to either peak gas flows or average gas flows). Furthermore, these disaggregated costs are related more strongly to the process of extending and replacing the distribution mains, which is a function of the length of distribution mains and not of the size or diameter of the mains. As such, NIPSCO's distribution mains are classified as 41% customer related and 59% demand related.

A. Allocation of NIPSCO's Transmission and High-Pressure Distribution Mains

Q37. Please describe the method used to allocate NIPSCO's investment in its transmission plant.

A37. NIPSCO's transmission system is a large diameter, high pressure pipeline system that moves large volumes of gas between dispersed interstate pipeline interconnecting points and its downstream distribution systems throughout the year. This transmission pipeline configuration permits the sourcing of gas supplies from multiple trading points and supply basins to the benefit of both sales and transportation customers. Therefore, a Peak and Average ("P&A")

demand allocation method reflecting the NIPSCO system load factor of 45.35 percent was used to ratably allocate transmission plant. Design Day demand was used to allocate the Peak portion of transmission plant or 54.65 percent. Annual Throughput was used to allocate the remaining 45.35 percent of transmission plant.

Q38. Are there other cost-related considerations particular to NIPSCO's transmission system that influenced your choice of the P&A methodology?

A38. Yes. From my discussions with NIPSCO pipeline operations personnel familiar with improvements to the transmission system over the last several years as well as the Transmission, Distribution and Storage System Improvement Charge ("TDSIC") investments in the transmission system, investments were made for increased transmission system reliability and supply diversity and flexibility. Investments under the TDSIC program include:

- Replacement of "at risk" pipeline, in other words, finding problems before they become emergencies;
- Investment in a major transmission segment in northwestern Indiana, referred to by NIPSCO as the 483 lb. system and the 295 lb. system, allowing for a secondary feed for redundancy, additional physical paths for supply, and to maintain higher operating pressures.

- Investment in a redundant feed into the Town of Kokomo for serving additional load growth in that area.
- The investments in TDSIC create an additional high-pressure feed to customers served in northwestern Indiana.

To summarize, the NIPSCO transmission system provides increased supply diversity, and price options, for transportation customers as well as core sales customers. It facilitates the transfer of supply from five of the seven pipeline interconnection points, even when NIPSCO might not be receiving gas from all interconnection points. It allows transportation customers to receive supply at various points of interstate pipeline delivery, whether near or far from their location on the system. The significant investment by NIPSCO in the transmission system since 2010 has resulted in increased redundancy through additional looping of the transmission system to provide secondary feeds and maintain higher allowed operating pressure and additional physical paths for less supply source restrictions. The culmination of improvements under TDSIC projects provide further enhanced services, with fewer restrictions. The operational improvements, cost-saving supply sourcing flexibility and associated pricing options described above were influential in the choice of the P&A allocation method for the NIPSCO transmission system mains.

Q39. Please describe the method used to allocate NIPSCO's investment in its high-pressure distribution plant.

A39. NIPSCO's high pressure distribution mains are pipelines that typically operate at pressures above 60 psig and serve as an intermediate pipeline system between the transmission system and the downstream distribution systems. Design Day demand was used to allocate the high-pressure distribution mains.

Q40. Are some NIPSCO customers served directly from the transmission or high-pressure distribution systems?

A40. Yes. The vast majority of NIPSCO's customers are served from distribution mains that operate at or below 60 psig. However, due to the pressure requirements and/or locations of some large customers, they are directly connected to either the transmission system or the high-pressure distribution system. These customers do not utilize the 60 psig distribution system, and therefore the peak demands of the Large Transportation (Class 228) and General Transportation (Class 238) customers that are directly connected to either transmission or high-pressure distribution pipelines were excluded from the allocation of the downstream distribution mains.

B. Description of Method used to Allocate NIPSCO's Underground Storage Plant

Q41. Please describe the method used to allocate NIPSCO's investment in its underground storage plant.

A41. NIPSCO's investment in its underground storage facility, commonly referred to as Trenton or Royal Center, and the associated non-current gas inventory, were allocated based on the incremental seasonal sales corresponding to the winter withdrawal period for the storage facility. This system load characteristic is representative of the function that the underground storage facility was designed to provide, that is, incremental capacity on NIPSCO's system to support the day-to-day incremental demand during the winter period, generally beginning with the first week of December and continuing through March.

Q42. How was NIPSCO's investment in its LNG facility treated for cost allocation purposes?

A42. NIPSCO's LNG plant was allocated to the customer classes on the basis of the three-day coincident peak excluding transportation classes from the test year, which reflects its design and operational characteristics as a peaking resource of last resort. As discussed by NIPSCO Witness Robles, the LNG facility has ten days of deliverability at its maximum daily vaporization capability. It is utilized to supplement system supply on "critical" winter days of high customer demand. Operationally, the peaking resource is held in reserve for these critical days, as the liquefaction capability of the facility requires about 40 days to replenish the amount of LNG consumed on a single maximum vaporization day.

C. Description of other Special Studies Conducted for the Purpose of Allocating other Distribution Plant Investment

Q43. Please describe the Special Studies conducted for purposes of allocating other distribution plant investment.

A43. Regarding NIPSCO's major customer related plant accounts, customer weighting factors were developed to allocate the following plant accounts: Services – Account No. 380, Meters – Account No. 381, Meter Installations – Account No. 382 and House Regulators – Account No. 383. These weighting factors reflect any differences in the current unit costs that particular customer groups cause the Company to incur. For example, the cost of a 5/8-inch plastic service line that could serve a residential customer, costs less, on a per unit basis, than the cost of a 2-inch or 4-inch steel service line to serve a larger commercial or industrial customer. The use of weighting factors takes these unit cost differences into account when assigning costs to the various customer classes.

Q44. What other noteworthy allocations have been made?

A44. For Industrial Measuring & Regulating Station Equipment – Account No. 385, an assignment of this plant to all but Service Classifications 211 and 215 was facilitated by the identification in the property records of specific types of equipment associated with the size and type of customers in these classes.

Q45. How were you able to determine the particular type and size of facilities for each plant account attributable to each of the customer groups?

A45. Based on its historical installation and operating experience, NIPSCO has established engineering and operational standards which enable the direct identification of the typical size and material type of service line by customer group. This information was obtained from the utility's customer engineering and property records. With regard to meters, NIPSCO was able to conduct a detailed analysis of data, contained in its customer information system and property records that identified the type and size of meter for each customer it serves, which can be aggregated by customer class. This approach was used to determine the allocation by customer class for house regulators and to assign the installation costs of meters and house regulators to specific customer classes.

D. Allocation of Depreciation Reserve and Expenses

Q46. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A46. These items were allocated by account in the same manner as their associated plant accounts.

E. Allocation of O&M Expenses

Q47. How did the ACOSS allocate distribution related O&M expenses?

A47. A utility's distribution related O&M expenses generally are thought to support the utility's corresponding plant in service accounts. As such, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts.

Q48. How did the ACOSS allocate Customer Account Expenses (FERC Account Nos. 901 – 904) and Demonstrating and Selling and Advertising Expenses (FERC Account Nos. 912 and 913)?

A48. Meter Reading Expense, Account No. 902, was allocated on the basis of the number of customers by class, which was weighted by the results of a meter reading labor time estimate based on the time records related to manually read meters and Automated Meter Reading devices by class. As part of the support for administrative costs attributable to NIPSCO's Alternative Regulatory Plan ("ARP") services, the Company prepares time studies to evaluate the level of service provided by several departmental cost centers that record costs to Account No. 901 - Customer Account Supervision, and Account No. 903 - Customer Records and Collections Expense. These analyses form the basis for the assignment of the labor-related administrative costs to the various rate classes. In addition, a further study of the activities related to the other costs (revenue recovery and bill processing) charged to Account No. 903 resulted in the construction of a composite allocation derived from a weighting of customers, bills, and late charges/credits. An analysis of uncollectible expenses by class was conducted for the purpose of allocating Account No. 904, Uncollectible Accounts Expense. FERC Account Nos. 912 and 913 were allocated to each rate class based on customer counts.

F. <u>Allocation of Administrative and General Expenses</u>

Q49. How did the ACOSS allocate Administrative and General ("A&G") Expenses (Account Nos. 920 - 935)?

A49. Account Nos. 920 – A&G Salaries, 921 – Office Supplies, Account No. 925 – Injuries and Damages, and 926 – Employee Pension & Benefits were allocated on the basis of NIPSCO's labor expenses. Account No. 924 – Property Insurance, was allocated on the basis of total plant, and Maintenance of General Plant – Account Nos. 932 and 935, were allocated on a general plant basis. All other A&G accounts were allocated on the basis of total O&M, exclusive of A&G.

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

Q50. How did the ACOSS allocate taxes other than income taxes?

A50. The ACOSS allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category, *i.e.*, payroll, property, or function. Typically, taxes of a utility other than income taxes, can be grouped into the following categories: (1) labor; (2) plant; and (3) function, *e.g.*, Transmission, Distribution, Storage, etc. In the ACOSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q51. How were income taxes allocated to each customer class?

A51. Current income taxes were allocated to each rate class based on the net operating income of each individual class. 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.

H. Allocation of Gas Supply Related Capacity Costs for GCA Purposes

Q52. Please describe the extent to which gas supply-related costs, subject to recovery through the Company's GCA mechanism, are reflected in the ACOSS.

A52. A separate cost analysis of the various pipeline and storage resources was performed for the purpose of establishing the appropriate allocation percentages by customer class for the capacity related or demand costs of interstate pipeline transportation, storage, and related transmission services subject to recovery through the GCA. For purposes of establishing the resulting GCA demand allocators, the customer classes have been grouped in the following manner:

Class 1 – Residential Sales	Rate Schedules 211, 215
Class 2 – General Service Sales	Rate Schedules 221, 225

The results of the pipeline and storage resource analysis for the period ending December 31, 2022, is summarized in Attachment 16-C.

VII. Results of NIPSCO's ACOSS

A. Rate of Return Results at Present Rates by Class under Existing and Proposed Service Classes

Q53. Please summarize the results of NIPSCO's ACOSS.

A53. Table 1 below presents a summary of the results of the Company's ACOSS that can be reviewed in detail in Schedule 1 of Attachment 16-B. The ACOSS shows an overall revenue deficiency to the Company of $161.9 million.

Table 1 - Summary Results of the Company's ACOSS

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current ROR	Current Relative ROR	Current R:C Ratio	Current Parity Ratio
Residential211	$ 376,460,321	$ 472,957,486	$ (96,497,165)	25.6%	3.8%	0.94	0.80	1.02
Multiple Family215	2,852,398	3,536,119	(683,720)	24.0%	4.3%	1.07	0.81	1.03
General Small221	121,103,007	143,390,577	(22,287,570)	18.4%	5.3%	1.32	0.85	1.08
General Large225	17,878,181	21,798,769	(3,920,588)	21.9%	5.4%	1.34	0.82	1.05
Large Transport - DP228 DP	17,762,595	15,256,629	2,505,966	-14.1%	10.9%	2.71	1.16	1.48
Large Transport - HP228 HP	42,214,459	83,946,622	(41,732,162)	98.9%	1.7%	0.41	0.50	0.64
Interruptible234	69,452	27,962	41,490	-59.7%	39.3%	9.81	2.46	3.14
General Transport238	6,039,043	5,362,302	676,742	-11.2%	10.5%	2.63	1.13	1.43
Toal Base Rate Margin	**$ 584,379,457**	**$ 746,276,464**	**$ (161,897,007)**	**27.7%**	**4.0%**	**1.00**	**0.79**	**1.00**
Miscellaneous Service Margin	9,252,291	9,252,291	-	0.0%				
Total System	**$ 593,631,748**	**$ 755,528,754**	**$ (161,897,007)**	**27.3%**				

Table 1 presents the revenue deficiency/excess for each rate class, the change in gas cost revenue by removing the interruptible credit and the remaining margin related deficiency/excess. Regarding rate class revenue levels, the ACOSS shows that all classes except Large Transport Rate 228 DP, Interruptible Rate 234, and General Transport Rate 238 are being charged rates that recover less than their indicated costs of service. In other words, to set each class's revenues equal to their cost to serve all classes except Rate 228 DP, Rate 234, and Rate 238 require an increase in revenues.

Q54. Have you prepared a more detailed summary of NIPSCO's ACOSS results?

A54. Yes. Attachment 16-B, Schedule 1 provides the cost of service and rate of return under present rates and the resulting allocation by rate class of NIPSCO's proposed revenue requirement. Attachment 16-B, Schedule 2 through Schedule 4 summarize the results of NIPSCO's ACOSS. Schedule 2 summarizes the costs allocated to NIPSCO's rate classes on a functionalized (e.g., by transmission and distribution), and classified (i.e., by demand, customer, and commodity) basis. Schedule 3 provides the ACOSS results by rate class for each FERC account and Schedule 4 provides details on the account balances and allocation methods.

B. <u>Alternative Cost of Service Analysis</u>

Q55. Have you included cost of service results under an alternative costing methodology in the ACOSS?

A55. Yes. Cost of service results have been included in <u>Attachment 16-B</u>, Schedule 7 that reflect a single change in the costing methodology employed for Transmission plant. This version of the ACOSS reflects the exclusive use of the Design Day Peak allocation factor for Transmission plant as an alternative approach to the Company's proposed use of the system load factor adjusted P&A allocation method, the use of which was explained earlier in my testimony.

Q56. What is the purpose for including this alternative costing methodology in the ACOSS?

A56. The Design Day Peak allocation method was employed for allocation of Transmission plant in the Company's ACOSS filed in its gas rate case filing in Cause No. 43894. A change to the P&A allocation method for Transmission plant was proposed in the ACOSS filed in the Company's gas rate case filing in Cause No. 44988. Certain parties to Cause No. 44988 and Cause No. 45621, specifically the NIPSCO Industrial Group and Steel Dynamics, Inc., challenged the proposed allocation change for Transmission plant. Since the change to the P&A costing methodology for the allocation of Transmission plant in the ACOSS may continue to be a topic of concern to the parties to the Company's current general rate filing, a comparison of the results of this alternative ACOSS have been included in Attachment 16-B, Schedule 7.

VIII. Sound Rate Design Principles

Q57. Please identify the principles of rate design utilized in development of the Company's rate design proposals.

A57. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles help inform the apportionment of revenues (i.e., revenue targets for each rate class) and the rate design of rate components within each rate class. These principles include:

(1) Cost of Service;
(2) Efficiency;
(3) Value of Service;
(4) Stability/Gradualism;
(5) Non-Discrimination;
(6) Administrative Simplicity; and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[1]

Q58. Can the objectives inherent in these principles compete with each other at times?

A58. Yes. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. There are tensions between cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q59. How are these principles translated into the design of rates?

[1] Principles of Public Utility Rates, Second Edition, Page 111-113, James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

A59. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

Q60. Should other factors be considered that would prevent the Company from simply translating the unit costs into rates for the various tariff services?

A60. 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. However, the use of three-part rates has become more widely accepted as the unbundling of gas utility services evolved over the last decade or so and the sale of the gas commodity in a competitive market is distinguishable from utility delivery service. The unit costs do provide useful information for the design of portions of tariff services, in particular 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.

Q61. Please describe other considerations or criteria that should be used in the design of utility rates.

A61. 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 with respect to 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 gas 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.

Q62. How then are the foregoing guidelines and criteria incorporated into the rate design process?

A62. 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.

IX. NIPSCO's Proposed Revenue Allocation by Class

A. Description of Proposed Revenue Requirement and Revenue Allocation Methodology Employed

Q63. What total gas revenue requirement is the Company utilizing in its proposal?

A63. The Company has used a total distribution revenue requirement of $755.5 million, as shown on Attachment 16-B, Schedule 1, exclusive of gas costs. Net of miscellaneous other revenue of $9.3 million, the total non-gas Rate Schedule Revenue Requirement (Margin) is $746.3 million.

Q64. Please describe the approach followed to apportion the current revenue responsibility to the Company's various rate schedules.

A64. As described earlier in my testimony, the allocation of revenues among rate schedules 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. NIPSCO Witness Robert Sears discusses the specific parameters that the Company used in its application of moderation to the allocation of revenues to the respective rate schedules.

Q65. What are the revenue targets by class and the percentage changes in revenues by rate class resulting from the Company's proposed revenue apportionment?

A65. Table 2 below presents a summary of the results of the Company's proposed revenue apportionment that can be reviewed in detail in Schedule 1 of Attachment 16-B. After evaluating the criteria listed above for each of the Company's proposed rate schedules, adjustments were made to class revenue levels with the intent to close the deficiency or surplus gaps between current class returns and uniform returns by class at the system average return of 7.5 percent at proposed rates, with no class receiving a revenue decrease.

Table 2 - Company's Proposed Revenue Apportionment

Customer Classes	Current Revenues	Proposed Revenue	Proposed Revenue Change	Proposed Percentage Change	Proposed ROR	Proposed Relative ROR	Proposed R:C Ratio	Proposed R:C Parity Ratio
Residential211	$ 376,460,321	$ 481,311,389	$ 104,851,068	27.9%	7.8%	1.05	1.02	1.02
Multiple Family215	2,852,398	3,646,843	794,445	27.9%	8.1%	1.08	1.03	1.03
General Small221	121,103,007	154,832,404	33,729,397	27.9%	8.9%	1.19	1.08	1.08
General Large225	17,878,181	22,857,581	4,979,400	27.9%	8.2%	1.10	1.05	1.05
Large Transport - DP228 DP	17,762,595	17,762,595	-	0.0%	9.8%	1.31	1.16	1.16
Large Transport - HP228 HP	42,214,459	59,757,157	17,542,697	41.6%	4.0%	0.54	0.71	0.71
Interruptible234	69,452	69,452	-	0.0%	35.5%	4.75	2.46	2.46
General Transport238	6,039,043	6,039,043	-	0.0%	9.5%	1.27	1.13	1.13
Toal Base Rate Margin	**$ 584,379,457**	**$ 746,276,464**	**$ 161,897,007**	**27.7%**	**7.5%**	**1.00**	**1.00**	**1.00**
Miscellaneous Service Margin	9,252,291	9,252,291	-	0.0%				
Total System	**$ 593,631,748**	**$ 755,528,755**	**$ 161,897,007**	**27.3%**				

As indicated in Table 1 in Section VII - Results of NIPSCO's ACOSS, all classes except Large Transport Rate 228 DP, Interruptible Rate 234 and General Transport Rate 238 are being charged rates that recover less than their indicated costs of service. In addition, Large Transport Rate 228 HP would require a 99% increase in distribution margin to match their cost to serve. To mitigate the total required increase, the Company is limiting the Large Transport Rate 228 HP increase to 150% of the overall system increase. The remaining increase is recovered from those classes that are below their cost to serve, while those above their cost to serve are seeing no change in their total revenues. The result of this proposed revenue apportionment is to move all classes closer to their cost to serve.

Q66. Is a cap to the multiplier of the overall system increase often used as a metric in determining each rate classes revenue increase?

A66. Yes. Often cost analysts use a cap on the multiplier of the overall system increase to set an upper bound on the revenue increase proposed for each individual rate class. I typically see these caps set between 1.5-2.5 times the overall system increase. In addition, the caps are informed by the magnitude of the overall system increase and the diversity of current revenue to cost ratios (or relative rate of returns) for each rate class. For instance, if the rate classes are close to their cost to serve and there is a double-digit overall system increase (e.g., 27%), a lower cap of 1.5 times the system increase may be most appropriate. In other instances, when the overall system increase is a modest single-digit figure (e.g., 5%) and classes are further apart from parity, a cap of 2.5 times the system increase may be most appropriate. Given the system margin increase (exclusive of gas costs) of 27 percent and the large increase required for the Large Transport Rate 228 HP to provide revenues equal to their cost to serve (a full movement to parity), a cap is proposed on Rate 228 HP's increase at 150% of the overall system increase (27.7% from Table 2 x 1.5 = 41.6%).. Consequently, this is still below the increase required to move Large

Transport Rate 228 HP to parity under the alternative design day allocation of transmission mains, which would require an increase of 61.2 percent.

Q67. Is the Company's proposed revenue allocation by class useful for the recovery and deferral of approved capital expenditures under TDSIC?

A67. Yes. The proposed margin revenues by rate schedule as shown in Attachment 16-B, Schedule 1, Page 2, Line 51, if approved by the Commission, combined with the allocated gas costs by rate schedule from the GCA, would fulfill the requirement under IC 8-1-39-9 to "use the customer class revenue allocation factor based on the firm load approved in the public utility's most recent retail base rate case order."[2] The Company proposes to use the same allocation for purposes of future Federally Mandated Cost Adjustment ("FMCA") proceedings.

X. Description of NIPSCO's Proposed Rate Structures and Rate Levels by Customer Class

Q68. Please describe the results of your ACOSS with respect to classified costs.

A68. The ACOSS summarized the costs allocated to the rate schedules on a classified basis, *i.e.*, by demand, customer, and commodity basis. Of particular interest,

[2] Ind. Code § 8-1-39-9, Sec. 9(a)(1).

are the customer and demand related costs. Attachment 16-B, Schedule 2, provides a summary of the functionalized and classified costs by rate class at equalized rates of return and the costs on a unit rate basis. These results were used as a guide in developing the monthly customer and demand charges proposed for the various rate schedules.

Q69. How were the proposed rates for each Rate Schedule calculated?

A69. Detailed calculations for each rate component of each Rate Schedule are included in Attachment 16-D. As the exhibit shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 16-D provides a presentation of the transition of revenues at current rates and existing 200 series rate schedules to the proposed revenues at the 300 series rate schedules.

Q70. Do the proposed rates include increases to the existing monthly customer charges?

A70. Yes. The following table of proposed rates, and the accompanying Attachment 16-D, includes an increase to the Residential monthly customer charge from its current level of $16.25 to the proposed level of $25.50. In addition, the Residential Multi-Family Service (Rate 215) monthly customer charge will be increased from $20.44 to $32.50. The General Service schedules (Rates 221 and 225) received increases in their monthly customer charges of approximately 45 percent. The proposed monthly customer charge increases for Rates 221 and 225 will contribute an additional amount toward demand-related fixed cost recovery, as reflected in the ACOSS Unit Cost Analysis, Attachment 16-B, Schedule 2. For the two Transport & Transport Balancing Services (Rates 228 and 238), the monthly customer charge increases by 2 percent for Rate 228 and 1.5 percent for Rate 238.

The Company utilized the Unit Cost Analysis from the ACOSS (Attachment 16-B, Schedule 2) 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 $33.53 per customer per month and the combined customer and demand related costs to be $50.26 per customer per month. This amount represents a straight fixed variable ("SFV") rate level.[3] The corresponding levels of

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[3] In a straight fixed variable rate design, a utility consolidates all of its fixed expenses into a fixed portion of a customer's bill, recuperating solely the variable expenses, which typically include costs like fuel and purchased power, through a variable charge.

customer costs for the Commercial & Industrial ("C&I") classes of customers are also shown in this Unit Cost Analysis, referenced above.

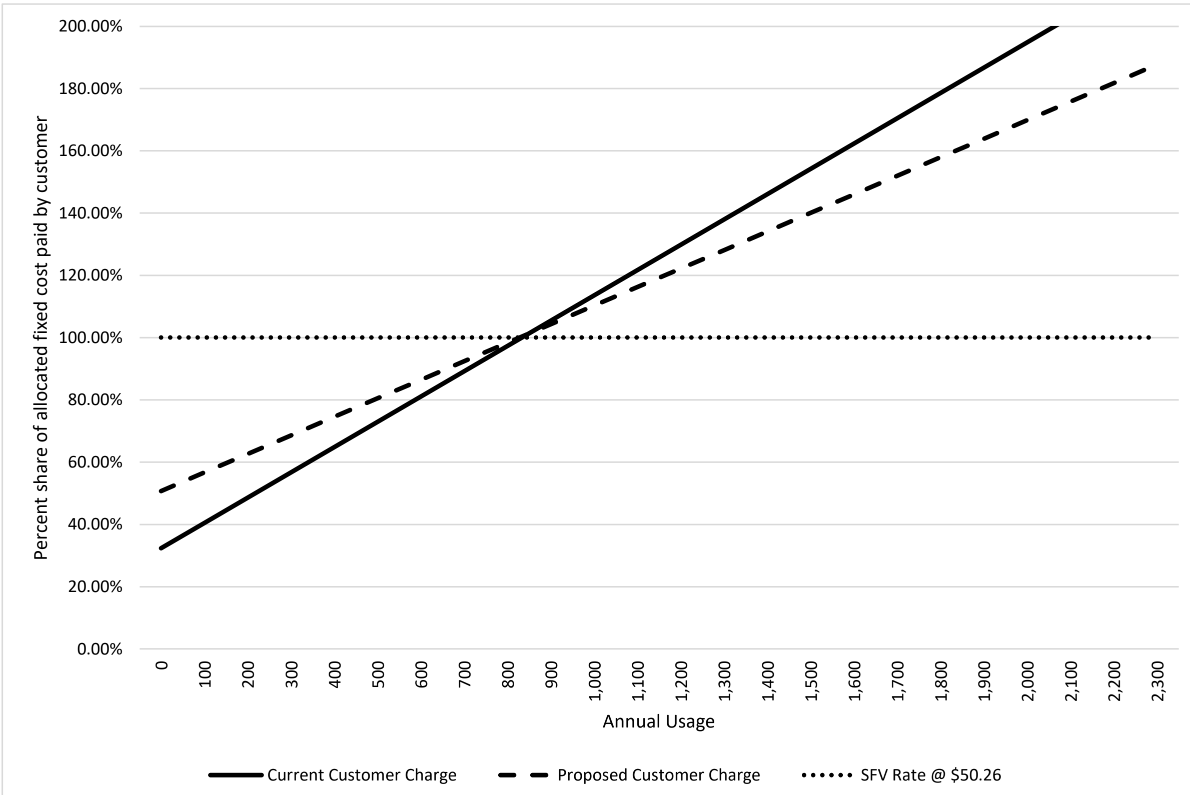
Q71. Do the proposed rates include increases to the existing demand charges?

A71. Yes. The Company has increased Demand Charges for the two Transportation and Balancing Services (Rates 228 and 238). Demand charges reduce intra-class subsidies by lowering the average cost of utility service for high load factor customers and thereby encourage efficient use of the distribution system. The demand billing determinants for customers served under these rate schedules will be determined at the average daily usage during the three billing months of December 2022 through February 2023, under current tariff provisions.

Q72. Please discuss the fairness of the Company's proposed customer charge versus the current customer charge.

A72. The Company's higher customer charge is fair because it increases the portion of the non-volumetric margin recovered through the non-volumetric customer charge. With a higher customer charge, a higher percentage of the non-volumetric costs are paid in equal shares. For example, each customer under an SFV rate design pays the full share of the non-volumetric cost allocated to the customer. Accordingly, each customer would not, under the SFV rate design, "overpay" or "underpay" its share of the non-gas costs based on the customer's consumption relative to average consumption, would not pay a higher delivery charge in the winter than in the summer, and would not pay a higher delivery charge during a cold spell. Under the continuation of the current customer charge, customers who have very little annual usage, such as owners of summer homes, can pay less than 40 percent of their allocated fixed costs, while very high use customers can pay over 200 percent. This is because a current customer charge of $16.25 is substantially less than the $50.26 cost of service allocation of non-volumetric costs. Figure 1 below compares the annual margin contribution that each residential gas customer would have made during the test year under the current customer charge, the Company's $25.50 proposal, and the full SFV rate, i.e., the fixed (non-volumetric) costs allocated to that customer through the Company's cost of service analysis.

