Northern Indiana Public Service Company LLC

Cause No. 45621

VERIFIED DIRECT TESTIMONY OF RONALD J. AMEN

TABLE OF CONTENTS

I. Introduction and Summary of Testimony

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

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

Q2. Please describe Atrium's business activities.

A2. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q3. On whose behalf are you testifying?

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

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

A4. I have over 40 years of experience in the utility industry, the last 24 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in <u>Attachment 17-A</u>.

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

A5. Yes. I testified on behalf of NIPSCO in two previous gas rate cases, Cause No. 44988, and Cause No. 43894, as well as submitting testimony on behalf of Northern Indiana Fuel & Light Company, Inc. ("NIFL") in Cause No. 43943 and Kokomo Gas and Fuel Company ("Kokomo") in Cause No. 43942. Also, I have previously testified on behalf of a former employer, Indiana Gas Company, Inc., on several occasions.

Q6. For what purpose has Atrium been retained by NIPSCO?

A6. 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; and provide support with the development of its rates.

Q7. Please summarize the purpose of your testimony.

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

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

Third, I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS. This presentation includes a discussion of the resulting unit costs by class for customer, demand, and commodity related costs with the ACOSS.

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

Finally, I discuss NIPSCO's rate design proposals. Proposed rate levels by class are presented as well as bill impacts by class.

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

A8. Yes. I am sponsoring Attachments 17-A through 17-J, all of which were prepared by me or under my supervision and direction.

Q9. Please describe the attachments.

A9. As stated earlier, Attachment 17-A contains further background information summarizing my education, presentation of expert testimony and other industry-related activities. The following is a listing of the remaining attachments:

Attachment 17-B	Description of the Atrium Model;
Attachment 17-C	100 Series Classes Load Characteristics;
Attachment 17-D	Graph of Miles of Mains v. No. of Residential Customers;
Attachment 17-E	Allocation of Pipeline and Storage Demand Costs for Gas Cost Adjustment ("GCA");
Attachment 17-F	COSS Summary Schedules for 100 Series Classes;
Attachment 17-G	Alternative Cost of Service Analysis;
Attachment 17-H	Rate Mitigation (pg. 1), Revenue Proof and Rate Design Schedules (pgs. 2-4);
Attachment 17-I	Typical Residential Customer Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels; and
Attachment 17-J	C&I Bill Impact Schedules.

II. Purpose of an ACOSS

Q10. What is an ACOSS?

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

Q11. What is the purpose of an ACOSS?

A11. The purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return 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.

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

A12. The Atrium Model was selected by NIPSCO for purposes of conducting the gas ACOSS in this general rate case filing. Atrium's PC-based ACOSS Model uses a Microsoft Excel platform and is available for both electric and gas utilities. This flexible and customizable model has been developed by Atrium to meet the needs of electric and gas utilities for improved cost analysis to facilitate the unbundling of supply, delivery services, and related products in today's competitive environment. The transparency provided by the structure of the Atrium Model allows for complete audit tracking capability, from account level input through each of the functionalization, classification, and allocation steps of a cost of service study. An informational compendium describing the Atrium Model's components, basic parameters, reporting capabilities and key features is attached hereto as Attachment 17-B.

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

A13. Yes. The Atrium Model in Excel format with formulas intact is being provided to the Commission in accordance with 170 IAC 1-5-15(e)(2). NIPSCO is filing a Motion for Protective Order with the Commission requesting that the Commission find the Model to be confidential, proprietary, and competitivelysensitive 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>

Q14. What is the guiding principle that should be followed when performing an ACOSS?

A14. C*ost causation* is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question: which customer or group of customers causes the utility to incur particular types of costs? In order to answer this question, it is necessary to establish a relationship between a utility's customers and the particular costs incurred by the utility in serving those customers.

Q15. What is the general framework of an ACOSS?

A15. As I indicated above, the ACOSS analysis is intended to establish cost responsibility among the various customer classes the utility serves. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. The most important theoretical principle underlying an ACOSS is that cost incurrence should follow cost causation. In other words, the costs that customers become responsible to pay should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q16. Please describe NIPSCO's derivation of its total revenue requirement.

A16. 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 Jeffrey Newcomb, the Company's revenue requirement is based upon a return equal to the weighted 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 $115,323,504, it has designed base rates to recover $574,801,185 of gross margin. I refer to this as the Company's "revenue requirement" throughout my testimony.

Q17. What are the steps to performing an ACOSS?

A17. 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.

Q18. Please describe cost functionalization.

A18. 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, LNG Storage, Transmission, Distribution, Distribution On-Site Customer, and Customer Accounts and Services.

Q19. Please describe cost classification.

A19. 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.

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 Campbell, 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.

IV. <u>Cost Allocation</u>

Q26. How is the concept of cost causation, discussed earlier, applied to the evaluation of the utility's transmission and distribution system?

A26. There are three basic components in gas utility operations which govern cost behavior. These are: (1) extending distribution services to all customers entitled to be attached to the system; (2) meeting the aggregate design day capacity requirements of all customers entitled to service on the peak day; and (3) delivering volumes of natural gas to all customers either on a sales or transportation basis. These operational components have been identified for purposes of the ACOSS as Customer Costs, Demand Costs and Commodity Costs, respectively.

Q27. Please explain.

A27. *Customer Costs* are incurred to extend service to and attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer Costs are largely a function of the number and density of customers served 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 and customer billing and accounting expenses.

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

Commodity Costs are those costs that vary with the throughput sold to, or transported for, customers. However, when as is the case with NIPSCO, a gas utility's cost of gas is not recovered through its base rates, very little of its remaining delivery service cost structure is commodity related.

Q28. How does the cost analyst establish the cost and utility service relationships?

A28. To establish these relationships, the cost analyst must analyze a utility's gas system design, physical configuration and operations, its accounting records and its system and customer load data, *e.g.*, annual and peak period gas consumption levels. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q29. Please explain the term "direct assignment."

A29. The term "direct assignment" means the allocation to a specific customer or class of customers based on exclusive identification of the customer or class with the particular plant or expense at issue. Usually costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or class of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or classes of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a "Special Study" as is done with costs associated with meters and services.

Q30. What prompts the analyst to elect to perform a Special Study?

A30. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q31. How do you determine whether to directly assign costs to a particular customer or customer class?

A31. Direct assignments of plant and expenses to particular customers or classes of customers are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on plant allocation methodologies associated with joint use plant.

Q32. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned to a specific customer or certain customer classes?

A32. No. The nature of utility operations is characterized by the existence of joint use facilities. To the extent that a utility's plant and expenses cannot be directly assigned to customer classes, allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q33. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform an ACOSS.

A33. As stated above, in order to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

Q34. Please describe the key issues related to the allocation of demand-related costs within a cost of service study.

A34. A complex part of the allocation process is the allocation of demand costs. Several methodologies have been used by gas utilities to develop allocation factors for the demand components of costs. It is not unusual for more than one demand cost allocation approach to be used in a cost of service study. Despite the use of different methodologies to allocate demand costs, there are three basic methodologies that form the foundation for the allocation process. These basic three methodologies are Coincident Peak Demand Allocations, Average and Excess Demand Allocations, and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed in greater detail below.

Q35. Please describe those three methodologies in greater detail.

A35. The concept of Coincident Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak demand(s) of the utility. Under this methodology, demand related costs are allocated to each customer class in proportion to the demand of that customer class coincident with the system peak. The Coincident Peak Demand Allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of consecutive cold days that surround the system peak, system peak days occurring over a period of several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day."

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand, i.e., total class demand minus average demand.

A simplified version of this methodology is the Average and Peak methodology. This cost methodology often gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks, which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each rate class' maximum demand, irrespective of the time of the system peak.

Q36. As stated earlier, the load characteristics of a utility's customers are an important element in determining the costs incurred by the utility in serving its customers. Have the load characteristics of the NIPSCO customers been summarized?

A36. Yes. The relevant load characteristics of NIPSCO's various customer groups are shown in Attachment 17-C [*Number of Customers, Annual Usage (therms), Peak Day (therms), Load Factor*]. In reviewing this information, it is important to point out that for each class of service, the absolute and relative level of certain of these load characteristics have a direct influence on the type and level of costs incurred by NIPSCO in serving its customers.

Q37. What are the implications of class load characteristics for purposes of determining the costs to serve a utility's customers?

A37. Annual load factor is an important indicator of how a customer utilizes a utility's distribution pipeline capacity. As a customer's annual load factor increases, it indicates that the customer is using the utility's system capacity more efficiently than a lower load factor customer. In addition, peak day demand is a key element in the sizing of a utility's facilities and in determining the level of costs incurred in serving its customers. The day-to-day utilization of a utility's facilities by its customers is measured by their annual gas consumption characteristics. Each of these characteristics can be a factor in any ultimate determination of the nature and extent of the allocation of costs to a customer or customer class.

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

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

Q38. What were the sources of the cost data analyzed in NIPSCO's ACOSS?

A38. All cost of service data were extracted from the Company's total cost of service (i.e., base rate revenue requirement) contained in the instant general rate case filing, which is based upon a future test year ending December 31, 2022. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company.

B. <u>Method Chosen for Allocation of Demand-related Costs</u>

Q39. How have the demand-related costs been allocated in NIPSCO's proposed ACOSS?

A39. A Coincident Peak Demand allocation methodology is the approach utilized in NIPSCO's ACOSS. This methodology is derived on a design day basis for allocating various portions of NIPSCO's capacity related costs. Capacity costs for NIPSCO consists of the capacity portion of the costs associated with city-gate facilities as well as the peak capacity portion of NIPSCO's transmission and distribution system.

Q40. Why has NIPSCO chosen to utilize a coincident peak demand methodology in developing its ACOSS allocation method?

A40. NIPSCO has based its proposed rates on the study results using the coincident peak allocation methodology because this demand allocation approach reflects cost causation on its system. The coincident peak demand allocation method strikes a balance with the other cost causative principle, that being a customer related element to the distribution system.

Q41. Please explain.

A41. From a gas engineering perspective, it has been my experience that a peak demand design criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system, whether the investment is driven by the need to replace aging and deteriorating pipelines or for the purpose of expanding transmission or distribution capacity to serve growing peak demand on the system. As NIPSCO Witness Campbell discusses, a utility's gas system sized only to accommodate average gas demands would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the utility is assured to satisfy its service obligation throughout the year. As such, cost causation with respect to peak capacity related costs are unrelated to average demand characteristics.

Additionally, use of average demand characteristics for the allocation of demand related costs penalizes customers that exhibit efficient gas consumption characteristics (*i.e.*, customers with high load factors), and encourages the inefficient use of the utility's gas system by customers with low load factors. Under-utilization of a utility's gas system is a result that a utility can hardly encourage, recognizing that higher system utilization will result in lower unit costs to all customers served by the utility. Therefore, the use of peak demand characteristics for the allocation of demand related costs is consistent with the goal of sending proper price signals to customers to encourage efficient use of the system and thereby prolong the need for distribution capacity additions. For the above-stated reasons and with few exceptions, it is inappropriate to rely upon the use of a commodity-based allocation factor, as derived from annual gas throughput volume, for purposes of allocating demand related costs to a utility.

Q42. Why did you choose to utilize NIPSCO' design day demand rather than its actual peak day demand as a demand allocation factor?

A42. Use of a utility's design day demand is superior to using its actual peak day demand or a historical average of multiple peak day demands over time for purposes of deriving demand allocation factors for a number of reasons. These reasons include:

(1) A utility's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands;

(2) Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time; and

(3) Design day demand provides more stable cost allocation results over time.

Q43. Please explain why NIPSCO's design day demand best reflects the factors that actually cause costs to be incurred.

A43. As NIPSCO Witness Campbell indicates, NIPSCO must consistently rely upon design day demand at 80 Heating Degree Days ("HDD") in the design of its own distribution facilities required to service its firm service customers. More importantly, design day demand directly measures the gas demand requirements of the utility's firm service customers which create the need for NIPSCO to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis.

In my opinion, there is no better way to capture the true cost causative factors of NIPSCO's operations than to utilize its design day peak requirements within its cost of service studies.

Q44. Please explain why use of design day demand provides more stable cost allocation results over time.

A44. By definition, a utility's design day demand is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of a utility's gas system and supply portfolio would tend to vary and make the installation of facilities and acquisition of supply resources and capacity a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days.

Q45. Has the Commission previously approved rates that were based upon the use of a design day for allocation of peak demand-related costs?

A45. Yes. In addition to NIPSCO (80 HDD), the Commission has approved rates that were based upon the use of a design day for allocation of peak demand-related costs for the following Indiana gas utilities: CenterPoint Indiana North (80 HDD), CenterPoint Indiana South (75 HDD), and Citizens Gas (82 HDD).

Q46. What are the results of utilizing design day as an allocator on the NIPSCO system?

A46. This method results in a peak day demand for NIPSCO of approximately 22.13 million therms. The resulting demand level reflects the current gas usage characteristics by class, for the base year, the twelve months ending December 31, 2020.

C. <u>Rationale for Classification of a Portion of Distribution Mains Investment as Customer-related</u>

Q47. Please discuss the rationale for the classification of a portion of the investment in distribution mains as customer related.

A47. Identifying a portion of mains investment as customer related is an accepted principle throughout the gas industry. The assumption is that distribution mains (FERC Account No. 376) are installed to meet both system peak load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the investment in this plant are charged based upon associated cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and numbers of customers.

Q48. What are the factors that affect the level of distribution mains facilities installed by a utility?

A48. 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 demands and the number of customers served by the utility.

Q49. Is the method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A49. Yes, it is. 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.

Q50. Please describe the zero-intercept method for determining a customer component of distribution mains costs.

A50. 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.

Q51. Please describe the minimum-sized unit approach.

A51. 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.

Q52. What method was employed in developing an appropriate classification for NIPSCO's distribution mains?

A52. Two separate regression analyses were conducted for the Company's investment in distribution mains: one for plastic distribution mains and one for steel distribution mains exclusive of high pressure mains. The "zero-intercept" regression results, which was \$7.95 per foot for plastic mains and \$25.03 per foot for steel mains, applied to the Company's total footage of distribution mains results in an investment amount equivalent to 50% of the total investment in distribution mains, on a current cost (year 2020) basis. The regressions' intercept values of \$7.95 and \$25.03 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 50% customer related and 50% demand related.

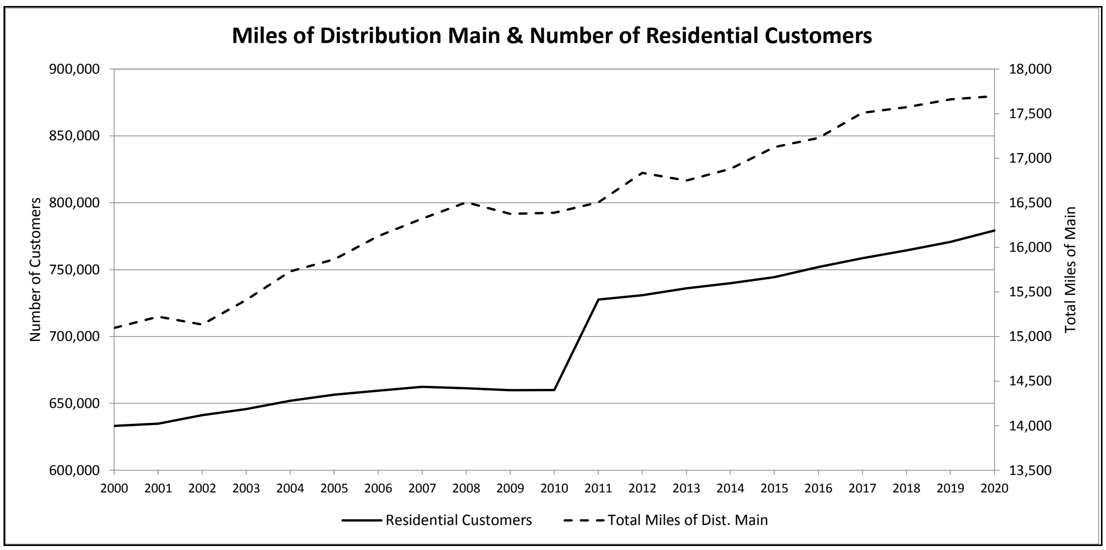
Q53. Why did you exclude certain distribution mains from the zero-intercept analysis?

A53. NIPSCO's high-pressure distribution grid, consisting of distribution mains operating at a maximum allowable operating pressure greater than 60 psig, and from which customer service connections are seldom made, were excluded from the zero-intercept analysis. These high-pressure mains serve a backbone distribution function; that is, they are designed with the capacity to move large volumes of gas under peak weather conditions from interstate pipeline receipt points or primary gate stations to various points on the distribution grid. On NIPSCO's system, the transmission mains and high-pressure backbone distribution related mains range in diameter but operate at pressures above 60 psig. Based on a review of the gas distribution system design and operations with NIPSCO's Engineering personnel, only the distribution mains at lower operating pressures were considered for the purpose of attaching customers. This comprises approximately 95 percent of NIPSCO's distribution pipeline system by linear footage.

