# VERIFIED REBUTTAL TESTIMONY OF RONALD J. AMEN

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

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

A1. My name is Ronald J. Amen. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211. I am a Director, Advisory & Planning.

**Q2. On whose behalf are you testifying?**

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

**Q3. Did you provide previous testimony in this proceeding?**

A3. Yes. I previously sponsored the following direct and supplemental direct testimony:

- <u>Exhibit No. 15</u> Direct Testimony of Ronald J. Amen
- <u>Exhibit No. 15-SD</u> Supplemental Direct Testimony of Ronald J. Amen

**Q4. Did you sponsor any attachments to your direct and supplemental testimony?**

A4. Yes. I sponsored the following <u>Attachments 15-A through 15-J and Attachments 15-F-SD through 15-J-SD</u>, all of which were prepared by me or under my supervision and direction:

- <u>Attachment 15-A</u>, Resume of Ronald J. Amen;

- Attachment 15-B, Description of the Black & Veatch Model;
- Attachment 15-C, 400 Series Classes Load Characteristics;
- Attachment 15-D, Graph of Miles of Mains v. No. of Residential Customers;
- Attachment 15-E, Allocation of Pipeline and Storage Demand Costs for Gas Cost Adjustment ("GCA");
- Attachment 15-F, COSS Summary Schedules for 400 Series Classes;
- Attachment 15-G, Alternative Cost of Service Analysis;
- Attachment 15-H, Rate Mitigation (pg. 1), Revenue Proof and Rate Design Schedules (pgs. 2-4);
- Attachment 15-I, Typical Residential Customer Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels;
- Attachment 15-J, C&I Bill Impact Schedules.
- Attachment 15-F-SD, COSS Summary Schedules for 400 Series Classes;
- Attachment 15-G-SD, Alternative Cost of Service Analysis;
- Attachment 15-H-SD, Rate Mitigation (pg. 1), Revenue Proof and Rate Design Schedules (pgs. 2-4);

- Attachment 15-I-SD, Typical Residential Customer Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels; and
- Attachment 15-J-SD, C&I Bill Impact Schedules.

**Q5. Please briefly summarize the subject of your direct testimony and the topics you will cover in your rebuttal testimony.**

A5. In my direct testimony I presented NIPSCO's Allocated Cost of Service Study ("ACOSS") and discussed its results, and I presented the various rate design proposals filed by NIPSCO in this proceeding. I updated NIPSCO's ACOSS and rate design proposals in my supplemental direct testimony to reflect the changes in NIPSCO's cost of service study model resulting from the Tax Cuts and Jobs Act ("TCJA") impact on the (2018) revenue requirement. I discussed the results of the cost of service study model with NIPSCO's new revenue requirement and the derivation of the proposed rates and impact on customers. My rebuttal testimony consists of this introduction, summary section and the following additional sections:

- NIPSCO's ACOSS – Transmission and High-Pressure Distribution Mains Cost Allocation;
- NIPSCO's Non-Residential Rate Design – Rate 428/128;

- NIPSCO's Residential Rate Design Proposal – Rate 411/111;
- NIPSCO's Updated Proposed Phase II ACOSS;
- NIPSCO's Proposed Phase I and II Class Revenue Allocations;
- NIPSCO's Proposed Phase I and II Rates and Customer Bill Impacts; and
- NIPSCO's Alternative ACOSS, Revenue Allocation and Rate Design under a Bifurcated Rate Schedule 428/128.

**Q6. Please summarize the purpose of your testimony?**

A6. First, I discuss the issues raised by the responsive testimonies of the NIPSCO Industrial Group ("IG") witness Nicholas Phillips Jr. and the Steel Dynamics, Inc. ("SDI") witness Kevin C. Higgins regarding the use of the Peak and Average ("P&A") allocation methodology for NIPSCO's Transmission Plant.

Second, I discuss the proposal by SDI witness Mr. Higgins to differentiate the rate design within Rate Schedule 128 (currently Rate Schedule 428) between the customers receiving service at high pressure and those customers receiving service at the lower distribution pressure.

Third, I discuss the recommendation by IG witness Mr. Phillips that the Commission reject NIPSCO's proposed Demand Charge for Rate Schedule 128 (currently Schedule 428).

Fourth, I will address the issues raised by the Office of Utility Consumer Counsel ("OUCC") witness Brien R. Krieger concerning NIPSCO's proposed monthly customer charge for residential Rate Schedule 111 (currently Rate Schedule 411).

Fifth, I will present the revised class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's updated ACOSS that results from the Company's revised proposed Phase I (Rate Base as of 5/31/18) revenue requirement of $409,981,113 and Phase II (Rate Base as of 12/31/18) revenue requirement of $436,585,562. This presentation includes the resulting unit costs by class for customer, demand and commodity related costs with the ACOSS.

Finally, I present NIPSCO's updated revenue allocation rate design proposals based on the Company's revised proposed revenue requirement for both Phase I and Phase II implementation. Proposed rate levels by class are presented as well as bill impacts by class.

**Q7. Are you sponsoring any attachments to your rebuttal testimony?**

A7. Yes. I am sponsoring the following attachments, all of which were prepared by me or under my supervision and direction.

- Attachment 15-A-R, Customer Charge Benchmarking (two pages)
- Attachment 15-B-R, Phase II - COSS Summary Schedules (four pages);
- Attachment 15-C-R, Phase II - Rate Mitigation (pg. 1), Revenue Proof and Rate Design Schedules (pgs. 2 – 4);
- Attachment 15-D-R, Phase II Typical Residential Customer Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels (one page);
- Attachment 15-E-R, Phase II - C&I Bill Impact Schedules (three pages);
- Attachment 15-F-R, Phase I - Revenue Proof and Rate Design Schedules (three pages);

- Attachment 15-G-R, Phase I - Typical Residential Customer Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels (one page);
- Attachment 15-H-R, Phase I - C&I Bill Impact Schedules (three pages);
- Attachment 15-I-R, Alternative COSS Summary Schedules (four pages); and
- Attachment 15-J-R, Alternative Revenue Proof and Rate Design Schedules (two pages).

## II. Allocation of Transmission and High-Pressure Distribution Mains in the NIPSCO ACOSS

### A. NIPSCO's Presentation in Direct Testimony

**Q8. Please summarize the importance of the physical configuration of the transmission and distribution system to the development of the ACOSS.**

A8. As I discussed in my direct testimony, 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.

**Q9. What are the specific physical characteristics of the NIPSCO system?**

A9. As discussed by NIPSCO Witness Campbell in his direct testimony, the physical configuration of the NIPSCO system is a dispersed / multiple city-gate, integrated transmission / distribution and multiple-pressure based system.

**Q10. Please describe the P&A methodology.**

A10. As I described the P&A allocation method in my direct testimony, it is a simplified version of the Average and Excess demand allocation methodology, also referred to as the "used and unused capacity" method, which allocates demand related costs to the classes of service based on system and class load factor characteristics.

The P&A methodology employed in the NIPSCO ACOSS weighted the peak demands (56%) and average demands (44%) according to the NIPSCO system load factor, then allocated the peak demand portion of the system capacity costs on the design day peak demand, and allocated the average demand portion of the system capacity costs on a throughput basis.

**Q11. Please summarize the rationale from your direct testimony for choosing the P&A method to allocate NIPSCO's investment in its transmission plant.**

A11. 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 P&A demand allocation method reflecting the NIPSCO system load factor of 44 percent was used to ratably allocate transmission plant.

**Q12. Please summarize the method used to allocate NIPSCO's investment in its high-pressure distribution plant.**

A12. 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.

**Q13. Are some NIPSCO customers served directly from the transmission or high-pressure distribution systems?**

A13. Yes. However, the vast majority of NIPSCO's customers are <u>not</u> directly connected to either the transmission system or high-pressure distribution system. The peak demands of customers that are directly connected to these high-pressure pipelines were excluded from the allocation of the downstream distribution mains, including 58 Rate 428/128 customers.

**B. <u>Positions of the Parties</u>**

**Q14. Please summarize the parties' positions and proposals related to NIPSCO's use of the P&A method for allocation of transmission mains in the ACOSS.**

A14. IG witness Mr. Phillips stresses that the P&A method is at odds with system design and cost causation, and recommends that a peak day demand allocation method be used in place of NIPSCO's proposed P&A method. Mr.

Philips states that design day peak demand by class best reflects the actual design of the system and is the method used by NIPSCO in its last base rate case. He points out that NIPSCO included a peak day demand allocation methodology for transmission plant as an alternate approach to its current case-in-chief, which is consistent with the methodology used in NIPSCO's last base rate case.[1] SDI witness Mr. Higgins also recommends that the Commission reject the use of the P&A method for purposes of allocating transmission plant because the P&A method unreasonably shifts costs to higher-load factor customer classes. He recommends that the Commission require NIPSCO to allocate transmission plant using the design day peak allocation method, as NIPSCO did in the ACOSS submitted in its last general rate case.[2]

### C. <u>NIPSCO's Rebuttal Position</u>

**Q15. What is your response to the argument that design day peak demand by class best reflects the actual capacity design of the pipeline system?**

A15. I do not disagree. In fact, as I stated in my direct testimony (as quoted variously by Mr. Higgins and Mr. Phillips in their direct testimonies), from a

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1 Phillips Direct at 3:5-15.
2 Higgins Direct at 4:6-10.

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.[3] For this reason, the Peak portion of the P&A methodology employed in the NIPSCO ACOSS uses the design day peak demands of the various customer classes.

**Q16. Does the National Association of Regulatory Commissioners ("NARUC") recognize alternative methods for allocation of demand or capacity costs?**

A16. Yes. The NARUC <u>Gas Distribution Rate Design Manual</u> states the following:

> Demand or capacity costs are allocated to customer classes based upon an analysis of system load conditions and on how each customer class affects such costs. These are largely joint or common costs, and their allocation generates the largest controversy surrounding a cost of service study. This subject has been studied and argued for years without resolution, and often represents the largest item which can dramatically alter the result of a study.[4]

The NARUC Manual discusses several cost allocation methodologies employed by natural gas utilities:

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[3] Amen, Exh. 15 at 23:15-18
[4] NARUC, <u>Gas Distribution Rate Design Manual</u>, at 25.

> The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.[5]

**Q17. Are there other cost-related considerations particular to NIPSCO's transmission system that influenced your choice of the P&A methodology?**

A17. Yes. I provided the following response to an IG information request that asked whether there had been any material changes in circumstances subsequent to the filing of NIPSCO's ACOSS in Cause No. 43894 that have a significant bearing on the selection of the method for allocating transmission plant investment:

> During discussions with NIPSCO, the following information was considered in selecting the method for allocating transmission investment:
>
> - The significant investment in transmission mains, since the filing of NIPSCO's ACOSS in Cause No. 43894, in expanding and upgrading the transmission system;
> - The integration of the Kokomo Gas and Northern Indiana Fuel & Light distribution systems into the NIPSCO pipeline system; and
> - The role that the transmission system plays in providing access to multiple trading points and supply basins for

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[5] Ibid, at 27.

purposes of sourcing gas supplies to the benefit of transportation and sales customers. [6]

**Q18. Please expand on the information you provided in the aforementioned response to the IG information request.**

A18. The following illustrative examples were compiled from my discussions with NIPSCO pipeline operations personnel familiar with improvement to the transmission system over the last several years as well as the TDSIC investments in the transmission system, which I have categorized 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

[6] Industrial Group's Request 2-027.