Figure 1 - Fixed Cost Incurrence & Recovery



Q73. Have you provided a schedule detailing the proposed rates, corresponding revenues, and illustrative bill impacts?

A73. Yes. <u>Attachment 16-D</u> shows the derivation of each rate component for each of NIPSCO's tariff schedules and the corresponding revenues generated from those proposed rates. <u>Attachment 16-E</u> provides average bill impacts under a range of monthly usages for residential classes (Rate 211 & Rate 215), and the commercial classes (Rate 221 & 225). <u>Attachment 16-F</u> provides bill comparisons at various ranges of consumption levels for all C&I rate schedules.

XI. Proposed Sales Reconciliation Adjustment Mechanism

A. Summary of Fixed Charge Recovery of Fixed Costs

Q74. Please define and describe the concept of a revenue decoupling mechanism.

A74. While a revenue decoupling ratemaking mechanism can take several forms, the basic approach consists of defining a target for the utility's margin revenues and placing over- and under-collections of revenue with reference to that target in a deferred account for refund or recovery in a subsequent period. Under these mechanisms, the gas utility cannot increase its earnings by increasing its sales volumes because any over-collected margin revenues are refunded to customers, thereby "breaking the link" so that the utility may recover an authorized amount of revenues (regardless of weather, customer conservation, etc.) even as sales fluctuate. There are three primary types of decoupling mechanisms (1) SFV rate design, (2) partial decoupling, and (3) full decoupling. These different types can apply to a subset of rate classes or to all rate classes. The fundamental principle and benefit of decoupling mechanisms is that they work in a reciprocal and balanced manner, where customer bills are protected during colder-than-normal weather and utility revenues are protected during warmer-than-normal weather.

Q75. Please provide more details on these different types of decoupling mechanisms.

A75. Straight fixed variable rate design is a rate design approach in which the fixed costs of operating a distribution utility are recovered in a fixed monthly charge with no recovery of fixed costs in volumetric rates. This results in a decoupling of margin revenue from sales volumes. Partial decoupling mechanisms partially decouple margin revenue from sales volumes by adjusting for a component that causes these differences to occur, such as weather or energy efficiency. Weather normalization adjustments correct for the over- or under-collection of revenues due to weather-related fluctuations throughout the year. Full decoupling mechanisms fully adjust for differences between authorized margin revenue and actual margin revenue regardless of the particular component causing the difference.

Q76. Do the proposed monthly customer and demand charge levels reflect the Company's intention to move to a greater recovery of fixed distribution costs in fixed charges?

A76. Yes. The Company has proposed monthly customer charges at levels that, in most cases, either approximate or reflect gradual movement toward their full customer related cost responsibility. The proposed $25.50 Residential monthly customer charge will bring this fixed charge to approximately 76 percent of the unit customer related cost, per customer, per month for the class. However, this $25.50 fixed charge level is only 50.7 percent of the full SFV pricing, as further discussed below. SFV pricing consists of the combined customer and demand related fixed costs of providing service to the Residential class. The proposed $32.50 monthly customer charge for the Residential Multi-Family rate schedule is approaching 89 percent of the fixed customer related cost level of $36.64 for this class, which is also 49.4 percent of full SFV pricing of $65.77. 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 within the Residential and C&I classes, are easily understood, and convey more appropriate price signals with respect to recovery of fixed distribution costs.

Q77. Has the IURC offered guidance on moving customer charges closer to a point where they recover 100% of fixed costs of service?

A77. Yes. NIPSCO's proposed rates will not take the rate design to a complete SFV model, but the proposed rates do take a gradual step closer to SFV than current rates. Still, they will be insufficient to fully decouple margin from sales volumes. 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 SFV pricing. Abrupt movement to SFV pricing could lead to rate shock, and gas 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.[4]

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.

Q78. Is the Company proposing 100% SFV rate design?

A78. No. The Company is proposing some movement towards SFV rate design, but given past positions of intervening parties, it does not believe a full movement to SFV is feasible. This is demonstrated through a review comparing proposed versus settled customer charges. Table 3 below provides a comparison between the Company's filed position in the last three gas rate cases and the settled outcome. It is also worth noting that over time the monthly customer charges are recovering a lower portion of a SFV charge with Residential Rate 111 moving from 49% in Cause No. 43894 to 40% in Cause No. 45621.

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

Table 3 – Outcome of Customer Charge Proposals

Rate	Cause No.	Existing	Proposed	Proposed Increase %	Settlement	Settled Increase %	Settlement Reduction from Proposed	Settled Charge as Percent of SFV
111	43894	$6.36	$20.00	214%	$11.00	73%	-45%	49%
	44988	$11.00	$19.50	77%	$14.00	27%	-28%	45%
	45621	$14.00	$24.50	75%	$16.50	18%	-33%	40%
115	43894	$3.70	$28.00	657%	$12.50	238%	-55%	44%
	44988	$12.50	$17.50	40%	$17.50	40%	0%	44%
	45621	$17.50	$28.50	63%	$20.75	19%	-27%	40%
121	43894		$30.00		$30.00		0%	62%
	44988	$30.00	$53.00	77%	$53.00	77%	0%	55%
	45621	$53.00	$80.00	51%	$67.00	26%	-16%	54%
125	43894		$160.00		$250.00		56%	90%
	44988	$250.00	$400.00	60%	$400.00	60%	0%	29%
	45621	$400.00	$640.00	60%	$500.00	25%	-22%	30%

Q79. Is the Company proposing any regulatory mechanism as an alternative to full SFV rate design?

A79. Yes. As described in the next section of this testimony the Company is proposing a Sales Reconciliation Adjustment mechanism.

B. <u>Summary of Proposed SRA Mechanism</u>

Q80. Please summarize the structure of NIPSCO's SRA mechanism.

A80. NIPSCO's proposed SRA mechanism is designed to reconcile the level of margin revenues that are provided by customers to the Company on an annual basis to the margin revenues that will ultimately be authorized in this rate case. The proposal will periodically adjust the Company's distribution service rates to recover the margin revenues per customer that fluctuate due to variances in gas volumes caused primarily by weather, energy efficiency gains and conservation efforts by its customers. The SRA mechanism will apply to the Residential Service Rate Schedules 311 and 315, and General Service Rate Schedules 321 and 325. These are the Company's weather sensitive customer classes that exhibit volatility in use per customer as a result of seasonal changes in heating degree days. NIPSCO Witness Dousias sponsors the key components of the SRA mechanism.

C. <u>Support & Rationale for the SRA Mechanism</u>

Q81. Why is the Company proposing the SRA mechanism?

A81. NIPSCO recovers a significant portion of its distribution revenues from volumetric rates. This results in variances between authorized revenues and actual revenues, which impacts the financial stability of the Company. The SRA will help ensure the level of margin revenues established to recover its fixed costs from its customers while simultaneously assuring customers do not pay more than the fixed costs to provide distribution service. Customers will continue to benefit from their energy conservation efforts, as the actual usage on each customer's bill is utilized to calculate their bill and will be used to collect or pass back a surcharge or credit from the SRA mechanism. Thus, the SRA mechanism will reflect the conservation behaviors of each customer.

Q82. What portion of NIPSCO's fixed costs is recovered through its current volumetric distribution charges?

A82. At proposed rates, approximately 50% of distribution revenues for Residential Service Rate Schedule 311 and 52% for General Service Rate Schedule 215 are recovered through the volumetric distribution charges. In addition, approximately 50% of distribution revenues for General Service Rate Schedule 221 and 75% for Rate 225, are recovered through the volumetric distribution charges.

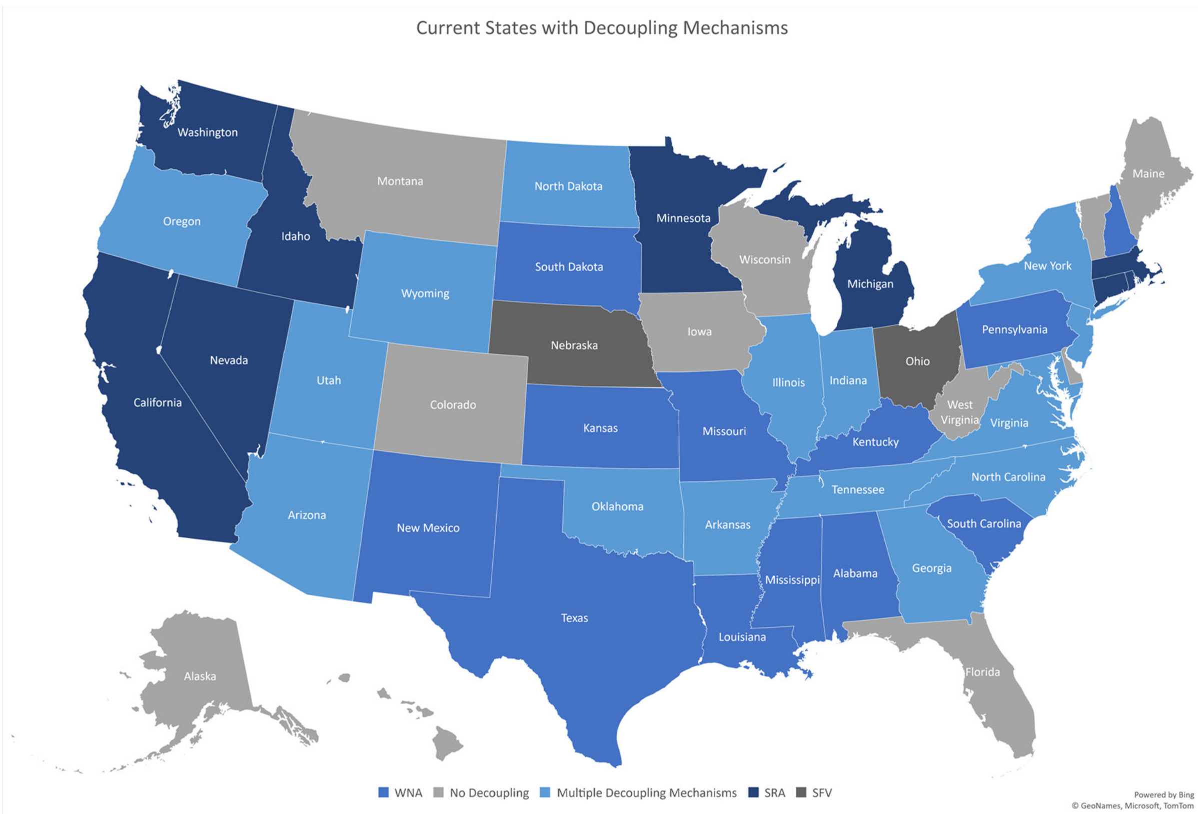
Q83. How does weather influence the recovery of costs for a gas utility and costs to customers?

A83. Weather-normalized gas volumes play a crucial role in determining a utility's base rates for gas service. In a base rate proceeding, the utility calculates its volumetric unit rates by dividing the expected costs to be covered through volumetric rates by the projected weather-normalized gas sales volumes. These rates are designed to enable the utility to recover its authorized revenue requirement under typical weather conditions. However, because actual weather conditions rarely align with these normalized conditions, there is almost always a discrepancy between the recovery of actual costs and those based on the normalized weather conditions. When temperatures are normal, the utility has a better chance of recovering its fixed costs, and customers' payments reflect the actual costs of service. However, normal temperatures are infrequent, leading to variations in revenue collection each year. During warmer weather, the utility may under-recover its costs, necessitating cost management efforts to maintain financial stability. Conversely, colder weather leads to higher bills for customers, potentially burdening customers with increased costs. This dynamic creates a risk of customers overpaying during cold periods and the utility under-recovering during warm periods.

Q84. Are decoupling mechanisms, like the one NIPSCO is proposing, widely accepted in the natural gas industry?

A84. Yes. Atrium Economics conducted a survey in spring 2023 which shows that many U.S. gas utilities, across a wide geographic area, have implemented decoupling mechanisms. Specifically, the survey results (provided in Figure 2 below) show there are 40 states that have approved decoupling mechanisms for gas companies serving dozens of different service territories. The examples of decoupling mechanisms shown in Figure 2 below are straight fixed variable (SFV), weather normalization adjustment (WNA), sales reconciliation adjustment (SRA), or some combination of mechanisms.

Figure 2. Map of U.S. States with Decoupling Mechanisms



Q85. Are decoupling mechanisms common across the industry?

A85. Yes. Decoupling mechanisms, which decouple or disassociate a utility's total distribution revenues from the sale of commodity through regulatory formulas, are a common ratemaking tool throughout the natural gas industry.

Table 4 below summarizes various approved and proposed decoupling mechanisms for 42 states in the U.S. and the District of Columbia.

Table 4 - Decoupling Mechanisms across the U.S.

State Name	SRA	SFV	WNA
Alabama			WNA
Arizona	SRA		WNA
Arkansas	SRA		WNA
California	SRA		
Connecticut	SRA		
Delaware			
Florida			
Georgia		SFV	WNA
Idaho	SRA		
Illinois	SRA	SFV	
Indiana	SRA		WNA
Kansas			WNA
Kentucky			WNA
Louisiana			WNA
Maryland	SRA		WNA
Massachusetts	SRA		
Michigan	SRA		
Minnesota	SRA		
Mississippi			WNA
Missouri			WNA
Nebraska		SFV	

State Name	SRA	SFV	WNA
Nevada	SRA		
New Hampshire			WNA
New Jersey	SRA		WNA
New Mexico			WNA
New York	SRA		WNA
North Carolina	SRA		WNA
North Dakota		SFV	WNA
Ohio		SFV	
Oklahoma		SFV	WNA
Oregon	SRA		WNA
Pennsylvania			WNA
Rhode Island	SRA		
South Carolina			WNA
South Dakota			WNA
Tennessee	SRA		WNA
Texas			WNA
Utah	SRA		WNA
Virginia	SRA		WNA
Washington	SRA		
Wyoming	SRA		WNA
Washington, D.C.	SRA		

Q86. Do decoupling mechanisms currently exist in Indiana?

A86. Yes. Both Indiana Gas Company and Southern Indiana Gas and Electric Company ("SIGECO") have in place decoupling mechanisms. The decoupling mechanisms for both companies contain two components, (1) a weather normalization adjustment titled Normal Temperature Adjustment ("NTA") and (2) a full decoupling mechanism through their Sales Reconciliation

Component ("SRC") within their Energy Efficiency Riders Sales. The NTA adjusts each customer's monthly billed amount to reverse the impact on margin recovery caused by non-normal temperatures during the billing period, as measured by actual heating degree day variations from normal heating degree days. Normal heating degree days for each customer's billing period are those utilized by the Commission for purposes of determining SIGECO's current base rates. The SRC within their Energy Efficiency Riders recover the differences between actual margins after the application of the NTA and authorized margins for each applicable Rate Schedules. Actual Margins are defined as monthly margins for each Rate Schedule, prior to the SRC Adjustment. Authorized margins are defined as the order granted monthly margins for each Rate Schedule as approved in Company's most recent general rate case as adjusted to reflect the change in number of customers from the order granted levels.

Q87. Do other NIPSCO affiliates have weather normalization adjustments or decoupling mechanisms in other jurisdictions?

A87. Yes. NIPSCO's affiliate Columbia Gas of Ohio has in place straight fixed variable rate design which partially removes the need for a decoupling mechanism. NIPSCO's affiliate Columbia Gas of Pennsylvania has in place a weather normalization adjustment which is a partial decoupling mechanism as bills are adjusted only for the impact from weather during the heating season months. The experience of Columbia Gas of Pennsylvania's ("Columbia") WNA demonstrates the fact that full decoupling and partial decoupling mechanisms are not a transfer of risks from shareholders to ratepayers. Some winters are colder than normal, and some warmer than normal, but on average, the actual heating degree days ("HDDs") will be close to the normal HDDs across multiple years. This can be seen in the actual application of Columbia's WNA for the implementation years of 2013 through 2020, as presented in their 2020 base rate case filing and summarized in Table 5 below.

Table 5 - 2013-2020 Columbia's WNA Net Adjustments

Columbia's Winter Seatson	Net WNA Adjustment (millions)
2013/2014 Season	-9.36
2014/2015 Season	-10.98
2015/2016 Season	11.52
2016/2017 Season	13.9
2017/2018 Season	-6.1
2018/2019 Season	-3.7
2019/2020 Season	2.45
2013 - 2020	-2.27

This illustrates a fundamental principle and benefit of decoupling mechanisms; they work in a reciprocal manner, where customer bills are protected during colder-than-normal weather (2013/2014, 2014/2015, 2017/2018, 2018/2019) and utility revenues during warmer-than-normal weather (2015/2016, 2016/2017, 2019/2020). Yet, on average and over time, they result in symmetry and neutrality between customers' costs and revenue collection.

Q88. Did the Pennsylvania Public Utility Commission find other benefits to implementing decoupling mechanisms in Pennsylvania?

A88. Yes. The stabilization of cash flows allows a utility to focus more acutely on operational items under its direct control, as Pennsylvania Public Utility Commission Chairman Gladys Brown Dutrieuille determined upon review of Columbia's WNA when she stated, "This decoupling of uncontrollable weather from revenues stabilizes Columbia's cashflow, and in turn, allows Columbia to more acutely focus on operational items within its control; namely infrastructure upgrades and repairs."[5]

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[5] Pa. PUC v. Columbia Gas of Pa., Inc., Docket Nos. R-2018-2647577, et al. (Statement of Chairman Brown Dutrieuille dated Dec. 6, 2018).

Q89. Please summarize how the interests of NIPSCO and its customers are served by implementing the Company's SRA proposal.

A89. There are significant benefits to both NIPSCO and its customers from implementing the Company's proposed SRA, including:

1. The SRA will break the link between the gas consumption of the Company's customers and its margin recovery and result in a better alignment of the interests of NIPSCO and its customers.

2. The SRA will address factors beyond the Company's control that contribute to under recovery of costs and the inability to achieve the level of returns that have been authorized by the Commission.

3. Under the SRA, NIPSCO will be able to continue promoting energy efficiency programs for its customers, without margin losses associated with the resulting decline in gas use per customer.

4. With the implementation of the SRA, customers will pay each year approximately the same amount for gas delivery service as if the Company had experienced normal weather, which is the same basis upon which the Commission establishes NIPSCO's base rates.

Ultimately, the SRA will result in a customer's annual bill more accurately reflecting the margin recovery amounts approved by the Commission in this rate case.

5. Customers will continue to benefit from their energy conservation efforts, as the actual usage on each customer's bill is utilized to calculate their bill and will be used to collect or pass back a surcharge or credit from the SRA mechanism. Thus, the SRA mechanism will reflect the conservation behaviors of each customer.

6. The implementation of the SRA will better align NIPSCO's financial stability and risk with that of its peers in the state of Indiana, many utilities in other states and its affiliates in other states.

Q90. Does this conclude your prepared direct testimony?

A90. 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: October 25, 2023

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, 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

17

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
- Public Service Commission of South Carolina
- 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 including various rate design components.
- 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 distributed CNG/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.

INDIANA UTILITY REGULATORY COMMISSION

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
GAS DIVISION

ATTACHMENT 16-B

COST OF SERVICE ALLOCATION STUDY

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

Table of Contents

I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Allocated Cost of Service Study ("ACOSS") model and related schedules prepared for Northern Indiana Public Service Company LLC ("NIPSCO" or "the Company") based on the Future Test Year ended December 31, 2024 ("TY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's ACOSS model used to develop the cost allocation study. The second section, NIPSCO Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section presents the results of the cost of service allocation.

1. Purpose of Cost Allocation

The purpose of ACOSS is to determine the cost of service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the ACOSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the ACOSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the ACOSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve and another pays less than its cost to serve).

2. ACOSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning the Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions, such as Production, Distribution, On-Site and Metering, Customer Services, and Gas Supply. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of gas plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of natural gas services: demand, commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Commodity-related costs are variable costs that vary with the quantity of gas consumed. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. Customer-related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be isolated and directly assigned to a particular customer or group of customers in the same class of service. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. Where costs cannot be directly assigned, the development of allocation factors by customer class use principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation.

3. Atrium Economics Cost of Service Study Model Overview

The Allocated Cost of Service Study ("ACOSS") is submitted in support of the direct testimony of John D. Taylor. The ACOSS model presented in this proceeding is a Microsoft Excel based model that allows the user to modify various inputs and assumptions.

ACOSS Model Capabilities

The Atrium Economics' ACOSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of costs of gas, income taxes, working capital, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Allocation

The Atrium ACOSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium ACOSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The ACOSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per therm, per dekatherm of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the ACOSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. NIPSCO's COST OF SERVICE PROCEDURES

1. Functionalization

The following functional cost categories were identified for purposes of NIPSCO's cost allocation:

- Storage
- Liquified Natural Gas (LNG)
- Transmission
- Distribution
- On-Site and Metering
- Customer Accounts and Services

NIPSCO's assigned functional categories are presented on Schedule 4.

2. Classification

The following classification categories were identified for purposes of NIPSCO's cost allocation:

- Commodity
- Demand
- Customer

NIPSCO's assigned classification categories are presented on Schedule 4.

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate costs among various customer classes.

3.1.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

Rate Schedule	ACOSS Customer Class
Rate 211 Residential Service	Residential 211
Rate 215 Multiple Family Housing Service	Multiple Family 215
Rate 221 General Service – Small	General Small 221
Rate 225 General Service – Large	General Large 225
Rate 228 Large Transportation and Balancing Service	Large Transport 228 DP
	Large Transport 228 HP
Rate 234A Off-Peak Non-Residential Interruptible Negotiated Service	Interruptible 234
Rate 238 General Transportation and Balancing Service	General Transport 238

3.1.2. External Allocation Factors

NIPSCO's External Allocation Factors are presented on Schedule 7. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

Customer Allocation Factors

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

CUSTOMERS	The factor is based on the total number of annual bills per customer class in the future test year.
DIST-CUST	Used to allocate non-high pressure distribution mains. The factor is based on the total number of annual bills per customer class in the future test year with transmission and high pressure customers subtracted.

METERS	Factor based on the weighted customer unit cost of meters used to serve customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific rate schedule. The average meter current replacement cost was linked to the meter records dataset to develop the total current cost of the investment for each customer class. Then the relative customer class unit cost was developed and multiplied by the customer count for each customer class.
SERVICES	The analysis relies upon the data contained in the Company's property records which provide an inventory of average number of service lines by customer class. Additionally, current unit costs per foot by service line pipe type and size were provided by the Company. The method employed to develop the service allocator was similar to that used for the meter allocator.
ACCT_385	Account 385 Industrial Measuring and Regulating Station Equipment. This plant was allocated to all but classes 111 and 115. It was facilitated by the identification in the property records of specific types of equipment associated with the size and type of customers in these classes.
UNCOLLECT	Account 904 Uncollectible Accounts It is based on a 3-year average of write-offs by rate class.
METER_READ	Account 902 Meter Reading Expenses. Meter Reading was allocated on the basis of the number of meters by class. This was then weighted by the results of a meter reading labor time estimate based on the time records related to manually read meters and Automated Meter Reading devices by class.
CUST_RECORDS	Account 903 Customer Records & Collection Expense. Company-provided time studies analyses that evaluate the level of service provided by several departmental cost centers (i.e. Acct 901, Acct 903, Acct 910) form the basis for the assignment of the labor-related administrative costs to the various rate classes. Cost centered not analyzed are allocated based on customer counts.
ACCT_901	Account 901 Customer Account Supervision. Same allocation methodology as Acct 903 above.
ACCT_910	Account 910 Customer Service and Information Expense. Same allocation methodology as Acct 903 above.
ACCT_879	Account 879 Customer Installation Expense. Factor based on service order hour count by customer class.

Commodity and Revenue Allocation Factors

Costs classified as "Commodity" are allocated among customer classes based on the weather-normalized volumes for the test period. The "Revenue" factors directly assign revenues to the relevant customer class.

TOTAL_VOLUME	This factor directly assigns Weather Normalized Volumes/Throughput to the specific class in the future test year.
WINTER_SEASxT	Weather Normalized Volumes/Throughput for winter season months (December – March) for all customer classes excluding transport classes.
BASE_REVENUE	Factor developed to directly assign associated current base rate revenues to the specific class in the future test year.
TDSIC_REVENUE	Factor developed to directly assign associated Transmission, Distribution, and Storage System Improvement Charge (TDSIC) revenues to the specific class in the future test year.
FMCA_REVENUE	Factor developed to directly assign associated Federally Mandated Cost Adjustment (FMCA) revenues to the specific class in the future test year.
GAS_REVENUE	Factor developed to directly assign associated gas cost revenues to the specific class in the future test year.
TOTAL_REVENUE	Base, TDSIC, FMCA, and Gas revenues summed together for each customer class in the future test year.
NONGAS_REVENUE	Total Revenue minus gas cost revenue for each customer class in the future test year.
LATE_FEES	Late Charge Revenue based on 3-year average of late payments and credits by customer class.
MISC_REVENUE	Factor developed to directly assign miscellaneous revenues to the specific class in the future test year.
SHUTOFF_RECONNECT	Factor based on shutoff/reconnect-specific service order hour count by customer class.

Demand Allocation Factors

Demand-related costs are generally allocated based on peak capacity demand for each customer class.

DESIGN_DAY	Design Peak Day – the factor is based on Design Peak Day capacity demand for each customer class.
HP_DIST_DESIGN_DAY	The factor is based on Design Peak Day capacity demand, excluding customers directly served on transmission main, for each customer class.
DIST_DESIGN_DAY	The factor is based on Design Peak Day capacity demand for distribution customers, excluding customers served at high pressure, for each customer class.
PEAK_AVG	Peak & Average demand allocation factor reflecting the Company system load factor.
SEASxTRANSPORT	Excess winter over summer average throughput, excluding transportation customers.
3-DAYxTRANSPORT	Factor based on Three Day Peak demand, excluding transportation customers, for each customer class.

Mains Analysis

The allocation of investment in facilities serving a distribution function should recognize that the cost of these facilities is driven by two principal factors. First is the cost of extending the system to connect individual customers. Second is the cost associated with the capacity requirements of the customers connected.

There are two widely accepted methods for the classification of mains between customer-related costs and demand-related costs. The two methods are the Minimum System Method and the Zero-Intercept Method, both relying on the Company's property record data to determine the cost of pipe by size and type. The unit cost for pipe in any year is determined by dividing the booked costs by the amount of pipe installed in a standard unit of measurement. A variety of factors, such as the length of pipe installed, location, installation conditions, etc., cause the annual unit cost of pipe by size and type to vary significantly. Thus, a simple average of the yearly costs is not adequate for a determination of the cost for each size of the pipe as it will not reflect a consistent set of data. Therefore, the original cost data was restated in terms of current cost using the Handy-Whitman index.

Zero-Intercept Study:

The zero-intercept study was performed using a Weighted Linear Regression (WLR) on the cost per foot by pipe diameter. Based on this relationship, the study estimates the cost of installing a hypothetical pipe with zero capacity, which is where the estimated diameter is zero (i.e., the zero-intercept). The zero-intercept determined value is then multiplied by all quantities of distribution mains currently installed by the utility to arrive at a total minimum system cost. Total minimum system cost divided by total system cost derives the portion of the system that is related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains and is classified as customer-related.