Q54. Have you analyzed the relationship between the number of customers served by NIPSCO and level of investment in distribution mains?

A54. Yes. I have performed such an analysis and provided a graphical representation of the relationship between total installed footage of distribution mains and the number of residential customers, the class of customers that represents most of the growth in recent years. This graph is shown below on Figure 1 and on Attachment 17-D. As would be expected, as the number of customers served by NIPSCO <u>increases</u>, the level of investment in mains, as measured by installed footage, also <u>increases</u>.

Figure 1: Miles of Main and Number of Residential Customers[1]



Q55. Why would one expect there to be a strong correlation between the number of customers served by NIPSCO and the length of its system of distribution mains?

A55. Development of NIPSCO's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at

[1] System acquisition included in miles and customers in 2010.

any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's more remote or "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of NIPSCO's distribution mains facilities, it is appropriate to analyze the cost causative factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system or "zero capacity" approach for classifying distribution mains simply reflects the fact that the average customer serviced by the utility requires a minimum amount of mains investment to receive such service. It is entirely appropriate to conclude that the number of customers served by NIPSCO represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. Thus, one can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

D. <u>Allocation of NIPSCO's Transmission and High-Pressure Distribution Mains</u>

Q56. Please describe the method used to allocate NIPSCO's investment in its transmission plant.

A56. 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, excluding the Large Transportation Class 128, of 19.98 percent was used to ratably allocate transmission plant. Design Day demand was used to allocate the Peak portion of transmission plant or 80.02 percent. Annual Throughput was used to allocate the remaining 19.98 percent of transmission plant.

Q57. Why was the Large Transportation Class 128 excluded from the calculation of the system load factor?

A57. The annual load factor of the Large Transportation Class 128 HP exceeds 100 percent; that is, the class' contribution to the system coincident peak is lower than the average daily use of the class. Including this class in the system load factor calculation would heavily skew the result and thereby under-allocate the cost of transmission mains based on the remaining classes' contribution to the system peak. By doing so, the over-allocation of transmission mains costs on the basis of class throughput would penalize the high load factor customers in the Large Transportation Class 128 HP for their highly efficient use of the transmission system.

Q58. Are there other cost-related considerations particular to NIPSCO's transmission system that influenced your choice of the P&A methodology?

A58. 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, I have categorized the following cost-related considerations as a) Increased Transmission System Reliability, and b) Supply Diversity and Flexibility.

<u>Increased Transmission System Reliability</u>

As daily "sendout" (i.e., total gas demand) has grown on the NIPSCO system, daily nomination caps have become commonplace. With increased frequency, NIPSCO has had to issue nomination cap directives to its large transportation customers when maintenance or emergency repair work is necessary on the transmission system to insure continuous system operations. Due to the extensive NIPSCO transmission system network, the Company has been able to manage around these events with only supply directives or nomination caps and not with periodic curtailments or supplying insufficient delivery pressures to its large transportation customers. In addition, investments under the TDSIC program include:

- Replacement of "at risk" pipeline, in other words, finding problems before they become emergencies;
- Investments to allow live pipeline pigging, which eliminates out-of-service down-time for pressure testing purposes;
- Investment in a major transmission segment in northwestern Indiana, referred to by NIPSCO as the "483 lb." system, allowing for a secondary feed for redundancy, LNG support, additional physical paths for supply, and to maintain higher operating pressures.

The investments in TDSIC I and II create an additional high-pressure feed to customers served from the 483 lb. system while replacing at risk pipeline segments, and the need for nomination caps is expected to be relaxed.

<u>Supply Diversity and Flexibility</u>

Most of the Large Transportation class customers' loads are located in Zone A on the NIPSCO transmission system.[2] This zone is supplied by five of the seven interstate pipelines that are connected to the NIPSCO transmission system.[3] Currently, only three of these interstate pipelines provide physical supply to the 483 lb. system mentioned earlier. Under most conditions, the majority of the 483 lb. demand can be served by any of the three points of delivery ("POD"). Had the POD facilities been sized only for peak day, it would have required all three POD facilities at near capacity to serve the demand on this system. However, the three POD facilities have been configured in such a way to allow for supply diversity, redundancy, and operational flexibility. Under most conditions, this benefits the transportation

---

[2] Under peak weather conditions, large transportation customers served from the high pressure system comprise approximately 35% of load (January 2020 3-day peak). Across all twelve months of the year this same group of customers comprise 66% of annual system throughput.

[3] These interstate pipelines are: Natural Gas Pipeline ("NGPL"), Northern Border Pipeline ("NBPL"), ANR Pipeline, Trunkline Pipeline, and Vector Pipeline.

customers by allowing them to move large quantities of supply to any one or more of the POD facilities to minimize their supply costs. Although two of the Zone A pipelines currently have no physical interconnection to some Large Transportation class customers, NIPSCO allows them to source significant amounts of supply from these points, while managing deliveries by displacement behind the scenes. The alternative would be to create additional Transportation Zones or islands where certain customers would be further restricted from a supply perspective.

To summarize, the NIPSCO transmission system provides increased supply diversity, and price options, for transportation customers as well as core GCA 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. It has consolidated multiple transportation zones across the NIPSCO system under a single balancing contract. 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 II projects provide further enhanced services, with fewer restrictions.

The operational improvements, cost-saving supply sourcing flexibility and associated pricing options described above were understandably influential in the choice of the P&A allocation method for the NIPSCO transmission system mains.

Q59. Please describe the method used to allocate NIPSCO's investment in its high-pressure distribution plant.

A59. NIPSCO's high pressure distribution mains are commonly referred to by NIPSCO as "Pseudo-Transmission" due to similarities in operating characteristics. These pipelines typically operate at pressures above 200 PSIG and serve as an intermediate pipeline system between the transmission system and the downstream distribution systems but don't meet the Federal Department of Transportation's SMYS (Specified Minimum Yield Strength) criteria for transmission pipelines. Design Day demand was used to allocate the high-pressure distribution mains.

Q60. Are some NIPSCO customers served directly from the transmission or high-pressure distribution systems?

A60. Yes. The vast majority of NIPSCO's customers are not directly connected to either the transmission system or high-pressure distribution system. However, the peak demands of the Large Transportation (Class 128) and General Transportation (Class 138) customers that are directly connected to these pipelines were excluded from the allocation of the downstream distribution mains.

E. <u>Description of Method used to Allocate NIPSCO's Underground Storage Plant</u>

Q61. Please describe the method used to allocate NIPSCO's investment in its underground storage plant.

A61. 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.

Q62. Please describe the operations at the Royal Center/Trenton storage facility.

A62. Trenton is a single cycle storage facility operated on a planned withdrawal basis during the 3½ to 4 month withdrawal period, followed by an injection cycle until the beginning of the subsequent winter withdrawal period. Generally, no injections occur during the winter withdrawal cycle. Withdrawals can be accelerated or decelerated to a degree depending on weather conditions and injections can be adjusted up or down to a degree to accommodate incidental system requirements. NIPSCO Witness Campbell provides additional operational details.

Q63. How was NIPSCO's investment in its LNG facility treated for cost allocation purposes?

A63. 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 Campbell, 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.

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

Q64. Please describe the Special Studies conducted for purposes of allocating other distribution plant investment.

A64. 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 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.

Q65. What other noteworthy allocations have been made?

A65. For Industrial Measuring & Regulating Station Equipment – Account No. 385, an assignment of this plant to all but Service Classifications 111 and 115 were facilitated by the identification in the property records of specific types of equipment associated with the size and type of customers in these classes.

Q66. How were you able to determine the particular type and size of facilities for each plant account attributable to each of the customer groups?

A66. 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.

G. Allocation of Depreciation Reserve and Expenses

Q67. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A67. These items were allocated by account in the same manner as their associated plant accounts.

H. Allocation of O&M Expenses

Q68. How did the ACOSS allocate distribution related O&M expenses?

A68. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's distribution related O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, i.e., expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Meters and House Regulator Expenses, is allocated on the same basis as its corresponding plant accounts, Account No. 381 – Meters and Account No. 383 – House Regulators. With the utility's detailed analyses supporting its assignment of plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

I. <u>Allocation of Customer Accounting Expenses (901 – 905)</u>

Q69. How did the ACOSS allocate Customer Accounting Expenses (FERC Account No. 901 – No. 904)?

A69. 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 901-Customer Account Supervision, and Account 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. The analysis revealed that residential and general service rate classes each have some responsibility for uncollectible costs on the NIPSCO system, with the residential classes (including multiple family) being responsible for 93 percent of these costs.

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

Q70. How did the ACOSS allocate Customer Information, Demonstrating and Selling Expenses (FERC Account Nos. 910 and 912)?

A70. Similar to the analyses described above with respect to administrative costs charged to Account No. 903, the Company's time studies attributable to NIPSCO's ARP services also form the basis for the assignment of the labor-related and other administrative costs recorded in Account No. 910 to the various rate classes. Account No. 912 was allocated to the rate classes based on customer counts.

K. Allocation of Administrative and General Expenses (920 – 935)

Q71. How did the ACOSS allocate Administrative and General ("A&G") expenses (Accounts 920-935)?

A71. Account Nos. 920 – A&G Salaries, 921 – Office Supplies, Account No. 925 – Injuries and Damages, and 926 – Employee Pensions & 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.

Q72. Please describe the extent to which administrative costs of providing various transportation-related services are reflected in the ACOSS.

A72. As described earlier, a portion of the administrative expenses, including those charged to the A&G accounts, were directly assigned to the ARP services via pro forma adjustments to the Company's revenue requirement based on the results of NIPSCO's ARP services cost study, involving the activities of various Company administrative groups. A detailed review was conducted of the various administrative activities that historically were required to support transportation service apart from those specific ARP services. These administrative functions included activities such as contract administration; gas volume control including volume scheduling, gas balancing, and nominations management; gas measurement support which includes reading and processing usage data special to transportation related billing. With the advent of more automated systems to perform these transportation related functions, additional administrative support is not required to be provided by NIPSCO personnel. Therefore, no incremental administrative costs specific to transportation service under the Company's distribution service tariffs were included in the ACOSS.

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

Q73. How did the ACOSS allocate taxes other than income taxes?

A73. 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.

Q74. How were income taxes allocated to each customer class?

A74. Current income taxes were allocated to each rate class based on each individual class' net operating income. 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.

M. <u>Allocation of Gas Supply Related Capacity Costs for GCA Purposes</u>

Q75. Please describe the extent to which gas supply-related costs, subject to recovery through the Company's GCA mechanism, are reflected in the ACOSS.

A75. 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 Classes 111, 115
Class 2 – General Service Sales	Rate Classes 121, 125

NIPSCO's current demand allocators were approved in Cause No. 43941 (merger between NIPSCO, NIFL and Kokomo). The results of the pipeline and storage resource analysis for the period ending December 31, 2022, is summarized in Attachment 17-E. The demand allocators by class appear on Page 1, Lines 2 and 3.

VI. Results of NIPSCO's ACOSS

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

Q76. Please describe the results of your ACOSS with respect to rate of return under the Company's existing "100 Series" rate classes.

A76. Attachment 17-F, Page 1, presents the summary results of the ACOSS at present rates under the Company's current 100 Series rate classes. As shown on Line 21 of this exhibit, at present rates the ACOSS shows the variation in the rates of return by rate schedule. The Residential (Rate 111) service class rate of return at 2.37 percent and the Multi-Family (Rate 115) service class rate of return at 3.02 percent are below the NIPSCO's current overall rate of return of 3.35 percent, as is the Large Transport & Transport Balancing (Rate 128 Distribution Pressure, "DP") service class rate of return at -4.28 percent. General Service Small (Rate 121), General Service Large (Rate 125), General Transport & Transport Balancing (Rate 138), C&I Off-Peak Interruptible (Rate 134), and Large Transport & Transport Balancing (Rate 128 High Pressure, "HP") service class are all above the system average rate of return.

B. <u>Description of Unit Cost Analysis</u>

Q77. Please describe the results of your ACOSS with respect to classified costs.

A77. 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, are the customer and demand related costs. <u>Attachment 17-F</u>, Page 4, provides a summary of the functionalized and classified costs by rate class at equalized rates of return and Page 5 shows the costs on a unit rate basis. As discussed in more detail later in my testimony, these results were used as a guide in developing the monthly customer and demand charges proposed for the various rate schedules.

C. Alternative Cost of Service Analysis

Q78. Have you included cost of service results under an alternative costing methodology in the ACOSS?

A78. Yes. Cost of service results have been included in Attachment 17-G 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.

Q79. What is the purpose for including this alternative costing methodology in the ACOSS?

A79. The Design Day Peak allocation method was employed for allocation of Transmission plant in the Company's ACOSS filed in its 2010 general 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 2017 general rate case filing in Cause No. 44988. Certain parties to Cause No. 44988, specifically the Industrial Group ("IG") and Steel Dynamics, Inc. ("SDI"), 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 class-by-class revenue (deficiency)/surplus results under the two costing methods has been included on Attachment 17-G, Page 2, Lines 46 and 47.

VII. Revenue Allocation and Rate Design Principles

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

Q80. How can the ACOSS results provide guidelines for rate design?

A80. ACOSS results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the rate of return results show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q81. Do the ACOSS results provide guidance in establishing rates within each rate class as well?

A81. Yes. The classified costs, as allocated to each class of service within the ACOSS, provide useful cost information in determining the level of customer, demand, and commodity charges.

Q82. Please explain how the classified costs can be used for rate design.

A82. As mentioned earlier, Attachment 17-F, Page 5, provides a summary of the Company's functionalized revenue requirement per unit of peak demand, annual throughput (commodity) and customer count for each rate class. If the classified costs presented in this schedule were used to set three-part rates (Customer, Demand and Commodity), the Company's fixed operating expenses and return on investment in its pro forma revenue requirement would be fully recovered.

B. Other Policy Considerations or Criteria that should be Used in the Design of Utility Rates.

Q83. Should other factors be considered that would prevent the Company from simply translating the unit costs into rates for the various tariff services?

A83. 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.

Q84. Please describe other considerations or criteria that should be used in the design of utility rates.

A84. 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.

Q85. How then are the foregoing guidelines and criteria incorporated into the rate design process?

A85. 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.

VIII. NIPSCO's Proposed Revenue Allocation by Class

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

Q86. What total gas revenue requirement is the Company utilizing in its proposal?

A86. The Company has used a total distribution revenue requirement of $580,855,092 as shown on Attachment 17-E, Page 2, Line 49, exclusive of gas costs. Net of miscellaneous other revenue of $6,053,907, the total non-gas Rate Schedule Revenue Requirement (Margin) is $574,801,185 as shown on Page 2, Line 47 of the exhibit.

Q87. Have the results of the ACOSS been used in establishing the class-by-class revenue responsibility levels at the Company's proposed revenue requirement?

A87. Yes. Attachment 17-F, Page 2, shows the class-by-class total margin responsibility levels at equalized rates of return, on Line 41, and at the Company's proposed revenue requirement apportionment on Line 49.

Q88. Please describe the approach followed to apportion the current revenue responsibility to the Company's various rate schedules.

A88. 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 Erin Whitehead discusses the specific parameters that the Company used in its application of moderation to the allocation of revenues to the respective rate schedules.

B. Resulting Revenues at Proposed Rates by Customer Class.

Q89. How does NIPSCO propose to distribute the revenue increase among the rate schedules?

A89. Attachment 17-F, Page 2, Line 53 shows the proposed distribution of the proposed margin revenue increase of $115,323,504 among the rate schedules. 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 6.87 percent at proposed rates, with no class receiving a revenue decrease. The applicable classes below the proposed system return are Residential Service (Rate 111), Multi-Family (Rate 115), Large Transport & Transport Balancing Service (Rate 128 DP and HP). For the classes exhibiting a current return above 6.87 percent: General Service Small (Rate 121), General Service Large (Rate 125), C&I Off-Peak Interruptible (Rate 134), and General Transport & Transport Balancing Service (Rate 438), their relative subsidization relationship to parity was reduced. The proposed revenue increases attributed to the General Service Small (Rate 121), General Service Large (Rate 125), and General Transport & Transport Balancing Service (Rate 138) classes modestly reduced their relative relationships to parity. The proposed increases to Residential Service (Rate 111), Multi-Family (Rate 115), and Large Transport & Transport Balancing Service class (Rate 128 HP) brought these classes to parity with the system average rate of return of 6.87 percent. The proposed increases to the Large Transport & Transport Balancing Service class (Rate 128 DP) results in a return of -1.55 percent or 45 percent of parity with the system rate of return. The increase to Rate 128 DP was limited to a 50 percent increase, which fell within the mitigation parameter of 150 percent of the system average increase. This principle was established by NIPSCO and discussed in Witness Whitehead's testimony. In so doing, the Company recognized the tension caused when removing subsidies between classes and the rate increases that result.