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 the Northwestern Indiana, 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 will eventually 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 IG customer load is located in Zone A on the NIPSCO transmission system.[7] This zone is supplied by five of the seven interstate pipelines that are connected to the NIPSCO transmission system.[8] 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 at near capacity to serve the demand on this system. However, the three POD have been configured in such a way to allow for supply diversity, redundancy, and operational flexibility. Under most conditions, this benefits the IG customers by allowing them to move large quantities of supply to any one or more of the POD to minimize their supply costs. Although two of the Zone A pipelines currently have no physical interconnection to some IG customers, NIPSCO allows them to source significant amounts of supply

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[7] Under peak weather conditions, IG transportation customers comprise approximately 25-35% of load; in January 2018, the "Big 9" (the 9 largest gas usage facilities in Northwest Indiana) was 30-50% of daily sendout. In July 2017, the Big 9 were 60-70% of daily sendout, averaging 49% of annual system throughput.

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

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 will 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.

**Q19. Mr. Phillips stated that the "average demand method or variations of that method have not been endorsed by the Commission."[9] Do you agree?**

A19. No. In a prior NIPSCO gas general rate case, the Commission approved the Company's proposed use of the P&A method, as modified by a Commission staff witness:

> Ms. Downton substantially modified Petitioner's peak and average method used for allocating demand-related costs. She allocated Petitioner's transmission system costs giving equal weight to the average of Petitioner's 3-day peak demands and the average daily consumption during the three winter months of December, January and February, rather than the whole year, as Petitioner had done… Ms. Downton's modifications and conclusions were not challenged or

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[9] Phillips Direct at 16:18-22.

> disputed by Petitioner. We find they are reasonable and should be accepted.[10]

The Commission has provided other commentary on the subject of previously approved cost of service methodologies that is pertinent to this issue:

> We have noted our preference to utilize previously approved allocation methodologies unless evidence demonstrates that system operating characteristics have changed since the last approved COSS allocation methodology.[11]

## III. <u>Non-Residential Rate Design Issues – Schedule 428/128</u>

### A. <u>NIPSCO's Presentation in Direct Testimony</u>

**Q20. Please summarize NIPSCO's proposed structural rate design changes for Schedule 428/128 in your direct testimony.**

A20. The Company introduced a Demand Charge for the two Transportation & Transportation Balancing Services (Rates 428 and 438). As indicated in my direct testimony, 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.

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[10] Northern Indiana Public Serv. Co., 97 P.U.R. 4th 259, Cause No. 38380, October 26, 1988.
[11] Northern Indiana Public Serv. Co., 2010 Ind. PUC LEXIS 294, at *263.

The Company proposes to establish the initial Demand Charges for these two rate schedules to recover approximately 25 percent of fixed demand-related costs of providing distribution service to these rate schedules. Under the Company's proposal, the demand billing determinant for customers served under these rates will be initially determined at the average daily usage during the three billing months of December 2015 through February 2016.

**B. <u>Positions of the Parties</u>**

**Q21. Please provide a summary of the parties' recommendations regarding the Schedule 428/128 rate structure.**

A21. SDI witness Mr. Higgins proposes to differentiate the rate design within Rate Schedule 428/128 between the customers receiving service at high pressure and those customers receiving service at the lower distribution pressure. IG witness Mr. Phillips recommended that the current Rates 428 and 438 rate forms be maintained and that NIPSCO's proposed Demand Charge be rejected.[12] Mr. Phillips states that the underlying demand volume for the proposed Demand Charge that he challenges, that is, average winter usage from a previous quarter (December 2015 through February 2016) is not an up-

[12] Phillips Direct at 3:33-34.

to-date price signal, and not peak day demands. In addition, he asserts that the current Schedule 428/128 rate structure contains accurate fixed cost recovery through its customer charge and high price first volumetric rate block.

### C. NIPSCO's Rebuttal Position

#### 1. Bifurcated Rate Design for Schedule 428/128

**Q22. What is your response to Mr. Higgins' proposal to restructure Schedule 428/128 to differentiate between those customers receiving service from high-pressure mains versus those served from distribution-pressure mains?**

A22. NIPSCO is not opposed to the concept of a bifurcated Schedule 428/128 similar to the approach embodied in Mr. Higgins' proposal, with recognition of both the underlying rationale, sufficient cost basis, and support from its Schedule 428 customers. However, NIPSCO prefers to do so with a more complete cost analysis within the ACOSS. The basis for Mr. Higgins' revision to the Schedule 428 rate structure is a NIPSCO response to an SDI information request whereby the allocation of non-high-pressure distribution mains in the ACOSS was removed from the 428 class.[13] The removal of the

[13] See NIPSCO Response to SDI 5-002(a), included in SDI Attachment KCH-1.

lower pressure distribution mains resulted in the $5.8 million estimate of the costs attributable to the Schedule 428 customers served from the lower-pressure mains throughout the distribution system referenced in Mr. Higgins' testimony.[14]

**Q23. What other distribution plant categories within the ACOSS would have significant impact on the differentiation of cost responsibility between the Schedule 428 customers served from the high-pressure system and lower distribution-pressure[15] mains?**

A23. The two most important distribution plant categories other than mains that would impact the ACOSS results for Schedule 428 customers would be the metering and associated pressure regulating equipment on the customers' premises, and the service lines that connect the customers to the distribution mains. Therefore, an analysis of these plant categories should be made to identify the respective cost responsibility of the high-pressure and lower, distribution-pressure subgroups within Schedule 428. The importance of this additional analysis relates to the hypothesis that the metering, pressure

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[14] Higgins Direct at 6:19-21.

[15] Distribution pressure mains on the NIPSCO system operate at pressure levels below 60 Pounds per Square Inch Gage ("PSIG").

regulating equipment and service pipe attributable to the customers directly served by the transmission and high-pressure distribution mains will be larger and costlier than the same facilities for the customers connected to the lower-pressure distribution mains.

**Q24. Have you conducted the foregoing cost analysis?**

A24. Yes. Company personnel compiled the necessary distribution plant data to facilitate the analysis and segmentation of the metering, pressure regulating equipment, and service line costs into the high-pressure and distribution-pressure subgroups within Schedule 428. An alternative version of the ACOSS was then developed to provide results for the high-pressure and distribution-pressure subgroups within Schedule 428, which are presented in Section VIII of my testimony. The alternative ACOSS results for Schedule 428 will provide a proper cost-based foundation for the eventual bifurcation of the proposed revenue requirement and rate structure between the high-pressure and distribution-pressure customers of Schedule 428.

**Q25. Is NIPSCO proposing to implement a bifurcated Schedule 428 at this time?**

A25. No. NIPSCO prefers to maintain Schedule 428 in its present form, as presented in its case-in-chief. However, if the Commission wishes to adopt the concept of a bifurcated Schedule 428 rate structure, as embodied in SDI's proposal, the Company felt it imperative to provide a sound, foundational cost basis for doing so, beyond the conceptual underpinnings. Therefore, the alternative ACOSS, a proposed separation of the Schedule 428 revenue requirement between the high-pressure and distribution-pressure customer groups, and a bifurcated rate structure, is presented in Section VIII of my testimony.

### 2. <u>Proposed Demand Charge for Schedule 428/128</u>

**Q26. What is your response to Mr. Phillips' recommendation to reject NIPSCO's proposed Demand Charge for Schedule 428/128?**

A26. The primary purpose of the introduction of the Demand Charges for Schedules 428/128 and 438/138 was not directed toward fixed cost recovery, as Mr. Phillips implied in his direct testimony.[16] Rather, the purpose was to reduce existing intra-class subsidies and encourage high load factor use of the distribution system by sending economically efficient price signals to the

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[16] Phillips Direct at 19:18-22.

customers within these two rate schedules.[17] Large-use industrial customers exhibit a wide range of load factors, which can cause some inequities within a rate class. The volumetric block rate tends to be discriminatory against high load factor customers with low average usage, while favoring large-use customers even though they may have lower than average load factors. Because of the greater variance in the load characteristics of large-use customers, natural gas distribution companies prefer rate forms that consider a customer's demand and load factor.[18] The Schedule 428 customers, are a diverse group, in size of annual throughput and load factor. The average cost per unit of delivered volume for Schedule 428 customers should be a function not only of the size of their annual throughput but their load factor as well.

## IV. Residential Rate Design – Monthly Customer Charge

### A. NIPSCO's Presentation in Direct Testimony

**Q27. Please summarize NIPSCO's proposal to increase the residential monthly customer charge for Schedule 411/111, as presented in your direct testimony.**

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[17] Load Factor is typically defined as the relationship of average load to peak load. Unit costs decrease with increasing load factor.

[18] See American Gas Association, Gas Rate Fundamentals, at 168-169.

A27. NIPSCO proposed an increase to the residential monthly customer charge for Schedule 411/111 from its present level of $11.00 to $19.50. 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 was depicted in Attachment 15-I to my direct testimony. This exhibit presented a monthly and annual bill for an average residential customer using 824 Therms per year, at the proposed revenue level for the class, comparing the proposed $19.50 customer charge with retaining the current $11.00 charge.

**Q28. Please discuss the fairness of the Company's proposed customer charge versus the current customer charge.**

A28. 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. The intent is to evolve the residential rate design, so that a typical customer will be less likely to "overpay" or "underpay" his or her share of the non-gas costs based on the customer's consumption relative to average consumption.

**B. Positions of the Parties**

**Q29. Please provide a summary of the selected parties' recommendations regarding the residential monthly customer charge.**

A29. OUCC witness Mr. Krieger recommended the Commission reject NIPSCO's proposed monthly customer charge and approve a customer charge not to exceed 50% of the approved margin percentage increase. Mr. Krieger included A.G.A.'s May 28, 2015 Energy Analysis titled, Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 Update, as partial support for his recommendation.[19]

**C. NIPSCO's Rebuttal Position**

**Q30. What is your response to Mr. Krieger's recommendation?**

A30. While NIPSCO witness Caister will address the policy considerations related to the level of the residential monthly customer charge, I will present updated customer charge information since the May 2015 date of the A.G.A. Energy Analysis document referenced by Mr. Krieger. Black & Veatch has compiled residential monthly customer charges from gas utilities listed in the A.G.A. document from the East North Central and West North Central regions, as of

[19] See Krieger, Exh. 8, Attachment BRK-2.

March 2018, including those gas utilities that have completed general rate cases since May 2015. This information is presented in Attachment 15-A-R, Customer Charge Benchmarking, pages 1 and 2.

In the East North Central region (Illinois, Indiana, Michigan, Ohio, and Wisconsin), the largest monthly customer charge from the Black & Veatch survey is $33.03 (Duke Energy Ohio) and the smallest monthly customer charge is $5.00 (Integrys, MI). The median customer charge among gas utilities with updated rates since May 2015 is $12.69, which is an average increase of $1.69. Of the fifteen gas utilities in the region with updated rates, eight had increased residential customer charges, six kept the residential customer charges constant, and one reduced the residential customer charge.

In the West North Central region (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota), the largest monthly customer charge from the Black & Veatch survey is $20.00 (Liberty Utilities, MO and Spire-MGE, MO) and the smallest monthly customer charge is $3.50 (MDU-Great Plains, ND). The median customer charge among gas utilities with updated rates since May 2015 is $13.16, which is an average increase of $3.16.