Zero-Intercept (Weighted Linear Regression)				
Material	**Cost $2022**	**Zero Intercept Unit Cost**	**Customer Component**	**Customer Component Percentage**
Plastic	$ 1,160,704,138	$ 9.48	$ 491,940,148	
Steel	$ 2,209,570,992	$ 26.77	$ 901,329,582	
Total	**$ 3,370,275,130**		**$ 1,393,269,730**	**41%**

The distribution main investment is functionalized to distribution, classified based on the results of the zero-intercept study to demand (59%) and customer (41%). The demand component of the mains investment is allocated based on each class's allocation of peak day. The customer component of the mains investment is allocated based on each class's number of customers.

Minimum System Study

In addition to the zero-intercept study discussed above, for comparison purposes, a minimum system study was performed. The study used 2" plastic as the minimum-sized main, then adjusted to the load-carrying capacity. The minimum system study yielded a customer component of 36.2% for distribution mains as depicted below.

Minimum System							
Material		**Cost $2022**		**Min System Unit Cost**		**Customer Component**	**Customer Component Percentage**
Plastic	$	1,160,704,138	$	15.51	$	805,074,902	
Steel	$	2,209,570,992	$	15.51	$	522,255,459	
Total	**$**	**3,370,275,130**			**$**	**1,327,330,360**	**39.0%**
Minimum System Adjusted for Load Carrying Capacity							**36.2%**

3.2.Internal Allocation Factors

NIPSCO's Internal Allocation Factors are presented on Schedule 8. Internal Allocation Factors are developed within the ACOSS model based on the cost ratios of allocated cost using the external allocation factors.

INT_PLANT	Plant Total excl General & Common Plant – The factor is based on the allocated total plant balance by customer class, excluding General Plant and the Gas Portion of Common Plant-in-Service totals.
INT_376&378	The factor is based on Acct 376 (Mains) and Acct 378 (M&R Station Equipment) allocated expenses.
INT_376-386	Based on specific Distribution Plant expenses from Acct 376 (Mains) through Acct 386 (Other Property on Customer Premises).
INT_MAINS	Distribution Plant Mains – The factor is based on the allocated plant balances by customer class of FERC Account 376 "Mains".
INT_MAIN_SVCS	Distribution Plant Mains and Services – The factor is based on the allocated plant balances by customer class of FERC Accounts 376 and 380, Mains and Services.
INT_RATEBASE	Total Rate Base – The factor is based on the derived rate base by customer class.
INT_REVREQ	Total Revenue Requirement – The factor is based on the total test year expenses at current rates and return on rate base.
INT_LABOR	Total Labor Expense – The factor is based on the total customer class allocated labor-related expenses.

INT_TOTAL_PLANT	Plant Total - The factor is based on the allocated total plant balance by customer class.
INT_STORE_PLANT	Storage Plant Total – The factor is based on the allocated total Storage plant balance by customer class.
INT_TRANS_PLANT	Transmission Plant Total – The factor is based on the allocated total Transmission plant balance by customer class.
INT_DIST_PLANT	Distribution Plant Total – The factor is based on the allocated total Distribution plant balance by customer class.
INT_GENERAL_PLANT	General Plant Total – The factor is based on the allocated total General plant balance by customer class.
INT_874-879	Based on specific Distribution Operation expenses from Acct 874 (Mains & Services) through Acct 879 (Customer Installation Expenses).
INT_887-893	Based on specific Distribution Maintenance expenses from Acct 887 (Mains) through Acct 893 (Meters & House Regulators).
INT_902-904	Based on specific Customer Accounts expenses from Acct 902 (Meter Reading) through Acct 904 (Uncollectible Accts).
INT_O&M_EX_A&G	Operation and Maintenance Expense excluding Administrative and General Expenses – The factor is based on the total customer class allocated O&M Expenses, excluding A&G Expenses.
INT_TDSIC_RB	This factor is based on the total rate base expenses allocated to TDSIC for Storage, Transmission and Distribution.
INT_FMCA_RB	This factor is based on the total rate base expenses allocated to FMCA for Storage, Transmission and Distribution.

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 1 - Summary of Cost of Service and Rate of Return Under Current and Proposed Rates

Line No.	Category Description	Total System	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
1	**Rate Base**									
2	Plant in Service	$ 5,224,370,516	$ 3,185,257,165	$ 24,365,578	$ 1,022,562,695	$ 165,216,914	$ 115,734,345	$ 673,750,208	$ 185,090	$ 37,298,521
3	Accumulated Reserve	(1,867,116,893)	(1,299,822,711)	(9,352,332)	(369,390,560)	(49,082,185)	(27,296,474)	(102,077,879)	(62,888)	(10,031,863)
4	Other Rate Base Items	127,556,422	72,679,273	709,711	34,835,243	8,213,512	1,137,011	9,645,192	1,278	335,202
5	**Total Rate Base**	**$ 3,484,810,045**	**$ 1,958,113,727**	**$ 15,722,957**	**$ 688,007,378**	**$ 124,348,241**	**$ 89,574,881**	**$ 581,317,521**	**$ 123,480**	**$ 27,601,860**
6	**Margin at Current Rates**									
7	Delivery Sales Margin	$ 518,908,768	$ 333,438,626	$ 2,467,973	$ 106,211,338	$ 15,546,399	$ 17,448,448	$ 38,166,417	$ 69,452	$ 5,560,115
8	TDSIC Margin	54,105,026	35,570,776	324,451	12,560,144	2,030,102	234,882	3,026,654	-	358,016
9	FMCA Margin	11,365,663	7,450,919	59,975	2,331,525	301,680	79,264	1,021,388	-	120,912
10	Miscellaneous Service Margin	9,252,291	7,172,253	69,508	1,552,096	244,051	54,429	137,677	377	21,901
11	**Total Margin at Current Rates**	**$ 593,631,748**	**$ 383,632,574**	**$ 2,921,906**	**$ 122,655,103**	**$ 18,122,232**	**$ 17,817,024**	**$ 42,352,136**	**$ 69,829**	**$ 6,060,944**
12	Gas Costs	$ 400,343,545	$ 281,660,647	$ 2,796,858	$ 99,234,135	$ 14,360,595	$ 1,096,097	$ 737,078	$ 253,760	$ 204,375
13	**Total Revenue at Current Rates**	**$ 993,975,293**	**$ 665,293,220**	**$ 5,718,764**	**$ 221,889,238**	**$ 32,482,827**	**$ 18,913,121**	**$ 43,089,214**	**$ 323,589**	**$ 6,265,319**
14	**Expenses at Current Rates**									
15	O&M and A&G Expenses	$ 258,774,122	$ 181,268,671	$ 1,312,163	$ 48,866,371	$ 6,488,986	$ 4,440,014	$ 14,429,012	$ 12,548	$ 1,956,358
16	Depreciation and Amortization Expense	159,468,672	107,308,242	761,834	29,635,366	3,690,205	2,340,733	14,950,998	3,763	777,531
17	Taxes Other Than Income	24,139,341	15,352,454	114,851	4,705,718	712,697	498,189	2,579,460	956	175,017
18	Current Income Taxes	11,531,666	6,076,781	55,890	3,007,592	551,260	803,451	792,364	4,007	240,320
19	**Total Expenses at Current Rates**	**$ 453,913,802**	**$ 310,006,148**	**$ 2,244,739**	**$ 86,215,047**	**$ 11,443,148**	**$ 8,082,387**	**$ 32,751,834**	**$ 21,274**	**$ 3,149,225**
20	**Operating Income at Current Rates**	**$ 139,717,946**	**$ 73,626,426**	**$ 677,167**	**$ 36,440,056**	**$ 6,679,084**	**$ 9,734,637**	**$ 9,600,302**	**$ 48,555**	**$ 2,911,719**
21	Current Rate of Return	4.01%	3.76%	4.31%	5.30%	5.37%	10.87%	1.65%	39.32%	10.55%
22	Current Relative Rate of Return	1.00	0.94	1.07	1.32	1.34	2.71	0.41	9.81	2.63
23	Current Revenue to Cost Ratio	0.79	0.80	0.81	0.85	0.82	1.16	0.50	2.46	1.13
24	Current Parity Ratio	1.00	1.02	1.03	1.08	1.05	1.48	0.64	3.14	1.43
25	**Current Revenue at Equal Rates of Return**									
26	Current Rate of Return	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%
27	Current Operating Income at Equal ROR	$ 139,717,946	$ 78,507,472	$ 630,387	$ 27,584,567	$ 4,985,546	$ 3,591,363	$ 23,307,006	$ 4,951	$ 1,106,653
28	Current Income Taxes - Equal ROR	11,531,666	6,479,640	52,029	2,276,701	411,484	296,414	1,923,651	409	91,338
29	Other Expenses - Equal ROR	442,382,136	303,929,367	2,188,849	83,207,455	10,891,888	7,278,936	31,959,470	17,267	2,908,905
30	**Current Margin at Equal Rate of Return**	**$ 593,631,748**	**$ 388,916,479**	**$ 2,871,265**	**$ 113,068,723**	**$ 16,288,917**	**$ 11,166,713**	**$ 57,190,128**	**$ 22,626**	**$ 4,106,896**
31	**Revenue Requirement at Equal Rates of Return**									
32	Required Return	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
33	Return on Rate Base	$ 260,663,791	$ 146,466,907	$ 1,176,077	$ 51,462,952	$ 9,301,248	$ 6,700,201	$ 43,482,551	$ 9,236	$ 2,064,619

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 1 - Summary of Cost of Service and Rate of Return Under Current and Proposed Rates

Line No.	Category Description	Total System	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
34	**Expenses at Required Return**									
35	O&M and A&G Expenses	$ 258,774,122	$ 181,268,671	$ 1,312,163	$ 48,866,371	$ 6,488,986	$ 4,440,014	$ 14,429,012	$ 12,548	$ 1,956,358
36	Increase in Uncollectibles	675,172	622,759	6,952	43,860	1,035	237	-	-	329
37	Depreciation and Amortization Expense	159,468,672	107,308,242	761,834	29,635,366	3,690,205	2,340,733	14,950,998	3,763	777,531
38	Taxes Other Than Income	24,139,341	15,352,454	114,851	4,705,718	712,697	498,189	2,579,460	956	175,017
39	Increase in TOTI	237,601	133,508	1,072	46,910	8,478	6,107	39,635	8	1,882
40	Income Taxes	11,531,666	6,479,640	52,029	2,276,701	411,484	296,414	1,923,651	409	91,338
41	Gross-up of Income Taxes	40,038,389	22,497,559	180,647	7,904,794	1,428,687	1,029,162	6,678,992	1,419	317,129
42	**Total Expenses at Required Return**	**$ 494,864,963**	**$ 333,662,832**	**$ 2,429,549**	**$ 93,479,720**	**$ 12,741,572**	**$ 8,610,857**	**$ 40,601,748**	**$ 19,103**	**$ 3,319,583**
43	**Total Revenue Requirement at Equal Rates of Return**	**$ 755,528,754**	**$ 480,129,738**	**$ 3,605,626**	**$ 144,942,672**	**$ 22,042,820**	**$ 15,311,058**	**$ 84,084,299**	**$ 28,339**	**$ 5,384,202**
44	LESS									
45	Current Miscellaneous Revenue Margin	9,252,291	7,172,253	69,508	1,552,096	244,051	54,429	137,677	377	21,901
46	Additional Miscellaneous Revenue Margin	-	-	-	-	-	-	-	-	-
47	**Total Base Rate Revenue Requirement at Equal Rates of Return**	**$ 746,276,464**	**$ 472,957,486**	**$ 3,536,119**	**$ 143,390,577**	**$ 21,798,769**	**$ 15,256,629**	**$ 83,946,622**	**$ 27,962**	**$ 5,362,302**
48	**Base Rate Margin (Deficiency)/Surplus**	**$ (161,897,007)**	**$ (96,497,165)**	**$ (683,720)**	**$ (22,287,570)**	**$ (3,920,588)**	**$ 2,505,966**	**$ (41,732,162)**	**$ 41,490**	**$ 676,742**
	Percent Margin Change at Equal Rates of Return	**27.27%**	**25.15%**	**23.40%**	**18.17%**	**21.63%**	**-14.07%**	**98.54%**	**-59.42%**	**-11.17%**
49	Total Base Revenue as Proposed	$ 746,276,464	$ 481,311,389	$ 3,646,843	$ 154,832,404	$ 22,857,581	$ 17,762,595	$ 59,757,157	$ 69,452	$ 6,039,043
50	Miscellaneous Revenue	9,252,291	7,172,253	69,508	1,552,096	244,051	54,429	137,677	377	21,901
51	Total Margin as Proposed	**$ 755,528,755**	**$ 488,483,641**	**$ 3,716,351**	**$ 156,384,500**	**$ 23,101,632**	**$ 17,817,024**	**$ 59,894,834**	**$ 69,829**	**$ 6,060,944**
52	Proposed Margin (Decrease)/Increase	$ 161,897,007	$ 104,851,068	$ 794,445	$ 33,729,397	$ 4,979,400	$ -	$ 17,542,697	$ -	$ -
53	Change in Miscellaneous Revenue	-	-	-	-	-	-	-	-	-
54	**Total Margin Increase as Proposed**	**$ 161,897,007**	**$ 104,851,068**	**$ 794,445**	**$ 33,729,397**	**$ 4,979,400**	**$ -**	**$ 17,542,697**	**$ -**	**$ -**
55	Percent Margin Change	27.27%	27.33%	27.19%	27.50%	27.48%	0.00%	41.42%	0.00%	0.00%
56	Estimated Gas Costs	$ 400,343,545	$ 281,660,647	$ 2,796,858	$ 99,234,135	$ 14,360,595	$ 1,096,097	$ 737,078	$ 253,760	$ 204,375
57	Total Revenue at Proposed Rates	$ 1,155,872,300	$ 770,144,288	$ 6,513,209	$ 255,618,635	$ 37,462,226	$ 18,913,121	$ 60,631,911	$ 323,589	$ 6,265,319
58	Percent Change in Total Bill	16.29%	15.76%	13.89%	15.20%	15.33%	0.00%	40.71%	0.00%	0.00%
59	**Operating Income at Proposed Rates**									
60	Operating Expenses	$ 443,294,908	$ 304,685,633	$ 2,196,872	$ 83,298,225	$ 10,901,401	$ 7,285,280	$ 31,999,105	$ 17,275	$ 2,911,116
61	Operating Income Prior to Taxes	312,233,846	183,798,008	1,519,479	73,086,275	12,200,231	10,531,744	27,895,728	52,554	3,149,828
62	Income Taxes	51,570,055	30,356,970	250,964	12,071,283	2,015,049	1,739,474	4,607,394	8,680	520,241
63	**Total Operating Income at Proposed Rates**	$ 260,663,792	$ 153,441,039	$ 1,268,514	$ 61,014,992	$ 10,185,182	$ 8,792,270	$ 23,288,335	$ 43,874	$ 2,629,587
64	Proposed Rate of Return	7.48%	7.84%	8.07%	8.87%	8.19%	9.82%	4.01%	35.53%	9.53%
65	Proposed Relative Rate of Return	1.00	1.05	1.08	1.19	1.10	1.31	0.54	4.75	1.27
66	Proposed Revenue to Cost / Parity Ratio	1.00	1.02	1.03	1.08	1.05	1.16	0.71	2.46	1.13
67	Class (Subsidies)/Excesses at Current Rates	$ (161,897,007)	$ (96,497,165)	$ (683,720)	$ (22,287,570)	$ (3,920,588)	$ 2,505,966	$ (41,732,162)	$ 41,490	$ 676,742
68	Class (Subsidies)/Excesses at Proposed Rates	$ 0	$ 8,353,903	$ 110,725	$ 11,441,827	$ 1,058,812	$ 2,505,966	$ (24,189,465)	$ 41,490	$ 676,742
69	Dollar Value of Change in Subsidies	$ 161,897,007	$ 104,851,068	$ 794,445	$ 33,729,397	$ 4,979,400	$ -	$ 17,542,697	$ -	$ -
70	Percent Change in Subsidies	-100%	-109%	-116%	-151%	-127%	0%	-42%	0%	0%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 2 - Functionalized and Classified Rate Base, Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
1	**Functional Rate Base**									
2	**Storage**									
3	Demand	$ 43,532,996	$ 27,353,074	$ 281,954	$ 13,436,969	$ 2,460,999	$ -	$ -	$ -	$ -
4	Commodity	$ 86,840,760	$ 52,357,099	$ 539,579	$ 27,186,543	$ 6,757,539	$ -	$ -	$ -	$ -
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 130,373,756	$ 79,710,173	$ 821,533	$ 40,623,512	$ 9,218,538	$ -	$ -	$ -	$ -
7	**LNG**									
8	Demand	$ 8,283,887	$ 5,101,464	$ 50,870	$ 2,526,634	$ 604,920	$ -	$ -	$ -	$ -
9	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 8,283,887	$ 5,101,464	$ 50,870	$ 2,526,634	$ 604,920	$ -	$ -	$ -	$ -
12	**Transmission**									
13	Demand	$ 1,346,750,529	$ 450,966,178	$ 4,484,020	$ 223,797,853	$ 53,540,126	$ 50,750,923	$ 549,263,465	$ 37,425	$ 13,910,539
14	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 1,346,750,529	$ 450,966,178	$ 4,484,020	$ 223,797,853	$ 53,540,126	$ 50,750,923	$ 549,263,465	$ 37,425	$ 13,910,539
17	**Distribution**									
18	Demand	$ 766,449,636	$ 434,147,177	$ 4,304,123	$ 213,163,905	$ 47,850,668	$ 34,126,693	$ 23,814,353	$ -	$ 9,042,717
19	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ 409,653,896	$ 374,861,133	$ 2,143,133	$ 32,231,792	$ 318,089	$ 59,887	$ 673	$ 436	$ 38,753
21	Subtotal	$ 1,176,103,532	$ 809,008,310	$ 6,447,256	$ 245,395,697	$ 48,168,758	$ 34,186,580	$ 23,815,025	$ 436	$ 9,081,470
22	**On-Site**									
23	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ 808,985,878	$ 601,617,301	$ 3,851,248	$ 173,774,431	$ 12,751,868	$ 4,378,480	$ 8,114,047	$ 84,601	$ 4,413,903
26	Subtotal	$ 808,985,878	$ 601,617,301	$ 3,851,248	$ 173,774,431	$ 12,751,868	$ 4,378,480	$ 8,114,047	$ 84,601	$ 4,413,903
27	**Cust. Accounts**									
28	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 14,312,462	$ 11,710,301	$ 68,031	$ 1,889,252	$ 64,032	$ 258,897	$ 124,984	$ 1,018	$ 195,948
31	Subtotal	$ 14,312,462	$ 11,710,301	$ 68,031	$ 1,889,252	$ 64,032	$ 258,897	$ 124,984	$ 1,018	$ 195,948
32	**Total**									
33	Demand	$ 2,165,017,048	$ 917,567,893	$ 9,120,967	$ 452,925,360	$ 104,456,713	$ 84,877,617	$ 573,077,817	$ 37,425	$ 22,953,256
34	Commodity	$ 86,840,760	$ 52,357,099	$ 539,579	$ 27,186,543	$ 6,757,539	$ -	$ -	$ -	$ -
35	Customer	$ 1,232,952,237	$ 988,188,735	$ 6,062,411	$ 207,895,475	$ 13,133,989	$ 4,697,265	$ 8,239,704	$ 86,055	$ 4,648,604
36	**TOTAL RATE BASE**	$ 3,484,810,045	$ 1,958,113,727	$ 15,722,957	$ 688,007,378	$ 124,348,241	$ 89,574,881	$ 581,317,521	$ 123,480	$ 27,601,860

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 2 - Functionalized and Classified Rate Base, Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
37	**Functional Revenue Requirement**									
38	**Storage**									
39	Demand	$ 14,539,634	$ 9,135,684	$ 94,170	$ 4,487,828	$ 821,952	$ -	$ -	$ -	$ -
40	Commodity	$ 8,065,708	$ 4,862,890	$ 50,116	$ 2,525,067	$ 627,635	$ -	$ -	$ -	$ -
41	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Subtotal	$ 22,605,342	$ 13,998,574	$ 144,286	$ 7,012,895	$ 1,449,587	$ -	$ -	$ -	$ -
43	**LNG**									
44	Demand	$ 12,604,898	$ 7,762,471	$ 77,404	$ 3,844,567	$ 920,456	$ -	$ -	$ -	$ -
45	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Subtotal	$ 12,604,898	$ 7,762,471	$ 77,404	$ 3,844,567	$ 920,456	$ -	$ -	$ -	$ -
48	**Transmission**									
49	Demand	$ 191,992,961	$ 64,289,807	$ 639,243	$ 31,904,656	$ 7,632,689	$ 7,235,059	$ 78,303,084	$ 5,335	$ 1,983,089
50	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	Subtotal	$ 191,992,961	$ 64,289,807	$ 639,243	$ 31,904,656	$ 7,632,689	$ 7,235,059	$ 78,303,084	$ 5,335	$ 1,983,089
53	**Distribution**									
54	Demand	$ 135,394,056	$ 77,074,739	$ 764,117	$ 37,843,278	$ 8,494,994	$ 6,058,558	$ 3,554,365	$ -	$ 1,604,005
55	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	Customer	$ 91,224,001	$ 83,474,683	$ 477,236	$ 7,177,428	$ 70,833	$ 13,336	$ 1,558	$ 97	$ 8,831
57	Subtotal	$ 226,618,058	$ 160,549,422	$ 1,241,353	$ 45,020,706	$ 8,565,827	$ 6,071,894	$ 3,555,923	$ 97	$ 1,612,836
58	**On-Site**									
59	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Customer	$ 243,715,819	$ 185,859,898	$ 1,209,188	$ 49,765,498	$ 3,178,088	$ 973,205	$ 1,725,727	$ 17,832	$ 986,383
62	Subtotal	$ 243,715,819	$ 185,859,898	$ 1,209,188	$ 49,765,498	$ 3,178,088	$ 973,205	$ 1,725,727	$ 17,832	$ 986,383
63	**Cust. Accounts**									
64	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Customer	$ 57,991,677	$ 47,669,566	$ 294,152	$ 7,394,351	$ 296,174	$ 1,030,899	$ 499,566	$ 5,074	$ 801,894
67	Subtotal	$ 57,991,677	$ 47,669,566	$ 294,152	$ 7,394,351	$ 296,174	$ 1,030,899	$ 499,566	$ 5,074	$ 801,894
68	**Total**									
69	Demand	$ 354,531,550	$ 158,262,701	$ 1,574,934	$ 78,080,329	$ 17,870,090	$ 13,293,618	$ 81,857,448	$ 5,335	$ 3,587,094
70	Commodity	$ 8,065,708	$ 4,862,890	$ 50,116	$ 2,525,067	$ 627,635	$ -	$ -	$ -	$ -
71	Customer	$ 392,931,497	$ 317,004,148	$ 1,980,577	$ 64,337,276	$ 3,545,095	$ 2,017,440	$ 2,226,851	$ 23,004	$ 1,797,108
72	**TOTAL REVENUE REQUIREMENT AT EQUAL R**	$ 755,528,754	$ 480,129,738	$ 3,605,626	$ 144,942,672	$ 22,042,820	$ 15,311,058	$ 84,084,299	$ 28,339	$ 5,384,202
73	Demand	46.92%	32.96%	43.68%	53.87%	81.07%	86.82%	97.35%	18.83%	66.62%
74	Energy	1.07%	1.01%	1.39%	1.74%	2.85%	0.00%	0.00%	0.00%	0.00%
75	Customer	52.01%	66.02%	54.93%	44.39%	16.08%	13.18%	2.65%	81.17%	33.38%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 2 - Functionalized and Classified Rate Base, Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
76	**Unit Costs**									
77	**Storage**									
78	Demand	$ 0.64	$ 1.03	$ 1.07	$ 1.03	$ 0.84	$ -	$ -	$ -	$ -
79	Commodity	$ 0.53	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ -	$ -	$ -	$ -
80	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	**LNG**									
82	Demand	$ 0.56	$ 0.88	$ 0.88	$ 0.88	$ 0.94	$ -	$ -	$ -	$ -
83	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	**Transmission**									
86	Demand	$ 8.52	$ 7.25	$ 7.27	$ 7.33	$ 7.81	$ 10.38	$ 10.64	$ -	$ 9.77
87	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	**Distribution**									
90	Demand	$ 6.01	$ 8.69	$ 8.69	$ 8.69	$ 8.69	$ 8.69	$ 0.48	$ -	$ 7.90
91	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	Customer	$ 0.02	$ 8.82	$ 8.82	$ 8.82	$ 8.82	$ 8.82	$ 2.06	$ 8.82	$ 8.15
93	**On-Site**									
94	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Customer	$ 0.07	$ 19.64	$ 22.35	$ 61.15	$ 395.73	$ 643.65	$ 2,282.71	$ 1,621.09	$ 909.95
97	**Cust. Accounts**									
98	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	Customer	$ 5.61	$ 5.04	$ 5.44	$ 9.09	$ 36.88	$ 681.81	$ 660.80	$ 461.32	$ 739.75
101	**Total**									
102	Demand	$ 15.73	$ 17.85	$ 17.91	$ 17.93	$ 18.28	$ 19.07	$ 11.13	#DIV/0!	$ 17.68
103	Commodity	$ 0.0022	$ 0.0073	$ 0.0074	$ 0.0072	$ 0.0056	$ -	$ -	$ -	$ -
104	Customer (per cust month)	$ 37.99	$ 33.49	$ 36.60	$ 79.06	$ 441.43	$ 1,334.29	$ 2,945.57	$ 2,091.23	$ 1,657.85
105	Customer (Onsite/Metering & Cust Acts)	$ 29.17	$ 24.67	$ 27.78	$ 70.24	$ 432.61	$ 1,325.47	$ 2,943.51	$ 2,082.41	$ 1,649.70
106	Demand & Customer (per cust month)	$ 72.26	$ 50.22	$ 65.71	$ 175.01	$ 2,666.57	$ 10,126.36	$ 111,222.62	$ 2,576.26	$ 4,966.98
107	**BILLING DETERMINANTS**									
108	Demand	22,544,240	8,868,376	87,921	4,354,324	977,451	697,110	7,356,136	0	202,922
109	Demand - Distribution	15,168,230	8,868,376	87,921	4,354,324	977,451	697,110	0	0	183,048
110	Commodity	3,731,430,274	669,107,758	6,766,825	352,607,227	112,620,923	207,677,634	2,330,559,588	379,287	51,711,032
111	Customers (Number of Bills)	10,343,630	9,464,351	54,109	813,776	8,031	1,512	756	11	1,084