Q90. Is the Company's proposed revenue allocation by class useful for the recovery and deferral of approved capital expenditures under TDSIC?

A90. Yes. The proposed margin revenues by rate schedule as shown in <u>Attachment 17-F</u>, Page 2, Line 49, 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."[4] The Company proposes to use the same allocation for purposes of future FMCA proceedings.

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

Q91. How were the proposed rates for each Rate Schedule calculated?

A91. Detailed calculations for each rate component of each Rate Schedule are included in Attachment 17-H. As the exhibit shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 17-H provides a presentation of the transition of revenues at current rates and existing 100 series rate classes to the proposed revenues at the 200 series rate classes.

Q92. Do the proposed rates include increases to the existing monthly customer charges?

A92. Yes. The following table of proposed rates, and the accompanying Attachment 17-H, pages 2-4, includes an increase to the Residential monthly customer charge from its current level of $14.00 to the proposed level of $24.50. In addition, the Residential Multi-Family Service (Rate 215) customer charge will

[4] IC 8-1-39-9, Sec. 9 (a) (1).

be increased from $17.50 to $28.50. The General Service schedules (Rates 221 and 225) received increases in their monthly customer charges from current levels of approximately 50 to 60 percent (respectively), in order to achieve full customer cost recovery. In the instance of Rate 221, the proposed customer charge increase will contribute an additional amount toward demand-related fixed cost recovery, as reflected in the ACOSS Unit Cost Analysis, Attachment 17-F, Page 5. For the two Transport & Transport Balancing Services (Rates 228 and 238), the customer charge increases by 60 percent for Rate 238 and 200 percent for Rate 228.

Q93. Do the proposed rates include increases to the existing demand charges?

A93. Yes. The Company has increased a Demand Charges for the two Transport & Transport Balancing Services (Rates 228 and 238). As indicated earlier, the use of three-part rates by gas utilities is more prevalent in today's competitive gas marketplace. 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 Company proposes to establish the Demand Charges for these C&I rate schedules to recover approximately 10 percent of fixed demand related costs of providing distribution service to Rate 228 and 25 percent of fixed demand related costs of distribution service to Rate 238. 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 2019 through February 2020, under current tariff provisions.

Table 1: Schedule of Proposed Rates

<table>
<tr><th>Rate Schedule</th><th>Rate Code</th><th>Monthly Charge</th><th>Demand Charge per Therm</th><th>Distribution Charge per Therm</th></tr>
<tr><td>Residential</td><td>211</td><td>$24.50</td><td>----</td><td>$0.22821</td></tr>
<tr><td>Multi-Family</td><td>215</td><td>$28.50</td><td>----</td><td>$0.18910</td></tr>
<tr><td>General Service – Small</td><td>221</td><td>$80.00</td><td>----</td><td>$0.14289</td></tr>
<tr><td>General Service – Large</td><td>225</td><td>$640.00</td><td>----</td><td>Block 1 $0.11093
Block 2 $0.10093
Block 3 $0.08093</td></tr>
<tr><td rowspan="2">Large Transportation
Balancing Charges:
Option 1 - $1,590.00
Option 2 - $660.00</td><td>228 DP</td><td>$3,000.00</td><td>$0.16680</td><td>Bock 1 $0.04491
Block 2 $0.01150</td></tr>
<tr><td>228 HP</td><td>$3,000.00</td><td>$0.06150</td><td>Bock 1 $0.04546
Block 2 $0.01150</td></tr>
<tr><td>C&I Off-Peak Interruptible</td><td>234</td><td>$637.00</td><td>----</td><td>$0.17000[5]</td></tr>
<tr><td>General Transportation
Balancing Charge $250.00</td><td>238</td><td>$1,200.00</td><td>$0.29414</td><td>$0.06905</td></tr>
</table>

Q94. 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?

[5] This charge is comprised of a Delivery Charge and a Gas Supply Charge and may vary based upon the customer's alternate fuel. The charge is individually negotiated within the terms of the customer's Service Agreement.

A94. Yes. The Company has proposed monthly customer charges at levels that in most cases either approximate or reflect significant movement toward their full customer related cost responsibility. The $24.50 Residential monthly customer charge will bring this fixed charge to approximately 83 percent of the unit customer related cost, per customer, per month for the class. However, this $24.50 fixed charge level is only 60 percent of the full Straight Fixed-Variable ("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 $28.50 customer charge for the Residential Multi-Family rate schedule is approaching 91 percent of the fixed customer related cost level of $31.44 for this class, which is also 60 percent of full SFV pricing of $51.98. 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.

The Company utilized the Unit Cost Analysis from the ACOSS (Attachment 17-F, Page 4) 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 $29.42 per customer per month and the combined customer and demand related costs to be $41.05 per customer per month, the full SFV level mentioned above. The corresponding levels of customer costs for the C&I classes of customers are also shown in this Unit Cost Analysis, referenced above.

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

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

In terms of understandability, customers should easily understand a full customer cost based charge. A full customer cost based charge is easily explained since the rate is based on customer costs. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is cold, and conversely should not pay less when the weather is warm.

Q95. Has the IURC offered guidance on moving customer charges closer to a point where they recover 100% of fixed costs of service?

A95. Yes. NIPSCO's proposed rates will not take the rate design to a complete SFV model, but the proposed rates do take a step closer to SFV than current rates. 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"[6]

In other words, while decoupling would be a mechanism available to natural gas utilities to address concerns about issues such as declining residential usage per customer and weather variations, moving to SFV pricing would be the ultimate rate design goal. NIPSCO's proposed rates make this movement.

Q96. Does SFV rate design allow gas customers to make informed decisions regarding their consumption?

A96. Yes. SFV rates provide a gas customer with two transparent and accurate price signals. The first price signal is the fixed charge, which communicates to the customer the levelized monthly cost to have access to a utility's gas distribution system. The second price signal is the volumetric rate, which communicates to the customer the incremental cost to the Company of supplying a single unit of the gas commodity. These expenses are incurred based on how much gas commodity service is used. When prices accurately reflect the economic cost of each component of a good or a service, the customer is better equipped to choose how much of that good or service they want to consume.

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

Fixed gas distribution costs are incurred whether or not a customer uses the underlying assets. Rates that collect a portion of a gas utility's fixed charges through a volumetric rate provide customers with two inefficient and inaccurate price signals. First, under these rate designs customers pay a fixed charge that is *less than* the fixed cost of the service. This is inefficient because it causes the customer to underestimate the economic cost to a utility to construct and maintain a gas delivery system to the customer's home. Second, non-SFV rates charge volumetric rates that are *greater than* the variable cost to deliver each unit of gas. This is also inefficient because it causes the customer to overestimate the economic cost of each unit of gas commodity. Inefficient price signals cause customers to make uneconomic and inefficient consumption decisions that are not in alignment with cost causation.

Q97. Are there other benefits for customers using SFV rate design?

A97. Yes. SFV rate design can result in the most stable monthly bills because fixed costs are recovered in equal monthly amounts and improve bill stability for customers by reducing or eliminating the recovery of fixed costs on a volumetric basis, which can lead to substantially higher bills in the winter versus the summer.

A. Discussion of Bill Impacts for the Residential Class

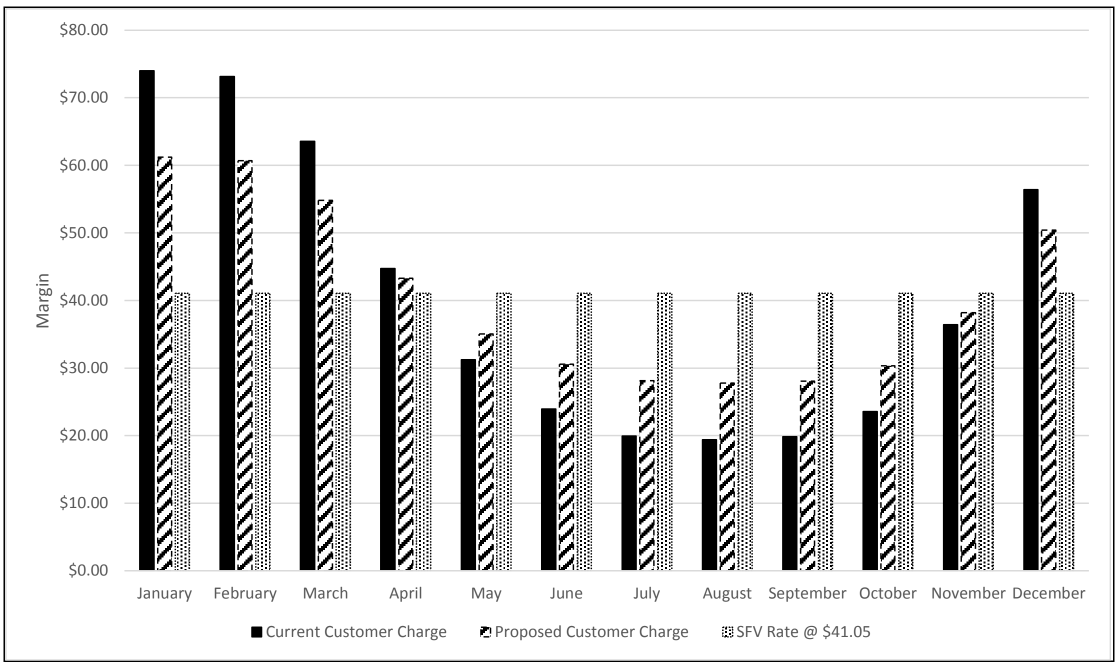
Q98. Please explain how the Company's proposed increase to the customer charge will impact the average Residential customer's gas bills.

A98. A higher customer charge provides increased bill stability for customers as well as increased revenue stability for the Company. The monthly bill impact for a typical gas customer is depicted on Attachment 17-I. This exhibit presents a monthly and annual bill for an average residential customer using 853 Therms per year, at the proposed revenue level for the class, comparing the proposed $24.50 customer charge with retaining the current $14.00 charge. Figure 2 below depicts a typical gas customer's monthly bills, for both gas costs and margin, under three different levels of customer charge:[7] (i) the $14.00 current monthly customer charge, (ii) the Company's $24.50 proposal, and (iii) the full $41.05 SFV (straight fixed variable) rate. Not surprisingly, the most stable monthly bills are produced by the full SFV rate, and the least stable are produced by the current customer charge. This result is intuitively obvious, since under the SFV rate, customers pay the full margin through a fixed customer charge each month, regardless of gas usage. By contrast, under the

[7] Each of the customer charges has a corresponding per therm delivery charge that is set to recover, in combination with the customer charge, the same total margin revenue under test-year billing determinants (i.e., a higher customer charge is accompanied by a lower per therm delivery charge.)

current monthly charge scenario, customers pay substantially more of the margin in the winter and less in the summer. As a result, the average bill in January is $12.80 higher under the current monthly customer charge than under the Company's proposed $24.50 charge.

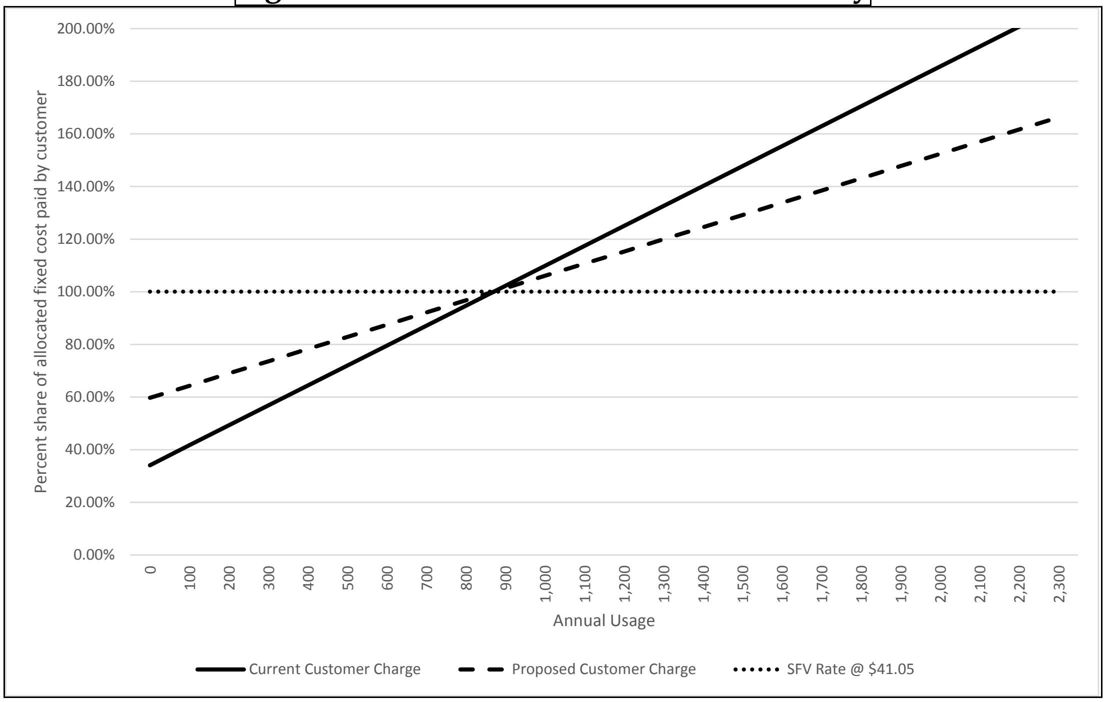
Figure 2: Customer Bill Stability – Monthly Variation



Q99. Please discuss the fairness of the Company's proposed customer charge versus the current customer charge.

A99. 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 him or her. Accordingly, each customer would not, under the SFV rate design, "overpay" or "underpay" his or her 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 35 percent of their allocated fixed costs, while very high use customers can pay over 200 percent. This is because a customer charge of $14.00 is substantially less than the $41.05 cost of service allocation of non-volumetric costs. Figure 3 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 $24.50 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 3: Fixed Cost Allocation & Recovery



B. <u>Rate Structure Changes to the C&I Tariff Schedules</u>

Q100. Has the Company made structural changes to any of the rate schedules?

A100. Yes. The Company proposes to eliminate the multiple declining blocks of the volumetric Transportation Charge in Rate 238 in favor of a single flat block rate. The existing rate differentials between the four rate blocks had been reduced over time to only one tenth of a cent per block in anticipation of transitioning to a flat block structure. Over 80 percent of the total therms of usage under Rate 238 during the 2020 test year occurred in the middle two blocks and only 6 percent of the total therms in the tail block, which applied to usage in excess of 90,000 therms per month. With the increases to the fixed cost recovery through the customer and demand charges of Rate 238, there remains no discernable rate design rationale nor cost basis for a declining block rate structure for this rate schedule.

Q101. Aside from Rate 238, were there other proposed changes to C&I tariff schedules?

A101. Yes. The tail block of Rate 225, which applies to usage in excess of 90,000 therms per month has been eliminated. Only 1.3 percent of 2020 test year usage under Rate 225 occurred in the tail block and 1 percent of the corresponding volumetric revenues were provided by the tail block rate. This proposed change is consistent with the Company's intent to recover a larger portion of fixed costs through fixed charges and thereby transition away from non-cost based price signals where possible.

C. Presentation of Bill Impacts by C&I Classes

Q102. Have you calculated bill impacts for the Commercial and Industrial rate classes that result from the Company's rate design proposal?

A102. Yes. Attachment 17-J provides bill comparisons at various ranges of consumption levels for all C&I rate schedules.

D. <u>Summary of Fixed Charge Recovery of Fixed Costs</u>

Q103. At the proposed levels, will the customer and demand based charges result in a more substantial recovery of the overall fixed costs for the Residential and C&I customer classes?

A103. Yes. Approximately $312.6 million of fixed, customer and demand related costs representing approximately 54 percent of the total fixed costs of the Company will be recovered through non-volumetric rates for the various classes of gas distribution service.

Q104. Does this conclude your prepared direct testimony?

A104. Yes.

VERIFICATION

I, Ronald J. Amen, Managing Partner, Atrium Economics, LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Ronald J. Amen

Ronald J. Amen

Dated: September 27, 2021

ATRIUM ECONOMICS
CENTERED ON ENERGY

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska, Bachelor of Science with Distinction, Business Administration, Finance and Economics,

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canadian National Energy Board, Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)
Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018)
Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC.

McDowell Rackner & Gibson Law Firm (2015 – 2016)
Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)
Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Fortis BC Energy, Inc. (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)
Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)
Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)
Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021)
Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission and North Dakota Public Service Commission. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. Pending settlement in North Dakota includes SFV rate design.