Of the eighteen gas utilities in the region with updated rates, seven had increased residential customer charges, eight kept the residential customer charges constant, and three reduced the residential customer charges. Our survey data did not distinguish between litigated rate determinations versus rate case settlements.

**Q31. What conclusions have you drawn from both the A.G.A. Energy Analysis report and the updated Black & Veatch customer charge survey data?**

A31. The range of monthly customer charge levels across the U.S. from the A.G.A. report as well as the two Midwestern regions surveyed by Black & Veatch indicate a range of cost differences and costing methodologies employed by gas utilities, and the related cost recovery policies by state regulatory bodies. As indicated in the A.G.A. report, only five responding member companies estimated that they recovered 25 percent or less of the fixed costs through the customer charge. Based on an $11.25 median monthly charge in the A.G.A. report, on average the full-cost customer charge would be about $24.00 to recover a utility's fixed customer-related costs, on a monthly basis.[20] While

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[20] American Gas Association, "Energy Analysis, Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 Update," at page 4.

modest growth has occurred in the median level of monthly customer charges since 2015, the Black & Veatch survey data shows progress by utilities in matching the level of customer-related costs with the corresponding fixed charges through which those costs are recovered.

## V. <u>ACOSS Results under NIPSCO's Phase II Revenue Requirement</u>

### A. <u>ACOSS Revisions from Supplemental Direct Filing</u>

**Q32. Please discuss revisions to the ACOSS related to NIPSCO's proposed Phase II revenue requirement.**

A32. The following revisions were made to the ACOSS:

- Adjustments were made to the input cost accounts in the ACOSS to correspond to the Phase II revenue requirements, as further discussed by Company Witness Konold;
- The current revenues by rate class were updated to reflect the TCJA, as described by Company Witness Konold; and
- The meter study and design day peak calculations within the ACOSS were revised to reflect partial-year, inter-class customer migrations between rate classes.

**Q33. Please describe the updates to the meter study and design day calculations.**

A33. In the Direct and Supplemental Direct filing partial-year, inter-class customer migrations were reflected in the customer billing determinants within the ACOSS and current revenues. However, the customer migrations were not included in the meter study or design day peak calculations. During the preparation of the ACOSS model, the Company provided details on the partial-year customer migrations, and the meter study and design day peak calculations were revised to reflect them. The revisions impacted rate classes 421, 425, 428 and 438. In addition, the design day peak calculations were updated to remove the monthly therms and customer counts for three NIPSCO electric generation stations that had been inadvertently included in the initial peak day study. The inter-class customer count and associated therm migrations are provided in the following Table 1. As noted above, three NIPSCO electric generation stations were removed from the design day calculations and are shown within the 'Removed' line.

**Table 1**

**Customer Migrations in Rebuttal Case**

| Rate Class | Customer Count | | | Therms | | |
|---|---|---|---|---|---|---|
| | Moving Out | Moving In | Net Change | Moving Out | Moving In | Net Change |
| **421** | (2) | 3 | 22 | (711,318) | 1,882,662 | 1,171,344 |
| **425** | (3) | 5 | 2 | (1,151,905) | 1,726,319 | 574,414 |
| **428** | (14) | 1 | (13) | (16,157,633) | 744,265 | (15,413,368) |
| **438** | (5) | 12 | 7 | (2,173,404) | 6,474,241 | 4,300,837 |
| **Removed** | - | 3 | 3 | - | 9,366,773 | 9,366,773 |
| **Total** | (24) | 24 | - | (20,194,260) | 20,194,260 | - |

**B. ACOSS Results at Present and Proposed Rates by Class**

**Q34. Please provide a summary of the ACOSS results under NIPSCO's proposed Phase II revenue requirement.**

A34. Summary schedules for the ACOSS results under the Company's proposed Phase II revenue requirement of $436,585,562 are presented in Attachment 15-B-R, ACOSS Summary Schedules, pages 1 – 4. Operating Income and Current Rate of Return by class are presented on page 1, lines 19 and 20 of the exhibit. The revenue (deficiencies)/surpluses by class at the proposed system rate of return are shown on page 2, line 43.

**C. <u>Unit Cost Analysis</u>**

**Q35. Have you included a unit cost analysis by class in <u>Attachment 15-B-R</u>?**

A35. Yes. The functionalized and classified unit costs by class are shown on page 4 of <u>Attachment 15-B-R</u>, along with the corresponding billing determinants used to compute the demand, commodity and customer unit costs.

## VI. <u>Proposed Phase II Revenue Allocation and Rate Design</u>

### A. <u>Phase II Revenue Allocation</u>

**Q36. How does NIPSCO propose to distribute the Phase II revenue increase among the rate schedules?**

A36. The proposed margin increases by class and corresponding percentage increases are shown on <u>Attachment 15-B-R</u>, page 2, lines 50 and 51 respectively, and appear in Table 2 below, along with estimated percentage total bill increases and proposed rates of return by class. The Company followed the same mitigation approach in the apportionment of margin increases to the respective classes as it employed in the direct case-in-chief; that is, limiting increases by the mitigation parameter of 150 percent of the system average increase. In so doing, the Company recognized the tension caused when removing subsidies between classes and the rate increases that result. The mitigation parameter limited the proposed increase to Schedule 428/128.

**Table 2**

**Proposed Phase II Margin Increase by Class**

| Description | Total Company | 411 | 415 | 421 | 425 | 428 | 434 | 438 |
|---|---|---|---|---|---|---|---|---|
| Proposed Margin Increase | $138,134,204 | $86,856,960 | $208,034 | $27,301,591 | $2,948,015 | $19,110,566 | - | $1,507,779 |
| Percent Margin Change | 47.34% | 46.55% | 9.58% | 44.28% | 27.96% | 70.51% | 0.00% | 44.94% |
| Percent Total Bill Increase | 9.64% | 19.75% | 3.96% | 14.36% | 5.07% | 2.66% | 0.00% | 8.12% |
| Proposed Rate of Return | 6.90% | 6.72% | 6.90% | 10.39% | 9.59% | 3.80% | 255.32% | 9.75% |

## B. Phase II Rate Design and Bill Impacts

**Q37. How were the proposed Phase II rates for each Rate Schedule determined?**

A37. Detailed calculations for each rate component of each Rate Schedule are included in Attachment 15-C-R, Phase II Rate Mitigation, Revenue Proof, and Rate Design Schedules, pages 1 – 4. As the exhibit shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 15-C-R provides a revenue proof of the transition of revenues at current rates using forecasted 2018 billing determinants, and existing 400 series rate classes to the proposed revenues at the 100 series rate classes. The proposed Phase II rate components by Rate Schedule are listed in Table 3, below.

**Table 3**

**Phase II - Schedule of Proposed Rates**

| Rate Schedule | Rate Code | Monthly Charge | Demand Charge per Therm | Distribution Charge per Therm |
|---|---|---|---|---|
| Residential | 111 | $19.50 | ---- | $0.15560 |
| Multi-Family | 115 | $17.50 | ---- | $0.17372 |
| General Service – Small | 121 | $53.00 | ---- | $0.14847 |
| General Service – Large | 125 | $400.00 | ---- | Block 1 $0.09261<br>Block 2 $0.08261<br>Block 3 $0.06261<br>Block 4 $0.05761 |
| Large Transportation<br>Balancing Charges:<br>Option 1 - $1,590.00<br>Option 2 - $660.00 | 128 | $1,000.00 | $0.12124 | Bock 1 $0.03828<br>Block 2 $0.00975 |
| C&I Off-Peak Interruptible | 134 | $637.00 | ---- | $0.16591[21] |
| General Transportation<br>Balancing Charge:<br>Option 1 - $365.00 | 138 | $750.00 | $0.3099 | Block 1 $0.05762<br>Block 2 $0.05662<br>Block 3 $0.05562<br>Block 4 $0.05462 |

**Q38. Have you calculated bill impacts for the Residential, Commercial and Industrial rate classes that result from the Company's Phase II rate design proposal?**

[21] 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.

A38. Yes. The monthly bill impacts for a Residential gas customer is depicted on Attachment 15-D-R, Phase II Typical Residential Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels. Attachment 15-E-R, Phase II C&I Bill Impact Schedules, pages 1 – 3, provides bill comparisons at various ranges of consumption levels for all C&I rate schedules.

## VII. Proposed Phase I Revenue Allocation and Rate Design

### A. Phase I Revenue Allocation

**Q39. Please explain the basis for NIPSCO's Phase I revenue allocation.**

A39. The reference point for the Phase I total system revenue requirement and thus, the basis for the proposed Phase I class-by-class revenue allocation, is the Phase II total revenue requirement of $436,585,562. A reduction of $26,604,449 or 6.09 percent from the Phase II revenue requirement was made to establish the interim, Phase I revenue requirement of $409,981,113. Equal percentage reductions of 6.19 percent were applied to each Rate Schedule as shown in Table 4, below. The difference between the overall system-wide percentage reduction of 6.09 and the class-by-class percentage reductions of 6.19 is due to the unchanged level of miscellaneous revenue between Phase I and Phase II.

**Table 4**

**Phase I Margin by Class**

| Class | | 12.31.2018 Proposed Margin | Equalized Reduction Phase II to Phase I | 5.31.2018 Proposed Margin |
|---|---|---|---|---|
| **System Total** | | **$ 429,730,539** | | **$ 403,126,090** |
| Residential | 411 | 273,450,242 | 6.19% | 256,521,045 |
| Multi-Family | 415 | 2,379,497 | 6.19% | 2,232,183 |
| General Service Small | 421 | 88,962,126 | 6.19% | 83,454,516 |
| General Service Large | 425 | 13,491,823 | 6.19% | 12,656,550 |
| Large Transp. | 428 | 46,215,315 | 6.19% | 43,354,143 |
| C&I Off-Peak Interruptible | 434 | 368,385 | 6.19% | 345,579 |
| General Transportation | 438 | 4,863,150 | 6.19% | 4,562,074 |
| Miscellaneous Revenues Margin | | 6,855,023 | 0.00% | 6,855,023 |
| **Total Margin** | | **$ 436,585,562** | **6.09%** | **$ 409,981,113** |

**B. Phase I Rate Design and Bill Impacts**

**Q40. How were the proposed Phase I rates for each Rate Schedule determined?**

A40. The proposed Phase I revenue levels by Rate Schedule were effectuated by ratable reductions in the volumetric Distribution Charges from the level of these charges in the Phase II rate design. The fixed Monthly Charges and Demand Charges in each Rate Schedule remained unchanged between Phase II and Phase I. Detailed calculations for each Distribution Charge component of each Rate Schedule are included in Attachment 15-F-R, Phase I Revenue Proof and Rate Design Schedules, pages 2 – 4. As the exhibit shows, the targeted total Phase I rate schedule revenue will be achieved using the proposed rates and volumes. The proposed Phase I rate components by Rate Schedule are listed in Table 5, below

**Table 5**

**Phase I - Schedule of Proposed Rates**

| Rate Schedule | Rate Code | Monthly Charge | Demand Charge per Therm | Distribution Charge per Therm |
|---|---|---|---|---|
| Residential | 111 | $19.50 | ---- | $0.12840 |
| Multi-Family | 115 | $17.50 | ---- | $0.15427 |
| General Service – Small | 121 | $53.00 | ---- | $0.13101 |
| General Service – Large | 125 | $400.00 | ---- | Block 1 $0.08575<br>Block 2 $0.07575<br>Block 3 $0.05575<br>Block 4 $0.05075 |
| Large Transportation<br>Balancing Charges:<br>Option 1 - $1,590.00<br>Option 2 - $660.00 | 128 | $1,000.00 | $0.12124 | Bock 1 $0.02939<br>Block 2 $0.00975 |
| C&I Off-Peak Interruptible | 134 | $637.00 | ---- | $0.15508[22] |
| General Transportation<br>Balancing Charge:<br>Option 1 - $365.00 | 138 | $750.00 | $0.30990 | Block 1 $0.05169<br>Block 2 $0.05069<br>Block 3 $0.04969<br>Block 4 $0.04869 |

The monthly bill impacts for a Residential gas customer is depicted on Attachment 15-G-R, Phase I Typical Residential Monthly Bill Comparison and Residential Bill Impacts at Various Usage Levels. Attachment 15-H-R, Phase I

[22] 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.