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
1	**RATE BASE**										
2	**Plant in Service**										
3	**Intangible Plant**										
4	Organization	301	7,147	5,024	36	1,351	163	117	400	0	57
5	Franchises & Consents	302	56,861	52,027	297	4,473	44	8	4	0	6
6	Misc. Intangible Plant	303	52,598,755	48,127,503	275,152	4,138,161	40,839	7,689	3,844	56	5,512
7	Subtotal - Intangible Plant		52,662,763	48,184,553	275,485	4,143,985	41,046	7,814	4,248	56	5,575
8	**Underground Storage Plant**										
9	Land & Land Rights	350	647,723	406,983	4,195	199,927	36,617	-	-	-	-
10	Structures & Improvements	351	6,923,349	4,350,146	44,841	2,136,973	391,389	-	-	-	-
11	Wells	352	30,827,097	19,369,581	199,660	9,515,145	1,742,712	-	-	-	-
12	Non-Recoverable Natural Gas	352.3	5,414,970	3,402,387	35,072	1,671,394	306,118	-	-	-	-
13	Lines	353	33,965,055	21,341,253	219,984	10,483,712	1,920,106	-	-	-	-
14	Compressor Station Equipment	354	5,235,333	3,289,515	33,908	1,615,947	295,963	-	-	-	-
15	Other Equipment	355	3,534,546	2,220,860	22,892	1,090,979	199,814	-	-	-	-
16	Purification Equipment	356	14,843,529	9,326,630	96,138	4,581,629	839,132	-	-	-	-
17	Other Equipment	357	1,014,216	637,262	6,569	313,050	57,335	-	-	-	-
18	Subtotal - Underground Storage Plant		102,405,819	64,344,618	663,260	31,608,755	5,789,186	-	-	-	-
19	**LNG Storage Plant**										
20	Land & Land Rights	360	1,245,964	767,302	7,651	380,026	90,985	-	-	-	-
21	Structures & Improvements	361	10,321,899	6,356,532	63,385	3,148,239	753,743	-	-	-	-
22	Gas Holders	362	18,160,971	11,184,066	111,523	5,539,202	1,326,180	-	-	-	-
23	Purification Equipment	363	23,885,413	14,709,347	146,676	7,285,190	1,744,200	-	-	-	-
24	Subtotal - LNG Storage Plant		53,614,248	33,017,248	329,236	16,352,657	3,915,107	-	-	-	-
25	**Transmission Plant**										
26	Land & Land Rights	365.1	39,692,486	13,291,228	132,157	6,595,945	1,577,977	1,495,771	16,188,323	1,103	409,982
27	Rights of Way	365.2	21,275,449	7,124,191	70,837	3,535,473	845,806	801,744	8,677,054	591	219,753
28	Structures and Improvements	366	13,418,077	4,493,111	44,676	2,229,765	533,436	505,647	5,472,476	373	138,595
29	Mains	367	1,050,465,783	351,753,743	3,497,537	174,562,387	41,761,313	39,585,734	428,425,654	29,191	10,850,224
30	Measuring & Regulating Station Equipment	369	342,330,838	114,631,200	1,139,794	56,887,229	13,609,377	12,900,389	139,617,411	9,513	3,535,923
31	Other Equipment	371	47,499	15,905	158	7,893	1,888	1,790	19,372	1	491
32	Subtotal - Transmission Plant		1,467,230,132	491,309,378	4,885,158	243,818,692	58,329,798	55,291,075	598,400,289	40,773	15,154,969
33	**Distribution Plant**										
34	Land & Land Rights	374	6,968,644	4,786,988	38,192	1,456,214	286,149	203,095	144,055	3	53,948
35	Structures & Improvements	375	12,965,582	7,278,598	72,160	3,573,752	802,230	572,143	513,393	-	153,307
36	Mains - High Pressure	376	167,342,597	93,942,516	931,344	46,125,265	10,354,121	7,384,472	6,626,198	-	1,978,683
37	Mains - Distribution Pressure	376	1,346,516,523	969,670,370	7,493,111	271,497,619	51,623,245	36,592,243	-	587	9,639,346
38	Compressor Station Equipment	377	-	-	-	-	-	-	-	-	-
39	M&R Station Equip. - General	378	80,713,398	31,750,759	314,776	15,589,450	3,499,493	2,495,809	26,336,604	-	726,507
40	M&R Station Equip. - City Gate	379	-	-	-	-	-	-	-	-	-
41	Services	380	954,615,664	812,643,232	4,964,822	129,725,812	5,253,438	697,215	358,804	938	971,402
42	Meters	381	197,671,725	141,577,260	966,964	52,867,894	1,899,332	125,926	57,157	-	177,193
43	Meter Installations	382	230,249,593	164,910,316	1,126,327	61,580,942	2,212,356	146,679	66,576	-	206,396
44	House Regulators	383	141,843,848	101,591,987	693,867	37,936,561	1,362,909	90,361	41,014	-	127,149
45	House Regulators Installations	384	3,879,273	2,778,429	18,976	1,037,523	37,274	2,471	1,122	-	3,477
46	Industrial Measuring & Regulating Station Equip.	385	76,257,656	-	-	41,816,888	10,967,759	5,843,785	11,914,467	127,619	5,587,138
47	Other Property on Cust. Premises	386	40,915	29,304	200	10,943	393	26	12	-	37
48	Other Equipment	387	-	-	-	-	-	-	-	-	-
49	Subtotal - Distribution Plant		3,219,065,417	2,330,959,758	16,620,740	663,218,862	88,298,698	54,154,225	46,059,402	129,147	19,624,584

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
50	**General Plant**										
51	Land & Land Rights	389	2,786,116	1,679,864	12,945	549,476	89,949	62,971	370,802	98	20,011
52	Structures & Improvements	390	27,966,319	16,862,043	129,937	5,515,503	902,885	632,091	3,722,014	981	200,866
53	Office Furniture & Equipment	391	1,780,440	1,251,410	8,851	336,567	40,564	29,251	99,520	96	14,181
54	Transportation Equipment	392	229,771	161,498	1,142	43,435	5,235	3,775	12,843	12	1,830
55	Stores Equipment	393	120,013	72,361	558	23,669	3,875	2,713	15,972	4	862
56	Tools, Shop & Garage Equip.	394	16,757,377	10,103,711	77,858	3,304,881	541,007	378,748	2,230,225	588	120,359
57	Laboratory Equip.	395	1,725,512	1,040,382	8,017	340,305	55,708	39,000	229,647	61	12,393
58	Power Operated Equip.	396	869,210	524,082	4,039	171,425	28,062	19,646	115,682	31	6,243
59	Communication Equip.	397	11,874,401	7,159,564	55,171	2,341,863	383,362	268,383	1,580,354	417	85,287
60	Miscellaneous Equip.	398	324,198	195,472	1,506	63,938	10,467	7,327	43,147	11	2,329
61	Subtotal - General Plant		64,433,357	39,050,387	300,024	12,691,062	2,061,112	1,443,905	8,420,207	2,299	464,361
62	**Gas Portion of Common Plant-In-Service**										
63	Organization	301	40,109	28,191	199	7,582	914	659	2,242	2	319
64	Intangible	303	179,469,188	126,142,685	892,185	33,926,073	4,088,840	2,948,550	10,031,672	9,682	1,429,500
65	Land & Land Rights	389	4,157,237	2,506,569	19,315	819,888	134,215	93,961	553,283	146	29,859
66	Structures & Improvements	390	55,649,667	33,553,470	258,560	10,975,198	1,796,634	1,257,786	7,406,367	1,953	399,699
67	Office Furniture & Equipment	391	6,584,223	4,627,823	32,732	1,244,653	150,008	108,174	368,034	355	52,444
68	Transportation Equipment	392	414,500	291,338	2,061	78,355	9,444	6,810	23,169	22	3,302
69	Stores Equipment	393	1,256,301	757,476	5,837	247,767	40,559	28,395	167,200	44	9,023
70	Tool, Shop & Garage Equipment	394	4,130,577	2,490,494	19,192	814,630	133,354	93,359	549,735	145	29,668
71	Laboratory Eqipment	395	941,395	567,606	4,374	185,661	30,393	21,277	125,289	33	6,761
72	Power Operated Equipment	396	2,686,496	1,619,799	12,482	529,829	86,733	60,720	357,543	94	19,296
73	Communication Equipment	397	8,130,403	4,902,154	37,776	1,603,474	262,488	183,762	1,082,068	285	58,396
74	Miscellaneous Equipment	398	1,498,685	903,619	6,963	295,570	48,385	33,873	199,459	53	10,764
75	Subtotal - Gas Portion of Common Plant-In-Service		264,958,780	178,391,223	1,291,676	50,728,681	6,781,966	4,837,325	20,866,063	12,815	2,049,032
76	**Total Plant in Service**		**5,224,370,516**	**3,185,257,165**	**24,365,578**	**1,022,562,695**	**165,216,914**	**115,734,345**	**673,750,208**	**185,090**	**37,298,521**
77	**Accumulated Depreciation**										
78	**Intangible Plant**										
79	Organization	301	36,462	25,628	181	6,893	831	599	2,038	2	290
80	Franchises & Consents	302	(41,766)	(38,216)	(218)	(3,286)	(32)	(6)	(3)	(0)	(4)
81	Misc. Intangible Plant	303	(43,409,319)	(39,719,231)	(227,080)	(3,415,190)	(33,704)	(6,345)	(3,173)	(46)	(4,549)
82	Subtotal - Intangible Plant		(43,414,623)	(39,731,819)	(227,118)	(3,411,583)	(32,906)	(5,752)	(1,138)	(44)	(4,263)
83	**Underground Storage Plant**										
84	Land & Land Rights	350	(488,413)	(306,884)	(3,163)	(150,754)	(27,611)	-	-	-	-
85	Structures & Improvements	351	(3,583,653)	(2,251,716)	(23,211)	(1,106,136)	(202,590)	-	-	-	-
86	Wells	352	(16,037,625)	(10,076,916)	(103,872)	(4,950,201)	(906,636)	-	-	-	-
87	Non-Recoverable Natural Gas	352.3	(5,009,091)	(3,147,360)	(32,443)	(1,546,114)	(283,173)	-	-	-	-
88	Lines	353	(22,501,232)	(14,138,192)	(145,736)	(6,945,269)	(1,272,035)	-	-	-	-
89	Compressor Station Equipment	354	(3,254,502)	(2,044,900)	(21,079)	(1,004,540)	(183,983)	-	-	-	-
90	Other Equipment	355	(2,285,968)	(1,436,342)	(14,806)	(705,591)	(129,230)	-	-	-	-
91	Purification Equipment	356	(9,723,531)	(6,109,583)	(62,977)	(3,001,282)	(549,689)	-	-	-	-
92	Other Equipment	357	(998,431)	(627,344)	(6,467)	(308,177)	(56,443)	-	-	-	-
93	Subtotal - Underground Storage Plant		(63,882,445)	(40,139,238)	(413,752)	(19,718,065)	(3,611,390)	-	-	-	-
94	**LNG Storage Plant**										
95	Land & Land Rights	360	154	95	1	47	11	-	-	-	-
96	Structures & Improvements	361	(9,307,742)	(5,731,984)	(57,157)	(2,838,915)	(679,685)	-	-	-	-
97	Gas Holders	362	(19,016,791)	(11,711,105)	(116,779)	(5,800,232)	(1,388,675)	-	-	-	-
98	Purification Equipment	363	(20,030,043)	(12,335,096)	(123,001)	(6,109,280)	(1,462,667)	-	-	-	-
99	Subtotal - LNG Storage Plant		(48,354,422)	(29,778,091)	(296,936)	(14,748,380)	(3,531,016)	-	-	-	-

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
100	**Transmission Plant**										
101	Land & Land Rights	365.1	803,316	268,994	2,675	133,492	31,936	30,272	327,627	22	8,297
102	Rights of Way	365.2	(3,190,857)	(1,068,475)	(10,624)	(530,244)	(126,853)	(120,244)	(1,301,371)	(89)	(32,958)
103	Structures and Improvements	366	(1,907,753)	(638,821)	(6,352)	(317,023)	(75,843)	(71,892)	(778,065)	(53)	(19,705)
104	Mains	367	(134,842,260)	(45,152,608)	(448,959)	(22,407,571)	(5,360,660)	(5,081,393)	(54,994,541)	(3,747)	(1,392,781)
105	Measuring & Regulating Station Equipment	369	(38,768,732)	(12,981,904)	(129,081)	(6,442,440)	(1,541,253)	(1,460,960)	(15,811,576)	(1,077)	(400,441)
106	Other Equipment	371	(50,131)	(16,787)	(167)	(8,331)	(1,993)	(1,889)	(20,446)	(1)	(518)
107	Subtotal - Transmission Plant		(177,956,418)	(59,589,600)	(592,508)	(29,572,117)	(7,074,665)	(6,706,107)	(72,578,370)	(4,945)	(1,838,106)
108	**Distribution Plant**										
109	Land & Land Rights	374	(499,116)	(342,859)	(2,735)	(104,299)	(20,495)	(14,546)	(10,318)	(0)	(3,864)
110	Structures & Improvements	375	(2,395,334)	(1,344,688)	(13,331)	(660,235)	(148,208)	(105,701)	(94,847)	-	(28,323)
111	Mains - High Pressure	376	(51,578,641)	(28,955,134)	(287,060)	(14,216,813)	(3,191,366)	(2,276,055)	(2,042,339)	-	(609,873)
112	Mains - Distribution Pressure	376	(415,025,781)	(298,873,572)	(2,309,540)	(83,681,492)	(15,911,411)	(11,278,528)	-	(181)	(2,971,057)
113	Compressor Station Equipment	377	-	-	-	-	-	-	-	-	-
114	M&R Station Equip. - General	378	(26,186,573)	(10,301,184)	(102,126)	(5,057,825)	(1,135,372)	(809,738)	(8,544,621)	-	(235,707)
115	M&R Station Equip. - City Gate	379	-	-	-	-	-	-	-	-	-
116	Services	380	(558,302,139)	(475,270,281)	(2,903,651)	(75,869,484)	(3,072,447)	(407,763)	(209,845)	(549)	(568,120)
117	Meters	381	(44,465,585)	(31,847,325)	(217,515)	(11,892,453)	(427,248)	(28,327)	(12,857)	-	(39,859)
118	Meter Installations	382	(137,896,178)	(98,764,571)	(674,556)	(36,880,745)	(1,324,977)	(87,846)	(39,872)	-	(123,610)
119	House Regulators	383	(81,653,996)	(58,482,562)	(399,432)	(21,838,605)	(784,574)	(52,017)	(23,610)	-	(73,195)
120	House Regulators Installations	384	(3,200,352)	(2,292,169)	(15,655)	(855,944)	(30,751)	(2,039)	(925)	-	(2,869)
121	Industrial Measuring & Regulating Station Equip.	385	(28,795,911)	-	-	(15,790,616)	(4,141,572)	(2,206,691)	(4,499,062)	(48,191)	(2,109,778)
122	Other Property on Cust. Premises	386	(37,829)	(27,094)	(185)	(10,117)	(363)	(24)	(11)	-	(34)
123	Other Equipment	387	-	-	-	-	-	-	-	-	-
124	Subtotal - Distribution Plant		(1,350,037,435)	(1,006,501,440)	(6,925,788)	(266,858,630)	(30,188,785)	(17,269,275)	(15,478,308)	(48,920)	(6,766,289)
125	**General Plant**										
126	Land & Land Rights	389	(277,436)	(167,277)	(1,289)	(54,716)	(8,957)	(6,271)	(36,924)	(10)	(1,993)
127	Structures & Improvements	390	(12,613,641)	(7,605,282)	(58,606)	(2,487,656)	(407,228)	(285,092)	(1,678,739)	(443)	(90,596)
128	Office Furniture & Equipment	391	(162,499)	(114,215)	(808)	(30,718)	(3,702)	(2,670)	(9,083)	(9)	(1,294)
129	Transportation Equipment	392	(272,929)	(191,833)	(1,357)	(51,593)	(6,218)	(4,484)	(15,256)	(15)	(2,174)
130	Stores Equipment	393	(49,357)	(29,759)	(229)	(9,734)	(1,593)	(1,116)	(6,569)	(2)	(355)
131	Tools, Shop & Garage Equip.	394	(6,166,494)	(3,718,032)	(28,651)	(1,216,153)	(199,083)	(139,374)	(820,693)	(216)	(44,290)
132	Laboratory Equip.	395	(881,531)	(531,512)	(4,096)	(173,855)	(28,460)	(19,924)	(117,322)	(31)	(6,332)
133	Power Operated Equip.	396	(843,824)	(508,776)	(3,921)	(166,418)	(27,243)	(19,072)	(112,304)	(30)	(6,061)
134	Communication Equip.	397	(1,539,185)	(928,038)	(7,151)	(303,557)	(49,692)	(34,788)	(204,849)	(54)	(11,055)
135	Miscellaneous Equip.	398	(212,840)	(128,330)	(989)	(41,976)	(6,871)	(4,811)	(28,327)	(7)	(1,529)
136	Subtotal - General Plant		(23,019,735)	(13,923,054)	(107,096)	(4,536,377)	(739,048)	(517,601)	(3,030,065)	(816)	(165,678)
137	**Gas Portion of Common Plant-In-Service**										
138	Organization	301	-	-	-	-	-	-	-	-	-
139	Intangible	303	(126,401,535)	(88,843,268)	(628,373)	(23,894,395)	(2,879,802)	(2,076,687)	(7,065,384)	(6,819)	(1,006,808)
140	Land & Land Rights	389	65,262	39,349	303	12,871	2,107	1,475	8,686	2	469
141	Structures & Improvements	390	(15,569,233)	(9,387,330)	(72,338)	(3,070,556)	(502,648)	(351,893)	(2,072,096)	(546)	(111,825)
142	Office Furniture & Equipment	391	(7,721,369)	(5,427,083)	(38,385)	(1,459,614)	(175,916)	(126,857)	(431,596)	(417)	(61,502)
143	Transportation Equipment	392	(143,471)	(100,840)	(713)	(27,121)	(3,269)	(2,357)	(8,019)	(8)	(1,143)
144	Stores Equipment	393	(501,123)	(302,148)	(2,328)	(98,831)	(16,179)	(11,326)	(66,694)	(18)	(3,599)
145	Tool, Shop & Garage Equipment	394	(1,924,485)	(1,160,351)	(8,942)	(379,546)	(62,131)	(43,497)	(256,128)	(68)	(13,822)
146	Laboratory Eqipment	395	(166,481)	(100,378)	(774)	(32,833)	(5,375)	(3,763)	(22,157)	(6)	(1,196)
147	Power Operated Equipment	396	(462,772)	(279,024)	(2,150)	(91,268)	(14,940)	(10,460)	(61,590)	(16)	(3,324)
148	Communication Equipment	397	(6,978,728)	(4,207,762)	(32,425)	(1,376,341)	(225,306)	(157,732)	(928,793)	(245)	(50,124)
149	Miscellaneous Equipment	398	(647,879)	(390,633)	(3,010)	(127,774)	(20,917)	(14,643)	(86,226)	(23)	(4,653)
150	Subtotal - Gas Portion of Common Plant-In-Service		(160,451,815)	(110,159,469)	(789,134)	(30,545,409)	(3,904,375)	(2,797,740)	(10,989,998)	(8,163)	(1,257,527)
151	**Total Accumulated Depreciation**		**(1,867,116,893)**	**(1,299,822,711)**	**(9,352,332)**	**(369,390,560)**	**(49,082,185)**	**(27,296,474)**	**(102,077,879)**	**(62,888)**	**(10,031,863)**

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
152	**Other Rate Base Items**										
153	Materials & Supplies		17,337,093	10,453,245	80,552	3,419,212	559,723	391,850	2,307,379	608	124,522
154	Gas Stored Underground - Current A/C 164 (13-mo avg)		70,092,430	42,259,376	435,515	21,943,278	5,454,263	-	-	-	-
155	Gas Stored Underground - Non-Current A/C 117		4,949,422	2,984,052	30,753	1,549,476	385,141	-	-	-	-
156	Cause No. 44988 Regulatory Assets		11,798,908	7,113,671	73,312	3,693,790	918,135	-	-	-	-
157	TDSIC - Gas 20 - Storage		145,256	91,268	941	44,835	8,212	-	-	-	-
158	TDSIC - Gas 20 - Transmission		12,353,156	4,136,516	41,130	2,052,800	491,100	465,516	5,038,154	343	127,595
159	TDSIC - Gas 20 - Distribution		2,376,380	1,720,763	12,270	489,602	65,184	39,978	34,002	95	14,487
160	FCMA - Storage		1,060,898	666,594	6,871	327,459	59,974	-	-	-	-
161	FCMA - Transmission		5,486,577	1,837,208	18,268	911,738	218,119	206,756	2,237,665	152	56,671
162	FCMA - Distribution		1,956,302	1,416,579	10,101	403,054	53,661	32,911	27,991	78	11,926
163	Subtotal - Other Rate Base Items		127,556,422	72,679,273	709,711	34,835,243	8,213,512	1,137,011	9,645,192	1,278	335,202
164	**TOTAL RATE BASE**		**3,484,810,045**	**1,958,113,727**	**15,722,957**	**688,007,378**	**124,348,241**	**89,574,881**	**581,317,521**	**123,480**	**27,601,860**
165	**OPERATION AND MAINTENANCE EXPENSE**										
166	**Storage, LNG, Transmission, and Distribution Expense**										
167	**Storage Operation Expenses**										
168	Storage Op Supervision-Engin	814	226,286	142,182	1,466	69,846	12,792	-	-	-	-
169	Maps & Records	815	-	-	-	-	-	-	-	-	-
170	Wells Expenses	816	569,154	357,616	3,686	175,676	32,175	-	-	-	-
171	Lines Expenses	817	365,752	229,813	2,369	112,894	20,677	-	-	-	-
172	Compressor Station Expenses	818	74,266	46,664	481	22,923	4,198	-	-	-	-
173	Compr. Station Fuel & Power	819	333,143	209,324	2,158	102,828	18,833	-	-	-	-
174	Measuring & Regulating Expenses	820	-	-	-	-	-	-	-	-	-
175	Purification Expenses	821	444,926	279,560	2,882	137,332	25,152	-	-	-	-
176	Storage Op Other	824	-	-	-	-	-	-	-	-	-
177	Subtotal - Storage Operation Expenses		2,013,527	1,265,159	13,041	621,499	113,828	-	-	-	-
178	**Storage Maintenance Expenses**										
179	Storage Maint Supervsn_Engin	830	193,299	121,455	1,252	59,664	10,928	-	-	-	-
180	Structures & Improvements	831	17,450	10,965	113	5,386	986	-	-	-	-
181	Reservoirs & Wells	832	30,813	19,361	200	9,511	1,742	-	-	-	-
182	Lines	833	13,944	8,761	90	4,304	788	-	-	-	-
183	Compressor Station Equipment	834	87,602	55,043	567	27,039	4,952	-	-	-	-
184	Measuring & Regulating	835	-	-	-	-	-	-	-	-	-
185	Purification Equipment	836	373,101	234,431	2,416	115,162	21,092	-	-	-	-
186	Other Equipment	837	300,547	188,843	1,947	92,767	16,990	-	-	-	-
187	Subtotal - Storage Maintenance Expenses		1,016,757	638,858	6,585	313,834	57,479	-	-	-	-
188	**LNG Operation Expenses**										
189	Other Storage-Op Superv-Eng	840	196,713	121,142	1,208	59,999	14,365	-	-	-	-
190	Labor & Expenses	841	1,938,432	1,193,744	11,904	591,233	141,551	-	-	-	-
191	LNG Op Supervision-Engineer	844.1	124,516	76,680	765	37,978	9,093	-	-	-	-
192	Power	842.2	1,636,937	1,008,074	10,052	499,275	119,535	-	-	-	-
193	Subtotal - LNG Operation Expenses		3,896,597	2,399,641	23,928	1,188,485	284,544	-	-	-	-
194	**LNG Maintenance Expenses**										
195	Other Storage-Maint Superv-Eng	843.1	70,223	43,246	431	21,419	5,128	-	-	-	-
196	Structures & Improvements	843.2	268	165	2	82	20	-	-	-	-
197	Gas Holders	843.3	31,697	19,520	195	9,668	2,315	-	-	-	-
198	Purification Equipment	843.4	359,158	221,180	2,206	109,545	26,227	-	-	-	-
199	Liquefaction Equipment	843.5	250,273	154,126	1,537	76,335	18,276	-	-	-	-
200	Vaporizing Equipment	843.6	17,918	11,034	110	5,465	1,308	-	-	-	-
201	Compressor Equipment	843.7	91,454	56,320	562	27,894	6,678	-	-	-	-
202	Measuring & Regulating	843.8	89	55	1	27	7	-	-	-	-
203	Other Equipment	843.9	524,054	322,728	3,218	159,840	38,268	-	-	-	-
204	Subtotal - LNG Maintenance Expenses		1,345,134	828,374	8,260	410,274	98,227	-	-	-	-

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
205	**Transmission Operation Expenses**										
206	Maint Supv-Eng-Gas Distr	850	766,844	256,782	2,553	127,431	30,486	28,898	312,752	21	7,921
207	System Cntl/Load Dispatching	851	-	-	-	-	-	-	-	-	-
208	Communication Exp Base Rate	852	2,088,724	699,420	6,954	347,096	83,037	78,711	851,873	58	21,574
209	Communication System Exp Scada	852.0001	11,766	3,940	39	1,955	468	443	4,799	0	122
210	Communication System Exp	852.0003	19,660	6,583	65	3,267	782	741	8,018	1	203
211	Power for Compressor Stn	855	182,587	61,140	608	30,342	7,259	6,881	74,467	5	1,886
212	Mains Expenses	856	995,339	333,294	3,314	165,402	39,570	37,508	405,942	28	10,281
213	Measuring_Regulating Stn Exp	857	2,022,626	677,286	6,734	336,112	80,410	76,221	824,915	56	20,892
214	Transm-Compr of Gs-Appl	858	-	-	-	-	-	-	-	-	-
215	Gas Transmission Exp	859	573,993	192,204	1,911	95,384	22,819	21,630	234,099	16	5,929
216	Rents-Easements	860	-	-	-	-	-	-	-	-	-
217	Subtotal - Transmission Operation Expenses		6,661,539	2,230,650	22,180	1,106,989	264,830	251,033	2,716,866	185	68,807
218	**Transmission Maintenance Expenses**										
219	Maint Supv-Eng-Gas Trans	861	1,320,433	442,154	4,396	219,424	52,494	49,759	538,530	37	13,639
220	Structures & Improvements	862	92,813	31,079	309	15,423	3,690	3,498	37,853	3	959
221	Mains	863	4,822,692	1,614,903	16,057	801,417	191,726	181,738	1,966,904	134	49,813
222	Measuring & Regulating	865	2,054,973	688,118	6,842	341,488	81,696	77,440	838,107	57	21,226
223	Trans Maint Commun Equip	866	21	7	0	4	1	1	9	0	0
224	Other Equipment	867	712	239	2	118	28	27	290	0	7
225	Subtotal - Transmission Maintenance Expenses		8,291,644	2,776,499	27,607	1,377,874	329,635	312,462	3,381,693	230	85,644
226	**Distribution Operation Expenses**										
227	Op Superv-Eng-Gas Distr	870	2,392,825	1,772,309	12,821	474,200	61,496	36,390	20,311	152	15,146
228	Mains & Services	874	19,135,666	14,544,775	103,794	3,467,856	521,175	346,313	54,148	12	97,594
229	Measuring & Regulating - Gen	875	625,828	351,326	3,483	172,499	38,722	27,616	24,781	-	7,400
230	Measuring & Regulating - Ind	876	1,149,199	-	-	630,178	165,284	88,066	179,550	1,923	84,198
231	Meter & House Regulator	878	3,960,795	2,836,817	19,375	1,059,326	38,057	2,523	1,145	-	3,550
232	Customer Installation Exp	879	6,071,040	5,185,484	39,137	802,198	31,990	6,055	3,028	32	3,116
233	Operations Exp Other	880	8,169,344	6,050,841	43,771	1,618,966	209,954	124,239	69,344	519	51,710
234	Rents	881	18	13	0	4	0	0	0	0	0
235	Subtotal - Distribution Operation Expenses		41,504,714	30,741,565	222,381	8,225,227	1,066,678	631,203	352,307	2,639	262,713
236	**Distribution Maintenance Expenses**										
237	Maint Supv-Eng-Gas Distr	885	10,905,928	8,129,491	57,681	2,184,611	270,004	166,226	46,110	110	51,694
238	Structures & Improvements	886	-	-	-	-	-	-	-	-	-
239	Mains	887	12,744,355	8,953,977	70,921	2,673,894	521,754	370,216	55,782	5	97,806
240	Compr. Station Equipment	888	(493)	(194)	(2)	(95)	(21)	(15)	(161)	-	(4)
241	Measuring & Regulating - Gen	889	843,755	473,666	4,696	232,567	52,206	37,233	33,410	-	9,977
242	Measuring & Regulating - Ind	890	161,526	-	-	88,575	23,231	12,378	25,237	270	11,834
243	Services	892	9,207,009	7,837,724	47,884	1,251,170	50,668	6,724	3,461	9	9,369
244	Meters & House Regulators	893	5,247,785	3,758,591	25,671	1,403,536	50,423	3,343	1,517	-	4,704
245	Other Equipment	894	-	-	-	-	-	-	-	-	-
246	Subtotal - Distribution Maintenance Expenses		39,109,866	29,153,254	206,851	7,834,259	968,266	596,106	165,356	394	185,379
247	**Total Storage, LNG, Transmission, and Distribution Expense**		**103,839,779**	**70,034,000**	**530,834**	**21,078,440**	**3,183,486**	**1,790,804**	**6,616,222**	**3,449**	**602,544**
248	**Customer Accounts, Service, and Sales Expense**										
249	**Customer Account**										
250	Customer Acnt Supervision	901	2,321,931	1,983,714	11,461	322,388	3,967	180	90	-	129
251	Meter Reading Expense	902	1,613,605	1,424,693	8,110	132,368	2,360	22,859	5,988	-	17,227
252	Customer Records and Collections	903	16,537,825	13,478,040	78,606	2,280,566	27,596	310,553	155,277	-	207,187
253	Uncollectible Accts	904	2,114,495	1,950,348	21,771	137,362	3,241	743	-	-	1,030
254	Misc Cust Accts Expense	905	-	-	-	-	-	-	-	-	-
255	Subtotal - Customer Account		22,587,856	18,836,795	119,948	2,872,684	37,164	334,336	161,355	-	225,574