Chesapeake Utilities Corporation (2020 – 2021)
Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided

a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)
Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)
Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)
Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)
Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)
Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently working with Tacoma Power for the potential incorporation of financial forecasting capabilities and revenue requirements development into the COSA model. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
    - Application Fees
    - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discuss accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in four general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)
Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)
In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)
Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)
Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and

documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes,"

Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

1 Atrium Economics COSS Model Software

1.1 COSS MODEL CAPABILITIES

The Atrium Economics' Cost of Service Study (COSS) model provides a large range of analytical capabilities including:

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

1.1.1 Follows Traditional 3-Step Allocation

The Atrium COSS 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 COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification and in total for each service class based upon a system average or individually set rate of return; and calculates unit costs by function for customer, commodity and demand categories. Accounting costs are reported by FERC account (at a summary 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.

1.1.2 Unit Cost Output Functionality

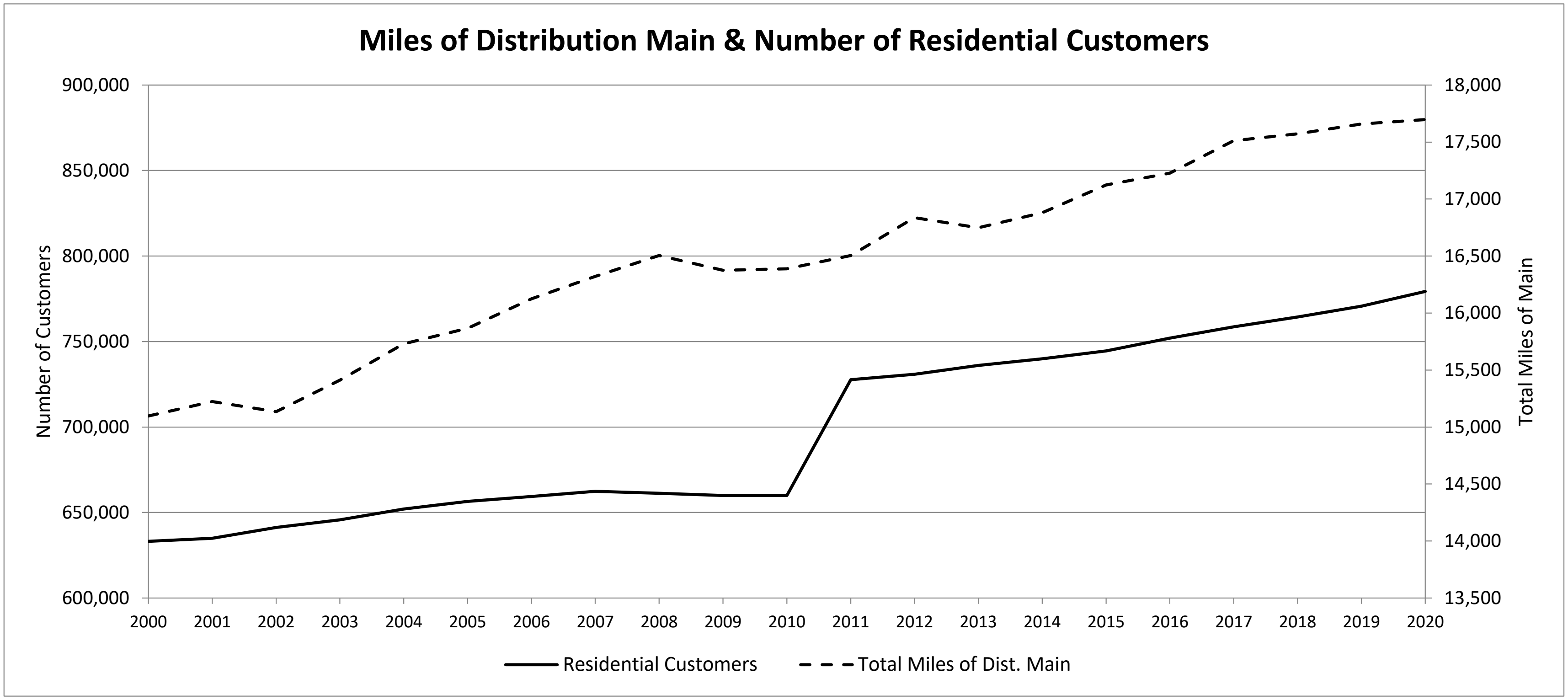
The Model calculates the unit cost of each of the functional classifications separately for each rate class based on primary and secondary billing determinants that are user-specified. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined 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 and for measuring the profitability of individual customers. Differences in unit costs between rate classes can then be analyzed and applied specifically to meet the individual situations of customers seeking special contracts from the utility or for pricing new and different services in separate rate classes.

1.2 ACCEPTANCE BY UTILITY REGULATORY COMMISSIONS

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

Northern Indiana Public Service Company
Load Characteristics of 100 Series Customers
2020 Customers, Normalized Throughput, Design Day

Line	Rate Schedule	Rate Code	Number of Customers	Annual Usage (therms)	Design Day (therms)	Load Factor
1	Residential	111	775,765	656,118,909	9,285,407	19.4%
2	Multiple Family	115	4,830	7,138,184	103,615	18.9%
3	General Small	121	67,284	294,488,709	3,952,915	20.4%
4	General Large	125	658	649,993	649,993	0.3%
5	Large Transport-DP	128 DP	105	187,206,621	2,555,994	20.1%
6	Large Transport-HP	128 HP	64	2,252,999,374	5,351,149	115.4%
7	Interruptible	134	2	1,055,641	-	
8	General Transport	138	89	48,065,999	235,338	56.0%
9	Total		848,797	3,447,723,429	22,134,411	


Miles of Distribution Main & Number of Residential Customers
900,000
850,000
800,000
750,000
700,000
650,000
600,000
Number of Customers
18,000
17,500
17,000
16,500
16,000
15,500
15,000
14,500
14,000
13,500
Total Miles of Main
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Residential Customers
Total Miles of Dist. Main

Miles of Main and Number of Residential Customers

	Total Customers [1]	Δ	Residential Customers [2]	Δ	Total Miles of Dist. Main [3]	Δ	Total Miles of Trans. Main [4]	Δ	Total Miles of Main	Δ
2020	847,866	1.1%	779,300	1.1%	17,697	0.2%	690	0.3%	18,387	0.2%
2019	838,853	0.7%	770,702	0.8%	17,659	0.5%	688	-1.0%	18,347	0.4%
2018	833,258	0.7%	764,426	0.8%	17,572	0.4%	695	4.4%	18,268	0.5%
2017	827,387	0.9%	758,554	0.9%	17,511	1.6%	666	0.0%	18,177	1.6%
2016	819,904	1.0%	752,011	1.0%	17,228	0.6%	666	0.0%	17,894	0.6%
2015	811,816	0.6%	744,548	0.6%	17,124	1.5%	665	-17.7%	17,790	0.6%
2014	807,211	0.5%	739,946	0.5%	16,879	0.8%	809	0.0%	17,688	0.7%
2013	803,137	0.6%	736,032	0.7%	16,749	-0.5%	809	0.0%	17,557	-0.5%
2012	797,972	0.4%	730,899	0.4%	16,837	2.0%	809	-0.1%	17,646	1.9%
2011	794,981	10.3%	727,663	10.3%	16,504	0.7%	809	0.0%	17,313	0.7%
2010	720,804	0.3%	659,973	0.0%	16,389	0.1%	809	-0.2%	17,198	0.1%
2009	718,305	-0.2%	659,953	-0.2%	16,376	-0.8%	811	24.5%	17,187	0.2%
2008	719,821	-0.1%	661,300	-0.2%	16,504	1.1%	651	0.0%	17,155	1.1%
2007	720,785	0.5%	662,441	0.5%	16,322	1.2%	651	0.6%	16,973	1.2%
2006	717,265	0.5%	659,419	0.4%	16,126	1.6%	647	0.0%	16,773	1.6%
2005	714,046	0.7%	656,557	0.7%	15,867	0.9%	647	-0.2%	16,514	0.8%
2004	709,323	1.0%	652,066	1.0%	15,731	2.1%	648	-19.5%	16,379	1.0%
2003	702,413	0.7%	645,771	0.7%	15,411	1.8%	805	-2.3%	16,216	1.6%
2002	697,769	1.2%	641,307	1.0%	15,134	-0.6%	824	36.7%	15,958	0.8%
2001	689,711	0.1%	634,931	0.3%	15,223	0.8%	603	1.5%	15,826	0.9%
2000	688,889		633,161		15,097		594		15,691	

Notes:
[1] Source: Company Information
[2] Total Residential Customers. 2011 increase represents merger of Kokomo Gas Company, Northern Indiana Fuel and Light, and NIPSCO.
[3] Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. 2011 miles adjusted for apparent reporting error.
[4] Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration.

Northern Indiana Publice Service Company
Allocation of Pipeline and Storage Demand Costs for GCA
For The Period Ending December 31, 2022

	(A)	(B)	(C)	(D)	(E)
Line No.	Description	Alloc. Basis	Total	Residential	General Service
1	Allocation Factors				
2	Design Day Demand	Peak	100.00%	67.10%	32.90%
3	Seasonal (Excess over Average)	Storage	100.00%	67.85%	32.15%
4	Average Throughput (Apr. - Oct.)	Off-Peak	100.00%	63.47%	36.53%
5	Pipeline Demand Costs				
6	Peak (Nov - Mar)		$ 27,189,773	18,244,338	8,945,435
7	Off-Peak (Apr - Oct)				
8	Storage Related	49.02%	$ 13,199,759	$ 8,956,037	$ 4,243,723
9	Summer Load Related	50.98%	$ 13,728,919	$ 8,713,745	$ 5,014,734
10	Total Off-Peak		$ 26,928,678	$ 17,669,781	$ 9,258,457
11	Total Pipeline Demand Costs [1]		$ 54,118,451	$ 35,914,119	$ 18,203,892
12	Storage Demand Costs [1]		$ 23,518,025	$ 15,956,980	$ 7,561,045
13	Total Demand Costs		$ 77,636,476	$ 51,871,099	$ 25,764,937
14	Pipeline Costs Only - Based on Line 11		100.00%	66.3621%	33.6371%
15	Storage Costs Only - Based on Line 13		100.00%	67.8500%	32.1500%

Note [1]:Demand costs reflect pipeline and storage rates effective September 2021 through August 2022.

Northern Indiana Public Service Company
Allocation Factors for GCA Demand Costs
Based on Annual Usage for the Year Ending December 31, 2022

Line No.	Description	Rate 111	Rate 115	Rate 121	Rate 125	Total	Residential %	General Service %
1	Design Day Demand	9,285,407	103,615	3,952,915	649,993	13,991,930	67.10%	32.90%
2	Seasonal (Excess over Average)	81,079,131	891,088	33,542,651	5,292,671	120,805,541	67.85%	32.15%
3	Average Throughput (Apr. - Oct.)	21,368,450	231,219	8,657,848	3,772,069	34,029,587	63.47%	36.53%
4		Actual Sales Volumes in Therms [(1)]						
5	January	119,838,171	1,291,261	44,435,402	9,565,321	175,130,155		
6	February	102,716,228	1,084,331	37,354,817	8,141,562	149,296,938		
7	March	79,864,061	864,509	27,223,189	6,697,746	114,649,506		
8	April	44,777,703	488,507	15,477,676	4,432,498	65,176,384		
9	May	23,908,907	258,094	8,864,681	3,471,367	36,503,049		
10	June	11,403,366	125,589	3,712,079	2,717,859	17,958,892		
11	July	11,441,630	119,205	4,063,564	3,160,872	18,785,270		
12	August	10,553,245	106,193	4,157,135	3,192,742	18,009,315		
13	September	13,404,249	132,342	6,609,827	3,723,445	23,869,863		
14	October	34,090,054	388,604	17,719,976	5,705,700	57,904,334		
15	November	65,184,564	696,209	28,406,355	6,402,794	100,689,922		
16	December	100,671,109	1,096,007	39,790,526	8,136,278	149,693,920		
17	Grand Total	617,853,286	6,650,850	237,815,228	65,348,183	927,667,547		
18	Average April - October	21,368,450	231,219	8,657,848	3,772,069			
19	Average November - March	93,654,827	1,006,463	35,442,058	7,788,740			
20	Excess over Average	72,286,376	775,244	26,784,209	4,016,671	103,862,501		

(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
12 Months Ending December 31, 2022

Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	Account Balance	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
1	**Rate Base**									
2	Plant in Service	$ 4,004,668,453	$ 2,572,021,517	$ 20,788,427	$ 728,183,713	$ 90,178,102	$ 237,008,971	$ 325,145,005	$ 41,313	$ 31,301,405
3	Accumulated Reserve	(1,705,969,359)	(1,184,936,665)	(9,087,662)	(315,250,049)	(34,612,586)	(70,837,853)	(80,147,624)	(26,047)	(11,070,872)
4	Other Rate Base Items	117,758,507	75,433,389	761,350	29,258,153	5,034,023	2,669,390	4,274,511	125	327,565
5	**Total Rate Base**	**$ 2,416,457,600**	**$ 1,462,518,240**	**$ 12,462,115**	**$ 442,191,817**	**$ 60,599,539**	**$ 168,840,508**	**$ 249,271,892**	**$ 15,390**	**$ 20,558,097**
6	**Margin at Current Rates**									
7	Delivery Sales Margin	$ 420,431,618	$ 269,858,395	$ 2,139,828	$ 90,958,439	$ 11,283,437	$ 8,958,749	$ 32,224,394	$ 194,747	$ 4,813,629
8	TDSIC Margin	21,203,255	13,484,447	160,038	4,936,053	1,149,714	93,115	1,217,201	-	162,686
9	FMCA Margin	17,842,809	11,983,283	104,301	3,166,741	426,371	139,692	1,844,715	-	177,706
10	Miscellaneous Service Margin	6,053,907	4,602,003	43,779	1,084,102	123,337	81,160	100,728	328	18,469
11	**Total Margin at Current Rates**	**$ 465,531,588**	**$ 299,928,128**	**$ 2,447,946**	**$ 100,145,335**	**$ 12,982,860**	**$ 9,272,717**	**$ 35,387,037**	**$ 195,075**	**$ 5,172,490**
12	Gas Costs	348,721,758	230,259,799	2,473,589	95,301,332	18,917,152	112,993	1,485,782	-	171,111
13	**Total Sales Revenue**	**$ 814,253,346**	**$ 530,187,927**	**$ 4,921,535**	**$ 195,446,668**	**$ 31,900,012**	**$ 9,385,710**	**$ 36,872,819**	**$ 195,075**	**$ 5,343,601**
14	**Expenses at Current Rates**									
15	O&M and A&G Expenses	$ 223,421,804	$ 156,371,385	$ 1,212,530	$ 37,315,124	$ 4,613,444	$ 10,019,878	$ 11,432,462	$ 41,239	$ 2,415,743
16	Depreciation and Amortization Expense	122,068,414	84,274,339	648,672	20,791,555	2,186,752	5,445,375	7,970,361	742	750,619
17	Taxes Other Than Income	34,955,761	22,949,079	191,607	6,964,204	965,702	1,399,844	2,203,182	4,000	278,145
18	Income Taxes	4,023,043	1,717,923	18,683	1,658,401	246,670	(358,985)	651,599	7,049	81,703
19	**Total Expenses at Current Rates**	**$ 384,469,022**	**$ 265,312,725**	**$ 2,071,492**	**$ 66,729,283**	**$ 8,012,567**	**$ 16,506,112**	**$ 22,257,603**	**$ 53,031**	**$ 3,526,209**
20	**Operating Income at Current Rates**	**$ 81,062,566**	**$ 34,615,403**	**$ 376,453**	**$ 33,416,053**	**$ 4,970,293**	**$ (7,233,395)**	**$ 13,129,434**	**$ 142,044**	**$ 1,646,281**
21	**Current Rate of Return**	**3.35%**	**2.37%**	**3.02%**	**7.56%**	**8.20%**	**-4.28%**	**5.27%**	**922.94%**	**8.01%**
22	**Current Revenue at Equal Rates of Return**									
23	Current Rate of Return	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%
24	Current Operating Income at Equal ROR	$ 81,062,566	$ 49,061,685	$ 418,055	$ 14,833,781	$ 2,032,874	$ 5,663,929	$ 8,362,083	$ 516	$ 689,643
25	Income Taxes - Equal ROR	4,023,043	2,434,876	20,748	736,184	100,889	281,094	415,001	26	34,226
26	Other Expenses - Equal ROR	380,445,979	263,594,802	2,052,809	65,070,882	7,765,897	16,865,097	21,606,004	45,981	3,444,506
27	**Total Margin @ Equal Rates of Return**	**$ 465,531,588**	**$ 315,091,363**	**$ 2,491,611**	**$ 80,640,847**	**$ 9,899,660**	**$ 22,810,121**	**$ 30,383,088**	**$ 46,523**	**$ 4,168,375**
28	**Current Class (Subsidies)/Excesses**	**$ -**	**$ (15,163,235)**	**$ (43,666)**	**$ 19,504,489**	**$ 3,083,200**	**$ (13,537,404)**	**$ 5,003,950**	**$ 148,552**	**$ 1,004,115**