C&I Bill Impact Schedules, pages 1 – 3, provides bill comparisons at various ranges of consumption levels for all C&I rate schedules.

## VIII. Alternative ACOSS, Revenue Allocation, and Rate Design under Bifurcation of Schedule 428/128

### A. Alternative ACOSS Summary under Bifurcated Schedule 428/128

**Q41. Please provide a summary of the Alternative ACOSS results under NIPSCO's proposed Phase II revenue requirement.**

A41. As discussed earlier in Section III-C-1, of my rebuttal testimony, an alternative version of the ACOSS was developed to provide results for the high-pressure and distribution-pressure subgroups within Schedule 428/128. The alternative ACOSS results, including the high-pressure and distribution-pressure subcategories within Schedule 428/128, are summarized in Attachment 15-I-R, pages 1 – 4.

### B. Alternative Schedule 428/128 Revenue Allocation and Rate Design

**Q42. Please describe the alternative Schedule 428/128 bifurcated revenue allocation and rate design.**

A42. A proposed separation of the Schedule 428/128 revenue requirement between the high-pressure and distribution-pressure customer subgroups was made using the alternative ACOSS results, and a bifurcated rate structure created, both of which are presented in Attachment 15-J-R. The approach to recovering the assigned revenue responsibility of each of the two subgroups in the bifurcated rate structure was consistent with that presented in NIPSCO's case-in-chief. The monthly charge for Schedule 428/128 was set at $1,000 for both subgroups, the respective demand charges were set at 25% of their respective demand-related unit costs, and the remainder of the subgroups' revenue responsibility was assigned to the volumetric Distribution Charge block rates. The Distribution Charge tail block rate for each of the two subgroups was set at the same unit rate per therm to provide the same price signal to large customers within Schedule 428/128 regardless of the pipeline operating pressure of the mains to which the customers are connected.

## IX. Summary of Rebuttal Findings and Recommendations

**Q43. Please summarize your findings and recommendations from your rebuttal testimony.**

A43. First, regarding the selection of a costing methodology for the NIPSCO transmission plant, this transmission system provides the following functional characteristics in addition to its design day peak capacity capability:

- Increased supply diversity, and price options, for transportation customers as well as core GCA sales customers.
- Transfer of supply across the NIPSCO pipeline system, which allows transportation customers to receive supply at various points of interstate pipeline delivery, whether near or far from their location on the system.
- 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 operational improvements in recent years, cost-saving supply sourcing flexibility and associated pricing options described above were influential in my recommendation that the P&A allocation method be used for the NIPSCO transmission system mains.

Second, regarding the concept of a bifurcated Schedule 428/128, NIPSCO is not opposed to a similar approach to that embodied in SDI witness Mr. Higgins' proposed rate structure, provided that it is supported by NIPSCO's Schedule 428/128 customers. For this reason, I have provided an Alternative ACOSS, Schedule 428/128 revenue allocation, and bifurcated rate design as presented in my rebuttal testimony. However, the Company prefers to maintain Schedule 428/128 in its present form, as presented in its case-in-chief.

Third, because of the greater variance in the load characteristics of large-use customers, NIPSCO prefers a rate design for its Schedule 428/128 that considers a customer's annual demand and load factor. In particular, Schedule 428/128 customers are a diverse group, in size of annual throughput and load factor. The average cost per unit of delivered volume for Schedule 428/128 and Schedule 438/138 customers should be a function not only of the size of their annual throughput but their load factor as well. Therefore, I recommend that the proposed demand charges for Schedule 428/128 and Schedule 438 be approved by the Commission.

Fourth, the range of residential monthly customer charge levels across the U.S. from the A.G.A. report, as well as the two Midwestern regions surveyed by Black & Veatch, indicate a range of cost differences and costing methodologies employed by gas utilities, and the related cost recovery policies by state regulatory bodies. Modest growth has occurred in the median level of residential monthly customer charges since 2015, and Black & Veatch's survey data supports the progress by utilities in matching the level of customer-related costs with the corresponding fixed charges through which those costs are recovered.

Fifth, the ACOSS results presented for NIPSCO's Phase II revenue requirement of $436,585,562, as summarized in <u>Attachment 15-B-R</u>, and the corresponding revenue apportionment and rate design, as presented in <u>Attachment 15-C-R</u>, should be approved by the Commission.

Finally, the revenue apportionment and rate design for the Phase I revenue requirement of $409,981,113, as presented in <u>Attachment 15-F-R</u> and <u>Attachment 15-G-R</u>, should also be approved by the Commission

**Q44. Does this conclude your prepared rebuttal testimony?**

A44. Yes.

**VERIFICATION**

I, Ronald J. Amen, Director, Black & Veatch Management Consulting, LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Ronald J. Amen

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Ronald J. Amen

Dated: March 27, 2018

NATURAL GAS CUSTOMER CHARGE - West North Central

| Line No. | Company | State | AGA Report Residential | B&V Update (Mar 2018) Residential | Change | Effective Date |
|---|---|---|---|---|---|---|
| 1 | ALLIANT - INTERSTATE P&L IA | IA | $12.82 | $12.82 | $0.00 | 2/15/2016 |
| 2 | BLACK HILLS ENERGY - IA | IA | $18.25 | $18.25 | $0.00 | 9/24/2015 |
| 3 | LIBERTY UTILITIES IA | IA | $7.95 | $16.00 | $8.05 | 6/18/2017 |
| 4 | MIDAMERICAN ENERGY COMPANY IA | IA | $10.00 | $10.00 | $0.00 | 4/20/2016 |
| 5 | ATMOS ENERGY CORPORATION KS | KS | $18.19 | $18.91 | $0.72 | 3/17/2016 |
| 6 | BLACK HILLS ENERGY - KS | KS | $17.25 | $17.25 | $0.00 | 1/1/2015 |
| 7 | ONEOK - KANSAS GAS SERVICE | KS | $15.35 | $16.70 | $1.35 | 1/1/2017 |
| 8 | CENTERPOINT ENERGY MN | MN | $9.50 | $9.50 | $0.00 | 12/1/2016 |
| 9 | INTEGRYS - MERC MN | MN | $8.50 | $9.50 | $1.00 | 3/1/2017 |
| 10 | MONTANA - DAKOTA UTILITIES GREAT PLAINS MN | MN | $6.50 | $6.90 | $0.40 | 6/7/2017 |
| 11 | XCEL - NORTHERN STATES POWER CO OF MINNESOTA | MN | $9.00 | $9.00 | $0.00 | 7/10/2015 |
| 12 | AMEREN - UNION ELECTRIC CO | MO | $15.00 | $15.00 | $0.00 | 2/20/2011 |
| 13 | LACLEDE GAS CO | MO | $20.70 | $19.50 | ($1.20) | 7/3/2013 |
| 14 | LIBERTY UTILITIES MO | MO | $20.00 | $20.00 | $0.00 | 1/4/2015 |
| 15 | SOUTHERN UNION/SPIRE - MISSOURI GAS ENERGY | MO | $27.87 | $20.00 | ($7.87) | 3/3/2018 |
| 16 | THE EMPIRE DISTRICT GAS COMPANY | MO | $16.50 | $16.50 | $0.00 | 4/1/2010 |
| 17 | MONTANA - DAKOTA UTILITIES CO ND | ND | $14.81 | $19.33 | $4.52 | 12/13/2016 |
| 18 | MONTANA - DAKOTA UTILITIES GREAT PLAINS ND | ND | $3.50 | $3.50 | $0.00 | 7/1/2017 |
| 19 | XCEL - NORTHERN STATES POWER CO OF NORTH DAKOTA | ND | $18.48 | $18.48 | $0.00 | 7/1/2007 |
| 20 | BLACK HILLS ENERGY - NE | NE | $13.50 | $13.50 | $0.00 | 3/1/2017 |
| 21 | METROPOLITAN UTILITIES DISTRICT | NE | $13.72 | $13.72 | $0.00 | 1/2/2017 |
| 22 | MIDAMERICAN ENERGY COMPANY NE | NE | $10.00 | $16.00 | $0.00 | 10/1/2015 |
| 23 | NORTHWESTERN ENERGY LLC NE | NE | $8.00 | $8.00 | $0.00 | 12/1/2007 |
| 24 | SOURCEGAS LLC NE | NE | $15.00 | $15.00 | $0.00 | 2/1/2015 |
| 25 | MIDAMERICAN ENERGY COMPANY SD | SD | $8.87 | $8.00 | ($0.87) | 7/1/2015 |
| 26 | MONTANA - DAKOTA UTILITIES CO SD | SD | $8.40 | $7.41 | ($0.99) | 7/1/2016 |
| 27 | NORTHWESTERN ENERGY LLC SD | SD | $8.00 | $8.00 | $0.00 | 12/1/2011 |
| 28 | Median | | $13.50 | $15.00 | | |
| 29 | # Utilities that Increased Customer Charge | | 7 | | | |
| 30 | # Utilities that Kept Customer Charge Constant | | 16 | | | |
| 31 | # Utilities that Decreased Customer Charge | | 4 | | | |
| 32 | Among Utilities with Updated Rates since May 2015: | | | | | |
| 33 | Median | | $10.00 | $13.16 | | |
| 34 | # Utilities that Increased Customer Charge | | 7 | | | |
| 35 | # Utilities that Kept Customer Charge Constant | | 8 | | | |
| 36 | # Utilities that Decreased Customer Charge | | 3 | | | |
| 37 | AGA Report Date: | | 5/31/2015 | | | |
| 38 | Sources: Utility tariffs | | | | | |