Northern Indiana Public Service Company
Gas Class Cost of Service Study
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Attachment 16-B
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Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
256	**Customer Service & Information Expenses**										
257	Supervision	907	-	-	-	-	-	-	-	-	-
258	Customer Assistance - other	908	-	-	-	-	-	-	-	-	-
259	Inf and Instruct Expense	909	109,095	99,821	571	8,583	85	16	8	0	11
260	Misc Cust Serv and Info Exp	910	636,580	229,127	1,310	58,282	97,785	90,380	45,190	2,440	112,067
261	Subtotal - Customer Service & Information Expenses		745,675	328,947	1,881	66,865	97,870	90,396	45,198	2,440	112,078
262	**Sales Expenses**										
263	Sales Supervision	911	-	-	-	-	-	-	-	-	-
264	Demonstrating and Selling Exp	912	933	854	5	73	1	0	0	0	0
265	Advertising Expense	913	404,276	369,910	2,115	31,806	314	59	30	0	42
266	Misc Sales Expense	916	-	-	-	-	-	-	-	-	-
267	Subtotal - Sales Expenses		405,209	370,764	2,120	31,879	315	59	30	0	42
268	**Total Customer Accounts, Service, and Sales Expense**		**23,738,740**	**19,536,506**	**123,948**	**2,971,429**	**135,348**	**424,791**	**206,583**	**2,440**	**337,694**
269	**Administrative and General Expenses**										
270	A_G Salaries	920	40,652,264	28,573,071	202,092	7,684,727	926,179	667,888	2,272,313	2,193	323,802
271	Discretionary and Spot Awards	920.01	500,119	351,517	2,486	94,540	11,394	8,217	27,955	27	3,984
272	Stock Compensation Expense	920.02	2,679,524	1,883,345	13,321	506,526	61,048	44,023	149,776	145	21,343
273	Office Supplies and Exp	921	7,945,472	5,584,597	39,499	1,501,977	181,021	130,538	444,123	429	63,287
274	Employee Expenses	921.01	441,773	310,507	2,196	83,511	10,065	7,258	24,693	24	3,519
275	Outside Service Employed	923	19,144,276	13,440,840	98,256	3,608,894	498,020	332,470	1,023,822	884	141,091
276	Management Fee	923.01	13,099,773	9,197,107	67,233	2,469,443	340,778	227,498	700,566	605	96,544
277	Property Insurance	924	1,710,048	1,042,603	7,975	334,707	54,079	37,882	220,533	61	12,209
278	Injuries and Damages	925	7,362,390	5,174,769	36,600	1,391,754	167,737	120,959	411,531	397	58,643
279	Employee Pension and Benefits	926	26,716,110	18,777,830	132,812	5,050,297	608,672	438,927	1,493,333	1,441	212,798
280	Non Service Pension & OPEB	926.01	(6,245,592)	(4,389,810)	(31,048)	(1,180,639)	(142,293)	(102,611)	(349,106)	(337)	(49,747)
281	Regulatory Commission Exp	928	(4)	(2)	(0)	(1)	(0)	(0)	(1)	(0)	(0)
282	General Advertising Expense	930.1	64,346	45,176	330	12,130	1,674	1,117	3,441	3	474
283	Misc General Exp	930.2	675,632	474,348	3,468	127,364	17,576	11,733	36,132	31	4,979
284	Rents Admin and General	931	8,902,644	6,250,381	45,692	1,678,240	231,594	154,608	476,107	411	65,611
285	Maint General Plant	932	7,519,393	4,963,777	36,335	1,447,752	201,871	143,388	668,550	345	57,376
286	Maint of General Plant	935	27,434	18,110	133	5,282	737	523	2,439	1	209
287	Subtotal - Administrative and General Expenses		131,195,603	91,698,165	657,380	24,816,502	3,170,151	2,224,418	7,606,207	6,659	1,016,120
288	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		**258,774,122**	**181,268,671**	**1,312,163**	**48,866,371**	**6,488,986**	**4,440,014**	**14,429,012**	**12,548**	**1,956,358**

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
289	**Adjustments, Depreciation and Amortization Expense**										
290	**Depreciation Expense**										
291	**Intangible Plant**										
292	Organization	301	-	-	-	-	-	-	-	-	-
293	Franchises & Consents	302	-	-	-	-	-	-	-	-	-
294	Misc. Intangible Plant	303	20,272,194	18,548,919	106,047	1,594,897	15,740	2,963	1,482	22	2,125
295	Subtotal - Intangible Plant		20,272,194	18,548,919	106,047	1,594,897	15,740	2,963	1,482	22	2,125
296	**Underground Storage Plant**										
297	Land & Land Rights	350	4,397	2,763	28	1,357	249	-	-	-	-
298	Structures & Improvements	351	236,536	148,623	1,532	73,010	13,372	-	-	-	-
299	Wells	352	1,025,663	644,455	6,643	316,583	57,983	-	-	-	-
300	Non-Recoverable Natural Gas	352.3	23,193	14,573	150	7,159	1,311	-	-	-	-
301	Lines	353	1,167,118	733,335	7,559	360,245	65,979	-	-	-	-
302	Compressor Station Equipment	354	145,156	91,206	940	44,804	8,206	-	-	-	-
303	Other Equipment	355	96,607	60,701	626	29,819	5,461	-	-	-	-
304	Purification Equipment	356	335,834	211,014	2,175	103,659	18,985	-	-	-	-
305	Other Equipment	357	1,022	642	7	315	58	-	-	-	-
306	Subtotal - Underground Storage Plant		3,035,526	1,907,311	19,660	936,951	171,604	-	-	-	-
307	**LNG Storage Plant**										
308	Land & Land Rights	360	-	-	-	-	-	-	-	-	-
309	Structures & Improvements	361	317,401	195,465	1,949	96,809	23,178	-	-	-	-
310	Gas Holders	362	148,491	91,445	912	45,291	10,843	-	-	-	-
311	Purification Equipment	363	1,007,587	620,502	6,187	307,320	73,578	-	-	-	-
312	Subtotal - LNG Storage Plant		1,473,479	907,412	9,048	449,420	107,599	-	-	-	-
313	**Transmission Plant**										
314	Land & Land Rights	365.1	-	-	-	-	-	-	-	-	-
315	Rights of Way	365.2	329,586	110,364	1,097	54,769	13,103	12,420	134,420	9	3,404
316	Structures and Improvements	366	236,737	79,273	788	39,340	9,411	8,921	96,552	7	2,445
317	Mains	367	14,520,405	4,862,231	48,346	2,412,945	577,259	547,187	5,922,053	404	149,981
318	Measuring & Regulating Station Equipment	369	7,667,582	2,567,528	25,529	1,274,169	304,825	288,945	3,127,174	213	79,198
319	Other Equipment	371	0	0	0	0	0	0	0	0	0
320	Subtotal - Transmission Plant		22,754,310	7,619,395	75,761	3,781,224	904,599	857,473	9,280,198	632	235,028
321	**Distribution Plant**										
322	Land & Land Rights	374	48,251	33,145	264	10,083	1,981	1,406	997	0	374
323	Structures & Improvements	375	218,583	122,708	1,217	60,249	13,525	9,646	8,655	-	2,585
324	Mains - High Pressure	376	2,353,425	1,321,162	13,098	648,683	145,615	103,852	93,188	-	27,827
325	Mains - Distribution Pressure	376	18,936,757	13,636,975	105,379	3,818,211	726,004	514,616	-	8	135,563
326	Compressor Station Equipment	377	-	-	-	-	-	-	-	-	-
327	M&R Station Equip. - General	378	1,790,487	704,336	6,983	345,825	77,630	55,365	584,232	-	16,116
328	M&R Station Equip. - City Gate	379	-	-	-	-	-	-	-	-	-
329	Services	380	31,773,694	27,048,244	165,251	4,317,830	174,857	23,206	11,943	31	32,332
330	Meters	381	16,431,512	11,768,645	80,379	4,394,657	157,882	10,468	4,751	-	14,729
331	Meter Installations	382	11,657,642	8,349,485	57,026	3,117,871	112,013	7,426	3,371	-	10,450
332	House Regulators	383	2,210,704	1,583,360	10,814	591,259	21,242	1,408	639	-	1,982
333	House Regulators Installations	384	24,377	17,459	119	6,520	234	16	7	-	22
334	Industrial Measuring & Regulating Station Equip.	385	1,307,238	-	-	716,841	188,014	100,176	204,242	2,188	95,777
335	Other Property on Cust. Premises	386	385	276	2	103	4	0	0	-	0
336	Other Equipment	387	-	-	-	-	-	-	-	-	-
337	Subtotal - Distribution Plant		86,753,055	64,585,794	440,533	18,028,133	1,619,001	827,585	912,025	2,227	337,757

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
338	**General Plant**										
339	Land & Land Rights	389	42,653	25,717	198	8,412	1,377	964	5,677	1	306
340	Structures & Improvements	390	2,333,255	1,406,815	10,841	460,163	75,328	52,736	310,531	82	16,758
341	Office Furniture & Equipment	391	1,877,531	1,319,652	9,334	354,920	42,776	30,846	104,947	101	14,955
342	Transportation Equipment	392	25,295	17,779	126	4,782	576	416	1,414	1	201
343	Stores Equipment	393	60,679	36,586	282	11,967	1,959	1,371	8,076	2	436
344	Tools, Shop & Garage Equip.	394	954,116	575,276	4,433	188,170	30,803	21,565	126,982	33	6,853
345	Laboratory Equip.	395	173,799	104,791	808	34,277	5,611	3,928	23,131	6	1,248
346	Power Operated Equip.	396	11,172	6,736	52	2,203	361	253	1,487	0	80
347	Communication Equip.	397	2,039,097	1,229,455	9,474	402,150	65,832	46,087	271,382	72	14,646
348	Miscellaneous Equip.	398	32,644	19,683	152	6,438	1,054	738	4,345	1	234
349	Subtotal - General Plant		7,550,242	4,742,490	35,698	1,473,482	225,677	158,904	857,971	301	55,718
350	**Amortization Expense**										
351	Amortization of Cause No 44988	407.32	10,083,012	5,665,641	45,493	1,990,693	359,791	259,178	1,681,995	357	79,864
352	TDSIC Gas 20	407	4,257,163	1,702,473	15,552	740,467	161,559	144,672	1,451,650	126	40,664
353	FMCA 20	407	2,177,476	1,003,852	9,023	420,514	84,949	61,369	580,144	59	17,565
354	Gas Plant	407	-	-	-	-	-	-	-	-	-
355	COVID	407	-	-	-	-	-	-	-	-	-
356	Rate Case Expense	407.2	1,112,216	624,954	5,018	219,585	39,687	28,589	185,534	39	8,809
357	Subtotal - Amortization Expense		17,629,866	8,996,920	75,087	3,371,259	645,986	493,808	3,899,322	581	146,902
358	**Total Adjustments, Depreciation and Amortization Expense**		**159,468,672**	**107,308,242**	**761,834**	**29,635,366**	**3,690,205**	**2,340,733**	**14,950,998**	**3,763**	**777,531**
359	**Taxes**										
360	**Taxes Other Than Income Taxes**										
361	Tax Exp-License_Franchise (PUF)	408.131	1,433,771	1,038,209	7,403	295,398	39,328	24,120	20,515	58	8,741
362	Tax Exp-Property	408.132	17,652,204	10,762,408	82,327	3,455,055	558,238	391,045	2,276,480	625	126,025
363	Tax Exp-Sales and Use Tax	408.133	-	-	-	-	-	-	-	-	-
364	Tax Exp-Gross Receipts	408.134	-	-	-	-	-	-	-	-	-
365	Tax Exp-State and Local-Other	408.136	-	-	-	-	-	-	-	-	-
366	Tax Exp-Payroll FICA-OASDI	408.145	4,154,391	2,919,978	20,652	785,328	94,649	68,254	232,215	224	33,090
367	Tax Exp-Payroll FICA-Medicare	408.146	877,578	616,819	4,363	165,893	19,994	14,418	49,053	47	6,990
368	Tax Exp-FUTA Employer	408.147	2,178	1,531	11	412	50	36	122	0	17
369	Tax Exp-SUTA Employer	408.148	19,219	13,509	96	3,633	438	316	1,074	1	153
370	Subtotal - Taxes Other Than Income Taxes		24,139,341	15,352,454	114,851	4,705,718	712,697	498,189	2,579,460	956	175,017
371	**Income Taxes**										
372	Income Taxes		11,531,666	6,479,640	52,029	2,276,701	411,484	296,414	1,923,651	409	91,338
373	Subtotal - Income Taxes		11,531,666	6,479,640	52,029	2,276,701	411,484	296,414	1,923,651	409	91,338
				-	-	-	-	-	-	-	-
374	**Total Taxes**		**35,671,007**	**21,832,093**	**166,880**	**6,982,420**	**1,124,181**	**794,603**	**4,503,111**	**1,364**	**266,355**
375	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**										
376	**Test Year Expenses at Current Rates**		453,913,802	310,409,007	2,240,878	85,484,156	11,303,371	7,575,350	33,883,121	17,675	3,000,243
377	**Return on Rate Base**		260,663,791	146,466,907	1,176,077	51,462,952	9,301,248	6,700,201	43,482,551	9,236	2,064,619
378	**Gross Up Items**			-	-	-	-	-	-	-	-
379	Federal and State Income Taxes		40,038,389	22,497,559	180,647	7,904,794	1,428,687	1,029,162	6,678,992	1,419	317,129
380	Uncollectibles		675,172	622,759	6,952	43,860	1,035	237	-	-	329
381	Taxes Other Than Income Taxes		237,601	133,508	1,072	46,910	8,478	6,107	39,635	8	1,882
382	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**755,528,754**	**480,129,738**	**3,605,626**	**144,942,672**	**22,042,820**	**15,311,058**	**84,084,299**	**28,339**	**5,384,202**

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301.0	7,147	INT_LABOR					
5	Franchises & Consents	302.0	56,861		DISTRIBUTION	CUSTOMER			CUSTOMERS
6	Misc. Intangible Plant	303.0	52,598,755		DISTRIBUTION	CUSTOMER			CUSTOMERS
7	Subtotal - Intangible Plant		52,662,763						
8	**Underground Storage Plant**								
9	Land & Land Rights	350.0	647,723		STORAGE	DEMAND	SEASxTRANSPORT		
10	Structures & Improvements	351.0	6,923,349		STORAGE	DEMAND	SEASxTRANSPORT		
11	Wells	352.0	30,827,097		STORAGE	DEMAND	SEASxTRANSPORT		
12	Non-Recoverable Natural Gas	352.3	5,414,970		STORAGE	DEMAND	SEASxTRANSPORT		
13	Lines	353.0	33,965,055		STORAGE	DEMAND	SEASxTRANSPORT		
14	Compressor Station Equipment	354.0	5,235,333		STORAGE	DEMAND	SEASxTRANSPORT		
15	Other Equipment	355.0	3,534,546		STORAGE	DEMAND	SEASxTRANSPORT		
16	Purification Equipment	356.0	14,843,529		STORAGE	DEMAND	SEASxTRANSPORT		
17	Other Equipment	357.0	1,014,216		STORAGE	DEMAND	SEASxTRANSPORT		
18	Subtotal - Underground Storage Plant		102,405,819						
19	**LNG Storage Plant**								
20	Land & Land Rights	360.0	1,245,964		LNG	DEMAND	3-DAYxTRANSPORT		
21	Structures & Improvements	361.0	10,321,899		LNG	DEMAND	3-DAYxTRANSPORT		
22	Gas Holders	362.0	18,160,971		LNG	DEMAND	3-DAYxTRANSPORT		
23	Purification Equipment	363.0	23,885,413		LNG	DEMAND	3-DAYxTRANSPORT		
24	Subtotal - LNG Storage Plant		53,614,248						
25	**Transmission Plant**								
26	Land & Land Rights	365.1	39,692,486		TRANSMISSION	DEMAND	PEAK_AVG		
27	Rights of Way	365.2	21,275,449		TRANSMISSION	DEMAND	PEAK_AVG		
28	Structures and Improvements	366.0	13,418,077		TRANSMISSION	DEMAND	PEAK_AVG		
29	Mains	367.0	1,050,465,783		TRANSMISSION	DEMAND	PEAK_AVG		
30	Measuring & Regulating Station Equipment	369.0	342,330,838		TRANSMISSION	DEMAND	PEAK_AVG		
31	Other Equipment	371.0	47,499		TRANSMISSION	DEMAND	PEAK_AVG		
32	Subtotal - Transmission Plant		1,467,230,132						
33	**Distribution Plant**								
34	Land & Land Rights	374.0	6,968,644	INT_376&378					
35	Structures & Improvements	375.0	12,965,582		DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY		
36	Mains - High Pressure	376.0	167,342,597		DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY		
37	Mains - Distribution Pressure	376.0	1,346,516,523		DISTRIBUTION	MIN_SYS	DIST_DESIGN_DAY		DIST_CUST
38	Compressor Station Equipment	377.0	0						
39	M&R Station Equip. - General	378.0	80,713,398		DISTRIBUTION	DEMAND	DESIGN_DAY		
40	M&R Station Equip. - City Gate	379.0	0						
41	Services	380.0	954,615,664		ON-SITE	CUSTOMER			SERVICES
42	Meters	381.0	197,671,725		ON-SITE	CUSTOMER			METERS
43	Meter Installations	382.0	230,249,593		ON-SITE	CUSTOMER			METERS
44	House Regulators	383.0	141,843,848		ON-SITE	CUSTOMER			METERS
45	House Regulators Installations	384.0	3,879,273		ON-SITE	CUSTOMER			METERS
46	Industrial Measuring & Regulating Station Equip.	385.0	76,257,656		ON-SITE	CUSTOMER			ACCT_385
47	Other Property on Cust. Premises	386.0	40,915		ON-SITE	CUSTOMER			METERS
48	Other Equipment	387.0	0	INT_376-386					
49	Subtotal - Distribution Plant		3,219,065,417						

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
50	**General Plant**								
51	Land & Land Rights	389.0	2,786,116	INT_PLANT					
52	Structures & Improvements	390.0	27,966,319	INT_PLANT					
53	Office Furniture & Equipment	391.0	1,780,440	INT_LABOR					
54	Transportation Equipment	392.0	229,771	INT_LABOR					
55	Stores Equipment	393.0	120,013	INT_PLANT					
56	Tools, Shop & Garage Equip.	394.0	16,757,377	INT_PLANT					
57	Laboratory Equip.	395.0	1,725,512	INT_PLANT					
58	Power Operated Equip.	396.0	869,210	INT_PLANT					
59	Communication Equip.	397.0	11,874,401	INT_PLANT					
60	Miscellaneous Equip.	398.0	324,198	INT_PLANT					
61	Subtotal - General Plant		64,433,357						
62	**Gas Portion of Common Plant-In-Service**								
63	Organization	301.0	40,109	INT_LABOR					
64	Intangible	303.0	179,469,188	INT_LABOR					
65	Land & Land Rights	389.0	4,157,237	INT_PLANT					
66	Structures & Improvements	390.0	55,649,667	INT_PLANT					
67	Office Furniture & Equipment	391.0	6,584,223	INT_LABOR					
68	Transportation Equipment	392.0	414,500	INT_LABOR					
69	Stores Equipment	393.0	1,256,301	INT_PLANT					
70	Tool, Shop & Garage Equipment	394.0	4,130,577	INT_PLANT					
71	Laboratory Eqipment	395.0	941,395	INT_PLANT					
72	Power Operated Equipment	396.0	2,686,496	INT_PLANT					
73	Communication Equipment	397.0	8,130,403	INT_PLANT					
74	Miscellaneous Equipment	398.0	1,498,685	INT_PLANT					
75	Subtotal - Gas Portion of Common Plant-In-Service		264,958,780						
76	**Total Plant in Service**		5,224,370,516						
77	**Accumulated Depreciation**								
78	**Intangible Plant**								
79	Organization	301.0	36,462	INT_LABOR	-	-	-	-	-
80	Franchises & Consents	302.0	(41,766)	-	DISTRIBUTION	CUSTOMER	-	-	CUSTOMERS
81	Misc. Intangible Plant	303.0	(43,409,319)	-	DISTRIBUTION	CUSTOMER	-	-	CUSTOMERS
82	Subtotal - Intangible Plant		(43,414,623)						
83	**Underground Storage Plant**								
84	Land & Land Rights	350.0	(488,413)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
85	Structures & Improvements	351.0	(3,583,653)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
86	Wells	352.0	(16,037,625)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
87	Non-Recoverable Natural Gas	352.3	(5,009,091)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
88	Lines	353.0	(22,501,232)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
89	Compressor Station Equipment	354.0	(3,254,502)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
90	Other Equipment	355.0	(2,285,968)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
91	Purification Equipment	356.0	(9,723,531)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
92	Other Equipment	357.0	(998,431)	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
93	Subtotal - Underground Storage Plant		(63,882,445)						
94	**LNG Storage Plant**								
95	Land & Land Rights	360.0	154	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
96	Structures & Improvements	361.0	(9,307,742)	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
97	Gas Holders	362.0	(19,016,791)	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
98	Purification Equipment	363.0	(20,030,043)	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
99	Subtotal - LNG Storage Plant		(48,354,422)						

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
100	**Transmission Plant**								
101	Land & Land Rights	365.1	803,316	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
102	Rights of Way	365.2	(3,190,857)	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
103	Structures and Improvements	366.0	(1,907,753)	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
104	Mains	367.0	(134,842,260)	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
105	Measuring & Regulating Station Equipment	369.0	(38,768,732)	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
106	Other Equipment	371.0	(50,131)	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
107	Subtotal - Transmission Plant		(177,956,418)						
108	**Distribution Plant**								
109	Land & Land Rights	374.0	(499,116)	INT_376&378	-	-	-	-	-
110	Structures & Improvements	375.0	(2,395,334)	-	DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY	-	-
111	Mains - High Pressure	376.0	(51,578,641)	-	DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY	-	-
112	Mains - Distribution Pressure	376.0	(415,025,781)	-	DISTRIBUTION	MIN_SYS	DIST_DESIGN_DAY	-	DIST_CUST
113	Compressor Station Equipment	377.0	0	-	-	-	-	-	-
114	M&R Station Equip. - General	378.0	(26,186,573)	-	DISTRIBUTION	DEMAND	DESIGN_DAY	-	-
115	M&R Station Equip. - City Gate	379.0	0	-	-	-	-	-	-
116	Services	380.0	(558,302,139)	-	ON-SITE	CUSTOMER	-	-	SERVICES
117	Meters	381.0	(44,465,585)	-	ON-SITE	CUSTOMER	-	-	METERS
118	Meter Installations	382.0	(137,896,178)	-	ON-SITE	CUSTOMER	-	-	METERS
119	House Regulators	383.0	(81,653,996)	-	ON-SITE	CUSTOMER	-	-	METERS
120	House Regulators Installations	384.0	(3,200,352)	-	ON-SITE	CUSTOMER	-	-	METERS
121	Industrial Measuring & Regulating Station Equip.	385.0	(28,795,911)	-	ON-SITE	CUSTOMER	-	-	ACCT_385
122	Other Property on Cust. Premises	386.0	(37,829)	-	ON-SITE	CUSTOMER	-	-	METERS
123	Other Equipment	387.0	0	INT_376-386	-	-	-	-	-
124	Subtotal - Distribution Plant		(1,350,037,435)						
125	**General Plant**								
126	Land & Land Rights	389.0	(277,436)	INT_PLANT	-	-	-	-	-
127	Structures & Improvements	390.0	(12,613,641)	INT_PLANT	-	-	-	-	-
128	Office Furniture & Equipment	391.0	(162,499)	INT_LABOR	-	-	-	-	-
129	Transportation Equipment	392.0	(272,929)	INT_LABOR	-	-	-	-	-
130	Stores Equipment	393.0	(49,357)	INT_PLANT	-	-	-	-	-
131	Tools, Shop & Garage Equip.	394.0	(6,166,494)	INT_PLANT	-	-	-	-	-
132	Laboratory Equip.	395.0	(881,531)	INT_PLANT	-	-	-	-	-
133	Power Operated Equip.	396.0	(843,824)	INT_PLANT	-	-	-	-	-
134	Communication Equip.	397.0	(1,539,185)	INT_PLANT	-	-	-	-	-
135	Miscellaneous Equip.	398.0	(212,840)	INT_PLANT	-	-	-	-	-
136	Subtotal - General Plant		(23,019,735)						
137	**Gas Portion of Common Plant-In-Service**								
138	Organization	301.0	0	INT_LABOR	-	-	-	-	-
139	Intangible	303.0	(126,401,535)	INT_LABOR	-	-	-	-	-
140	Land & Land Rights	389.0	65,262	INT_PLANT	-	-	-	-	-
141	Structures & Improvements	390.0	(15,569,233)	INT_PLANT	-	-	-	-	-
142	Office Furniture & Equipment	391.0	(7,721,369)	INT_LABOR	-	-	-	-	-
143	Transportation Equipment	392.0	(143,471)	INT_LABOR	-	-	-	-	-
144	Stores Equipment	393.0	(501,123)	INT_PLANT	-	-	-	-	-
145	Tool, Shop & Garage Equipment	394.0	(1,924,485)	INT_PLANT	-	-	-	-	-
146	Laboratory Eqipment	395.0	(166,481)	INT_PLANT	-	-	-	-	-
147	Power Operated Equipment	396.0	(462,772)	INT_PLANT	-	-	-	-	-
148	Communication Equipment	397.0	(6,978,728)	INT_PLANT	-	-	-	-	-
149	Miscellaneous Equipment	398.0	(647,879)	INT_PLANT	-	-	-	-	-
150	Subtotal - Gas Portion of Common Plant-In-Service		(160,451,815)						
151	**Total Accumulated Depreciation**		(1,867,116,893)						