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	Account Balance	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
29	**Revenue Requirement at Equal Rates of Return**									
30	Required Return	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
31	Required Return	$ 166,010,637	$ 100,475,003	$ 856,147	$ 30,378,578	$ 4,163,188	$ 11,599,343	$ 17,124,979	$ 1,057	$ 1,412,341
31	**Operating Income (Deficiency)/Surplus**	**$ (84,948,071)**	**$ (65,859,601)**	**$ (479,694)**	**$ 3,037,475**	**$ 807,105**	**$ (18,832,738)**	**$ (3,995,545)**	**$ 140,987**	**$ 233,940**
32	**Expenses at Required Return**									
33	O&M and A&G Expenses	223,421,804	156,371,385	1,212,530	37,315,124	4,613,444	10,019,878	11,432,462	41,239	2,415,743
34	Increase in Uncollectibles	336,250	307,502	4,715	23,117	687	-	-	-	229
35	Depreciation and Amortization Expense	122,068,414	84,274,339	648,672	20,791,555	2,186,752	5,445,375	7,970,361	742	750,619
36	Taxes Other Than Income	34,955,761	22,949,079	191,607	6,964,204	965,702	1,399,844	2,203,182	4,000	278,145
37	Increase TOTI	1,830,885	1,108,058	9,442	335,057	45,943	127,929	188,868	12	15,577
38	Income Taxes	4,023,043	2,434,759	20,746	736,228	100,953	281,100	415,004	26	34,227
39	Gross Up - Income Taxes	28,208,298	17,071,757	145,466	5,162,200	707,847	1,970,987	2,909,875	180	239,987
40	**Total Expenses at Required Return**	**$ 414,844,455**	**$ 284,516,879**	**$ 2,233,178**	**$ 71,327,484**	**$ 8,621,327**	**$ 19,245,113**	**$ 25,119,751**	**$ 46,198**	**$ 3,734,525**
41	**Total Revenue Requirement at Equal Rates of Return**	**$ 580,855,092**	**$ 384,991,882**	**$ 3,089,325**	**$ 101,706,061**	**$ 12,784,516**	**$ 30,844,456**	**$ 42,244,730**	**$ 47,256**	**$ 5,146,866**
42	LESS									
43	Current Miscellaneous Revenue Margin	6,053,907	4,602,003	43,779	1,084,102	123,337	81,160	100,728	328	18,469
44	Additional Miscellaneous Revenue Margin	-	-	-	-	-	-	-	-	-
45	**Total Rate Margin at Equal Rates of Return**	**$ 574,801,185**	**$ 380,389,879**	**$ 3,045,546**	**$ 100,621,959**	**$ 12,661,179**	**$ 30,763,296**	**$ 42,144,002**	**$ 46,928**	**$ 5,128,397**
46	**Base Rate Margin (Deficiency)/Surplus**	**$ (115,323,504)**	**$ (85,063,754)**	**$ (641,380)**	**$ (1,560,726)**	**$ 198,344**	**$ (21,571,739)**	**$ (6,857,693)**	**$ 147,819**	**$ 25,623**
47	**Rate Schedule Margin as Proposed**	**$ 574,801,185**	**$ 380,389,879**	**$ 3,045,546**	**$ 114,431,216**	**$ 14,854,760**	**$ 13,787,335**	**$ 42,144,002**	**$ 194,747**	**$ 5,953,700**
48	Miscellaneous Revenue	6,053,907	4,602,003	43,779	1,084,102	123,337	81,160	100,728	328	18,469
49	**Total Margin as Proposed**	**$ 580,855,092**	**$ 384,991,882**	**$ 3,089,325**	**$ 115,515,318**	**$ 14,978,097**	**$ 13,868,495**	**$ 42,244,730**	**$ 195,075**	**$ 5,972,169**
50	Current Revenue to Cost Ratio	0.81	0.79	0.80	1.00	1.03	0.30	0.84	4.16	1.01
51	Current Parity Ratio	1.00	0.97	0.99	1.23	1.27	0.37	1.04	5.13	1.25
52	Proposed Revenue to Cost Ratio	1.00	1.00	1.00	1.14	1.17	0.45	1.00	4.15	1.16
53	Proposed Margin Increase	$ 115,323,504	$ 85,063,754	$ 641,380	$ 15,369,983	$ 1,995,237	$ 4,595,778	$ 6,857,693	$ (0)	$ 799,680
54	Percent Margin Change	25.10%	28.80%	26.68%	15.52%	15.52%	50.00%	19.43%	0.00%	15.52%
55	Estimated Gas Cost	$ 348,721,758	230,259,799	2,473,589	95,301,332	18,917,152	112,993	1,485,782	-	171,111
56	Total Bill Before Increase	$ 808,199,440	$ 525,585,924	$ 4,877,756	$ 194,362,565	$ 31,776,675	$ 9,304,550	$ 36,772,091	$ 194,747	$ 5,325,132
57	Percent Total Bill Increase	14.27%	16.18%	13.15%	7.91%	6.28%	49.39%	18.65%	0.00%	15.02%
58	Income Prior to Taxes	$ 198,241,978	$ 119,981,520	$ 1,022,359	$ 50,086,262	$ 7,165,569	$ (3,124,531)	$ 20,449,858	$ 149,082	$ 2,511,858
59	Income Taxes	32,231,341	19,507,298	166,221	8,143,318	1,165,020	(508,005)	3,324,858	24,239	408,393
60	**Operating Income**	**$ 166,010,637**	**$ 100,474,222**	**$ 856,138**	**$ 41,942,945**	**$ 6,000,549**	**$ (2,616,527)**	**$ 17,125,000**	**$ 124,843**	**$ 2,103,465**
61	**Proposed Return**	**6.87%**	**6.87%**	**6.87%**	**9.49%**	**9.90%**	**-1.55%**	**6.87%**	**811.18%**	**10.23%**

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

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

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Functional Rate Base									
1	**Storage**									
2	Demand	9,257,985	6,213,534	68,289	2,570,556	405,606	-	-	-	-
3	Commodity	77,835,846	51,117,498	558,947	22,050,518	4,108,882	-	-	-	-
4	Customer	-	-	-	-	-	-	-	-	-
5	Subtotal	87,093,830	57,331,032	627,236	24,621,074	4,514,488	-	-	-	-
6	**LNG**									
7	Demand	5,447,958	3,604,617	40,137	1,541,920	261,284	-	-	-	-
8	Commodity	-	-	-	-	-	-	-	-	-
9	Customer	-	-	-	-	-	-	-	-	-
10	Subtotal	5,447,958	3,604,617	40,137	1,541,920	261,284	-	-	-	-
11	**Transmission**									
12	Demand	698,387,516	277,091,930	3,088,460	118,256,908	19,720,200	76,403,535	196,191,516	-	7,634,965
13	Commodity	-	-	-	-	-	-	-	-	-
14	Customer	-	-	-	-	-	-	-	-	-
15	Subtotal	698,387,516	277,091,930	3,088,460	118,256,908	19,720,200	76,403,535	196,191,516	-	7,634,965
16	**Distribution**									
17	Demand	578,874,556	296,664,493	3,310,438	126,293,820	20,766,973	81,662,834	43,279,910	-	6,896,088
18	Commodity	-	-	-	-	-	-	-	-	-
19	Customer	399,872,546	365,240,364	2,304,554	31,948,560	289,994	49,946	2	946	38,181
20	Subtotal	978,747,102	661,904,857	5,614,992	158,242,380	21,056,967	81,712,779	43,279,912	946	6,934,269
21	**On-Site**									
22	Demand	-	-	-	-	-	-	-	-	-
23	Commodity	-	-	-	-	-	-	-	-	-
24	Customer	632,746,162	451,381,652	3,018,807	137,714,601	14,912,534	10,394,763	9,605,501	5,929	5,712,375
25	Subtotal	632,746,162	451,381,652	3,018,807	137,714,601	14,912,534	10,394,763	9,605,501	5,929	5,712,375
26	**Cust. Accounts**									
27	Demand	-	-	-	-	-	-	-	-	-
28	Commodity	-	-	-	-	-	-	-	-	-
29	Customer	14,035,032	11,204,153	72,482	1,814,934	134,067	329,430	194,963	8,515	276,488
30	Subtotal	14,035,032	11,204,153	72,482	1,814,934	134,067	329,430	194,963	8,515	276,488
31	**Total**									
32	Demand	1,291,968,014	583,574,574	6,507,324	248,663,204	41,154,063	158,066,369	239,471,427	-	14,531,053
33	Commodity	77,835,846	51,117,498	558,947	22,050,518	4,108,882	-	-	-	-
34	Customer	1,046,653,740	827,826,169	5,395,843	171,478,095	15,336,594	10,774,139	9,800,466	15,390	6,027,044
35	**TOTAL RATE BASE**	2,416,457,600	1,462,518,240	12,462,115	442,191,817	60,599,539	168,840,508	249,271,892	15,390	20,558,097

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

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

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Functional Revenue Requirement									
36	**Storage**									
37	Demand	$ 5,022,553	$ 3,370,907	$ 37,047	$ 1,394,553	$ 220,046	$ -	$ -	$ -	$ -
38	Commodity	$ 6,910,580	$ 4,538,418	$ 49,626	$ 1,957,734	$ 364,803	$ -	$ -	$ -	$ -
39	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Subtotal	$ 11,933,133	$ 7,909,324	$ 86,673	$ 3,352,287	$ 584,849	$ -	$ -	$ -	$ -
41	**LNG**									
42	Demand	$ 11,226,056	$ 7,427,669	$ 82,707	$ 3,177,278	$ 538,401	$ -	$ -	$ -	$ -
43	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Subtotal	$ 11,226,056	$ 7,427,669	$ 82,707	$ 3,177,278	$ 538,401	$ -	$ -	$ -	$ -
46	**Transmission**									
47	Demand	$ 107,919,847	$ 42,818,232	$ 477,251	$ 18,273,905	$ 3,047,307	$ 11,806,422	$ 30,316,920	$ -	$ 1,179,810
48	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	Subtotal	$ 107,919,847	$ 42,818,232	$ 477,251	$ 18,273,905	$ 3,047,307	$ 11,806,422	$ 30,316,920	$ -	$ 1,179,810
51	**Distribution**									
52	Demand	$ 106,014,498	$ 54,126,932	$ 603,995	$ 23,042,519	$ 3,788,969	$ 14,899,520	$ 8,292,429	$ -	$ 1,260,134
53	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	$ 96,868,608	$ 85,402,230	$ 572,753	$ 9,602,590	$ 523,454	$ 145,166	$ 533,244	$ 3,018	$ 86,153
55	Subtotal	$ 202,883,106	$ 139,529,163	$ 1,176,748	$ 32,645,109	$ 4,312,423	$ 15,044,686	$ 8,825,673	$ 3,018	$ 1,346,287
56	**On-Site**									
57	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	Customer	$ 189,827,155	$ 141,858,515	$ 944,117	$ 37,143,432	$ 3,654,525	$ 2,565,295	$ 2,252,170	$ 1,842	$ 1,407,259
60	Subtotal	$ 189,827,155	$ 141,858,515	$ 944,117	$ 37,143,432	$ 3,654,525	$ 2,565,295	$ 2,252,170	$ 1,842	$ 1,407,259
61	**Cust. Accounts**									
62	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	Customer	$ 57,065,796	$ 45,444,176	$ 321,774	$ 7,115,895	$ 649,623	$ 1,428,301	$ 850,100	$ 42,396	$ 1,213,532
65	Subtotal	$ 57,065,796	$ 45,444,176	$ 321,774	$ 7,115,895	$ 649,623	$ 1,428,301	$ 850,100	$ 42,396	$ 1,213,532
66	**Total**									
67	Demand	$ 230,182,953	$ 107,743,740	$ 1,201,001	$ 45,888,255	$ 7,594,722	$ 26,705,943	$ 38,609,349	$ -	$ 2,439,944
68	Commodity	$ 6,910,580	$ 4,538,418	$ 49,626	$ 1,957,734	$ 364,803	$ -	$ -	$ -	$ -
69	Customer	$ 343,761,559	$ 272,704,921	$ 1,838,643	$ 53,861,917	$ 4,827,602	$ 4,138,762	$ 3,635,514	$ 47,256	$ 2,706,944
70	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 580,855,092	$ 384,987,079	$ 3,089,270	$ 101,707,907	$ 12,787,128	$ 30,844,704	$ 42,244,862	$ 47,256	$ 5,146,887
71	Demand	39.63%	27.99%	38.88%	45.12%	59.39%	86.58%	91.39%	0.00%	47.41%
72	Energy	1.19%	1.18%	1.61%	1.92%	2.85%	0.00%	0.00%	0.00%	0.00%
73	Customer	59.18%	70.83%	59.52%	52.96%	37.75%	13.42%	8.61%	100.00%	52.59%

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

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

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Unit Costs									
74	**Storage**									
75	Demand	$ 0.23	$ 0.36	$ 0.36	$ 0.35	$ 0.34	$ -	$ -	$ -	$ -
76	Commodity	$ 1.86	$ 6.76	$ 6.81	$ 5.64	$ 3.66	$ -	$ -	$ -	$ -
77	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	**LNG**									
79	Demand	$ 0.51	$ 0.80	$ 0.80	$ 0.80	$ 0.83	$ -	$ -	$ -	$ -
80	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	**Transmission**									
83	Demand	$ 4.88	$ 4.61	$ 4.61	$ 4.62	$ 4.69	$ 4.62	$ 5.67	$ -	$ 5.01
84	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	**Distribution**									
87	Demand	$ 4.79	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 1.55	$ -	$ 5.35
88	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Customer	$ 9.55	$ 9.21	$ 9.79	$ 11.84	$ 71.13	$ 114.53	$ 694.33	$ 125.73	$ 80.00
90	**On-Site**									
91	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	Customer	$ 18.71	$ 15.31	$ 16.14	$ 45.81	$ 496.60	$ 2,023.97	$ 2,932.51	$ 76.73	$ 1,306.76
94	**Cust. Accounts**									
95	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97	Customer	$ 5.62	$ 4.90	$ 5.50	$ 8.78	$ 88.27	$ 1,126.90	$ 1,106.90	$ 1,766.52	$ 1,126.87
98	**Total**									
99	Demand	$ 10.40	$ 11.60	$ 11.59	$ 11.61	$ 11.68	$ 10.45	$ 7.22	$ -	$ 10.37
100	Commodity	$ 0.0019	$ 0.0068	$ 0.0068	$ 0.0056	$ 0.0037	$ -	$ -	$ -	$ -
101	Customer (per cust month)	$ 33.87	$ 29.42	$ 31.44	$ 66.43	$ 656.01	$ 3,265.41	$ 4,733.74	$ 1,968.98	$ 2,513.62
102	Customer (Onsite/Metering & Cust Acts)	$ 24.33	$ 20.21	$ 21.65	$ 54.59	$ 584.87	$ 3,150.88	$ 4,039.41	$ 1,843.25	$ 2,433.62
103	Demand & Customer (per cust month)	$ 56.56	$ 41.05	$ 51.98	$ 123.03	$ 1,688.02	$ 24,335.95	$ 55,006.33	$ 1,968.98	$ 4,779.31
104	**BILLING DETERMINANTS**									
105	Demand	22,134,411	9,285,407	103,615	3,952,915	649,993	2,555,994	5,351,149	0	235,338
106	Demand - Distribution	16,757,159	9,285,407	103,615	3,952,915	649,993	2,555,994	0	0	209,235
107	Commodity	3,707,233,778	671,804,472	7,291,448	346,915,023	99,542,792	193,916,786	2,333,755,050	1,055,641	52,952,568
108	Customers (Number of Bills)	10,148,325	9,268,598	58,482	810,749	7,359	1,267	768	24	1,077

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

Summary of Cost of Service Study Results
Transmission System Allocated on Design Day