NATURAL GAS CUSTOMER CHARGE - East North Central

| Line No. | Company | State | AGA Report Residential | B&V Update (Mar 2018) Residential | Change | Effective Date |
|---|---|---|---|---|---|---|
| 1 | AGL - Nicor | IL | $13.55 | $16.72 | $3.17 | 8-Feb-18 |
| 2 | Ameren - Illinois | IL | $22.31 | $21.35 | ($0.96) | 18-Dec-15 |
| 3 | Integrys - North Shore Gas Co | IL | $24.48 | $23.94 | ($0.54) | 26-Feb-15 |
| 4 | Integrys - Peoples Gas Light & Coke Co | IL | $30.83 | $30.84 | $0.01 | 26-Feb-15 |
| 5 | Liberty Utilities IL | IL | $9.90 | $15.24 | $5.34 | 1-Dec-15 |
| 6 | Midamerican Energy Company IL | IL | $12.69 | $12.69 | $0.00 | 11-Apr-17 |
| 7 | Mt Carmel Public Utility Co | IL | $15.00 | $15.00 | $0.00 | 1-Jan-14 |
| | | | | | | |
| 5 | Citizens Gas & Coke Utility | IN | $9.00 | $9.00 | $0.00 | 6-Sep-11 |
| 6 | Nisource - NIPSCO | IN | $11.00 | $11.00 | $0.00 | 1-Nov-13 |
| 7 | Vectren - Indiana Gas Co Inc | IN | $11.25 | $11.25 | $0.00 | 9-Sep-14 |
| 8 | Vectren - Southern Indiana Gas & Electric Co (Vectren South) | IN | $11.00 | $11.00 | $0.00 | 3-May-16 |
| | | | | | | |
| 9 | Consumers Energy Co | MI | $11.50 | $11.75 | $0.25 | 7-Aug-17 |
| 10 | Continental Energy - SEMCO | MI | $11.50 | $11.50 | $0.00 | 1-Apr-11 |
| 11 | DTE - Citizens Gas Fuel Co | MI | $10.50 | $10.50 | $0.00 | 2-Oct-17 |
| 12 | DTE - Michigan Consolidated | MI | $10.50 | $10.50 | $0.00 | 1-Jan-13 |
| 13 | Integrys - Michigan Gas Utilities Co | MI | $12.00 | $13.00 | $1.00 | 11-Dec-17 |
| 14 | Integrys - Wisconsin Public Service Corp MI | MI | $5.00 | $5.00 | $0.00 | 1-Jul-09 |
| 15 | XCEL - Northern States Power Co of Michigan | MI | $7.25 | $11.00 | $3.75 | 1-Jan-18 |
| | | | | | | |
| 14 | Dominion East Ohio | OH | $23.58 | $27.71 | $4.13 | 14-Feb-18 |
| 15 | Duke Energy Ohio | OH | $33.03 | $33.03 | $0.00 | 2-Dec-13 |
| 16 | Nisource - Columbia Gas of Ohio Inc | OH | $24.69 | $17.81 | ($6.88) | 1-Apr-12 |
| 17 | Vectren Energy Delivery of Ohio | OH | $18.37 | $18.37 | $0.00 | 1-Apr-11 |
| | | | | | | |
| 18 | Allete - Superior Water Light & Power Co | WI | $7.25 | $7.25 | $0.00 | 14-Aug-17 |
| 19 | Alliant - Wisconsin Power & Light Co | WI | $1.51 | $12.51 | $11.00 | 1-Jan-17 |
| 20 | City Gas Co | WI | $8.50 | $8.50 | $0.00 | 1-Jan-11 |
| 21 | Integrys - Wisconsin Public Service Corp WI | WI | $17.00 | $17.00 | $0.00 | 1-Jan-17 |
| 22 | Madison Gas & Electric Co | WI | $21.60 | $21.60 | $0.00 | |
| 23 | WE Energies | WI | $9.90 | $9.90 | $0.00 | 1-Mar-18 |
| 24 | Xcel - Northern State Power Co of Wisconsin | WI | $10.25 | $14.00 | $3.75 | 1-Jan-18 |
| | | | | | | |
| 25 | Median | | $11.50 | $12.69 | | |
| 26 | # Utilities that Increased Customer Charge | | 9 | | | |
| 27 | # Utilities that Kept Customer Charge Constant | | 17 | | | |
| 28 | # Utilities that Decreased Customer Charge | | 3 | | | |
| | | | | | | |
| 29 | Among Utilities with Updated Rates since May 2015: | | | | | |
| 30 | Median | | $11.00 | $12.69 | | |
| 31 | # Utilities that Increased Customer Charge | | 8 | | | |
| 32 | # Utilities that Kept Customer Charge Constant | | 6 | | | |
| 33 | # Utilities that Decreased Customer Charge | | 1 | | | |
| | | | | | | |
| 34 | AGA Report Date: | | 5/31/2015 | | | |
| | | | | | | |
| 35 | Sources: Utility tariffs | | | | | |

## Northern Indiana Public Service Company
## Class Cost of Service Study
## Phase II Test Year Ending 12/31/2018

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. 428 | C&I Off-Peak Interruptible 434 | General Transp. 438 |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **Rate Base** | | | | | | | | |
| 1 | Plant in Service | $ 2,931,233,313 | $ 1,830,942,419 | $ 16,025,307 | $ 518,537,316 | $ 80,180,483 | $ 461,038,281 | $ 198,060 | $ 24,311,447 |
| 2 | Accumulated Reserve | (1,524,896,207) | (1,070,451,405) | (8,944,369) | (270,977,202) | (35,265,899) | (129,872,392) | (116,344) | (9,268,595) |
| 3 | Other Rate Base Items | 113,872,189 | 64,802,307 | 614,649 | 32,300,618 | 10,261,569 | 5,611,844 | 1,914 | 279,289 |
| 4 | Total Rate Base | $ 1,520,209,295 | $ 825,293,322 | $ 7,695,586 | $ 279,860,732 | $ 55,176,153 | $ 336,777,733 | $ 83,630 | $ 15,322,140 |
| | **Margin at Current Rates** | | | | | | | | |
| 5 | Delivery Sales Margin | 253,890,377 | 161,226,006 | 1,748,693 | 52,486,271 | 8,601,429 | 26,355,285 | 368,385 | 3,104,307 |
| 6 | TDSIC Margin | 30,889,257 | 20,761,654 | 368,794 | 7,263,627 | 1,494,654 | 749,464 | - | 251,063 |
| 7 | Other Riders Exlcuding TDSIC | 7,017,960 | 4,605,622 | 53,977 | 1,910,637 | 447,724 | - | - | 0 |
| 8 | Miscellaneous Revenues Margin | 6,653,764 | 4,277,223 | 46,343 | 980,929 | 159,243 | 1,155,750 | 2,109 | 32,167 |
| 9 | Total Margin | $ 298,451,358 | $ 190,870,506 | $ 2,217,806 | $ 62,641,465 | $ 10,703,051 | $ 28,260,499 | $ 370,494 | $ 3,387,538 |
| 10 | Total Margin Exlcuding Misc. Revenues | $ 291,797,594 | $ 186,593,282 | $ 2,171,463 | $ 61,660,536 | $ 10,543,808 | $ 27,104,749 | $ 368,385 | $ 3,355,371 |
| 11 | Gas Costs (Trackable) | 316,907,620 | $ 207,808,679 | $ 2,403,993 | $ 84,370,019 | $ 20,731,302 | $ 1,434,877 | $ - | $ 158,748 |
| 12 | Total Sales Revenue | $ 615,358,978 | $ 398,679,185 | $ 4,621,799 | $ 147,011,484 | $ 31,434,353 | $ 29,695,376 | $ 370,494 | $ 3,546,286 |
| | **Expenses at Current Rates** | | | | | | | | |
| 13 | Operation and Maintenance | 201,760,740 | 139,383,666 | 1,168,501 | 35,128,025 | 4,423,958 | 19,413,076 | 65,456 | 2,178,060 |
| 14 | Amortization and Depreciation Expense | 75,739,074 | 50,795,598 | 423,433 | 12,616,872 | 1,767,496 | 9,588,923 | 5,304 | 541,449 |
| 15 | Taxes Other Than Income | 26,901,840 | 17,573,018 | 161,851 | 4,933,996 | 720,673 | 3,232,715 | 14,808 | 264,780 |
| 16 | Other Tax Adjustments | - | - | - | - | - | - | - | - |
| 17 | Income Taxes | (10,106,527) | (9,535,723) | 95,403 | 1,419,293 | 821,641 | (3,026,724) | 84,052 | 35,530 |
| 18 | Total Expenses - Current | $ 294,295,128 | $ 198,216,559 | $ 1,849,189 | $ 54,098,186 | $ 7,733,768 | $ 29,207,990 | $ 169,618 | $ 3,019,818 |
| 19 | Operating Income - Current | $ 4,156,230 | $ (7,346,053) | $ 368,618 | $ 8,543,279 | $ 2,969,283 | $ (947,491) | $ 200,876 | $ 367,719 |
| 20 | Current Rate of Return | 0.27% | -0.89% | 4.79% | 3.05% | 5.38% | -0.28% | 240.20% | 2.40% |
| | **Present Revenue Requirement at Equal Rates of Return** | | | | | | | | |
| 21 | Present Return | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% |
| 22 | Present Operating Income @ Equal Return | $ 4,156,230 | $ 2,256,340 | $ 21,040 | $ 765,135 | $ 150,851 | $ 920,745 | $ 229 | $ 41,891 |
| 23 | Income Taxes | (10,106,527) | (5,486,645) | (51,161) | (1,860,546) | (366,817) | (2,238,937) | (556) | (101,863) |
| 24 | Other Expenses | 304,401,655 | 207,752,282 | 1,753,785 | 52,678,893 | 6,912,127 | 32,234,713 | 85,567 | 2,984,288 |
| 25 | Total Margin @ Equal Rates of Return | $ 298,451,358 | $ 204,521,977 | $ 1,723,664 | $ 51,583,482 | $ 6,696,160 | $ 30,916,521 | $ 85,239 | $ 2,924,315 |
| 26 | Delivery Margin @ Equal Rates of Return | $ 291,797,594 | $ 200,244,753 | $ 1,677,320 | $ 50,602,552 | $ 6,536,917 | $ 29,760,771 | $ 83,131 | $ 2,892,149 |
| 27 | Present (Subsidies)/Excesses | $ (0) | $ (13,651,471) | $ 494,143 | $ 11,057,983 | $ 4,006,891 | $ (2,656,022) | $ 285,255 | $ 463,222 |