Northern Indiana Public Service Company
Gas Class Cost of Service Study
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Attachment 16-B
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
152	**Other Rate Base Items**								
153	Materials & Supplies		17,337,093	INT_PLANT					
154	Gas Stored Underground - Current A/C 164 (13-mo avg)		70,092,430		STORAGE	COMMODITY		WINTER_SEASxT	
155	Gas Stored Underground - Non-Current A/C 117		4,949,422		STORAGE	COMMODITY		WINTER_SEASxT	
156	Cause No. 44988 Regulatory Assets		11,798,908		STORAGE	COMMODITY		WINTER_SEASxT	
157	TDSIC - Gas 20 - Storage		145,256	INT_STORE_PLANT					
158	TDSIC - Gas 20 - Transmission		12,353,156	INT_TRANS_PLANT					
159	TDSIC - Gas 20 - Distribution		2,376,380	INT_DIST_PLANT					
160	FCMA - Storage		1,060,898	INT_STORE_PLANT					
161	FCMA - Transmission		5,486,577	INT_TRANS_PLANT					
162	FCMA - Distribution		1,956,302	INT_DIST_PLANT					
163	Subtotal - Other Rate Base Items		127,556,422						
164	**TOTAL RATE BASE**		3,484,810,045						
165	**OPERATION AND MAINTENANCE EXPENSE**								
166	**Storage, LNG, Transmission, and Distribution Expense**								
167	**Storage Operation Expenses**								
168	Storage Op Supervision-Engin	814.0	226,286		STORAGE	DEMAND	SEASxTRANSPORT		
169	Maps & Records	815.0	0						
170	Wells Expenses	816.0	569,154		STORAGE	DEMAND	SEASxTRANSPORT		
171	Lines Expenses	817.0	365,752		STORAGE	DEMAND	SEASxTRANSPORT		
172	Compressor Station Expenses	818.0	74,266		STORAGE	DEMAND	SEASxTRANSPORT		
173	Compr. Station Fuel & Power	819.0	333,143		STORAGE	DEMAND	SEASxTRANSPORT		
174	Measuring & Regulating Expenses	820.0	0						
175	Purification Expenses	821.0	444,926		STORAGE	DEMAND	SEASxTRANSPORT		
176	Storage Op Other	824.0	0		STORAGE	DEMAND	SEASxTRANSPORT		
177	**Subtotal - Storage Operation Expenses**		2,013,527						
178	**Storage Maintenance Expenses**								
179	Storage Maint Supervsn_Engin	830.0	193,299		STORAGE	DEMAND	SEASxTRANSPORT		
180	Structures & Improvements	831.0	17,450		STORAGE	DEMAND	SEASxTRANSPORT		
181	Reservoirs & Wells	832.0	30,813		STORAGE	DEMAND	SEASxTRANSPORT		
182	Lines	833.0	13,944		STORAGE	DEMAND	SEASxTRANSPORT		
183	Compressor Station Equipment	834.0	87,602		STORAGE	DEMAND	SEASxTRANSPORT		
184	Measuring & Regulating	835.0	0		STORAGE	DEMAND	SEASxTRANSPORT		
185	Purification Equipment	836.0	373,101		STORAGE	DEMAND	SEASxTRANSPORT		
186	Other Equipment	837.0	300,547		STORAGE	DEMAND	SEASxTRANSPORT		
187	**Subtotal - Storage Maintenance Expenses**		1,016,757						
188	**LNG Operation Expenses**								
189	Other Storage-Op Superv-Eng	840.0	196,713		LNG	DEMAND	3-DAYxTRANSPORT		
190	Labor & Expenses	841.0	1,938,432		LNG	DEMAND	3-DAYxTRANSPORT		
191	LNG Op Supervision-Engineer	844.1	124,516		LNG	DEMAND	3-DAYxTRANSPORT		
192	Power	842.2	1,636,937		LNG	DEMAND	3-DAYxTRANSPORT		
193	Subtotal - LNG Operation Expenses		3,896,597						
194	**LNG Maintenance Expenses**								
195	Other Storage-Maint Superv-Eng	843.1	70,223		LNG	DEMAND	3-DAYxTRANSPORT		
196	Structures & Improvements	843.2	268		LNG	DEMAND	3-DAYxTRANSPORT		
197	Gas Holders	843.3	31,697		LNG	DEMAND	3-DAYxTRANSPORT		
198	Purification Equipment	843.4	359,158		LNG	DEMAND	3-DAYxTRANSPORT		
199	Liquefaction Equipment	843.5	250,273		LNG	DEMAND	3-DAYxTRANSPORT		
200	Vaporizing Equipment	843.6	17,918		LNG	DEMAND	3-DAYxTRANSPORT		
201	Compressor Equipment	843.7	91,454		LNG	DEMAND	3-DAYxTRANSPORT		
202	Measuring & Regulating	843.8	89		LNG	DEMAND	3-DAYxTRANSPORT		
203	Other Equipment	843.9	524,054		LNG	DEMAND	3-DAYxTRANSPORT		
204	**Subtotal - LNG Maintenance Expenses**		1,345,134						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
205	**Transmission Operation Expenses**								
206	Maint Supv-Eng-Gas Distr	850.0	766,844		TRANSMISSION	DEMAND	PEAK_AVG		
207	System Cntl/Load Dispatching	851.0	0						
208	Communication Exp Base Rate	852.0	2,088,724		TRANSMISSION	DEMAND	PEAK_AVG		
209	Communication System Exp Scada	852.0	11,766		TRANSMISSION	DEMAND	PEAK_AVG		
210	Communication System Exp	852.0	19,660		TRANSMISSION	DEMAND	PEAK_AVG		
211	Power for Compressor Stn	855.0	182,587		TRANSMISSION	DEMAND	PEAK_AVG		
212	Mains Expenses	856.0	995,339		TRANSMISSION	DEMAND	PEAK_AVG		
213	Measuring_Regulating Stn Exp	857.0	2,022,626		TRANSMISSION	DEMAND	PEAK_AVG		
214	Transm-Compr of Gs-Appl	858.0	0						
215	Gas Transmission Exp	859.0	573,993		TRANSMISSION	DEMAND	PEAK_AVG		
216	Rents-Easements	860.0	0						
217	**Subtotal - Transmission Operation Expenses**		6,661,539						
218	**Transmission Maintenance Expenses**								
219	Maint Supv-Eng-Gas Trans	861.0	1,320,433		TRANSMISSION	DEMAND	PEAK_AVG		
220	Structures & Improvements	862.0	92,813		TRANSMISSION	DEMAND	PEAK_AVG		
221	Mains	863.0	4,822,692		TRANSMISSION	DEMAND	PEAK_AVG		
222	Measuring & Regulating	865.0	2,054,973		TRANSMISSION	DEMAND	PEAK_AVG		
223	Trans Maint Commun Equip	866.0	21		TRANSMISSION	DEMAND	PEAK_AVG		
224	Other Equipment	867.0	712		TRANSMISSION	DEMAND	PEAK_AVG		
225	**Subtotal - Transmission Maintenance Expenses**		8,291,644						
226	**Distribution Operation Expenses**								
227	Op Superv-Eng-Gas Distr	870.0	2,392,825	INT_874-879					
228	Mains & Services	874.0	19,135,666	INT_MAIN_SVCS					
229	Measuring & Regulating - Gen	875.0	625,828		DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY		
230	Measuring & Regulating - Ind	876.0	1,149,199		ON-SITE	CUSTOMER			ACCT_385
231	Meter & House Regulator	878.0	3,960,795		ON-SITE	CUSTOMER			METERS
232	Customer Installation Exp	879.0	6,071,040		ON-SITE	CUSTOMER			ACCT_879
233	Operations Exp Other	880.0	8,169,344	INT_874-879					
234	Rents	881.0	18	INT_874-879					
235	Subtotal - Distribution Operation Expenses		41,504,714						
236	**Distribution Maintenance Expenses**								
237	Maint Supv-Eng-Gas Distr	885.0	10,905,928	INT_887-893					
238	Structures & Improvements	886.0	0	INT_887-893					
239	Mains	887.0	12,744,355	INT_MAINS					
240	Compr. Station Equipment	888.0	(493)		DISTRIBUTION	DEMAND	DESIGN_DAY		
241	Measuring & Regulating - Gen	889.0	843,755		DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY		
242	Measuring & Regulating - Ind	890.0	161,526		ON-SITE	CUSTOMER			ACCT_385
243	Services	892.0	9,207,009		ON-SITE	CUSTOMER			SERVICES
244	Meters & House Regulators	893.0	5,247,785		ON-SITE	CUSTOMER			METERS
245	Other Equipment	894.0	0	INT_887-893					
246	Subtotal - Distribution Maintenance Expenses		39,109,866						
247	**Total Storage, LNG, Transmission, and Distribution Expense**		103,839,779						
248	**Customer Accounts, Service, and Sales Expense**								
249	**Customer Account**								
250	Customer Acnt Supervision	901.0	2,321,931		CUST. ACCOUNTS	CUSTOMER			ACCT_901
251	Meter Reading Expense	902.0	1,613,605		CUST. ACCOUNTS	CUSTOMER			METER_READ
252	Customer Records and Collections	903.0	16,537,825		CUST. ACCOUNTS	CUSTOMER			CUST_RECORDS
253	Uncollectible Accts	904.0	2,114,495		CUST. ACCOUNTS	CUSTOMER			UNCOLLECT
254	Misc Cust Accts Expense	905.0	0	INT_902-904					
255	Subtotal - Customer Account		22,587,856						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
256	**Customer Service & Information Expenses**								
257	Supervision	907.0	0						
258	Customer Assistance - other	908.0	0						
259	Inf and Instruct Expense	909.0	109,095		CUST. ACCOUNTS	CUSTOMER			CUSTOMERS
260	Misc Cust Serv and Info Exp	910.0	636,580		CUST. ACCOUNTS	CUSTOMER			ACCT_910
261	Subtotal - Customer Service & Information Expenses		745,675						
262	**Sales Expenses**								
263	Sales Supervision	911.0	0		CUST. ACCOUNTS	CUSTOMER			CUSTOMERS
264	Demonstrating and Selling Exp	912.0	933		CUST. ACCOUNTS	CUSTOMER			CUSTOMERS
265	Advertising Expense	913.0	404,276		CUST. ACCOUNTS	CUSTOMER			CUSTOMERS
266	Misc Sales Expense	916.0	0						
267	Subtotal - Sales Expenses		405,209						
268	**Total Customer Accounts, Service, and Sales Expense**		23,738,740						
269	**Administrative and General Expenses**								
270	A_G Salaries	920.0	40,652,264	INT_LABOR					
271	Discretionary and Spot Awards	920.0	500,119	INT_LABOR					
272	Stock Compensation Expense	920.0	2,679,524	INT_LABOR					
273	Office Supplies and Exp	921.0	7,945,472	INT_LABOR					
274	Employee Expenses	921.0	441,773	INT_LABOR					
275	Outside Service Employed	923.0	19,144,276	INT_O&M_EX_A&G					
276	Management Fee	923.0	13,099,773	INT_O&M_EX_A&G					
277	Property Insurance	924.0	1,710,048	INT_TOTAL_PLANT					
278	Injuries and Damages	925.0	7,362,390	INT_LABOR					
279	Employee Pension and Benefits	926.0	26,716,110	INT_LABOR					
280	Non Service Pension & OPEB	926.01	(6,245,592)	INT_LABOR					
281	Regulatory Commission Exp	928.0	(4)	INT_RATEBASE					
282	General Advertising Expense	930.1	64,346	INT_O&M_EX_A&G					
283	Misc General Exp	930.2	675,632	INT_O&M_EX_A&G					
284	Rents Admin and General	931.0	8,902,644	INT_O&M_EX_A&G					
285	Maint General Plant	932.0	7,519,393	INT_GENERAL_PLANT					
286	Maint of General Plant	935.0	27,434	INT_GENERAL_PLANT					
287	Subtotal - Administrative and General Expenses		131,195,603						
288	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		258,774,122						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
289	**Adjustments, Depreciation and Amortization Expense**								
290	**Depreciation Expense**								
291	**Intangible Plant**								
292	Organization	301.0	0	INT_LABOR	-	-	-	-	-
293	Franchises & Consents	302.0	0	-	DISTRIBUTION	CUSTOMER	-	-	CUSTOMERS
294	Misc. Intangible Plant	303.0	20,272,194	-	DISTRIBUTION	CUSTOMER	-	-	CUSTOMERS
295	Subtotal - Intangible Plant		20,272,194						
296	**Underground Storage Plant**								
297	Land & Land Rights	350.0	4,397	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
298	Structures & Improvements	351.0	236,536	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
299	Wells	352.0	1,025,663	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
300	Non-Recoverable Natural Gas	352.3	23,193	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
301	Lines	353.0	1,167,118	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
302	Compressor Station Equipment	354.0	145,156	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
303	Other Equipment	355.0	96,607	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
304	Purification Equipment	356.0	335,834	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
305	Other Equipment	357.0	1,022	-	STORAGE	DEMAND	SEASxTRANSPORT	-	-
306	Subtotal - Underground Storage Plant		3,035,526						
307	**LNG Storage Plant**								
308	Land & Land Rights	360.0	0	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
309	Structures & Improvements	361.0	317,401	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
310	Gas Holders	362.0	148,491	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
311	Purification Equipment	363.0	1,007,587	-	LNG	DEMAND	3-DAYxTRANSPORT	-	-
312	Subtotal - LNG Storage Plant		1,473,479						
313	**Transmission Plant**								
314	Land & Land Rights	365.1	0	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
315	Rights of Way	365.2	329,586	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
316	Structures and Improvements	366.0	236,737	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
317	Mains	367.0	14,520,405	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
318	Measuring & Regulating Station Equipment	369.0	7,667,582	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
319	Other Equipment	371.0	0	-	TRANSMISSION	DEMAND	PEAK_AVG	-	-
320	Subtotal - Transmission Plant		22,754,310						
321	**Distribution Plant**								
322	Land & Land Rights	374.0	48,251	INT_376&378	-	-	-	-	-
323	Structures & Improvements	375.0	218,583	-	DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY	-	-
324	Mains - High Pressure	376.0	2,353,425	-	DISTRIBUTION	DEMAND	HP_DIST_DESIGN_DAY	-	-
325	Mains - Distribution Pressure	376.0	18,936,757	-	DISTRIBUTION	MIN_SYS	DIST_DESIGN_DAY	-	DIST_CUST
326	Compressor Station Equipment	377.0	0	-	-	-	-	-	-
327	M&R Station Equip. - General	378.0	1,790,487	-	DISTRIBUTION	DEMAND	DESIGN_DAY	-	-
328	M&R Station Equip. - City Gate	379.0	0	-	-	-	-	-	-
329	Services	380.0	31,773,694	-	ON-SITE	CUSTOMER	-	-	SERVICES
330	Meters	381.0	16,431,512	-	ON-SITE	CUSTOMER	-	-	METERS
331	Meter Installations	382.0	11,657,642	-	ON-SITE	CUSTOMER	-	-	METERS
332	House Regulators	383.0	2,210,704	-	ON-SITE	CUSTOMER	-	-	METERS
333	House Regulators Installations	384.0	24,377	-	ON-SITE	CUSTOMER	-	-	METERS
334	Industrial Measuring & Regulating Station Equip.	385.0	1,307,238	-	ON-SITE	CUSTOMER	-	-	ACCT_385
335	Other Property on Cust. Premises	386.0	385	-	ON-SITE	CUSTOMER	-	-	METERS
336	Other Equipment	387.0	0	INT_376-386	-	-	-	-	-
337	Subtotal - Distribution Plant		86,753,055						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
338	**General Plant**								
339	Land & Land Rights	389.0	42,653	INT_PLANT	-	-	-	-	-
340	Structures & Improvements	390.0	2,333,255	INT_PLANT	-	-	-	-	-
341	Office Furniture & Equipment	391.0	1,877,531	INT_LABOR	-	-	-	-	-
342	Transportation Equipment	392.0	25,295	INT_LABOR	-	-	-	-	-
343	Stores Equipment	393.0	60,679	INT_PLANT	-	-	-	-	-
344	Tools, Shop & Garage Equip.	394.0	954,116	INT_PLANT	-	-	-	-	-
345	Laboratory Equip.	395.0	173,799	INT_PLANT	-	-	-	-	-
346	Power Operated Equip.	396.0	11,172	INT_PLANT	-	-	-	-	-
347	Communication Equip.	397.0	2,039,097	INT_PLANT	-	-	-	-	-
348	Miscellaneous Equip.	398.0	32,644	INT_PLANT	-	-	-	-	-
349	Subtotal - General Plant		7,550,242						
350	**Amortization Expense**								
351	Amortization of Cause No 44988	407.3	10,083,012	INT_RATEBASE					
352	TDSIC Gas 20	407.0	4,257,163	INT_TDSIC_RB					
353	FMCA 20	407.0	2,177,476	INT_FMCA_RB					
354	Gas Plant	407.0	0	INT_RATEBASE					
355	COVID	407.0	0		DISTRIBUTION	CUSTOMER			UNCOLLECT
356	Rate Case Expense	407.2	1,112,216	INT_RATEBASE					
357	Subtotal - Amortization Expense		17,629,866						
358	**Total Adjustments, Depreciation and Amortization Expense**		159,468,672						
359	**Taxes**								
360	**Taxes Other Than Income Taxes**								
361	Tax Exp-License_Franchise (PUF)	408.131	1,433,771	INT_DIST_PLANT					
362	Tax Exp-Property	408.132	17,652,204	INT_TOTAL_PLANT					
363	Tax Exp-Sales and Use Tax	408.133	0		DISTRIBUTION	CUSTOMER			BASE_REVENUE
364	Tax Exp-Gross Receipts	408.134	0		DISTRIBUTION	CUSTOMER			TOTAL_REVENUE
365	Tax Exp-State and Local-Other	408.136	0						
366	Tax Exp-Payroll FICA-OASDI	408.145	4,154,391	INT_LABOR					
367	Tax Exp-Payroll FICA-Medicare	408.146	877,578	INT_LABOR					
368	Tax Exp-FUTA Employer	408.147	2,178	INT_LABOR					
369	Tax Exp-SUTA Employer	408.148	19,219	INT_LABOR					
370	Subtotal - Taxes Other Than Income Taxes		24,139,341						
371	**Income Taxes**								
372	Income Taxes		11,531,666	INT_RATEBASE					
373	Subtotal - Income Taxes		11,531,666						
374	**Total Taxes**		35,671,007						
375	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
376	**Test Year Expenses at Current Rates**		453,913,802	n/a	n/a	n/a	n/a	n/a	n/a
377	**Return on Rate Base**		260,663,791	INT_RATEBASE					
378	**Gross Up Items**								
379	Federal and State Income Taxes		40,038,389	INT_RATEBASE					
380	Uncollectibles		675,172		CUST. ACCOUNTS	CUSTOMER			UNCOLLECT
381	Taxes Other Than Income Taxes		237,601	INT_RATEBASE					
382	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**755,528,754**						

Northern Indiana Public Service Company
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Attachment 17-B
Schedule 5 - External Allocation Factors

Line	Allocation Factor	Description	Total	Residential 211 / 111	Multiple Family 215 / 115	General Small 221 / 121	General Large 225 / 125	Large Transport - DP 228 DP / 128 DP	Large Transport - HP 228 HP / 128 HP	Interruptible 234 / 134	General Transport 238 / 138
1	**DEMAND ALLOCATION FACTORS**										
2	**Design Day**										
3		Design Peak Day	22,544,240	8,868,376	87,921	4,354,324	977,451	697,110	7,356,136	-	202,922
4	DESIGN_DAY	Design Peak Day Percent	100%	39.34%	0.39%	19.31%	4.34%	3.09%	32.63%	0.00%	0.90%
5	**Design Peak Day Excluding Customers Directly on Transmission Main**										
6		Design Peak Day Excluding HP	15,797,501	8,868,376	87,921	4,354,324	977,451	697,110	625,527	-	186,792
7	HP_DIST_DESIGN_DAY	Design Peak Day Excluding HP %	100%	56.14%	0.56%	27.56%	6.19%	4.41%	3.96%	0.00%	1.18%
8	**Design Peak Day Excluding High Pressure**										
9		Design Peak Day Excluding HP	15,168,230	8,868,376	87,921	4,354,324	977,451	697,110	-	-	183,048
10	DIST_DESIGN_DAY	Design Peak Day Excluding HP %	100%	58.47%	0.58%	28.71%	6.44%	4.60%	0.00%	0.00%	1.21%
11	**Peak and Average**										
12		Peak & Average (Load Factor Weighted)	16,956,993	5,678,134	56,458	2,817,848	674,126	639,007	6,915,800	471	175,148
13	PEAK_AVG	Peak & Average (Load Factor Weighted) %	100%	33.49%	0.33%	16.62%	3.98%	3.77%	40.78%	0.00%	1.03%
14	**Excess Winter Over Summer Average, Excluding Transport**										
15		Excess over Average Excluding Transport	130,255,930	81,843,670	843,639	40,205,018	7,363,603	-	-	-	-
16	SEASxTRANSPORT	Excess over Average Excluding Transport %	100%	62.83%	0.65%	30.87%	5.65%	0.00%	0.00%	0.00%	0.00%
17	**Three Day Peak Excluding Transport**										
18		Three Day Peak Excluding Transport	9,543,622	5,877,246	58,606	2,910,860	696,910	-	-	-	-
19	3-DAYxTRANSPORT	Three Day Peak Excluding Transport Percent	100%	61.58%	0.61%	30.50%	7.30%	0.00%	0.00%	0.00%	0.00%
20	**CUSTOMER ALLOCATORS**										
21	**Customer Count**										
22		2022 Customer Count	843,646	775,123	4,608	63,208	450	104	63	1	89
23		2024 Adjusted Customer Count	861,969	788,696	4,509	67,815	669	126	63	1	90
24	CUSTOMERS	2024 Adjusted Customer Count Percent	100%	91.50%	0.52%	7.87%	0.08%	0.01%	0.01%	0.00%	0.01%
25	**Customer Count for Distribution Mains**										
26		2024 Customer Count for Distribution Mains	861,897	788,696	4,509	67,815	669	126	-	1	81
27	DIST_CUST	2024 Customer Count for Distribution Mains %	100%	91.51%	0.52%	7.87%	0.08%	0.01%	0.00%	0.00%	0.01%
28	**Customer Meters**										
29		Average Cost per Meter		200	231	854	3,837	6,406	6,397	-	5,360
30		Relative Weighting Factor		1.00	1.16	4.28	19.23	32.10	32.05	-	26.86
31		Total Meters		793,978	4,690	69,325	554	22	10	-	37
32		Weighted Meter Count	1,108,561	793,978	5,423	296,488	10,652	706	321	-	994
33	METERS	Weighted Meter Count Percent	100%	71.62%	0.49%	26.75%	0.96%	0.06%	0.03%	0.00%	0.09%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
Attachment 17-B
Schedule 5 - External Allocation Factors

Line	Allocation Factor	Description	Total	Residential	Multiple Family	General Small	General Large	Large Transport - DP	Large Transport - HP	Interruptible	General Transport
				211	215	221	225	228 DP	228 HP	234	238
				111	115	121	125	128 DP	128 HP	134	138
34	**Service Lines**										
35		Service Cost per Service	354,835	2,436	2,519	4,453	22,566	75,418	85,386	99,578	62,478
36		Relative Weighting Factor		1.00	1.03	1.83	9.26	30.96	35.06	40.88	25.65
37		Weighted Services (based on Meter Count)	932,690	793,978	4,851	126,746	5,133	681	351	1	949
38	SERVICES	Weighted Services (based on Meter Count) %	100%	85.13%	0.52%	13.59%	0.55%	0.07%	0.04%	0.00%	0.10%
39	**Account 385**										
40		Industrial M&R Costs	29,634,040	-	-	16,250,215	4,262,116	2,270,919	4,630,011	49,593	2,171,185
41	ACCT_385	Industrial M&R Costs Percent	100%	0.00%	0.00%	54.84%	14.38%	7.66%	15.62%	0.17%	7.33%
42	**Uncollectible**										
43		Relative Weighting Factor		1.00	1.95	0.82	1.96	2.39	-	-	4.61
44		Write-Offs Weighted Customers	855,075	788,696	8,804	55,547	1,311	301	-	-	417
45	UNCOLLECT	Write-Offs Weighted Customers Percent	100%	92.24%	1.03%	6.50%	0.15%	0.04%		0.00%	0.05%
46	**Meter Reading**										
47		Relative Weighting Factor		1.00	1.00	1.08	1.95	100.43	52.62		105.57
48		Weighted Customers	893,276	788,696	4,489	73,278	1,306	12,655	3,315		9,537
49	METER_READ	Weighted Customers Percent	100%	88.29%	0.50%	8.20%	0.15%	1.42%	0.37%		1.07%
50	**Customer Records & Collections**										
51		Relative Weighting Factor		1.00	1.02	1.97	2.41	144.23	144.23	-	134.21
52		Weighted Customers	967,746	788,696	4,600	133,452	1,615	18,173	9,086	-	12,124
53	CUST_RECORDS	Weighted Customers Percent	100%	81.50%	0.48%	13.79%	0.17%	1.88%	0.94%	0.00%	1.25%
54	**Customer Account Supervision**										
55		Relative Weighting Factor		1.00	1.01	1.89	2.36	0.57	0.57	-	0.57
56		Weighted Customers	923,166	788,696	4,557	128,177	1,577	72	36	-	51
57	ACCT_901	Weighted Customers Percent	100%	85.43%	0.49%	13.88%	0.17%	0.01%	0.00%	0.00%	0.01%
58	**Customer Service and Informational Expenses**										
59		Relative Weighting Factor		1.00	1.00	2.96	502.94	2,469.09	2,469.09	9,160.91	4,270.33
60		Weighted Customers	2,191,226	788,696	4,509	200,617	336,594	311,106	155,553	8,398	385,754
61	ACCT_910	Weighted Customers Percent	100%	35.99%	0.21%	9.16%	15.36%	14.20%	7.10%	0.38%	17.60%
62	**Customer Installation Exp**										
63		Relative Weighting Factor		1.00	1.32	1.80	7.27	7.31	7.31	5.37	5.25
64		Weighted Customers	923,386	788,696	5,953	122,012	4,866	921	460	5	474
65	ACCT_879	Weighted Customers Percent	100%	85.41%	0.64%	13.21%	0.53%	0.10%	0.05%	0.00%	0.05%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
Attachment 17-B
Schedule 5 - External Allocation Factors