Line No.	Revenue Requirement Summary	Account Balance	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
1	**Rate Base**									
2	Plant in Service	$ 4,004,668,453	$ 2,591,624,277	$ 21,011,578	$ 736,164,289	$ 91,151,247	$ 242,246,494	$ 291,386,479	$ 41,313	$ 31,042,776
3	Accumulated Reserve	(1,705,969,359)	(1,188,942,593)	(9,133,264)	(316,880,922)	(34,811,454)	(71,908,168)	(73,248,891)	(26,047)	(11,018,020)
4	Other Rate Base Items	117,758,507	75,718,873	764,600	29,374,378	5,048,196	2,745,667	3,782,871	125	323,798
5	**Total Rate Base**	**$ 2,416,457,600**	**$ 1,478,400,557**	**$ 12,642,914**	**$ 448,657,745**	**$ 61,387,989**	**$ 173,083,993**	**$ 221,920,458**	**$ 15,390**	**$ 20,348,555**
6	**Margin at Current Rates**									
7	Delivery Sales Margin	$ 420,431,618	$ 269,858,395	$ 2,139,828	$ 90,958,439	$ 11,283,437	$ 8,958,749	$ 32,224,394	$ 194,747	$ 4,813,629
8	TDSIC Margin	21,203,255	13,484,447	160,038	4,936,053	1,149,714	93,115	1,217,201	-	162,686
9	FMCA Margin	17,842,809	11,983,283	104,301	3,166,741	426,371	139,692	1,844,715	-	177,706
10	Miscellaneous Service Margin	6,053,908	4,607,358	43,840	1,086,282	123,603	82,591	91,507	328	18,398
11	**Total Margin at Current Rates**	**$ 465,531,589**	**$ 299,933,483**	**$ 2,448,007**	**$ 100,147,515**	**$ 12,983,126**	**$ 9,274,147**	**$ 35,377,817**	**$ 195,075**	**$ 5,172,419**
12	Gas Costs	348,721,758	230,259,799	2,473,589	95,301,332	18,917,152	112,993	1,485,782	-	171,111
13	**Total Sales Revenue**	**$ 814,253,347**	**$ 530,193,282**	**$ 4,921,596**	**$ 195,448,848**	**$ 31,900,278**	**$ 9,387,140**	**$ 36,863,599**	**$ 195,075**	**$ 5,343,530**
14	**Expenses at Current Rates**									
15	O&M and A&G Expenses	$ 223,421,806	$ 156,919,322	$ 1,218,768	$ 37,538,197	$ 4,640,645	$ 10,166,278	$ 10,488,844	$ 41,239	$ 2,408,514
16	Depreciation and Amortization Expense	122,068,413	84,770,090	654,316	20,993,383	2,211,362	5,577,831	7,116,611	742	744,078
17	Taxes Other Than Income	34,955,761	23,044,649	192,695	7,003,112	970,446	1,425,379	2,038,597	4,000	276,884
18	Income Taxes	4,023,043	1,664,310	18,073	1,636,574	244,008	(373,310)	743,929	7,049	82,410
19	**Total Expenses at Current Rates**	**$ 384,469,023**	**$ 266,398,371**	**$ 2,083,851**	**$ 67,171,265**	**$ 8,066,462**	**$ 16,796,178**	**$ 20,387,981**	**$ 53,031**	**$ 3,511,886**
20	**Operating Income at Current Rates**	**$ 81,062,566**	**$ 33,535,112**	**$ 364,156**	**$ 32,976,250**	**$ 4,916,664**	**$ (7,522,030)**	**$ 14,989,836**	**$ 142,044**	**$ 1,660,534**
21	**Current Rate of Return**	**3.35%**	**2.27%**	**2.88%**	**7.35%**	**8.01%**	**-4.35%**	**6.75%**	**922.94%**	**8.16%**
22	**Current Revenue at Equal Rates of Return**									
23	Current Rate of Return	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%
24	Current Operating Income at Equal ROR	$ 81,062,566	$ 49,594,473	$ 424,120	$ 15,050,687	$ 2,059,323	$ 5,806,281	$ 7,444,551	$ 516	$ 682,613
25	Income Taxes - Equal ROR	4,023,043	2,461,317	21,049	746,949	102,202	288,159	369,465	26	33,877
26	Other Expenses - Equal ROR	380,445,980	264,734,061	2,065,778	65,534,691	7,822,453	17,169,488	19,644,052	45,981	3,429,475
27	**Total Margin @ Equal Rates of Return**	**$ 465,531,589**	**$ 316,789,852**	**$ 2,510,946**	**$ 81,332,327**	**$ 9,983,979**	**$ 23,263,928**	**$ 27,458,068**	**$ 46,523**	**$ 4,145,966**
28	**Current Class (Subsidies)/Excesses**	**$ -**	**$ (16,856,369)**	**$ (62,940)**	**$ 18,815,188**	**$ 2,999,147**	**$ (13,989,781)**	**$ 7,919,749**	**$ 148,552**	**$ 1,026,453**

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

Summary of Cost of Service Study Results
Transmission System Allocated on Design Day

Line No.	Revenue Requirement Summary	Account Balance	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
29	**Revenue Requirement at Equal Rates of Return**									
30	Required Return	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
31	Required Return	$ 166,010,637	$ 101,566,118	$ 868,568	$ 30,822,787	$ 4,217,355	$ 11,890,870	$ 15,245,935	$ 1,057	$ 1,397,946
31	**Operating Income (Deficiency)/Surplus**	**$ (84,948,071)**	**$ (68,031,006)**	**$ (504,413)**	**$ 2,153,463**	**$ 699,309**	**$ (19,412,901)**	**$ (256,099)**	**$ 140,987**	**$ 262,588**
32	**Expenses at Required Return**									
33	O&M and A&G Expenses	223,421,806	156,919,322	1,218,768	37,538,197	4,640,645	10,166,278	10,488,844	41,239	2,408,514
34	Increase in Uncollectibles	336,250	307,502	4,715	23,117	687	-	-	-	229
35	Depreciation and Amortization Expense	122,068,413	84,770,090	654,316	20,993,383	2,211,362	5,577,831	7,116,611	742	744,078
36	Taxes Other Than Income	34,955,761	23,044,649	192,695	7,003,112	970,446	1,425,379	2,038,597	4,000	276,884
37	Increase TOTI	1,830,885	1,120,091	9,579	339,956	46,541	131,144	168,145	12	15,418
38	Income Taxes	4,023,043	2,461,201	21,047	746,993	102,265	288,165	369,468	26	33,878
39	Gross Up - Income Taxes	28,208,298	17,257,158	147,576	5,237,679	717,051	2,020,523	2,590,591	180	237,541
40	**Total Expenses at Required Return**	**$ 414,844,456**	**$ 285,880,014**	**$ 2,248,695**	**$ 71,882,436**	**$ 8,688,998**	**$ 19,609,319**	**$ 22,772,255**	**$ 46,198**	**$ 3,716,541**
41	**Total Revenue Requirement at Equal Rates of Return**	**$ 580,855,093**	**$ 387,446,132**	**$ 3,117,263**	**$ 102,705,223**	**$ 12,906,353**	**$ 31,500,189**	**$ 38,018,191**	**$ 47,256**	**$ 5,114,486**
42	LESS									
43	Current Miscellaneous Revenue Margin	6,053,908	4,607,358	43,840	1,086,282	123,603	82,591	91,507	328	18,398
44	Additional Miscellaneous Revenue Margin	-	-	-	-	-	-	-	-	-
45	**Total Rate Margin at Equal Rates of Return**	**$ 574,801,186**	**$ 382,838,774**	**$ 3,073,424**	**$ 101,618,941**	**$ 12,782,749**	**$ 31,417,599**	**$ 37,926,683**	**$ 46,927**	**$ 5,096,088**
46	**Base Rate Margin (Deficiency)/Surplus Under Design Day Allocation of Transmission**	**$ (115,323,504)**	**$ (87,512,649)**	**$ (669,257)**	**$ (2,557,708)**	**$ 76,773**	**$ (22,226,042)**	**$ (2,640,374)**	**$ 147,819**	**$ 57,933**
47	**Base Rate Margin (Deficiency)/Surplus Under Peak & Average Allocation of Transmission**	**$ (115,323,504)**	**$ (85,063,754)**	**$ (641,380)**	**$ (1,560,726)**	**$ 198,344**	**$ (21,571,739)**	**$ (6,857,693)**	**$ 147,819**	**$ 25,623**

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
Transmission System Allocated on Design Day

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Functional Rate Base									
1	**Storage**									
2	Demand	$ 9,257,985	$ 6,213,534	$ 68,289	$ 2,570,556	$ 405,606	$ -	$ -	$ -	$ -
3	Commodity	$ 77,835,846	$ 51,117,498	$ 558,947	$ 22,050,518	$ 4,108,882	$ -	$ -	$ -	$ -
4	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Subtotal	$ 87,093,830	$ 57,331,032	$ 627,236	$ 24,621,074	$ 4,514,488	$ -	$ -	$ -	$ -
6	**LNG**									
7	Demand	$ 5,447,958	$ 3,604,617	$ 40,137	$ 1,541,920	$ 261,284	$ -	$ -	$ -	$ -
8	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Subtotal	$ 5,447,958	$ 3,604,617	$ 40,137	$ 1,541,920	$ 261,284	$ -	$ -	$ -	$ -
11	**Transmission**									
12	Demand	$ 698,387,516	$ 292,974,247	$ 3,269,259	$ 124,722,836	$ 20,508,650	$ 80,647,020	$ 168,840,082	$ -	$ 7,425,422
13	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Subtotal	$ 698,387,516	$ 292,974,247	$ 3,269,259	$ 124,722,836	$ 20,508,650	$ 80,647,020	$ 168,840,082	$ -	$ 7,425,422
16	**Distribution**									
17	Demand	$ 578,874,556	$ 296,664,493	$ 3,310,438	$ 126,293,820	$ 20,766,973	$ 81,662,834	$ 43,279,910	$ -	$ 6,896,088
18	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Customer	$ 399,872,546	$ 365,240,364	$ 2,304,554	$ 31,948,560	$ 289,994	$ 49,946	$ 2	$ 946	$ 38,181
20	Subtotal	$ 978,747,102	$ 661,904,857	$ 5,614,992	$ 158,242,380	$ 21,056,967	$ 81,712,779	$ 43,279,912	$ 946	$ 6,934,269
21	**On-Site**									
22	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Customer	$ 632,746,162	$ 451,381,652	$ 3,018,807	$ 137,714,601	$ 14,912,534	$ 10,394,763	$ 9,605,501	$ 5,929	$ 5,712,375
25	Subtotal	$ 632,746,162	$ 451,381,652	$ 3,018,807	$ 137,714,601	$ 14,912,534	$ 10,394,763	$ 9,605,501	$ 5,929	$ 5,712,375
26	**Cust. Accounts**									
27	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Customer	$ 14,035,032	$ 11,204,153	$ 72,482	$ 1,814,934	$ 134,067	$ 329,430	$ 194,963	$ 8,515	$ 276,488
30	Subtotal	$ 14,035,032	$ 11,204,153	$ 72,482	$ 1,814,934	$ 134,067	$ 329,430	$ 194,963	$ 8,515	$ 276,488
31	**Total**									
32	Demand	$ 1,291,968,014	$ 599,456,891	$ 6,688,123	$ 255,129,132	$ 41,942,513	$ 162,309,854	$ 212,119,992	$ -	$ 14,321,510
33	Commodity	$ 77,835,846	$ 51,117,498	$ 558,947	$ 22,050,518	$ 4,108,882	$ -	$ -	$ -	$ -
34	Customer	$ 1,046,653,740	$ 827,826,169	$ 5,395,843	$ 171,478,095	$ 15,336,594	$ 10,774,139	$ 9,800,466	$ 15,390	$ 6,027,044
35	**TOTAL RATE BASE**	$ 2,416,457,600	$ 1,478,400,557	$ 12,642,914	$ 448,657,745	$ 61,387,989	$ 173,083,993	$ 221,920,458	$ 15,390	$ 20,348,555

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
Transmission System Allocated on Design Day

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Functional Revenue Requirement									
36	**Storage**									
37	Demand	$ 5,022,553	$ 3,370,907	$ 37,047	$ 1,394,553	$ 220,046	$ -	$ -	$ -	$ -
38	Commodity	$ 6,910,580	$ 4,538,418	$ 49,626	$ 1,957,734	$ 364,803	$ -	$ -	$ -	$ -
39	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Subtotal	$ 11,933,133	$ 7,909,324	$ 86,673	$ 3,352,287	$ 584,849	$ -	$ -	$ -	$ -
41	**LNG**									
42	Demand	$ 11,226,056	$ 7,427,669	$ 82,707	$ 3,177,278	$ 538,401	$ -	$ -	$ -	$ -
43	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Subtotal	$ 11,226,056	$ 7,427,669	$ 82,707	$ 3,177,278	$ 538,401	$ -	$ -	$ -	$ -
46	**Transmission**									
47	Demand	$ 107,919,847	$ 45,272,481	$ 505,189	$ 19,273,067	$ 3,169,144	$ 12,462,156	$ 26,090,380	$ -	$ 1,147,430
48	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	Subtotal	$ 107,919,847	$ 45,272,481	$ 505,189	$ 19,273,067	$ 3,169,144	$ 12,462,156	$ 26,090,380	$ -	$ 1,147,430
51	**Distribution**									
52	Demand	$ 106,014,498	$ 54,126,932	$ 603,995	$ 23,042,519	$ 3,788,969	$ 14,899,520	$ 8,292,429	$ -	$ 1,260,134
53	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	$ 96,868,608	$ 85,402,231	$ 572,753	$ 9,602,590	$ 523,454	$ 145,166	$ 533,244	$ 3,018	$ 86,153
55	Subtotal	$ 202,883,107	$ 139,529,163	$ 1,176,748	$ 32,645,109	$ 4,312,423	$ 15,044,686	$ 8,825,673	$ 3,018	$ 1,346,287
56	**On-Site**									
57	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	Customer	$ 189,827,155	$ 141,858,515	$ 944,117	$ 37,143,432	$ 3,654,525	$ 2,565,295	$ 2,252,170	$ 1,842	$ 1,407,259
60	Subtotal	$ 189,827,155	$ 141,858,515	$ 944,117	$ 37,143,432	$ 3,654,525	$ 2,565,295	$ 2,252,170	$ 1,842	$ 1,407,259
61	**Cust. Accounts**									
62	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	Customer	$ 57,065,796	$ 45,444,176	$ 321,774	$ 7,115,895	$ 649,623	$ 1,428,301	$ 850,100	$ 42,396	$ 1,213,532
65	Subtotal	$ 57,065,796	$ 45,444,176	$ 321,774	$ 7,115,895	$ 649,623	$ 1,428,301	$ 850,100	$ 42,396	$ 1,213,532
66	**Total**									
67	Demand	$ 230,182,953	$ 110,197,989	$ 1,228,939	$ 46,887,417	$ 7,716,559	$ 27,361,676	$ 34,382,809	$ -	$ 2,407,564
68	Commodity	$ 6,910,580	$ 4,538,418	$ 49,626	$ 1,957,734	$ 364,803	$ -	$ -	$ -	$ -
69	Customer	$ 343,761,560	$ 272,704,922	$ 1,838,643	$ 53,861,917	$ 4,827,602	$ 4,138,762	$ 3,635,514	$ 47,256	$ 2,706,944
70	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 580,855,093	$ 387,441,329	$ 3,117,208	$ 102,707,068	$ 12,908,965	$ 31,500,438	$ 38,018,323	$ 47,256	$ 5,114,507
71	Demand	39.63%	28.44%	39.42%	45.65%	59.78%	86.86%	90.44%	0.00%	47.07%
72	Energy	1.19%	1.17%	1.59%	1.91%	2.83%	0.00%	0.00%	0.00%	0.00%
73	Customer	59.18%	70.39%	58.98%	52.44%	37.40%	13.14%	9.56%	100.00%	52.93%

Northern Indiana Public Service Company
12 Months Ending December 31, 2022

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
Transmission System Allocated on Design Day