**Northern Indiana Public Service Company**
**Class Cost of Service Study**
**Phase II Test Year Ending 12/31/2018**

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. 428 | C&I Off-Peak Interruptible 434 | General Transp. 438 |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **Revenue Requirement at Equal Rates of Return** | | | | | | | | |
| 28 | Required Return | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% |
| 29 | Required Operating Income | $ 104,894,469 | $ 56,945,254 | $ 530,996 | $ 19,310,396 | $ 3,807,156 | $ 23,237,670 | $ 5,770 | $ 1,057,228 |
| 30 | Operating Income (Deficiency) / Surplus | $ (100,738,239) | $ (64,291,307) | $ (162,378) | $ (10,767,117) | $ (837,873) | $ (24,185,160) | $ 195,105 | $ (689,509) |
| | **Expenses at Required Return** | | | | | | | | |
| 31 | Operation and Maintenance | $ 201,760,740 | $ 139,383,666 | $ 1,168,501 | $ 35,128,025 | $ 4,423,958 | $ 19,413,076 | $ 65,456 | $ 2,178,060 |
| 32 | Uncollectible Account Increase | 419,808 | $ 372,244 | $ 2,499 | $ 43,691 | $ 1,331 | $ 42 | $ - | $ - |
| 33 | Amortization and Depreciation Expense | 75,739,074 | 50,795,598 | 423,433 | 12,616,872 | 1,767,496 | 9,588,923 | 5,304 | 541,449 |
| 34 | Taxes Other Than Income | 26,901,840 | 17,573,018 | 161,851 | 4,933,996 | 720,673 | 3,232,715 | 14,808 | 264,780 |
| 35 | Other Tax Adjustments | - | - | - | - | - | - | - | - |
| 36 | Tax Increases | 2,117,717 | 1,344,797 | 14,586 | 437,792 | 71,745 | 219,831 | 3,073 | 25,893 |
| 37 | Income Taxes | 24,751,913 | 13,437,353 | 125,299 | 4,556,668 | 898,373 | 5,483,385 | 1,362 | 249,474 |
| 38 | Total Expenses - Required | $ 331,691,093 | $ 222,906,676 | $ 1,896,169 | $ 57,717,043 | $ 7,883,576 | $ 37,937,972 | $ 90,001 | $ 3,259,655 |
| 39 | Total Revenue Requirement at Equal Return | $ 436,585,562 | $ 279,851,930 | $ 2,427,164 | $ 77,027,439 | $ 11,690,732 | $ 61,175,641 | $ 95,772 | $ 4,316,883 |
| 40 | Current Miscellaneous Revenues Margin | $ 6,653,764 | $ 4,277,223 | $ 46,343 | $ 980,929 | $ 159,243 | $ 1,155,750 | $ 2,109 | $ 32,167 |
| 41 | Additional Miscellaneous Revenues Margin | $ 201,259 | $ 189,400 | $ 1,324 | $ 10,504 | $ 16 | $ 2 | $ 9 | $ 3 |
| 42 | Delivery Margin @ Equal Rates of Return | $ 429,730,539 | $ 275,385,307 | $ 2,379,497 | $ 76,036,005 | $ 11,531,473 | $ 60,019,889 | $ 93,653 | $ 4,284,714 |
| 43 | Revenue (Deficiency)/Surplus | $ (138,134,204) | $ (88,792,025) | $ (208,034) | $ (14,375,470) | $ (987,665) | $ (32,915,140) | $ 274,732 | $ (929,343) |
| 44 | Rate Schedule Margin as Proposed | $ 429,730,539 | $ 273,450,242 | $ 2,379,497 | $ 88,962,126 | $ 13,491,823 | $ 46,215,315 | $ 368,385 | $ 4,863,150 |
| 45 | Miscellaneous Revenues Margin | 6,855,023 | 4,466,623 | 47,668 | 991,434 | 159,259 | 1,155,752 | 2,118 | 32,169 |
| 46 | Total Margin as Proposed | $ 436,585,562 | $ 277,916,865 | $ 2,427,164 | $ 89,953,560 | $ 13,651,082 | $ 47,371,067 | $ 370,504 | $ 4,895,320 |
| 47 | Current Revenue to Cost Ratio | 0.68 | 0.68 | 0.91 | 0.81 | 0.91 | 0.45 | 3.93 | 0.78 |
| 48 | Current Parity Ratio | 1.00 | 1.00 | 1.34 | 1.19 | 1.35 | 0.67 | 5.79 | 1.15 |
| 49 | Proposed Revenue to Cost Ratio | 1.00 | 0.99 | 1.00 | 1.17 | 1.17 | 0.77 | 3.93 | 1.14 |
| 50 | Proposed Margin Increase | $ 138,134,204 | $ 86,856,960 | $ 208,034 | $ 27,301,591 | $ 2,948,015 | $ 19,110,566 | $ - | $ 1,507,779 |
| 51 | Precent Margin Change | 47.34% | 46.55% | 9.58% | 44.28% | 27.96% | 70.51% | 0.00% | 44.94% |
| 52 | 2018 Estimated Gas Costs - See Attach. 15-H | $ 1,140,704,025 | $ 253,286,838 | $ 3,081,831 | $ 128,440,152 | $ 47,569,477 | $ 692,239,681 | $ 864,453 | $ 15,221,592 |
| 53 | Total Bill Before Increase | $ 1,432,501,619 | $ 439,880,120 | $ 5,253,294 | $ 190,100,688 | $ 58,113,285 | $ 719,344,430 | $ 1,232,839 | $ 18,576,963 |
| 54 | Percent Total Bill Increase | 9.64% | 19.75% | 3.96% | 14.36% | 5.07% | 2.66% | 0.00% | 8.12% |
| 55 | Income Prior to Taxes | $ 101,522,510 | $ 53,179,615 | $ 513,926 | $ 31,615,761 | $ 5,645,120 | $ 8,686,092 | $ 280,317 | $ 1,601,678 |
| 56 | Income Taxes | $ 24,751,913 | $ 12,965,570 | $ 125,299 | $ 7,708,148 | $ 1,376,321 | $ 2,117,731 | $ 68,343 | $ 390,501 |
| 57 | Operating Income | $ 104,894,469 | $ 55,481,972 | $ 530,996 | $ 29,085,036 | $ 5,289,558 | $ 12,798,749 | $ 213,521 | $ 1,494,637 |
| 58 | **Proposed Return** | **6.90%** | **6.72%** | **6.90%** | **10.39%** | **9.59%** | **3.80%** | **255.32%** | **9.75%** |

**Northern Indiana Public Service Company**
**Proposed Test Year Without Gas**
**Functional Revenue Requirement**

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. 428 | C&I Off-Peak Interruptible 434 | General Transp. 438 |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **Storage** | | | | | | | | |
| 1 | Demand | $ 7,530,294 | $ 4,814,947 | $ 57,966 | $ 2,213,118 | $ 444,262 | $ - | $ - | $ - |
| 2 | Commodity | $ 7,123,913 | $ 3,934,082 | $ 38,517 | $ 2,330,198 | $ 821,116 | $ - | $ - | $ - |
| 3 | Customer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 4 | Sub-total | $ 14,654,206 | $ 8,749,029 | $ 96,483 | $ 4,543,317 | $ 1,265,378 | $ - | $ - | $ - |
| | **LNG** | | | | | | | | |
| 5 | Demand | $ 7,582,353 | $ 4,767,828 | $ 56,996 | $ 2,221,918 | $ 535,610 | $ - | $ - | $ - |
| 6 | Commodity | $ 3,188,678 | $ 1,760,903 | $ 17,240 | $ 1,043,001 | $ 367,533 | $ - | $ - | $ - |
| 7 | Customer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | Sub-total | $ 10,771,031 | $ 6,528,731 | $ 74,236 | $ 3,264,920 | $ 903,143 | $ - | $ - | $ - |
| | **Transmission** | | | | | | | | |
| 9 | Demand | $ 81,968,293 | $ 25,681,066 | $ 307,758 | $ 12,041,978 | $ 3,012,662 | $ 39,747,398 | $ - | $ 1,177,429 |
| 10 | Commodity | $ 2,115,016 | $ 383,948 | $ 4,672 | $ 194,725 | $ 75,184 | $ 1,423,877 | $ 1,299 | $ 31,310 |
| 11 | Customer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | Sub-total | $ 84,083,309 | $ 26,065,014 | $ 312,431 | $ 12,236,703 | $ 3,087,847 | $ 41,171,276 | $ 1,299 | $ 1,208,739 |
| | **Distribution** | | | | | | | | |
| 13 | Demand | $ 71,735,186 | $ 36,714,514 | $ 427,733 | $ 16,064,536 | $ 3,613,608 | $ 13,793,990 | $ 15,341 | $ 1,105,464 |
| 14 | Commodity | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | Customer | $ 255,341,830 | $ 201,794,642 | $ 1,516,281 | $ 40,917,963 | $ 2,820,756 | $ 6,210,376 | $ 79,132 | $ 2,002,680 |
| 16 | Sub-total | $ 327,077,015 | $ 238,509,156 | $ 1,944,014 | $ 56,982,499 | $ 6,434,364 | $ 20,004,366 | $ 94,473 | $ 3,108,144 |
| | **TOTAL** | | | | | | | | |
| 17 | Demand | $ 168,816,125 | $ 71,978,355 | $ 850,454 | $ 32,541,551 | $ 7,606,142 | $ 53,541,388 | $ 15,341 | $ 2,282,893 |
| 18 | Commodity | $ 12,427,607 | $ 6,078,934 | $ 60,429 | $ 3,567,925 | $ 1,263,833 | $ 1,423,877 | $ 1,299 | $ 31,310 |
| 19 | Customer | $ 255,341,830 | $ 201,794,642 | $ 1,516,281 | $ 40,917,963 | $ 2,820,756 | $ 6,210,376 | $ 79,132 | $ 2,002,680 |
| 20 | TOTAL REVENUE REQUIREMENT | $ 436,585,562 | $ 279,851,930 | $ 2,427,164 | $ 77,027,439 | $ 11,690,732 | $ 61,175,641 | $ 95,772 | $ 4,316,883 |
| | Functional Revenue Requirement After Other Revenue Credit | | | | | | | | |
| | Other Revenue | $ 6,855,023 | $ 4,466,623 | $ 47,668 | $ 991,434 | $ 159,259 | $ 1,155,752 | $ 2,118 | $ 32,169 |
| | **TOTAL** | | | | | | | | |
| 21 | Demand | $ 166,099,262 | $ 70,829,533 | $ 833,751 | $ 32,122,703 | $ 7,502,526 | $ 52,529,865 | $ 15,002 | $ 2,265,881 |
| 22 | Commodity | $ 12,239,094 | $ 5,981,910 | $ 59,243 | $ 3,522,001 | $ 1,246,616 | $ 1,396,977 | $ 1,270 | $ 31,076 |
| 23 | Customer | $ 251,392,183 | $ 198,573,865 | $ 1,486,503 | $ 40,391,301 | $ 2,782,330 | $ 6,093,047 | $ 77,381 | $ 1,987,756 |
| 24 | TOTAL REVENUE REQUIREMENT | $ 429,730,539 | $ 275,385,307 | $ 2,379,497 | $ 76,036,005 | $ 11,531,473 | $ 60,019,889 | $ 93,653 | $ 4,284,714 |