Line	Allocation Factor	Description	Total	Residential 211 111	Multiple Family 215 115	General Small 221 121	General Large 225 125	Large Transport - DP 228 DP 128 DP	Large Transport - HP 228 HP 128 HP	Interruptible 234 134	General Transport 238 138
66	**COMMODITY and REVENUE ALLOCATORS**										
67	**Total Volume**										
68		2024 Adjusted Billing Determinants	3,731,430,274	669,107,758	6,766,825	352,607,227	112,620,923	207,677,634	2,330,559,588	379,287	51,711,032
69	TOTAL_VOLUME	2024 Adjusted Billing Determinants Percent	100%	17.93%	0.18%	9.45%	3.02%	5.57%	62.46%	0.01%	1.39%
70	**Winter Season Excl. Transport**										
71		Winter Season Excl. Transport	729,731,846	439,962,092	4,534,140	228,451,322	56,784,292	-	-	-	-
72	WINTER_SEASxT	Winter Season Excl. Transport Percent	100%	60.29%	0.62%	31.31%	7.78%	0.00%	0.00%	0.00%	0.00%
73	**Base Rate Revenue**										
74		2024 Base Rate Revenues	513,696,504	333,438,626	2,467,973	106,211,338	15,546,399	14,613,209	36,316,051	69,452	5,033,457
75	BASE_REVENUE	2024 Base Rate Revenues Percent	100%	64.91%	0.48%	20.68%	3.03%	2.84%	7.07%	0.01%	0.98%
76	**TDSIC Revenues**										
77		2024 TDSIC Revenues	54,105,026	35,570,776	324,451	12,560,144	2,030,102	234,882	3,026,654	-	358,016
78	TDSIC_REVENUE	2024 TDSIC Revenues Percent	100%	65.74%	0.60%	23.21%	3.75%	0.43%	5.59%	0.00%	0.66%
79	**FMCA Revenues**										
80		2024 FMCA Revenues	11,365,663	7,450,919	59,975	2,331,525	301,680	79,264	1,021,388	-	120,912
81	FMCA_REVENUE	2024 FMCA Revenues Percent	100%	65.56%	0.53%	20.51%	2.65%	0.70%	8.99%	0.00%	1.06%
82	**Gas Revenue**										
83		Gas Revenue	398,108,688	279,902,092	2,794,957	100,535,547	14,617,679	-	-	258,413	-
84	GAS_REVENUE	Gas Revenue Percent	100%	70.31%	0.70%	25.25%	3.67%	0.00%	0.00%	0.06%	0.00%
85	**Total Revenue**										
86		Total Revenue	982,527,895	656,362,412	5,647,355	221,638,554	32,495,861	17,784,217	42,228,571	327,865	6,043,060
87	TOTAL_REVENUE	Total Revenue Percent	100%	66.80%	0.57%	22.56%	3.31%	1.81%	4.30%	0.03%	0.62%
88	**Non-Gas Revenue**										
89		Non Gas Revenue	584,419,207	376,460,321	2,852,398	121,103,007	17,878,181	17,784,217	42,228,571	69,452	6,043,060
90	NONGAS_REVENUE	Non Gas Revenue Percent	100%	64.42%	0.49%	20.72%	3.06%	3.04%	7.23%	0.01%	1.03%
91	**Late Fees**										
92		Relative Weighting Factor		1.00	1.70	2.58	35.95	64.90	64.90	96.61	36.72
93		3-Year Avg Late Fees Weighted Cust	1,010,890	788,696	7,648	174,815	24,060	8,177	4,089	89	3,317
94	LATE_FEES	3-Year Avg Late Fees Weighted Cust Percent	100%	78.02%	0.76%	17.29%	2.38%	0.81%	0.40%	0.01%	0.33%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
Attachment 17-B
Schedule 5 - External Allocation Factors

Line	Allocation Factor	Description	Total	Residential 211 111	Multiple Family 215 115	General Small 221 121	General Large 225 125	Large Transport - DP 228 DP 128 DP	Large Transport - HP 228 HP 128 HP	Interruptible 234 134	General Transport 238 138
95	**Miscellaneous Revenue**										
96		Relative Weighting Factor		1.00	1.47	4.77	108.59	0.65	-	-	1.38
97		Weighted Customers	1,191,460	788,696	6,612	323,271	72,674	82	-	-	125
98	MISC_REVENUE	Weighted Customers Percent	100%	66.20%	0.55%	27.13%	6.10%	0.01%	0.00%	0.00%	0.01%
99	**Alternative Regulatroy Programs**										
100		ARP Margin Removal	7,803,388	7,238,875	55,665	508,848	-	-	-	-	-
101	ARP	ARP Margin Removal Percent	100%	92.77%	0.71%	6.52%	0.00%	0.00%	0.00%	0.00%	0.00%
102	**Balancing and Storage Revenue**										
103		Balancing and Storage Revenue	5,252,014	-	-	-	-	2,856,861	1,864,478	-	530,675
104	BAL_STORE_REV	Balancing and Storage Revenue Percent	100%	0.00%	0.00%	0.00%	0.00%	54.40%	35.50%	0.00%	10.10%
105	**Reconnect-Shut-Offs**										
106		Relative Weighting Factor		1.00	1.17	1.37	0.93	-	-	-	0.34
107		Weighted Customers	887,470	788,696	5,279	92,842	623	-	-	-	30
108	SHUTOFF_RECONNECT	Weighted Customers Percent	100%	88.87%	0.59%	10.46%	0.07%	0.00%	0.00%	0.00%	0.00%

109 ***FUNCTIONAL PLANT ALLOCATORS***

Line	Allocation Factor	Description	Total
110	**TDSIC Allocation**		
111	TDSIC - Gas 20 - Storage		1.0%
112	TDSIC - Gas 20 - Transmission		83.0%
113	TDSIC - Gas 20 - Distribution		16.0%
114	**FMCA Allocation**		
115	FMCA - Storage		12.5%
116	FMCA - Transmission		64.5%
117	FMCA - Distribution		23.0%
118	**Mains High Pressure vs. Distribution Pressure Split**		
119	High Pressure Mains %		11.1%
120	Distribution Pressure Mains %		88.9%

121 ***MAINS CLASSIFICATION***

Line	Allocation Factor	Description	Total
122	**Customer and Demand Componenets of Mains**		
123		Customer Component	41.00%
124	MIN_SYS	Demand Component	59.00%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 6 - Internal Allocation Factors Summary

Line No.	Category Description	Total System	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
1	**Allocation Factor Basis**									
2	INT_PLANT	4,842,315,615	2,919,631,002	22,498,394	954,998,966	156,332,790	109,445,300	644,459,691	169,920	34,779,553
3	INT_376&378	1,594,572,518	1,095,363,645	8,739,231	333,212,334	65,476,859	46,472,523	32,962,802	587	12,344,536
4	INT_376-386	3,199,131,191	2,318,894,173	16,510,388	658,188,896	87,210,320	53,378,986	45,401,954	129,144	19,417,329
5	INT_MAINS	1,513,859,120	1,063,612,887	8,424,455	317,622,884	61,977,366	43,976,714	6,626,198	587	11,618,029
6	INT_MAIN_SVCS	2,468,474,784	1,876,256,119	13,389,277	447,348,696	67,230,804	44,673,929	6,985,002	1,525	12,589,431
7	INT_RATEBASE	3,484,810,045	1,958,113,727	15,722,957	688,007,378	124,348,241	89,574,881	581,317,521	123,480	27,601,860
8	INT_REVREQ	714,577,593	456,875,913	3,416,955	136,947,108	20,604,620	14,275,551	77,365,672	26,912	5,064,862
9	INT_LABOR	60,379,687	42,438,793	300,162	11,413,913	1,375,628	991,995	3,375,004	3,257	480,934
10	INT_TOTAL_PLANT	5,224,370,516	3,185,257,165	24,365,578	1,022,562,695	165,216,914	115,734,345	673,750,208	185,090	37,298,521
11	INT_STORE_PLANT	102,405,819	64,344,618	663,260	31,608,755	5,789,186	-	-	-	-
12	INT_TRANS_PLANT	1,467,230,132	491,309,378	4,885,158	243,818,692	58,329,798	55,291,075	598,400,289	40,773	15,154,969
13	INT_DIST_PLANT	3,219,065,417	2,330,959,758	16,620,740	663,218,862	88,298,698	54,154,225	46,059,402	129,147	19,624,584
14	INT_GENERAL_PLANT	329,392,137	217,441,610	1,591,700	63,419,743	8,843,078	6,281,230	29,286,270	15,114	2,513,393
15	INT_874-879	30,942,528	22,918,402	165,789	6,132,058	795,228	470,573	262,652	1,967	195,858
16	INT_887-893	28,203,938	21,023,763	149,170	5,649,647	698,262	429,879	119,246	284	133,686
17	INT_902-904	20,265,925	16,853,081	108,487	2,550,296	33,197	334,155	161,265	-	225,444
18	INT_O&M_EX_A&G	127,578,519	89,570,506	654,783	24,049,868	3,318,834	2,215,596	6,822,805	5,889	940,238
19	INT_TDSIC_RB	14,874,792	5,948,547	54,341	2,587,237	564,496	505,494	5,072,156	439	142,083
20	INT_FMCA_RB	8,503,778	3,920,381	35,240	1,642,251	331,755	239,667	2,265,656	231	68,597
		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-
20	**Allocation Factor %**									
21	INT_PLANT	100.0%	60.3%	0.5%	19.7%	3.2%	2.3%	13.3%	0.0%	0.7%
22	INT_376&378	100.0%	68.7%	0.5%	20.9%	4.1%	2.9%	2.1%	0.0%	0.8%
23	INT_376-386	100.0%	72.5%	0.5%	20.6%	2.7%	1.7%	1.4%	0.0%	0.6%
24	INT_MAINS	100.0%	70.3%	0.6%	21.0%	4.1%	2.9%	0.4%	0.0%	0.8%
25	INT_MAIN_SVCS	100.0%	76.0%	0.5%	18.1%	2.7%	1.8%	0.3%	0.0%	0.5%
26	INT_RATEBASE	100.0%	56.2%	0.5%	19.7%	3.6%	2.6%	16.7%	0.0%	0.8%
27	INT_REVREQ	100.0%	63.9%	0.5%	19.2%	2.9%	2.0%	10.8%	0.0%	0.7%
28	INT_LABOR	100.0%	70.3%	0.5%	18.9%	2.3%	1.6%	5.6%	0.0%	0.8%
29	INT_TOTAL_PLANT	100.0%	61.0%	0.5%	19.6%	3.2%	2.2%	12.9%	0.0%	0.7%
30	INT_STORE_PLANT	100.0%	62.8%	0.6%	30.9%	5.7%	0.0%	0.0%	0.0%	0.0%
31	INT_TRANS_PLANT	100.0%	33.5%	0.3%	16.6%	4.0%	3.8%	40.8%	0.0%	1.0%
32	INT_DIST_PLANT	100.0%	72.4%	0.5%	20.6%	2.7%	1.7%	1.4%	0.0%	0.6%
33	INT_GENERAL_PLANT	100.0%	66.0%	0.5%	19.3%	2.7%	1.9%	8.9%	0.0%	0.8%
34	INT_874-879	100.0%	74.1%	0.5%	19.8%	2.6%	1.5%	0.8%	0.0%	0.6%
35	INT_887-893	100.0%	74.5%	0.5%	20.0%	2.5%	1.5%	0.4%	0.0%	0.5%
36	INT_902-904	100.0%	83.2%	0.5%	12.6%	0.2%	1.6%	0.8%	0.0%	1.1%
37	INT_O&M_EX_A&G	100.0%	70.2%	0.5%	18.9%	2.6%	1.7%	5.3%	0.0%	0.7%
38	INT_TDSIC_RB	100.0%	40.0%	0.4%	17.4%	3.8%	3.4%	34.1%	0.0%	1.0%
39	INT_FMCA_RB	100.0%	46.1%	0.4%	19.3%	3.9%	2.8%	26.6%	0.0%	0.8%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 7 - Alternative COSS – Design Day Allocation of Transmission Plant

Line No.	Category Description	Total System	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
1	**Rate Base**									
2	Plant in Service	$ 5,224,370,516	$ 3,274,946,315	$ 25,239,785	$ 1,063,895,828	$ 170,737,256	$ 105,370,837	$ 548,774,580	$ 142,501	$ 35,263,414
3	Accumulated Reserve	(1,867,116,893)	(1,312,049,384)	(9,471,506)	(375,025,207)	(49,834,733)	(25,883,692)	(85,040,856)	(57,083)	(9,754,432)
4	Other Rate Base Items	127,556,422	74,030,705	722,884	35,458,049	8,296,693	980,854	7,762,065	636	304,537
5	**Total Rate Base**	**$ 3,484,810,045**	**$ 2,036,927,636**	**$ 16,491,163**	**$ 724,328,670**	**$ 129,199,215**	**$ 80,467,999**	**$ 471,495,789**	**$ 86,055**	**$ 25,813,519**
6	**Margin at Current Rates**									
7	Delivery Sales Margin	$ 518,908,768	$ 333,438,626	$ 2,467,973	$ 106,211,338	$ 15,546,399	$ 17,448,448	$ 38,166,417	$ 69,452	$ 5,560,115
8	TDSIC Margin	54,105,026	35,570,776	324,451	12,560,144	2,030,102	234,882	3,026,654	-	358,016
9	FMCA Margin	11,365,663	7,450,919	59,975	2,331,525	301,680	79,264	1,021,388	-	120,912
10	Miscellaneous Service Margin	9,252,291	7,188,564	69,667	1,559,613	245,055	52,544	114,948	369	21,530
11	**Total Margin at Current Rates**	**$ 593,631,748**	**$ 383,648,885**	**$ 2,922,065**	**$ 122,662,620**	**$ 18,123,236**	**$ 17,815,139**	**$ 42,329,408**	**$ 69,821**	**$ 6,060,574**
12	Gas Costs	$ 400,343,545	$ 281,663,944	$ 2,796,890	$ 99,235,655	$ 14,360,798	$ 1,095,716	$ 732,484	$ 253,759	$ 204,301
13	**Total Revenue at Current Rates**	**$ 993,975,293**	**$ 665,312,829**	**$ 5,718,955**	**$ 221,898,275**	**$ 32,484,033**	**$ 18,910,855**	**$ 43,061,891**	**$ 323,580**	**$ 6,264,874**
14	**Expenses at Current Rates**									
15	O&M and A&G Expenses	$ 258,774,122	$ 183,111,347	$ 1,330,124	$ 49,715,565	$ 6,602,402	$ 4,227,094	$ 11,861,371	$ 11,673	$ 1,914,547
16	Depreciation and Amortization Expense	159,468,672	109,295,703	781,206	30,551,285	3,812,533	2,111,084	12,181,608	2,820	732,434
17	Taxes Other Than Income	24,139,341	15,691,056	118,152	4,861,763	733,538	459,064	2,107,641	795	167,333
18	Current Income Taxes	11,531,666	5,760,189	52,804	2,861,691	531,774	840,033	1,233,513	4,158	247,503
19	**Total Expenses at Current Rates**	**$ 453,913,802**	**$ 313,858,295**	**$ 2,282,286**	**$ 87,990,304**	**$ 11,680,247**	**$ 7,637,275**	**$ 27,384,133**	**$ 19,445**	**$ 3,061,817**
20	**Operating Income at Current Rates**	**$ 139,717,946**	**$ 69,790,590**	**$ 639,779**	**$ 34,672,316**	**$ 6,442,989**	**$ 10,177,865**	**$ 14,945,274**	**$ 50,376**	**$ 2,998,757**
21	Current Rate of Return	4.01%	3.43%	3.88%	4.79%	4.99%	12.65%	3.17%	58.54%	11.62%
22	Current Relative Rate of Return	1.00	0.85	0.97	1.19	1.24	3.15	0.79	14.60	2.90
23	Current Revenue to Cost Ratio	0.79	0.78	0.79	0.82	0.80	1.27	0.62	3.04	1.18
24	Current Parity Ratio	1.00	0.99	1.00	1.04	1.01	1.62	0.79	3.86	1.50
25	**Current Revenue at Equal Rates of Return**									
26	Current Rate of Return	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%
27	Current Operating Income at Equal ROR	$ 139,717,946	$ 81,667,391	$ 661,187	$ 29,040,812	$ 5,180,038	$ 3,226,237	$ 18,903,878	$ 3,450	$ 1,034,952
28	Current Income Taxes - Equal ROR	11,531,666	6,740,445	54,571	2,396,893	427,536	266,279	1,560,238	285	85,420
29	Other Expenses - Equal ROR	442,382,136	308,098,106	2,229,482	85,128,613	11,148,472	6,797,241	26,150,620	15,287	2,814,314
30	**Current Margin at Equal Rate of Return**	**$ 593,631,748**	**$ 396,505,942**	**$ 2,945,240**	**$ 116,566,318**	**$ 16,756,047**	**$ 10,289,757**	**$ 46,614,736**	**$ 19,022**	**$ 3,934,686**
31	**Revenue Requirement at Equal Rates of Return**									
32	Required Return	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
33	Return on Rate Base	$ 260,663,791	$ 152,362,187	$ 1,233,539	$ 54,179,785	$ 9,664,101	$ 6,019,006	$ 35,267,885	$ 6,437	$ 1,930,851

Northern Indiana Public Service Company
Gas Class Cost of Service Study
12 Months Ended Dec 31, 2024
Attachment 16-B
Schedule 7 - Alternative COSS – Design Day Allocation of Transmission Plant

Line No.	Category Description	Total System	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238
34	**Expenses at Required Return**									
35	O&M and A&G Expenses	$ 258,774,122	$ 183,111,347	$ 1,330,124	$ 49,715,565	$ 6,602,402	$ 4,227,094	$ 11,861,371	$ 11,673	$ 1,914,547
36	Increase in Uncollectibles	675,172	622,759	6,952	43,860	1,035	237	-	-	329
37	Depreciation and Amortization Expense	159,468,672	109,295,703	781,206	30,551,285	3,812,533	2,111,084	12,181,608	2,820	732,434
38	Taxes Other Than Income	24,139,341	15,691,056	118,152	4,861,763	733,538	459,064	2,107,641	795	167,333
39	Increase in TOTI	237,601	138,881	1,124	49,386	8,809	5,486	32,147	6	1,760
40	Income Taxes	11,531,666	6,740,445	54,571	2,396,893	427,536	266,279	1,560,238	285	85,420
41	Gross-up of Income Taxes	40,038,389	23,403,084	189,474	8,322,104	1,484,422	924,529	5,417,205	989	296,582
42	**Total Expenses at Required Return**	**$ 494,864,963**	**$ 339,003,274**	**$ 2,481,603**	**$ 95,940,857**	**$ 13,070,274**	**$ 7,993,773**	**$ 33,160,211**	**$ 16,567**	**$ 3,198,405**
43	**Total Revenue Requirement at Equal Rates of Return**	**$ 755,528,754**	**$ 491,365,461**	**$ 3,715,142**	**$ 150,120,641**	**$ 22,734,376**	**$ 14,012,779**	**$ 68,428,096**	**$ 23,004**	**$ 5,129,256**
44	LESS									
45	Current Miscellaneous Revenue Margin	9,252,291	7,188,564	69,667	1,559,613	245,055	52,544	114,948	369	21,530
46	Additional Miscellaneous Revenue Margin	-	-	-	-	-	-	-	-	-
47	**Total Base Rate Revenue Requirement at Equal Rates of Return**	**$ 746,276,464**	**$ 484,176,897**	**$ 3,645,475**	**$ 148,561,028**	**$ 22,489,321**	**$ 13,960,235**	**$ 68,313,148**	**$ 22,634**	**$ 5,107,726**
48	**Base Rate Margin (Deficiency)/Surplus**	**$ (161,897,007)**	**$ (107,716,577)**	**$ (793,077)**	**$ (27,458,021)**	**$ (4,611,140)**	**$ 3,802,360**	**$ (26,098,688)**	**$ 46,818**	**$ 931,318**
	Percent Margin Change at Equal Rates of Return	**27.27%**	**28.08%**	**27.14%**	**22.38%**	**25.44%**	**-21.34%**	**61.66%**	**-67.05%**	**-15.37%**
49	Total Base Revenue as Proposed	$ 746,276,464	$ 481,311,389	$ 3,646,843	$ 154,832,404	$ 22,857,581	$ 17,762,595	$ 59,757,157	$ 69,452	$ 6,039,043
50	Miscellaneous Revenue	9,252,291	7,188,564	69,667	1,559,613	245,055	52,544	114,948	369	21,530
51	Total Margin as Proposed	**$ 755,528,755**	**$ 488,499,953**	**$ 3,716,510**	**$ 156,392,017**	**$ 23,102,636**	**$ 17,815,139**	**$ 59,872,105**	**$ 69,821**	**$ 6,060,574**
52	Proposed Margin (Decrease)/Increase	$ 161,897,007	$ 104,851,068	$ 794,445	$ 33,729,397	$ 4,979,400	$ -	$ 17,542,697	$ -	$ -
53	Change in Miscellaneous Revenue	-	-	-	-	-	-	-	-	-
54	**Total Margin Increase as Proposed**	**$ 161,897,007**	**$ 104,851,068**	**$ 794,445**	**$ 33,729,397**	**$ 4,979,400**	**$ -**	**$ 17,542,697**	**$ -**	**$ -**
55	Percent Margin Change	27.27%	27.33%	27.19%	27.50%	27.48%	0.00%	41.44%	0.00%	0.00%
56	Estimated Gas Costs	$ 400,343,545	$ 281,663,944	$ 2,796,890	$ 99,235,655	$ 14,360,798	$ 1,095,716	$ 732,484	$ 253,759	$ 204,301
57	Total Revenue at Proposed Rates	$ 1,155,872,300	$ 770,163,896	$ 6,513,400	$ 255,627,672	$ 37,463,433	$ 18,910,855	$ 60,604,588	$ 323,580	$ 6,264,874
58	Percent Change in Total Bill	16.29%	15.76%	13.89%	15.20%	15.33%	0.00%	40.74%	0.00%	0.00%
59	**Operating Income at Proposed Rates**									
60	Operating Expenses	$ 443,294,908	$ 308,859,746	$ 2,237,558	$ 85,221,860	$ 11,158,316	$ 6,802,965	$ 26,182,768	$ 15,293	$ 2,816,403
61	Operating Income Prior to Taxes	312,233,846	179,640,207	1,478,952	71,170,157	11,944,319	11,012,174	33,689,337	54,528	3,244,171
62	Income Taxes	51,570,055	29,670,247	244,271	11,754,808	1,972,782	1,818,824	5,564,294	9,006	535,823
63	**Total Operating Income at Proposed Rates**	$ 260,663,792	$ 149,969,960	$ 1,234,681	$ 59,415,349	$ 9,971,538	$ 9,193,350	$ 28,125,043	$ 45,522	$ 2,708,348
64	Proposed Rate of Return	7.48%	7.36%	7.49%	8.20%	7.72%	11.42%	5.97%	52.90%	10.49%
65	Proposed Relative Rate of Return	1.00	0.98	1.00	1.10	1.03	1.53	0.80	7.07	1.40
66	Proposed Revenue to Cost / Parity Ratio	1.00	0.99	1.00	1.04	1.02	1.27	0.87	3.04	1.18

Northern Indiana Publice Service Company
Allocation of Pipeline and Storage Demand Costs for GCA
For The Period Ending December 31, 2024

	(A)	(B)	(C)	(D)	(E)
Line No.	Description	Alloc. Basis	Total	Residential	General Service
1	Allocation Factors				
2	Design Day Demand	Peak	100.00%	62.68%	37.32%
3	Seasonal (Excess over Average)	Storage	100.00%	63.48%	36.52%
4	Average Throughput (Apr. - Oct.)	Off-Peak	100.00%	70.63%	29.37%
5	Pipeline Demand Costs				
6	Peak (Nov - Mar)		$ 33,458,047	20,971,504	12,486,543
7	Off-Peak (Apr - Oct)				
8	Storage Related	55.93%	$ 15,254,285	$ 9,683,420	$ 5,570,865
9	Summer Load Related	44.07%	$ 12,021,009	$ 8,490,438	$ 3,530,570
10	Total Off-Peak		$ 27,275,294	$ 18,173,859	$ 9,101,435
11	Total Pipeline Demand Costs [1]		$ 60,733,341	$ 39,145,363	$ 21,587,978
12	Storage Demand Costs [1]		$ 25,614,985	$ 16,260,392	$ 9,354,593
13	Total Demand Costs		$ 86,348,326	$ 55,405,755	$ 30,942,571
14	Pipeline Costs Only - Based on Line 11		100.00%	64.4545%	35.5455%
15	Storage Costs Only - Based on Line 13		100.00%	63.4800%	36.5200%

Note [1]:Demand costs reflect pipeline and storage rates effective December 2023 through November 2024.

Northern Indiana Public Service Company
Allocation Factors for GCA Demand Costs
Based on Annual Usage for the Year Ending December 31, 2024

Line No.	Description	Rate 111	Rate 115	Rate 121	Rate 125	Total	Residential %	General Service %
1	Design Day Demand	8,868,376	87,921	4,354,324	977,451	14,288,072	62.68%	37.32%
2	Seasonal (Excess over Average)	81,843,670	843,639	40,205,018	7,363,603	130,255,930	63.48%	36.52%
3	Average Throughput (Apr. - Oct.)	22,794,674	240,888	8,107,657	1,473,111	32,616,330	70.63%	29.37%
4		Actual Sales Volumes in Therms [1]						
5	January	122,851,665	1,185,702	40,893,531	4,695,206	169,626,104		
6	February	114,606,078	1,153,722	38,614,705	4,286,567	158,661,072		
7	March	96,242,680	981,153	32,732,816	3,811,443	133,768,092		
8	April	60,056,637	616,602	18,150,737	2,478,665	81,302,641		
9	May	32,849,039	340,034	9,541,413	1,505,722	44,236,208		
10	June	16,588,638	185,319	5,464,587	1,402,994	23,641,538		
11	July	10,723,530	120,607	4,966,073	1,159,282	16,969,492		
12	August	10,207,354	120,266	4,361,274	1,126,245	15,815,139		
13	September	11,329,235	119,942	4,964,287	1,244,100	17,657,564		
14	October	17,808,286	183,445	9,305,229	1,394,768	28,691,728		
15	November	44,211,836	428,787	17,740,941	2,361,729	64,743,293		
16	December	85,080,820	797,220	28,110,251	3,130,875	117,119,166		
17	Grand Total	622,555,798	6,232,799	214,845,844	28,597,596	872,232,037		
18	Average April - October	22,794,674	240,888	8,107,657	1,473,111			
19	Average November - March	92,598,616	909,317	31,618,449	3,657,164			
20	Excess over Average	69,803,942	668,429	23,510,792	2,184,053	96,167,215		
21	Total GCA Throughput April - October					228,314,310		
22	Storage Net Injection April - October					289,723,747		
23	Storage Percentage					56%		

(1) Volumes are actual booked sales. Unbilled values are included but no normalization for weather. Includes GCA, PPS and Dependabill Sales. Does not include Choice Sales since Demand Costs used in the calculation have already been allocated to the Choice Suppliers. PPS and Dependabill are included. Those customers do not receive any benefit from the Transporation and Storage contracts but do pay for them as a result of the agreement initially setting up those programs.