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Unit Costs									
74	**Storage**									
75	Demand	$ 0.23	$ 0.36	$ 0.36	$ 0.35	$ 0.34	$ -	$ -	$ -	$ -
76	Commodity	$ 1.86	$ 6.76	$ 6.81	$ 5.64	$ 3.66	$ -	$ -	$ -	$ -
77	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	**LNG**									
79	Demand	$ 0.51	$ 0.80	$ 0.80	$ 0.80	$ 0.83	$ -	$ -	$ -	$ -
80	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	**Transmission**									
83	Demand	$ 4.88	$ 4.88	$ 4.88	$ 4.88	$ 4.88	$ 4.88	$ 4.88	$ -	$ 4.88
84	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	**Distribution**									
87	Demand	$ 4.79	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 1.55	$ -	$ 5.35
88	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Customer	$ 9.55	$ 9.21	$ 9.79	$ 11.84	$ 71.13	$ 114.53	$ 694.33	$ 125.73	$ 80.00
90	**On-Site**									
91	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	Customer	$ 18.71	$ 15.31	$ 16.14	$ 45.81	$ 496.60	$ 2,023.97	$ 2,932.51	$ 76.73	$ 1,306.76
94	**Cust. Accounts**									
95	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97	Customer	$ 5.62	$ 4.90	$ 5.50	$ 8.78	$ 88.27	$ 1,126.90	$ 1,106.90	$ 1,766.52	$ 1,126.87
98	**Total**									
99	Demand	$ 10.40	$ 11.87	$ 11.86	$ 11.86	$ 11.87	$ 10.70	$ 6.43	$ -	$ 10.23
100	Commodity	$ 0.0019	$ 0.0068	$ 0.0068	$ 0.0056	$ 0.0037	$ -	$ -	$ -	$ -
101	Customer (per cust month)	$ 33.87	$ 29.42	$ 31.44	$ 66.43	$ 656.01	$ 3,265.41	$ 4,733.74	$ 1,968.98	$ 2,513.62
102	Customer (Onsite/Metering & Cust Acts)	$ 24.33	$ 20.21	$ 21.65	$ 54.59	$ 584.87	$ 3,150.88	$ 4,039.41	$ 1,843.25	$ 2,433.62
103	Demand & Customer (per cust month)	$ 56.56	$ 41.31	$ 52.45	$ 124.27	$ 1,704.58	$ 24,853.31	$ 49,503.02	$ 1,968.98	$ 4,749.25
104	**BILLING DETERMINANTS**									
105	Demand	22,134,411	9,285,407	103,615	3,952,915	649,993	2,555,994	5,351,149	0	235,338
106	Demand - Distribution	16,757,159	9,285,407	103,615	3,952,915	649,993	2,555,994	0	0	209,235
107	Commodity	3,707,233,778	671,804,472	7,291,448	346,915,023	99,542,792	193,916,786	2,333,755,050	1,055,641	52,952,568
108	Customers (Number of Bills)	10,148,325	9,268,598	58,482	810,749	7,359	1,267	768	24	1,077

Northern Indiana Public Service Company
Revenue Proof and Rate Design

	Total System	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138	Miscellaneous Revenue
Current Distribution Margin	$ 465,531,588	$ 295,326,125	$ 2,404,167	$ 99,061,233	$ 12,859,523	$ 9,191,556	$ 35,286,309	$ 194,747	$ 5,154,021	$ 6,053,907
Proposed Increase/ (Decrease)	115,323,504	$ 85,063,754	$ 641,379	$ 15,369,983	$ 1,995,237	$ 4,595,778	$ 6,857,693	$ -	$ 799,679	$ -
Proposed Margin	$ 580,855,092	$ 380,389,879	$ 3,045,546	$ 114,431,216	$ 14,854,760	$ 13,787,335	$ 42,144,002	$ 194,747	$ 5,953,700	$ 6,053,907
Resulting Increase % (Dist Margin)	24.8%	28.8%	26.7%	15.5%	15.5%	50.0%	19.4%	0.0%	15.5%	0.0%
Resulting Increase % with Total Revenue	14.2%	16.2%	13.1%	7.9%	6.3%	49.4%	18.6%	0.0%	15.0%	0.0%
Multiple of System Increase		1.15	1.06	0.62	0.62	1.99	0.77	-	0.62	
Proposed Revenue	$ 929,576,850	$ 610,649,678	$ 5,519,135	$ 209,732,549	$ 33,771,912	$ 13,900,328	$ 43,629,784	$ 194,747	$ 6,124,811	$ 6,053,907
Proposed Rate of Return	6.87%	6.87%	6.87%	9.49%	9.90%	-1.55%	6.87%	811.18%	10.23%	0.00%
Proposed Revenue to Cost Ratio	1.00	1.00	1.00	1.14	1.17	0.45	1.00	4.15	1.16	0.00%
Current Relative Revenue to Cost Ratio	1.00	0.97	0.99	1.23	1.27	0.37	1.04	5.13	1.25	0.00%
						Current: 0.76				
						Proposed: 0.77				

	Total System
Rate Margin Increase	115,323,504
System Increase (Total Distribution Margin)	25.10%
System Increase (Total Revenue)	14.16%

Northern Indiana Public Service Company
Revenue Proof and Rate Design

Line No.	(A) Description	(B) 2022 Forecasted Billing Determinants (Therms/Bills)	(C) Current Rate	(D) 2022 Total Revenue ("Margins")	(E) 2022 Forecasted Billing Determinants (Therms/Bills)	(F) Proposed Rate	(G) Total Revenue ("Margins") 2022
1	**Residential - Rate 211**						
2	Customer Charge						
3	Customer Charge - 211	9,231,053	$ 14.00	$ 129,234,742	9,231,053	$ 24.50	$ 226,160,799
4	Customer Charge - 251	37,545	$ 14.00	$ 525,630	37,545	$ 24.50	$ 919,853
5	Total Customer Charge	9,268,598		$ 129,760,372	9,268,598		$ 227,080,651
6	Delivery Charge						
7	All Therms - 211	669,912,337 Therms	$ 0.20854	$ 139,703,519	669,912,337 Therms	$ 0.22821	$ 152,877,433
8	All Therms - 251	1,892,135 Therms	$ 0.20854	$ 394,586	1,892,135 Therms	$ 0.22821	$ 431,795
9	Total Delivery Charge	671,804,472 Therms		$ 140,098,105	671,804,472 Therms		$ 153,309,228
10	Residential - Rate 211 Sales			$ 269,858,477			$ 380,389,879
11	Adjustment of Charges for FMCA			$ 11,983,283			
12	Adjustment of Charges for TDSIC			$ 13,484,448			
13	Total Rider			$ 25,467,731			$ -
14			Total Margin	$ 295,326,207		Total Margin	$ 380,389,879
15			Revenue Proof	$ 295,326,207		Target Margin	$ 380,389,879
16			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
17	**Multi-Family - Rate 215**						
18	Customer Charge						
19	Customer Charge - 215	58,410	$ 17.50	$ 1,022,175	58,410	$ 28.50	$ 1,664,685
20	Customer Charge- 251	72	$ 17.50	$ 1,260	72	$ 28.50	$ 2,052
21	Total Customer Charge	58,482		$ 1,023,435	58,482		$ 1,666,737
22	Delivery Charge						
23	All Therms - 215	7,280,514 Therms	$ 0.15311	$ 1,114,720	7,280,514 Therms	$ 0.18910	$ 1,376,742
24	All Therms - 251	10,933 Therms	$ 0.15311	$ 1,674	10,933 Therms	$ 0.18910	$ 2,068
25	Total Delivery Charge	7,291,448 Therms		$ 1,116,394	7,291,448 Therms		$ 1,378,809
26	Multi-Family - Rate 215 Sales			$ 2,139,829			$ 3,045,546
27	Adjustment of Charges for FMCA			$ 104,301			
28	Adjustment of Charges for TDSIC			$ 160,038			
29	Total Rider			$ 264,339			$ -
30			Total Margin	$ 2,404,167		Total Margin	$ 3,045,546
31			Revenue Proof	$ 2,404,167		Target Margin	$ 3,045,546
32			Over/(Under)	$ (0)		Over/(Under)	$ -
				0.000%			
33	**Small General Service - Rate 221**						
34	Customer Charge						
35	Customer Charge - 221	810,533	$ 53.00	$ 42,958,263	810,533	$ 80.00	$ 64,842,662
36	Customer Charge- 251	216	$ 53.00	$ 11,448.00	216	$ 80.00	$ 17,280
37	Total Customer Charge	810,749		$ 42,969,711	810,749		$ 64,859,942
38	Delivery Charge						
39	All Therms - 221	346,877,624 Therms	$ 0.13833	$ 47,983,582	346,877,624 Therms	$ 0.14289	$ 49,565,930
40	All Therms - 251	37,399 Therms	$ 0.13833	$ 5,173	37,399 Therms	$ 0.14289	$ 5,344
41	Total Delivery Charge	346,915,023 Therms		$ 47,988,755	346,915,023 Therms		$ 49,571,274
42	Small General Service - Rate 221 Sales			$ 90,958,467			$ 114,431,216
43	Adjustment of Charges for FMCA			$ 3,166,741			
44	Adjustment of Charges for TDSIC			$ 4,936,053			
45	Total Rider			$ 8,102,794			$ -
46			Total Margin	$ 99,061,261		Total Margin	$ 114,431,216
47			Revenue Proof	$ 99,061,260		Target Margin	$ 114,431,216
48			Over/(Under)	$ 0		Over/(Under)	$ -
				0.000%			

Northern Indiana Public Service Company
Revenue Proof and Rate Design

Line No.	(A) Description	(B) 2022 Forecasted Billing Determinants (Therms/Bills)	(C) Current Rate	(D) 2022 Total Revenue ("Margins")	(E) 2022 Forecasted Billing Determinants (Therms/Bills)	(F) Proposed Rate	(G) Total Revenue ("Margins") 2022
49	**General Service Large - Rate 225**						
50	Customer Charge						
51	Customer Charge - 225	7,359	$ 400	$ 2,943,636	7,359	$ 640.00	$ 4,709,818
52	Customer Charge- 251	-	$ 400	$ -	-	$ 640.00	$ -
53	Total Customer Charge	7,359		$ 2,943,636	7,359		$ 4,709,818
54	Delivery Charge						
55	First 6,000 Therms	34,906,629 Therms	$ 0.09286	$ 3,241,430	34,906,629 Therms	$ 0.11093	$ 3,872,236
56	Next 24,000 Therms	52,081,041 Therms	$ 0.08286	$ 4,315,435	52,081,041 Therms	$ 0.10093	$ 5,256,604
57	Next 60,000 Therms	11,300,071 Therms	$ 0.06286	$ 710,322	11,300,071 Therms	$ 0.08093	$ 914,529
58	All over 90,000 Therms	1,255,051 Therms	$ 0.05786	$ 72,617	1,255,051 Therms	$ 0.08093	$ 101,573
59	First 6,000 Therms - Rate 251	0 Therms	0.09286	$ -	0 Therms	$ 0.11093	$ -
60	Next 24,000 Therms - Rate 251	0 Therms	0.08286	$ -	0 Therms	$ 0.10093	$ -
61	Next 60,000 Therms - Rate 251	0 Therms	0.06286	$ -	0 Therms	$ 0.08093	$ -
62	All over 90,000 Therms	0 Therms	0.05786	$ -	0 Therms	$ 0.08093	$ -
63	Total Delivery Charge	99,542,792 Therms		$ 8,339,804	99,542,792 Therms		$ 10,144,942
64	General Service Large - Rate 225 Sales			$ 11,283,441			$ 14,854,760
65	Adjustment of Charges for FMCA			$ 426,371			
66	Adjustment of Charges for TDSIC			$ 1,149,714			
67	Total Rider			$ 1,576,085			$ -
68			Total Margin	$ 12,859,526		Total Margin	$ 14,854,760
69			Revenue Proof	$ 12,859,526		Target Margin	$ 14,854,760
70			Over/(Under)	$ (0)		Over/(Under)	$ -
				0.000%			
71	**LargeTransportation - Rate 228**						
72	Customer Charge	2,035	$ 1,000.00	$ 2,035,455	2,035	$ 3,000.00	$ 6,106,364
73	Demand Charge - HP	82,923,675 Therms	$ 0.03075	$ 2,549,903	82,923,675 Therms	$ 0.06150	$ 5,099,806
74	Demand Charge - DP	7,241,358 Therms	$ 0.11120	$ 805,239	7,241,358 Therms	$ 0.16680	$ 1,207,859
		90,165,033 Therms		3,355,142	90,165,033 Therms		6,307,665
75	Administrative Charges for Balancing Services						
76	Category A & C	349	$ 1,590.00	554,974	349	$ 1,590.00	554,974
77	Category B	1,727	$ 660.00	1,139,732	1,727	$ 660.00	1,139,732
78	Total Administrative Charges for Balancing Se	2,076		1,694,706			1,694,706
79	Transportation charge - HP						
80	First 300,000 Therms	191,178,797 Therms	$ 0.03280	6,270,665	191,178,797 Therms	$ 0.04546	8,691,128
81	All Over 300,000 Therms	2,142,576,253 Therms	$ 0.00986	21,125,802	2,142,576,253 Therms	$ 0.01150	24,639,627
82	Total Transportation Charge	2,333,755,050 Therms		27,396,466	2,333,755,050 Therms		33,330,755
83	Transportation charge- DP						
84	First 300,000 Therms	154,976,410 Therms	$ 0.03377	5,233,553	154,976,410 Therms	$ 0.04491	6,960,153
85	All Over 300,000 Therms	38,940,376 Therms	$ 0.00986	383,952	38,940,376 Therms	$ 0.01150	447,814
86	Total Transportation Charge	193,916,786 Therms		5,617,505	193,916,786 Therms		7,407,967
87	Pooling Agreement Fee	1,840	$ 60.00	110,400	1,840	$ 60.00	110,400
88	Company Nomination Exchange	781	$ 10.00	7,810	781	$ 10.00	7,810
89	Imbalance Exchange Service Charge	-	$ 10.00	-	-	$ 10.00	-
90	Pool Adminstration Charge - Cat. A	19	$ 1,000.00	19,198	19	$ 1,000.00	19,198
91	Pool Adminstration Charge - Cat. B	131	$ 500.00	65,364	131	$ 500.00	65,364
92	Pool Adminstration Charge - Cat. C	-	$ 250.00	-		$ 250.00	-
93	Pool Participation Fee - Cat. A	167	$ 2,500.00	418,241	167	$ 2,500.00	418,241
94	Pool Participation Fee - Cat. B	1,444	$ 87.50	126,307	1,444	$ 87.50	126,307
95	Pool Participation Fee - Cat. C	91	$ 250.00	22,855	91	$ 250.00	22,855

Northern Indiana Public Service Company
Revenue Proof and Rate Design

Line No.	(A) Description	(B) 2022 Forecasted Billing Determinants (Therms/Bills)	(C) Current Rate	(D) 2022 Total Revenue ("Margins")	(E) 2022 Forecasted Billing Determinants (Therms/Bills)	(F) Proposed Rate	(G) Total Revenue ("Margins") 2022
96	Imbalance Net Throughput Fee						
97	Volumetric Fee - Cat. A & C	1,826,604,204 Therms	$ 0.00015	273,991	1,826,604,204 Therms	$ 0.00015	273,991
98	Volumetric Fee - Cat. B	264,767,331 Therms	$ 0.00015	39,715	264,767,331 Therms	$ 0.00015	39,715
99	LargeTransportation - Rate 228 Sales			$ 41,183,155			$ 55,931,337
100	Adjustment of Charges for FMCA			$ 1,984,407			
101	Adjustment of Charges for TDSIC			$ 1,310,316			
102	Total Rider			$ 3,294,723			$ -
103			Total Margin	44,477,878		Total Margin	55,931,337
104			Revenue Proof	$ 44,477,750		Target Margin	$ 55,931,337
105			Over/(Under)	$ 128		Over/(Under)	$ -
				0.000%			
106	**C&I Off-Peak Interruptible - Rate 234A**						
107	Customer Charge						
108	Customer Charge - 234A	24	$ 637.00	$ 15,288.00	24	$ 637.00	$ 15,288
109	Minimum Charge				0		$ -
110	Total Customer Charge	24		$ 15,288.00	24		$ 15,288
111	Delivery Charge						
112	Off-Peak Intrrpt Gas	0 Therms	0	0	0 Therms		$ -
113	Off-Peak Intrrpt Contract	1,055,641 Therms	$ 0.17000	$ 179,458.89	1,055,641 Therms	$ 0.17000	$ 179,459
114	Total Delivery Charge	1,055,641 Therms		$ 179,458.89	1,055,641 Therms		$ 179,459
115	C&I Off-Peak Interruptible - Rate 234A Sales			$ 194,747			$ 194,747
116	Total Rider			$ -			$ -
117			Total Margin	$ 194,747		Total Margin	$ 194,747
118			Revenue Proof	$ 194,747		Target Margin	$ 194,747
119			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
120	**General Transportation & Balancing - Rate 238**						
121	Customer Charge	1,077	$ 750.00	$ 807,682	1,077	$ 1,200.00	$ 1,292,291
122	Administrative Charges for Balancing Service	1,022	$ 250.00	$ 255,500	1,022	$ 250.00	$ 255,500
123	Demand Charge	2,073,788	$ 0.12063	$ 250,161	2,073,788	$ 0.29414	$ 609,986
124	Transportation charge						
125	First 6,000 Therms	6,759,541 Therms	$ 0.06483	$ 438,221	6,759,541 Therms	$ 0.06905	$ 466,779
126	Next 24,000 Therms	23,799,583 Therms	$ 0.06383	$ 1,519,127	23,799,583 Therms	$ 0.06905	$ 1,643,478
127	Next 60,000 Therms	19,063,020 Therms	$ 0.06283	$ 1,197,730	19,063,020 Therms	$ 0.06905	$ 1,316,395
128	All Over 90,000 Therms	3,330,423 Therms	$ 0.06183	$ 205,920	3,330,423 Therms	$ 0.06905	$ 229,982
129	Total Transportation Charge	52,952,568 Therms		$ 3,360,998	52,952,568 Therms		$ 3,656,634
130	General Transportation & Balancing - Rate 238 Sales			$ 4,674,341			$ 5,814,410
131	Pooling Agreement Fee	1,328	$ 60.00	$ 79,670	1,328	$ 60.00	$ 79,670
132	Company Nomination Exchange	383	$ 10.00	$ 3,830	383	$ 10.00	$ 3,830
133	Pool Administration Charge	110	$ 250.00	$ 27,523	110	$ 250.00	$ 27,523
134	Pool Participation Fee	904	$ 25.00	$ 22,592	904	$ 25.00	$ 22,592
135	Volumetric Charge - Pool Operator	37,836,387 Therms	$ 0.00015	$ 5,675	37,836,387 Therms	$ 0.00	$ 5,675
136	Adjustment of Charges for FMCA			$ 177,706			
137	Adjustment of Charges for TDSIC			$ 162,686			
138	Total Rider			$ 479,682			$ 139,290
139			Total Margin	$ 5,154,023		Total Margin	$ 5,953,700
140			Revenue Proof	$ 5,154,023		Target Margin	$ 5,953,700
141			Over/(Under)	$ -		Over/(Under)	$ -
				0.000%			
142	All Classes						
143			Total Margin	$ 459,477,809		Total Margin	$ 574,801,185
144			Revenue Proof	$ 459,477,681		Target Margin	$ 574,801,185
145			Over/(Under)	$ 128		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	123,278,735	121,613,442	102,032,757	63,344,850	35,547,402	20,517,606	12,306,531	11,132,985	12,048,544	19,784,277	46,519,397	87,992,385	656,118,909
	Customer Count	766,564	767,104	768,048	769,087	769,871	770,397	770,990	771,441	771,983	773,317	774,440	774,529	9,247,771
2	Volumes (therms)	160.82	158.54	132.85	82.36	46.17	26.63	15.96	14.43	15.61	25.58	60.07	113.61	853
3	Current Revenues	109.66	108.30	93.02	62.99	41.46	29.84	23.49	22.58	23.28	29.22	49.73	81.57	675.14
4	Proposed Revenues	117.22	115.90	101.09	71.99	51.12	39.86	33.70	32.82	33.50	39.25	59.13	90.00	785.59
5	Difference	7.57	7.61	8.08	9.00	9.66	10.01	10.21	10.24	10.22	10.03	9.40	8.43	110.44
6	Avg. Monthly Increase	9.20												