## Northern Indiana Public Service Company
## Proposed Test Year Without Gas
## Unit Costs

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. 428 | C&I Off-Peak Interruptible 434 | General Transp. 438 |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **Storage** | | | | | | | | |
| 1 | Demand (per Design Day) | $ 0.3517 | $ 0.6197 | $ 0.6310 | $ 0.6161 | $ 0.5291 | $ - | $ - | $ - |
| 2 | Commodity (per therm) | $ 0.0021 | $ 0.0063 | $ 0.0051 | $ 0.0074 | $ 0.0067 | $ - | $ - | $ - |
| 3 | Customer (per customer per month) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 4 | Demand and Commodity (per therm) | $ 0.0043 | $ 0.0141 | $ 0.0127 | $ 0.0144 | $ 0.0104 | $ - | $ - | $ - |
| | **Transmission** | | | | | | | | |
| 5 | Demand (per Design Day) | $ 3.8281 | $ 3.3051 | $ 3.3503 | $ 3.3523 | $ 3.5880 | $ 4.5021 | $ - | $ 4.0609 |
| 6 | Commodity (per therm) | $ 0.0006 | $ 0.000617 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 |
| 7 | Customer (per customer per month) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | Demand and Commodity (per therm) | $ 0.0245 | $ 0.0419 | $ 0.0413 | $ 0.0388 | $ 0.0253 | $ 0.0178 | $ 0.0006 | $ 0.0238 |
| | **Distrubition** | | | | | | | | |
| 9 | Demand (per Design Day) | $ 3.3502 | $ 4.7251 | $ 4.6563 | $ 4.4722 | $ 4.3037 | $ 1.5624 | $ - | $ 3.8127 |
| 10 | Commodity (per therm) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | Customer (per customer per month) | $ 25.73 | $ 22.28 | $ 24.94 | $ 51.50 | $ 345.56 | $ 3,299.88 | $ 2,637.72 | $ 1,775.43 |
| 12 | Demand and Commodity (per therm) | $ 0.0209 | $ 0.0590 | $ 0.0565 | $ 0.0509 | $ 0.0297 | $ 0.0060 | $ 0.0073 | $ 0.0218 |
| | **TOTAL** | | | | | | | | |
| 13 | Demand (per Design Day) | $ 7.5299 | $ 8.6498 | $ 8.6376 | $ 8.4406 | $ 8.4208 | $ 6.0645 | $ - | $ 7.8735 |
| 14 | Commodity (per therm) | $ 0.0027 | $ 0.0069 | $ 0.0057 | $ 0.0080 | $ 0.0074 | $ 0.0006 | $ 0.0006 | $ 0.0006 |
| 15 | Customer (per customer per month) | $ 25.73 | $ 22.28 | $ 24.94 | $ 51.50 | $ 345.56 | $ 3,299.88 | $ 2,637.72 | $ 1,775.43 |
| | Demand and Customer (per customer pe | $ 42.07 | $ 29.74 | $ 38.16 | $ 91.26 | $ 1,259.96 | $ 31,149.26 | $ 3,079.43 | $ 3,770.96 |
| 16 | Demand and Commodity (per therm) | $ 0.0497 | $ 0.1150 | $ 0.1105 | $ 0.1041 | $ 0.0654 | $ 0.0238 | $ 0.0079 | $ 0.0456 |
| 17 | DESIGN DAY PEAK | 21,412,453 | 7,770,154 | 91,861 | 3,592,121 | 839,647 | 8,828,725 | 0 | 289,945 |
| 18 | TOTAL THROUGHPUT | 3,427,490,303 | 622,207,258 | 7,571,986 | 315,561,686 | 121,839,923 | 2,307,465,604 | 2,105,207 | 50,738,639 |
| 19 | NO. OF CUSTOMERS * 12 | 9,924,627 | 9,058,064 | 60,805 | 794,556 | 8,163 | 1,882 | 30 | 1,128 |

**Northern Indiana Public Service Company**
**Revenue Requirement Mitigation**
**Phase II Test Year Ending 12/31/2018**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Class** | | **Pro Forma Rate Schedule Margin Including Riders** | **Proposed Margin for Equal Rates of Return** | **Revenue to Cost Ratio** | **ACOSS Proposed Increase (Decrease) @ 6.74% ROR** | **ACOSS Rate Increase** | **Proposed Increase (Decrease) - Post Apportionment** | **Proposed Revenue to Cost Ratio** | **Proposed Margin Increase %** | **Proposed Margin** | **2018 Estimated Gas Costs** | **Proposed Revenue Increase % with est. Gas Costs** |
| 1 | **System Total** | | **$ 291,797,594** | **$ 429,730,539** | **0.68** | **$ 138,134,204** | **47.34%** | **$ 138,134,204** | **1.00** | **47.34%** | **$ 429,730,539** | **$ 1,140,704,025** | **9.64%** |
| 2 | Residential | 411 | 186,593,282 | 275,385,307 | 0.68 | 88,792,025 | 47.59% | 86,856,960 | 0.99 | 46.55% | 273,450,242 | 253,286,838 | 19.75% |
| 3 | Multi-Family | 415 | 2,171,463 | 2,379,497 | 0.91 | 208,034 | 9.58% | 208,034 | 1.00 | 9.58% | 2,379,497 | 3,081,831 | 3.96% |
| 4 | General Service Small | 421 | 61,660,536 | 76,036,005 | 0.81 | 14,375,470 | 23.31% | 27,301,591 | 1.17 | 44.28% | 88,962,126 | 128,440,152 | 14.36% |
| 5 | General Service Large | 425 | 10,543,808 | 11,531,473 | 0.91 | 987,665 | 9.37% | 2,948,015 | 1.17 | 27.96% | 13,491,823 | 47,569,477 | 5.07% |
| 6 | Large Transp. | 428 | 27,104,749 | 60,019,889 | 0.45 | 32,915,140 | 121.44% | 19,110,566 | 0.77 | 70.51% | 46,215,315 | 692,239,681 | 2.66% |
| 7 | C&I Off-Peak Interruptib | 434 | 368,385 | 93,653 | 3.93 | (274,732) | -74.58% | - | 3.93 | 0.00% | 368,385 | 864,453 | 0.00% |
| 8 | General Transportation | 438 | 3,355,371 | 4,284,714 | 0.78 | 929,343 | 27.70% | 1,507,779 | 1.14 | 44.94% | 4,863,150 | 15,221,592 | 8.12% |
| 9 | iscellaneous Revenues Margin | | $ 6,653,764 | $ 6,855,023 | | $ 201,259 | | $ 201,259 | 150% Sys. Incr.= | 71.01% | $ 6,855,023 | Miscellaneous Revenues Margin | |
| 10 | **Total Margin** | | **$ 298,451,358** | **$ 436,585,562** | | | | | | | **$ 436,585,562** | **Total Margin** | |

Note: Column C and D are from ACOSS Results.
Note: Column L 2018 Estimated Gas Costs Derivation Inclusive of Choice and Transport Customers
Rates 411, 415, 421 and 425 2018 Estimated Gas Costs average factors are based on estimated therms, gas costs, bad debt revenues, and URT revenues.
Rate 434 2018 Estimated Gas Costs are based on the same average factor as Rates 421 and 425.
Rates 428 and 438 2018 Estimated Gas Costs factors are based on market research estimate for these transportation customers.

**Northern Indiana Public Service Company**
**Revenue Proof and Rate Design**

| Line No. | Description | 2018 Forecasted Billing Determinants (Bills or Therms) | 400 Series Rate | 2018 Total Revenue ("Margins") | Phase II Proposed Rates: 2018 Forecasted Billing Determinants (Therms/Bills) | Proposed Rate | Total Revenue ("Margins") 2018 |
|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| 1 | **Residential - Rate 411** | | | | | | |
| 2 | Customer Charge | | | | | | |
| 3 | Customer Charge - 411 | 9,031,590 | $ 11.00 | $ 99,347,489 | 9,031,590 | $ 19.50 | $ 176,116,003 |
| 4 | Customer Charge - 451 | 26,474 | $ 11.00 | $ 291,211 | 26,474 | $ 19.50 | $ 516,238 |
| 5 | Total Customer Charge | 9,058,064 | | $ 99,638,700 | 9,058,064 | | $ 176,632,242 |
| 6 | Delivery Charge | | | | | | |
| 7 | All Therms - 411 | 619,541,105 Therms | $ 0.09898 | $ 61,323,405 | 619,541,105 Therms | $ 0.15560 | $ 96,403,136 |
| 8 | All Therms - 451 | 2,666,152 Therms | $ 0.09898 | $ 263,901 | 2,666,152 Therms | $ 0.15560 | $ 414,864 |
| 9 | Total Delivery Charge | 622,207,258 Therms | | $ 61,587,306 | 622,207,258 Therms | | $ 96,818,001 |
| 10 | Residential - Rate 411 Sales | | | $ 161,226,006 | | | $ 273,450,242 |
| 11 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 4,605,622 | | | |
| 12 | Adjustment of Charges for TDSIC | | | $ 20,761,654 | | | |
| 13 | Total Rider | | | $ 25,367,276 | | | $ - |
| 14 | | | Total Margin | $ 186,593,282 | | Total Margin | $ 273,450,242 |
| 15 | | | Revenue Proof | $ 186,593,282 | | Target Margin | $ 273,450,242 |
| 16 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 17 | **Multi-Family - Rate 415** | | | | | | |
| 18 | Customer Charge | | | | | | |
| 19 | Customer Charge - 415 | 60,765 | $ 12.50 | $ 759,567 | 60,765 | $ 17.50 | $ 1,063,394 |
| 20 | Customer Charge- 451 | 40 | $ 12.50 | $ 495 | 40 | $ 17.50 | $ 692 |
| 21 | Total Customer Charge | 60,805 | | $ 760,062 | 60,805 | | $ 1,064,086 |
| 22 | Delivery Charge | | | | | | |
| 23 | First 45 therms | 2,314,726 Therms | $ 0.16526 | $ 382,537 | 2,314,726 Therms | $ 0.17372 | $ 402,116 |
| 24 | Over 45 therms | 5,247,754 Therms | $ 0.11526 | $ 604,869 | 5,247,754 Therms | $ 0.17372 | $ 911,643 |
| 25 | First 45 Therms - 451 | 2,565 Therms | $ 0.16526 | $ 424 | 2,565 Therms | $ 0.17372 | $ 446 |
| 26 | Over 45 Therms - 451 | 6,942 Therms | $ 0.11526 | $ 800 | 6,942 Therms | $ 0.17372 | $ 1,206 |
| 27 | Total Delivery Charge | 7,571,986 Therms | | $ 988,631 | 7,571,986 Therms | | $ 1,315,411 |
| 28 | Multi-Family - Rate 415 Sales | | | $ 1,748,693 | | | $ 2,379,497 |
| 29 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 53,977 | | | |
| 30 | Adjustment of Charges for TDSIC | | | $ 368,794 | | | |
| 31 | Total Rider | | | $ 422,770 | | | $ - |
| 32 | | | Total Margin | $ 2,171,463 | | Total Margin | $ 2,379,497 |
| 33 | | | Revenue Proof | $ 2,171,463 | | Target Margin | $ 2,379,497 |
| 34 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 35 | **Small General Service - Rate 421** | | | | | | |
| 36 | Customer Charge | | | | | | |
| 37 | Customer Charge - 421 | 794,556 | $ 30.00 | $ 23,836,668 | 794,556 | $ 53.00 | $ 42,111,447 |
| 38 | Customer Charge- 451 | - | $ 30.00 | $ - | - | $ 53.00 | $ - |
| 39 | Total Customer Charge | 794,556 | | $ 23,836,668 | 794,556 | | $ 42,111,447 |
| 40 | Delivery Charge | | | | | | |
| 41 | All Therms | 315,561,686 Therms | $ 0.09079 | $ 28,649,603 | 315,561,686 Therms | $ 0.14847 | $ 46,850,679 |
| 42 | All Therms - 451 | 0 Therms | $ 0.09079 | $ - | 0 Therms | $ 0.14847 | $ - |
| 43 | Total Delivery Charge | 315,561,686 Therms | | $ 28,649,603 | 315,561,686 Therms | | $ 46,850,679 |
| 44 | Small General Service - Rate 421 Sales | | | $ 52,486,271 | | | $ 88,962,126 |
| 45 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 1,910,584 | | | |
| 46 | Gas Demand-Side Management ("GDSM") Rider - Rider 472 | | | $ 52 | | | |
| 47 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 48 | Adjustment of Charges for TDSIC | | | $ 7,263,627 | | | |
| 49 | Total Rider | | | $ 9,174,264 | | | $ - |
| 50 | | | Total Margin | $ 61,660,536 | | Total Margin | $ 88,962,126 |
| 51 | | | Revenue Proof | $ 61,660,536 | | Target Margin | $ 88,962,126 |
| 52 | | | Over/(Under) | $ - | | Over/(Under) | $ - |