Northern Indiana Public Service Company
Revenue Proof and Rate Design

	Total System	Residential 211	Multiple Family 215	General Small 221	General Large 225	Large Transport - DP 228 DP	Large Transport - HP 228 HP	Interruptible 234	General Transport 238	Miscellaneous Revenue
Current Distribution Margin	$ 593,631,748	$ 376,460,321	$ 2,852,398	$ 121,103,007	$ 17,878,181	$ 17,762,595	$ 42,214,459	$ 69,452	$ 6,039,043	$ 9,252,291
Proposed Increase/ (Decrease)	161,897,007	$ 104,851,068	$ 794,445	$ 33,729,397	$ 4,979,400	$ -	$ 17,542,697	$ -	$ -	$ -
Proposed Margin	$ 755,528,755	$ 481,311,389	$ 3,646,843	$ 154,832,404	$ 22,857,581	$ 17,762,595	$ 59,757,157	$ 69,452	$ 6,039,043	$ 9,252,291
Resulting Increase % (Dist Margin)	27.3%	27.9%	27.9%	27.9%	27.9%	0.0%	41.6%	0.0%	0.0%	0.0%
Resulting Increase % with Total Revenue	16.3%	15.9%	14.1%	15.3%	15.4%	0.0%	40.8%	0.0%	0.0%	0.0%
Multiple of System Increase		1.01	1.01	1.01	1.01	-	1.50	-	-	
Proposed Revenue	$ 1,155,872,300	$ 762,972,035	$ 6,443,702	$ 254,066,539	$ 37,218,176	$ 18,858,692	$ 60,494,235	$ 323,212	$ 6,243,419	$ 9,252,291
Proposed Rate of Return	7.48%	7.84%	8.07%	8.87%	8.19%	9.82%	4.01%	35.53%	9.53%	0.00%
Proposed Revenue to Cost Ratio	1.00	1.02	1.03	1.08	1.05	1.16	0.71	2.46	1.13	0.00%
Current Relative Revenue to Cost Ratio	1.00	1.02	1.03	1.08	1.05	1.48	0.64	3.14	1.43	0.00%

228 Combined - Proposed: 0.78
228 Combined - Current: 0.77

	Total System
Rate Margin Increase	161,897,007
System Increase (Total Distribution Margin)	27.70%
System Increase (Total Revenue)	16.29%

Northern Indiana Public Service Company
Revenue Proof and Rate Design

Line No.	(A) Description	(B) 2024 Forecasted Billing Determinants (Therms/Bills)	(C) Current Rate	(D) 2024 Total Revenue ("Margins")	(E) 2024 Forecasted Billing Determinants (Therms/Bills)	(F) Proposed Rate	(G) Total Revenue ("Margins") 2024
1	**Residential - Rate 311**						
2	Customer Charge						
3	Customer Charge - 311	9,452,087	$ 16.25	$ 153,596,414	9,452,087	$ 25.50	$ 241,028,219
4	Customer Charge - 351	12,264	$ 16.25	$ 199,290	12,264	$ 25.50	$ 312,732
5	Total Customer Charge	9,464,351		$ 153,795,704	9,464,351		$ 241,340,951
6	Delivery Charge						
7	All Therms - 311	668,164,884 Therms	$ 0.27930	$ 186,618,452	668,164,884 Therms	$ 0.35864	$ 239,632,284
8	All Therms - 351	942,874 Therms	$ 0.27930	$ 263,345	942,874 Therms	$ 0.35864	$ 338,155
9	Total Delivery Charge	669,107,758 Therms		$ 186,881,797	669,107,758 Therms		$ 239,970,438
10	Residential - Rate 311 Sales			$ 340,677,501			$ 481,311,389
11	Adjustment of Charges for TDSIC			$ 35,570,776			$ -
12	Adjustment of Charges for FMCA			$ 7,450,919			$ -
13	Total Rider			$ 43,021,695			$ -
14			Total Margin	$ 383,699,196		Total Margin	$ 481,311,389
15			Revenue Proof	$ 383,699,196		Target Margin	$ 481,311,389
16			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
17	**Multi-Family - Rate 315**						
18	Customer Charge						
19	Customer Charge - 315	54,109	$ 20.44	$ 1,105,988	54,109	$ 32.50	$ 1,758,543
20	Customer Charge- 351	-	$ 20.44	$ -	-	$ 32.50	$ -
21	Total Customer Charge	54,109		$ 1,105,988	54,109		$ 1,758,543
22	Delivery Charge						
23	All Therms - 315	6,766,825 Therms	$ 0.20950	$ 1,417,650	6,766,825 Therms	$ 0.27905	$ 1,888,301
24	All Therms - 351	0 Therms	$ 0.20950	$ -	0 Therms	$ 0.27905	$ -
25	Total Delivery Charge	6,766,825 Therms		$ 1,417,650	6,766,825 Therms		$ 1,888,301
26	Multi-Family - Rate 315 Sales			$ 2,523,638			$ 3,646,843
27	Adjustment of Charges for TDSIC			$ 324,451			$ -
28	Adjustment of Charges for FMCA			$ 59,975			$ -
29	Total Rider			$ 384,426			$ -
30			Total Margin	$ 2,908,064		Total Margin	$ 3,646,843
31			Revenue Proof	$ 2,908,064		Target Margin	$ 3,646,843
32			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
33	**Small General Service - Rate 321**						
34	Customer Charge						
35	Customer Charge - 321	813,716	$ 66.00	$ 53,705,256	813,716	$ 96.00	$ 78,116,736
36	Customer Charge- 351	60	$ 66.00	$ 3,960.00	60	$ 96.00	$ 5,760
37	Total Customer Charge	813,776		$ 53,709,216	813,776		$ 78,122,496
38	Delivery Charge						
39	All Therms - 321	352,589,776 Therms	$ 0.15034	$ 53,008,347	352,589,776 Therms	$ 0.21755	$ 76,706,112
40	All Therms - 351	17,451 Therms	$ 0.15034	$ 2,624	17,451 Therms	$ 0.21755	$ 3,796
41	Total Delivery Charge	352,607,227 Therms		$ 53,010,970	352,607,227 Therms		$ 76,709,908
42	Small General Service - Rate 321 Sales			$ 106,720,186			$ 154,832,404
43	Adjustment of Charges for TDSIC			$ 12,560,144			
44	Adjustment of Charges for FMCA			$ 2,331,525			
45	Total Rider			$ 14,891,669			$ -
46			Total Margin	$ 121,611,855		Total Margin	$ 154,832,404
47			Revenue Proof	$ 121,611,855		Target Margin	$ 154,832,404
48			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			

Northern Indiana Public Service Company
Revenue Proof and Rate Design

Line No.	(A) Description	(B) 2024 Forecasted Billing Determinants (Therms/Bills)	(C) Current Rate	(D) 2024 Total Revenue ("Margins")	(E) 2024 Forecasted Billing Determinants (Therms/Bills)	(F) Proposed Rate	(G) Total Revenue ("Margins") 2024
49	**General Service Large - Rate 325**						
50	Customer Charge						
51	Customer Charge - 325	8,031	$ 493	$ 3,955,428	8,031	$ 715.00	$ 5,742,165
52	Customer Charge- 351	-	$ 493	$ -	-	$ 715.00	$ -
53	Total Customer Charge	8,031		$ 3,955,428	8,031		$ 5,742,165
54	Delivery Charge						
55	First 6,000 Therms	45,215,318 Therms	$ 0.11007	$ 4,976,850	45,215,318 Therms	$ 0.16253	$ 7,348,897
56	Next 24,000 Therms	60,268,832 Therms	$ 0.10021	$ 6,039,540	60,268,832 Therms	$ 0.14797	$ 8,918,082
57	All over 30,000 Therms	7,136,772 Therms	$ 0.08051	$ 574,582	7,136,772 Therms	$ 0.11888	$ 848,436
58	Total Delivery Charge	112,620,923 Therms		$ 11,590,971	112,620,923 Therms		$ 17,115,416
59	General Service Large - Rate 325 Sales			$ 15,546,399			$ 22,857,581
60	Adjustment of Charges for TDSIC			$ 2,030,102			
61	Adjustment of Charges for FMCA			$ 301,680			
62	Total Rider			$ 2,331,782			$ -
63			Total Margin	$ 17,878,181		Total Margin	$ 22,857,581
64			Revenue Proof	$ 17,878,181		Target Margin	$ 22,857,581
65			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
66	**LargeTransportation - Rate 328**						
67	Customer Charge	2,268	$ 2,955.09	$ 6,702,144	2,268	$ 3,000.00	$ 6,804,000
68	Demand Charge - HP	81,726,330 Therms	$ 0.05577	$ 4,557,877	81,726,330 Therms	$ 0.21404	$ 17,492,582
69	Demand Charge - DP	6,624,069 Therms	$ 0.16764	$ 1,110,459	6,624,069 Therms	$ 0.16764	$ 1,110,459
		88,350,399 Therms		$ 5,668,336	88,350,399 Therms		18,603,041
70	Transportation charge - HP						
71	First 300,000 Therms	187,076,059 Therms	$ 0.03691	$ 6,904,977	187,076,059 Therms	$ 0.06320	11,822,909
72	All Over 300,000 Therms	2,143,483,529 Therms	$ 0.01036	$ 22,206,489	2,143,483,529 Therms	$ 0.01208	25,890,258
73	Total Transportation Charge	2,330,559,588 Therms		$ 29,111,467	2,330,559,588 Therms		37,713,167
74	Transportation charge- DP						
75	First 100,000 Therms	175,126,550 Therms	$ 0.05202	$ 9,110,083	175,126,550 Therms	$ 0.05302	9,285,033
76	All Over 100,000 Therms	32,551,084 Therms	$ 0.01036	$ 337,229	32,551,084 Therms	$ 0.01208	393,171
77	Total Transportation Charge	207,677,634 Therms		$ 9,447,312	207,677,634 Therms		9,678,204
78	LargeTransportation - Rate 328 Sales			$ 50,929,260			$ 72,798,412
79	Adjustment of Charges for TDSIC			$ 3,261,537			$ -
80	Adjustment of Charges for FMCA			$ 1,100,652			$ -
81	Total Trackers			$ 4,362,189			$ -
82	Balancing and Storage			$ 3,584,970			$ 3,584,970
83	Supplier Aggregation			$ 1,136,370			$ 1,136,370
84	Total Other Riders			$ 4,721,340			$ 4,721,340
85			Total Margin	60,012,788		Total Margin	77,519,752
86			Revenue Proof	$ 60,012,788		Target Margin	$ 77,519,752
87			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			

Northern Indiana Public Service Company
Revenue Proof and Rate Design

Line No.	(A) Description	(B) 2024 Forecasted Billing Determinants (Therms/Bills)	(C) Current Rate	(D) 2024 Total Revenue ("Margins")	(E) 2024 Forecasted Billing Determinants (Therms/Bills)	(F) Proposed Rate	(G) Total Revenue ("Margins") 2024
88	**C&I Off-Peak Interruptible - Rate 334A**						
89	Customer Charge						
90	Customer Charge - 334A	11	$ 627.46	$ 6,902.06	11	$ 627.46	$ 6,902
91	Minimum Charge	-			-		$ -
92	Total Customer Charge	11		$ 6,902.06	11		$ 6,902
93	Delivery Charge						
94	Off-Peak Intrrpt Gas			0	0 Therms		$ -
95	Off-Peak Intrrpt Contract	379,287 Therms	$ 0.16491	$ 62,549.91	379,287 Therms	$ 0.16491	$ 62,550
96	Total Delivery Charge	379,287 Therms		$ 62,549.91	379,287 Therms		$ 62,550
97	C&I Off-Peak Interruptible - Rate 334A Sales			$ 69,452			$ 69,452
98	Total Rider			$ -			$ -
99			Total Margin	$ 69,452		Total Margin	$ 69,452
100			Revenue Proof	$ 69,452		Target Margin	$ 69,452
101			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
102	**General Transportation & Balancing - Rate 338**						
103	Customer Charge	1,084	$ 1,182.04	$ 1,281,331	1,084	$ 1,200.00	$ 1,300,800
104	Demand Charge	2,125,040	$ 0.28275	$ 600,855	2,125,040	$ 0.42200	$ 896,773
105	Transportation charge						
106	All Therms	51,711,032 Therms	$ 0.06094	$ 3,151,270	51,711,032 Therms	$ 0.06402	$ 3,310,795
107	Total Transportation Charge	51,711,032 Therms		$ 3,151,270	51,711,032 Therms		$ 3,310,795
108	General Transportation & Balancing - Rate 338 Sales			$ 5,033,457			$ 5,508,368
109	Adjustment of Charges for TDSIC			$ 358,016			$ -
110	Adjustment of Charges for FMCA			$ 120,912			$ -
111	Total Trackers			$ 478,928			$ -
112	Balancing and Storage			$ 475,291			$ 475,291
113	Supplier Aggregation			$ 55,384			$ 55,384
114	Total Other Riders			$ 530,675			$ 530,675
115			Total Margin	$ 6,043,060		Total Margin	$ 6,039,043
116			Revenue Proof	$ 6,043,060		Target Margin	$ 6,039,043
117			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
118	All Classes						
119			Total Margin	$ 592,222,595		Total Margin	$ 746,276,464
120			Revenue Proof	$ 592,222,595		Target Margin	$ 746,276,464
121			Over/(Under)	$ -		Over/(Under)	$ -

Northern Indiana Public Service Company
Residential Customer Monthly Bill Comparison

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
1	Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Normal Therms	132,187,962	123,334,195	103,500,659	64,566,329	35,327,934	17,804,597	11,487,619	10,936,362	12,125,962	19,111,205	47,456,646	91,268,288	669,107,758
	Customer Count	789,380	789,814	789,857	789,035	787,945	786,446	785,768	786,167	786,566	788,871	791,502	793,000	9,464,351
2	Volumes (therms)	167.46	156.16	131.04	81.83	44.84	22.64	14.62	13.91	15.42	24.23	59.96	115.09	847
3	Current Revenues	145.68	136.94	117.53	79.49	50.90	33.75	27.55	27.00	28.16	34.97	62.59	105.20	849.77
4	Proposed Revenues	157.44	148.54	128.75	89.98	60.83	43.34	37.02	36.46	37.65	44.59	72.74	116.18	973.51
5	Difference	11.77	11.60	11.22	10.48	9.92	9.59	9.47	9.46	9.48	9.61	10.15	10.98	123.75
6	Avg. Monthly Increase	10.31												

Residential - Rate 311

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
7	(A)	(B)	(C)	(D)	(E)	(F)	(G)
8		Present	Proposed				
9		Rates	Rates				
10	Customer Charge	$16.25	$25.50				
11	Delivery Charge	$0.27930	$0.35864				
12	FMCA Charge	$0.01114	$0.00000				
13	TDSIC Charge	$0.05316	$0.00000				
14	GDSM Charge	$0.01096	$0.01096				
15	Average Gas Charge	$0.41832	$0.41832				
16	ANNUAL	REVENUE AT	REVENUE AT				
17	CONSUMPTION	PRESENT	PROPOSED	REVENUE CHANGE			
18	(Therms)	RATES	RATES	AMOUNT	PERCENT	Customers	Customers
19	100	$ 272	$ 385	$ 113	41.32%	44,030	5.17%
20	200	$ 350	$ 464	$ 114	32.61%	39,062	4.59%
21	300	$ 427	$ 542	$ 116	27.06%	37,253	4.37%
22	400	$ 504	$ 621	$ 117	23.21%	42,783	5.02%
23	500	$ 581	$ 700	$ 119	20.38%	58,206	6.83%
24	600	$ 659	$ 779	$ 120	18.22%	77,674	9.12%
25	700	$ 736	$ 858	$ 122	16.51%	90,972	10.68%
26	800	$ 813	$ 936	$ 123	15.13%	93,592	10.99%
27	900	$ 891	$ 1,015	$ 125	13.98%	85,317	10.02%
28	1,000	$ 968	$ 1,094	$ 126	13.02%	70,134	8.23%
29	1,100	$ 1,045	$ 1,173	$ 128	12.20%	55,003	6.46%
30	1,200	$ 1,122	$ 1,252	$ 129	11.50%	40,910	4.80%
31	1,300	$ 1,200	$ 1,330	$ 131	10.88%	30,562	3.59%
32	1,400	$ 1,277	$ 1,409	$ 132	10.34%	22,195	2.61%
33	1,500	$ 1,354	$ 1,488	$ 134	9.86%	15,858	1.86%
34	1,600	$ 1,432	$ 1,567	$ 135	9.44%	11,517	1.35%
35	1,700	$ 1,509	$ 1,645	$ 137	9.05%	8,418	0.99%
36	1,800	$ 1,586	$ 1,724	$ 138	8.71%	6,276	0.74%
37	1,900	$ 1,663	$ 1,803	$ 140	8.39%	4,614	0.54%
38	2,000	$ 1,741	$ 1,882	$ 141	8.11%	3,539	0.42%
39	2,100	$ 1,818	$ 1,961	$ 143	7.84%	2,669	0.31%
40	2,200	$ 1,895	$ 2,039	$ 144	7.60%	2,044	0.24%
41	2,300	$ 1,973	$ 2,118	$ 146	7.38%	1,608	0.19%
42	>2300 (avg. 4,496)	$ 3,670	$ 3,849	$ 179	4.87%	7,654	0.90%

Illustrative Monthly Bill Impacts			
Description	Monthly Bill Impact (~Avg)	Monthly Bill Impact (~Avg)	Monthly Bill Impact (~Avg)
Volumes (therms)	50	70	100
Current Revenues	54.89	70.35	93.54
Proposed Revenue	64.90	80.65	104.29
Difference	10.00	10.30	10.75
Percent Increase	18%	15%	11%

Northern Indiana Public Service Company
Bill Impacts

Multi-Family - Rate 315

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Present Rates	Proposed Rates				
34	Customer Charge	$ 20.44	$ 32.50				
35	Delivery Charge	$0.21	$0.28				
36	FMCA Charge	$0.00886	$0.00000				
37	TDSIC Charge	$0.04795	$0.00000				
38	GDSM Charge	$0.00608	$0.00608				
39	Average Gas Cost	$0.41832	$0.41832				
40	ANNUAL	REVENUE AT	REVENUE AT	REVENUE CHANGE			
41	CONSUMPTION	PRESENT	PROPOSED			Customer	Percent of
42	(Therms)	RATES	RATES	AMOUNT	PERCENT	Count	Customers
43	250	$ 418	$ 566	$ 148	35.39%	644	12.38%
44	500	$ 591	$ 742	$ 151	25.58%	563	10.82%
45	750	$ 763	$ 918	$ 154	20.21%	613	11.78%
46	1,000	$ 936	$ 1,093	$ 157	16.82%	692	13.30%
47	1,250	$ 1,109	$ 1,269	$ 161	14.49%	698	13.42%
48	1,500	$ 1,281	$ 1,445	$ 164	12.79%	552	10.61%
49	1,750	$ 1,454	$ 1,621	$ 167	11.49%	432	8.30%
50	2,000	$ 1,627	$ 1,797	$ 170	10.46%	306	5.88%
51	2,250	$ 1,799	$ 1,973	$ 173	9.64%	197	3.79%
52	2,500	$ 1,972	$ 2,149	$ 177	8.95%	141	2.71%
53	2,750	$ 2,145	$ 2,325	$ 180	8.38%	97	1.86%
54	3,000	$ 2,317	$ 2,500	$ 183	7.89%	57	1.10%
55	3,500	$ 2,663	$ 2,852	$ 189	7.11%	89	1.71%
56	4,000	$ 3,008	$ 3,204	$ 196	6.51%	49	0.94%
57	4,500	$ 3,353	$ 3,556	$ 202	6.03%	24	0.46%
58	5,000	$ 3,699	$ 3,907	$ 208	5.64%	10	0.19%
59	5,500	$ 4,044	$ 4,259	$ 215	5.31%	5	0.10%
60	6,000	$ 4,390	$ 4,611	$ 221	5.04%	5	0.10%
61	6,500	$ 4,735	$ 4,962	$ 228	4.81%	6	0.12%
62	7,000	$ 5,080	$ 5,314	$ 234	4.60%	-	0.00%
63	7,500	$ 5,426	$ 5,666	$ 240	4.43%	1	0.02%
64	8,000	$ 5,771	$ 6,018	$ 247	4.27%	4	0.08%
65	8,500	$ 6,116	$ 6,369	$ 253	4.14%	-	0.00%
66	9,000	$ 6,462	$ 6,721	$ 259	4.01%	2	0.04%
67	>9,000 (avg. 18,376)	$ 12,938	$ 13,317	$ 379	2.93%	15	0.29%

Northern Indiana Public Service Company
Bill Impacts

Small General Service - Rate 321

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Present Rates	Proposed Rates				
68	Customer Charge	$ 66.00	$ 96.00				
69	Delivery Charge	$0.15034	$0.21755				
	FMCA Charge	$0.00661	$0.00000				
70	TDSIC Charge	$0.03562	$0.00000				
71	GDSM Charge	$0.00794	$0.00794				
72	Average Gas Cost	$0.41832	$0.41832				
73	ANNUAL	REVENUE AT	REVENUE AT	REVENUE CHANGE			
74	CONSUMPTION	PRESENT	PROPOSED			Customer	Percent of
75	(Therms)	RATES	RATES	AMOUNT	PERCENT	Count	Customers
76	500	$ 1,101	$ 1,474	$ 372	33.82%	13,059	20.37%
77	1,000	$ 1,411	$ 1,796	$ 385	27.29%	10,950	17.08%
78	1,500	$ 1,720	$ 2,118	$ 397	23.11%	7,139	11.14%
79	2,000	$ 2,030	$ 2,440	$ 410	20.20%	5,001	7.80%
80	2,500	$ 2,339	$ 2,762	$ 422	18.06%	3,583	5.59%
81	3,000	$ 2,649	$ 3,083	$ 435	16.42%	2,797	4.36%
82	3,500	$ 2,958	$ 3,405	$ 447	15.13%	2,305	3.60%
83	4,000	$ 3,267	$ 3,727	$ 460	14.08%	1,831	2.86%
84	4,500	$ 3,577	$ 4,049	$ 472	13.21%	1,555	2.43%
85	5,000	$ 3,886	$ 4,371	$ 485	12.48%	1,377	2.15%
86	6,000	$ 4,505	$ 5,015	$ 510	11.32%	2,131	3.32%
87	7,000	$ 5,124	$ 5,659	$ 535	10.44%	1,557	2.43%
88	8,000	$ 5,743	$ 6,303	$ 560	9.75%	1,278	1.99%
89	9,000	$ 6,362	$ 6,946	$ 585	9.19%	1,024	1.60%
90	10,000	$ 6,980	$ 7,590	$ 610	8.74%	833	1.30%
91	15,000	$ 10,075	$ 10,809	$ 735	7.29%	2,624	4.09%
92	20,000	$ 13,169	$ 14,028	$ 860	6.53%	1,370	2.14%
93	25,000	$ 16,263	$ 17,247	$ 984	6.05%	831	1.30%
94	30,000	$ 19,357	$ 20,466	$ 1,109	5.73%	581	0.91%
95	35,000	$ 22,451	$ 23,686	$ 1,234	5.50%	426	0.66%
96	40,000	$ 25,546	$ 26,905	$ 1,359	5.32%	343	0.54%
97	45,000	$ 28,640	$ 30,124	$ 1,484	5.18%	270	0.42%
98	50,000	$ 31,734	$ 33,343	$ 1,609	5.07%	182	0.28%
99	>50,000 (avg. 107032)	$ 67,028	$ 70,061	$ 3,033	4.53%	1,060	1.65%

Northern Indiana Public Service Company
Bill Impacts

General Service Large - Rate 325

Line No.	(A)	(B)	(C)
		Present Rates	Proposed Rates
100	Customer Charge	$ 492.52	$ 715.00
	Delivery Charge		
101	First 6,000 Therms	$0.11007	$0.16253
102	Next 24,000 Therms	$0.10021	$0.14797
103	All over 30,000 Therm	$0.08051	$0.11888
104	FMCA Charge	$0.00268	
105	TDSIC Charge	$0.01803	
106	GDSM Charge	$0.00040	$0.00040
107	Average Gas Cost	$0.41832	$0.41832

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
108	ANNUAL	REVENUE AT	REVENUE AT	REVENUE CHANGE			
109	CONSUMPTION	PRESENT	PROPOSED			Customer	Percent of
110	(Therms)	RATES	RATES	AMOUNT	PERCENT	Count	Customers
111	1,250	$ 6,597	$ 9,307	$ 2,709	41.07%	5	0.78%
112	2,500	$ 7,284	$ 10,033	$ 2,749	37.74%	6	0.93%
113	5,000	$ 8,658	$ 11,486	$ 2,829	32.67%	14	2.18%
114	10,000	$ 11,405	$ 14,393	$ 2,987	26.19%	6	0.93%
115	20,000	$ 16,900	$ 20,205	$ 3,305	19.56%	16	2.49%
116	30,000	$ 22,395	$ 26,018	$ 3,622	16.18%	12	1.87%
117	40,000	$ 27,871	$ 31,802	$ 3,931	14.10%	14	2.18%
118	50,000	$ 33,342	$ 37,579	$ 4,237	12.71%	14	2.18%
119	60,000	$ 38,763	$ 43,283	$ 4,520	11.66%	20	3.12%
120	70,000	$ 44,160	$ 48,950	$ 4,790	10.85%	28	4.36%
121	80,000	$ 49,647	$ 54,751	$ 5,104	10.28%	33	5.14%
122	90,000	$ 55,019	$ 60,382	$ 5,363	9.75%	51	7.94%
123	100,000	$ 60,415	$ 66,048	$ 5,633	9.32%	31	4.83%
124	125,000	$ 73,974	$ 80,316	$ 6,342	8.57%	59	9.19%
125	150,000	$ 87,535	$ 94,587	$ 7,052	8.06%	54	8.41%
126	175,000	$ 101,029	$ 108,760	$ 7,730	7.65%	50	7.79%
127	200,000	$ 114,544	$ 122,962	$ 8,418	7.35%	38	5.92%
128	250,000	$ 141,311	$ 150,980	$ 9,669	6.84%	56	8.72%
129	300,000	$ 167,949	$ 178,806	$ 10,858	6.46%	46	7.17%
130	350,000	$ 194,308	$ 206,222	$ 11,914	6.13%	24	3.74%
131	400,000	$ 220,824	$ 233,869	$ 13,045	5.91%	22	3.43%
132	450,000	$ 246,491	$ 260,262	$ 13,771	5.59%	10	1.56%
133	500,000	$ 273,287	$ 288,322	$ 15,035	5.50%	13	2.02%
134	550,000	$ 299,265	$ 315,174	$ 15,910	5.32%	3	0.47%
135	>550,000 (avg. 962,948)	$ 514,382	$ 537,783	$ 23,401	4.55%	14	2.18%