Residential - Rate 211

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
8		Present	Proposed				
9		Rates	Rates				
10	Customer Charge	$14.00	$24.50				
11	Delivery Charge	$0.20854	$0.22821				
12	FMCA Charge	$0.01784	$0.00000				
13	TDSIC Charge	$0.02007	$0.00000				
14	GDSM Charge	$0.00861	$0.00861				
15	Average Gas Charg	$0.33974	$0.33974				
16	ANNUAL	REVENUE AT	REVENUE AT				
17	CONSUMPTION	PRESENT	PROPOSED	REVENUE CHANGE			
18	(Therms)	RATES	RATES	AMOUNT	PERCENT	Customers	Customers
19	100	$ 227	$ 352	$ 124	54.59%	50,349	6.00%
20	200	$ 287	$ 409	$ 122	42.64%	44,994	5.36%
21	300	$ 346	$ 467	$ 121	34.79%	45,795	5.46%
22	400	$ 406	$ 525	$ 119	29.24%	56,963	6.79%
23	500	$ 465	$ 582	$ 117	25.11%	76,961	9.17%
24	600	$ 525	$ 640	$ 115	21.92%	93,708	11.17%
25	700	$ 584	$ 698	$ 113	19.38%	98,756	11.77%
26	800	$ 644	$ 755	$ 111	17.30%	90,284	10.76%
27	900	$ 703	$ 813	$ 110	15.58%	74,061	8.83%
28	1,000	$ 763	$ 871	$ 108	14.13%	57,138	6.81%
29	1,100	$ 822	$ 928	$ 106	12.88%	42,143	5.02%
30	1,200	$ 882	$ 986	$ 104	11.81%	30,113	3.59%
31	1,300	$ 941	$ 1,044	$ 102	10.87%	21,223	2.53%
32	1,400	$ 1,001	$ 1,101	$ 100	10.04%	14,857	1.77%
33	1,500	$ 1,060	$ 1,159	$ 99	9.30%	10,589	1.26%
34	1,600	$ 1,120	$ 1,216	$ 97	8.65%	7,449	0.89%
35	1,700	$ 1,179	$ 1,274	$ 95	8.06%	5,444	0.65%
36	1,800	$ 1,239	$ 1,332	$ 93	7.52%	4,029	0.48%
37	1,900	$ 1,298	$ 1,389	$ 91	7.04%	2,998	0.36%
38	2,000	$ 1,358	$ 1,447	$ 90	6.59%	2,133	0.25%
39	2,100	$ 1,417	$ 1,505	$ 88	6.19%	1,741	0.21%
40	2,200	$ 1,477	$ 1,562	$ 86	5.82%	1,312	0.16%
41	2,300	$ 1,536	$ 1,620	$ 84	5.47%	987	0.12%
	>2300 (avg. 4,496)	$ 2,842	$ 2,886	$ 44	1.55%	4,995	0.60%

Illustrative Monthly Bill Impacts			
Description	Monthly Bill Impact (~Avg)	Monthly Bill Impact (~Avg)	Monthly Bill Impact (~Avg)
Volumes (therms)	50	70	100
Current Revenues	43.74	55.64	73.48
Proposed Revenue	53.33	64.86	82.16
Difference	9.59	9.22	8.68
Percent Increase	22%	17%	12%

Northern Indiana Public Service Company
Bill Impacts

Residential - Rate 211

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Present Rates	Proposed Rates				
1	Customer Charge	$ 14.00	$ 24.50				
2	Delivery Charge	$0.20854	$0.22821				
3	FMCA Charge	$0.01784	$0.00000				
4	TDSIC Charge	$0.02007	$0.00000				
5	GDSM Charge	$0.00861	$0.00861				
6	Average Gas Charge	$0.33974	$0.33974				
7	ANNUAL	REVENUE AT	REVENUE AT	REVENUE CHANGE			
8	CONSUMPTION	PRESENT	PROPOSED			Customer	Percent of
9	(Therms)	RATES	RATES	AMOUNT	PERCENT	Count	Customers
10	100	$ 227	$ 352	$ 124	54.59%	50,349	6.00%
11	200	$ 287	$ 409	$ 122	42.64%	44,994	5.36%
12	300	$ 346	$ 467	$ 121	34.79%	45,795	5.46%
13	400	$ 406	$ 525	$ 119	29.24%	56,963	6.79%
14	500	$ 465	$ 582	$ 117	25.11%	76,961	9.17%
15	600	$ 525	$ 640	$ 115	21.92%	93,708	11.17%
16	700	$ 584	$ 698	$ 113	19.38%	98,756	11.77%
17	800	$ 644	$ 755	$ 111	17.30%	90,284	10.76%
18	900	$ 703	$ 813	$ 110	15.58%	74,061	8.83%
19	1,000	$ 763	$ 871	$ 108	14.13%	57,138	6.81%
20	1,100	$ 822	$ 928	$ 106	12.88%	42,143	5.02%
21	1,200	$ 882	$ 986	$ 104	11.81%	30,113	3.59%
22	1,300	$ 941	$ 1,044	$ 102	10.87%	21,223	2.53%
23	1,400	$ 1,001	$ 1,101	$ 100	10.04%	14,857	1.77%
24	1,500	$ 1,060	$ 1,159	$ 99	9.30%	10,589	1.26%
25	1,600	$ 1,120	$ 1,216	$ 97	8.65%	7,449	0.89%
26	1,700	$ 1,179	$ 1,274	$ 95	8.06%	5,444	0.65%
27	1,800	$ 1,239	$ 1,332	$ 93	7.52%	4,029	0.48%
28	1,900	$ 1,298	$ 1,389	$ 91	7.04%	2,998	0.36%
29	2,000	$ 1,358	$ 1,447	$ 90	6.59%	2,133	0.25%
30	2,100	$ 1,417	$ 1,505	$ 88	6.19%	1,741	0.21%
31	2,200	$ 1,477	$ 1,562	$ 86	5.82%	1,312	0.16%
32	2,300	$ 1,536	$ 1,620	$ 84	5.47%	987	0.12%
33	>2300 (avg. 4,496)	$ 2,842	$ 2,886	$ 44	1.55%	4,995	0.60%

Multi-Family - Rate 215

Line No.	(A)	(B)	(C)
		Present Rates	Proposed Rates
34	Customer Charge	$ 17.50	$ 28.50
35	Delivery Charge	$0.15	$0.19
36	FMCA Charge	$0.01430	$0.00000
37	TDSIC Charge	$0.02195	$0.00000
38	GDSM Charge	$0.00317	$0.00317
39	Average Gas Cost	$0.33974	$0.33974

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
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	$ 343	$ 475	$ 132	38.46%	644	12.38%
44	500	$ 476	$ 608	$ 132	27.70%	563	10.82%
45	750	$ 609	$ 741	$ 132	21.64%	613	11.78%
46	1,000	$ 742	$ 874	$ 132	17.75%	692	13.30%
47	1,250	$ 875	$ 1,007	$ 132	15.04%	698	13.42%
48	1,500	$ 1,008	$ 1,140	$ 132	13.05%	552	10.61%
49	1,750	$ 1,141	$ 1,273	$ 132	11.52%	432	8.30%
50	2,000	$ 1,275	$ 1,406	$ 131	10.32%	306	5.88%
51	2,250	$ 1,408	$ 1,539	$ 131	9.34%	197	3.79%
52	2,500	$ 1,541	$ 1,672	$ 131	8.52%	141	2.71%
53	2,750	$ 1,674	$ 1,805	$ 131	7.84%	97	1.86%
54	3,000	$ 1,807	$ 1,938	$ 131	7.26%	57	1.10%
55	3,500	$ 2,073	$ 2,204	$ 131	6.32%	89	1.71%
56	4,000	$ 2,339	$ 2,470	$ 131	5.60%	49	0.94%
57	4,500	$ 2,605	$ 2,736	$ 131	5.02%	24	0.46%
58	5,000	$ 2,871	$ 3,002	$ 131	4.55%	10	0.19%
59	5,500	$ 3,137	$ 3,268	$ 131	4.16%	5	0.10%
60	6,000	$ 3,404	$ 3,534	$ 130	3.83%	5	0.10%
61	6,500	$ 3,670	$ 3,800	$ 130	3.55%	6	0.12%
62	7,000	$ 3,936	$ 4,066	$ 130	3.31%	-	0.00%
63	7,500	$ 4,202	$ 4,332	$ 130	3.09%	1	0.02%
64	8,000	$ 4,468	$ 4,598	$ 130	2.91%	4	0.08%
65	8,500	$ 4,734	$ 4,864	$ 130	2.74%	-	0.00%
66	9,000	$ 5,000	$ 5,130	$ 130	2.59%	2	0.04%
67	>9,000 (avg. 18,376)	$ 9,991	$ 10,118	$ 127	1.27%	15	0.29%

Small General Service - Rate 221

Line No.	(A)	(B) Present Rates	(C) Proposed Rates
68	Customer Charge	$ 53.00	$ 80.00
69	Delivery Charge	$0.13833	$0.14289
	FMCA Charge	$0.00913	$0.00000
70	TDSIC Charge	$0.01423	$0.00000
71	GDSM Charge	$0.00655	$0.00655
72	Average Gas Cost	$0.33974	$0.33974

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
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	$ 890	$ 1,205	$ 315	35.35%	16,153	25.42%
77	1,000	$ 1,144	$ 1,449	$ 305	26.68%	11,431	17.99%
78	1,500	$ 1,398	$ 1,694	$ 296	21.16%	6,900	10.86%
79	2,000	$ 1,652	$ 1,938	$ 286	17.34%	4,669	7.35%
80	2,500	$ 1,906	$ 2,183	$ 277	14.53%	3,371	5.31%
81	3,000	$ 2,160	$ 2,428	$ 268	12.39%	2,632	4.14%
82	3,500	$ 2,414	$ 2,672	$ 258	10.70%	1,979	3.11%
83	4,000	$ 2,668	$ 2,917	$ 249	9.33%	1,676	2.64%
84	4,500	$ 2,922	$ 3,161	$ 239	8.19%	1,378	2.17%
85	5,000	$ 3,176	$ 3,406	$ 230	7.24%	1,155	1.82%
86	6,000	$ 3,684	$ 3,895	$ 211	5.73%	1,782	2.80%
87	7,000	$ 4,192	$ 4,384	$ 192	4.59%	1,321	2.08%
88	8,000	$ 4,700	$ 4,873	$ 174	3.69%	1,118	1.76%
89	9,000	$ 5,208	$ 5,363	$ 155	2.97%	863	1.36%
90	10,000	$ 5,716	$ 5,852	$ 136	2.38%	734	1.16%
91	15,000	$ 8,256	$ 8,298	$ 42	0.51%	2,267	3.57%
92	20,000	$ 10,796	$ 10,744	$ (52)	-0.48%	1,159	1.82%
93	25,000	$ 13,335	$ 13,190	$ (146)	-1.09%	736	1.16%
94	30,000	$ 15,875	$ 15,635	$ (240)	-1.51%	509	0.80%
95	35,000	$ 18,415	$ 18,081	$ (334)	-1.81%	340	0.54%
96	40,000	$ 20,955	$ 20,527	$ (428)	-2.04%	243	0.38%
97	45,000	$ 23,495	$ 22,973	$ (522)	-2.22%	184	0.29%
98	50,000	$ 26,035	$ 25,419	$ (616)	-2.37%	146	0.23%
99	>50,000 (avg. 107032)	$ 55,006	$ 53,318	$ (1,688)	-3.07%	787	1.24%

General Service Large - Rate 225

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Present Rates	Proposed Rates				
100	Customer Charge	$ 400.00	$ 640.00				
	Delivery Charge						
101	First 6,000 Therms	$0.09286	$0.11093				
102	Next 24,000 Therms	$0.08286	$0.10093				
103	Next 60,000 Therms	$0.06286	$0.08093				
104	All over 90,000 Therm	$0.05786	$0.08093				
	FMCA Charge	$0.00428					
105	TDSIC Charge	$0.01155					
106	GDSM Charge	($0.00002)	($0.00002)				
107	Average Gas Cost	$0.33974	$0.33974				
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	$ 5,361	$ 8,243	$ 2,883	53.78%	5	0.77%
112	2,500	$ 5,921	$ 8,807	$ 2,886	48.73%	7	1.08%
113	5,000	$ 7,042	$ 9,933	$ 2,891	41.06%	10	1.54%
114	10,000	$ 9,284	$ 12,187	$ 2,902	31.26%	12	1.85%
115	20,000	$ 13,768	$ 16,693	$ 2,925	21.24%	12	1.85%
116	30,000	$ 18,214	$ 21,161	$ 2,947	16.18%	13	2.01%
117	40,000	$ 22,733	$ 25,702	$ 2,970	13.06%	16	2.47%
118	50,000	$ 27,143	$ 30,135	$ 2,992	11.02%	20	3.09%
119	60,000	$ 31,578	$ 34,592	$ 3,014	9.55%	38	5.86%
120	70,000	$ 36,006	$ 39,043	$ 3,037	8.43%	39	6.02%
121	80,000	$ 40,338	$ 43,397	$ 3,059	7.58%	44	6.79%
122	90,000	$ 44,877	$ 47,959	$ 3,081	6.87%	41	6.33%
123	100,000	$ 49,277	$ 52,381	$ 3,104	6.30%	31	4.78%
124	125,000	$ 60,321	$ 63,481	$ 3,160	5.24%	74	11.42%
125	150,000	$ 71,282	$ 74,498	$ 3,216	4.51%	50	7.72%
126	175,000	$ 82,014	$ 85,286	$ 3,272	3.99%	40	6.17%
127	200,000	$ 93,203	$ 96,530	$ 3,328	3.57%	30	4.63%
128	250,000	$ 114,994	$ 118,434	$ 3,439	2.99%	49	7.56%
129	300,000	$ 136,846	$ 140,397	$ 3,551	2.60%	42	6.48%
130	350,000	$ 157,774	$ 161,438	$ 3,663	2.32%	25	3.86%
131	400,000	$ 177,706	$ 181,481	$ 3,775	2.12%	16	2.47%
132	450,000	$ 200,898	$ 204,785	$ 3,887	1.93%	3	0.46%
133	500,000	$ 221,760	$ 225,778	$ 4,018	1.81%	6	0.93%
134	550,000	$ 242,848	$ 246,959	$ 4,111	1.69%	4	0.62%
					Over 700,000	11	1.70%