**Northern Indiana Public Service Company**
**Revenue Proof and Rate Design**

| Line No. | (A) Description | (B) 2018 Forecasted Billing Determinants (Bills or Therms) | (C) 400 Series Rate | (D) 2018 Total Revenue ("Margins") | Phase II Proposed Rates (E) 2018 Forecasted Billing Determinants (Therms/Bills) | (F) Proposed Rate | (G) Total Revenue ("Margins") 2018 |
|---|---|---|---|---|---|---|---|
| 53 | **General Service Large - Rate 425** | | | | | | |
| 54 | Customer Charge | | | | | | |
| 55 | Customer Charge - 425 | 8,163 | $ 250 | $ 2,040,705 | 8,163 | $ 400.00 | $ 3,265,128 |
| 56 | Customer Charge- 451 | - | $ 250 | $ - | - | $ 400.00 | $ - |
| 57 | Total Customer Charge | 8,163 | | $ 2,040,705 | 8,163 | | $ 3,265,128 |
| 58 | Delivery Charge | | | | | | |
| 59 | First 6,000 Therms | 42,934,570 Therms | $ 0.05658 | $ 2,429,256 | 42,934,570 Therms | $ 0.09261 | $ 3,976,031 |
| 60 | Next 24,000 Therms | 65,746,788 Therms | $ 0.05358 | $ 3,522,741 | 65,746,788 Therms | $ 0.08261 | $ 5,431,129 |
| 61 | Next 60,000 Therms | 12,302,656 Therms | $ 0.04658 | $ 573,063 | 12,302,656 Therms | $ 0.06261 | $ 770,229 |
| 62 | All over 90,000 Therms | 855,908 Therms | $ 0.04158 | $ 35,589 | 855,908 Therms | $ 0.05761 | $ 49,306 |
| 63 | First 6,000 Therms - Rate 451 | 0 Therms | $ 0.06 | $ - | 0 Therms | $ 0.09261 | $ - |
| 64 | Next 24,000 Therms - Rate 451 | 0 Therms | $ 0.05 | $ - | 0 Therms | $ 0.08261 | $ - |
| 65 | Next 60,000 Therms - Rate 451 | 0 Therms | $ 0.05 | $ - | 0 Therms | $ 0.06261 | $ - |
| 66 | All over 90,000 Therms | 0 Therms | $ 0.04 | $ - | 0 Therms | $ 0.05761 | $ - |
| 67 | Total Delivery Charge | 121,839,923 Therms | | $ 6,560,650 | 121,839,923 Therms | | $ 10,226,696 |
| 68 | General Service Large - Rate 425 Sales | | | $ 8,601,354 | | | $ 13,491,823 |
| 69 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 447,672 | | | |
| 70 | Gas Demand-Side Management ("GDSM") Rider - Rider 472 | | | $ 52 | | | |
| 71 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 72 | Adjustment of Charges for TDSIC | | | $ 1,494,654 | | | |
| 73 | Total Rider | | | $ 1,942,378 | | | $ - |
| 74 | | | Total Margin | $ 10,543,733 | | Total Margin | $ 13,491,823 |
| 75 | | | Revenue Proof | $ 10,543,733 | | Target Margin | $ 13,491,823 |
| 76 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 77 | **LargeTransportation - Rate 428** | | | | | | |
| 78 | Customer Charge | 1,882 | $ 350.00 | $ 658,700 | 1,882 | $ 1,000.00 | $ 1,882,000 |
| 79 | Demand Charge | | | | 83,404,689 | $ 0.12124 | $ 10,111,999 |
| 80 | Administrative Charges for Balancing Services | | | | | | |
| 81 | Category A & C | 335 | $ 1,325.00 | 444,302 | 335 | $ 1,590.00 | 533,163 |
| 82 | Category B | 1,547 | $ 550.00 | 850,850 | 1,547 | $ 660.00 | 1,021,020 |
| 83 | Total Administrative Charges for Balancing Ser | 1,882 | | 1,295,152 | | | 1,554,183 |
| 84 | Transportation charge | | | | | | |
| 85 | First 300,000 Therms | 321,996,061 Therms | $ 0.02565 | 8,257,602 | 321,996,061 Therms | $ 0.03828 | 12,326,056 |
| 86 | All Over 300,000 Therms | 1,985,469,543 Therms | $ 0.00765 | 15,178,997 | 1,985,469,543 Therms | $ 0.00975 | 19,358,328 |
| 87 | Total Transportation Charge | 2,307,465,604 Therms | | 23,436,599 | 2,307,465,604 Therms | | 31,684,384 |
| 88 | Pooling Agreement Fee | 1,792 | $ 50.00 | 89,579 | 1,792 | $ 60.00 | 107,494 |
| 89 | Company Nomination Exchange | 1,711 | $ 10.00 | 17,109 | 1,711 | $ 10.00 | 17,109 |
| 90 | Imbalance Exchange Service Charge | - | $ 10.00 | - | - | $ 10.00 | - |
| 91 | Pool Adminstration Charge - Cat. A | 12 | $ 1,000.00 | 11,528 | 12 | $ 1,000.00 | 11,528 |
| 92 | Pool Adminstration Charge - Cat. B | 133 | $ 500.00 | 66,285 | 133 | $ 500.00 | 66,285 |
| 93 | Pool Adminstration Charge - Cat. C | - | $ 250.00 | - | | $ 250.00 | - |
| 94 | Pool Participation Fee - Cat. A | 127 | $ 2,500.00 | 317,015 | 127 | $ 2,500.00 | 317,015 |
| 95 | Pool Participation Fee - Cat. B | 1,490 | $ 87.50 | 130,373 | 1,490 | $ 87.50 | 130,373 |
| 96 | Pool Participation Fee - Cat. C | 127 | $ 250.00 | 31,702 | 127 | $ 250.00 | 31,702 |

**Northern Indiana Public Service Company**
**Revenue Proof and Rate Design**

| | | | | | Phase II Proposed Rates | | |
|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| Line No. | Description | 2018 Forecasted Billing Determinants (Bills or Therms) | 400 Series Rate | 2018 Total Revenue ("Margins") | 2018 Forecasted Billing Determinants (Therms/Bills) | Proposed Rate | Total Revenue ("Margins") 2018 |
| 97 | Imbalance Net Throughput Fee | | | | | | |
| 98 | Volumetric Fee - Cat. A & C | 1,706,733,053 Therms | $ 0.00015 | 256,010 | 1,706,733,053 Therms | $ 0.00015 | 256,010 |
| 99 | Volumetric Fee - Cat. B | 301,556,580 Therms | $ 0.00015 | 45,233 | 301,556,580 Therms | $ 0.00015 | 45,233 |
| 100 | LargeTransportation - Rate 428 Sales | | | $ 26,355,285 | | | $ 46,215,315 |
| 101 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 102 | Adjustment of Charges for TDSIC | | | $ 749,464 | | | |
| 103 | Total Rider | | | $ 749,464 | | | $ - |
| 104 | | | Total Margin | 27,104,749 | | Total Margin | 46,215,315 |
| 105 | | | Revenue Proof | $ 27,104,749 | | Target Margin | $ 46,215,315 |
| 106 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 107 | **C&I Off-Peak Interruptible - Rate 434A** | | | | | | |
| 108 | Customer Charge | | | | | | |
| 109 | Customer Charge - 434A | 30 | $ 350.00 | $ 10,500.00 | 30 | $ 637.00 | $ 19,110 |
| 110 | Minimum Charge | | | | 0 | | $ - |
| 111 | Total Customer Charge | 30 | | $ 10,500.00 | 30 | | $ 19,110 |
| 112 | Delivery Charge | | | | | | |
| 113 | Off-Peak Intrrpt Gas | 0 Therms | $ - | 0 | 0 Therms | | $ - |
| 114 | Off-Peak Intrrpt Contract | 2,105,207 Therms | $ 0.17000 | $ 357,885.23 | 2,105,207 Therms | $ 0.16591 | $ 349,275 |
| 115 | Total Delivery Charge | 2,105,207 Therms | | $ 357,885.23 | 2,105,207 Therms | | $ 349,275 |
| 116 | C&I Off-Peak Interruptible - Rate 434A Sales | | | $ 368,385 | | | $ 368,385 |
| 117 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | | | | |
| 118 | Universal Service Fund Rider - Rider 473 | | | | | | |
| 119 | Total Rider | | | $ - | | | $ - |
| 120 | | | Total Margin | $ 368,385 | | Total Margin | $ 368,385 |
| 121 | | | Revenue Proof | $ 368,385 | | Target Margin | $ 368,385 |
| 122 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 123 | **General Transportation & Balancing - Rate 438** | | | | | | |
| 124 | Customer Charge | 1,128 | $ 250.00 | $ 282,000 | 1,128 | $ 750.00 | $ 846,000 |
| 125 | Administrative Charges for Balancing Services | 1,090 | $ 200.00 | $ 218,069 | 1,090 | $ 365.00 | $ 397,975 |
| 126 | Demand Charge | | | | 2,074,885 | $ 0.3099 | $ 642,944 |
| 127 | Transportation charge | | | | | | |
| 128 | First 6,000 Therms | 6,556,648 Therms | $ 0.05658 | $ 370,978 | 6,556,648 Therms | $ 0.05762 | $ 377,806 |
| 129 | Next 24,000 Therms | 24,063,992 Therms | $ 0.05358 | $ 1,289,359 | 24,063,992 Therms | $ 0.05662 | $ 1,362,546 |
| 130 | Next 60,000 Therms | 18,267,408 Therms | $ 0.04198 | $ 766,874 | 18,267,408 Therms | $ 0.05562 | $ 1,016,066 |
| 131 | All Over 90,000 Therms | 1,850,590 Therms | $ 0.03698 | $ 68,436 | 1,850,590 Therms | $ 0.05462 | $ 101,083 |
| 132 | Total Transportation Charge | 50,738,639 Therms | | $ 2,495,646 | 50,738,639 Therms | | $ 2,857,501 |
| 133 | General Transportation & Balancing - Rate 438 Sales | | | $ 2,995,715 | | | $ 4,744,420 |
| 134 | Pooling Agreement Fee | 1,006 | $ 50.00 | $ 50,313 | 1,006 | $ 60.00 | $ 60,376 |
| 135 | Company Nomination Exchange | 450 | $ 10.00 | $ 4,500 | 450 | $ 10.00 | $ 4,500 |
| 136 | Pool Administration Charge | 105 | $ 250.00 | $ 26,178 | 105 | $ 250.00 | $ 26,178 |
| 137 | Pool Participation Fee | 877 | $ 25.00 | $ 21,927 | 877 | $ 25.00 | $ 21,927 |
| 138 | Imbalance Net-Admin Charge | 38,330,520 Therms | $ 0.00015 | $ 5,750 | 38,330,520 Therms | $ 0.00015 | $ 5,750 |
| 139 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 140 | Adjustment of Charges for TDSIC | | | $ 251,063 | | | |
| 141 | Total Rider | | | $ 359,731 | | | $ 118,730 |
| 142 | | | Total Margin | $ 3,355,446 | | Total Margin | $ 4,863,150 |
| 143 | | | Revenue Proof | $ 3,355,446 | | Target Margin | $ 4,863,150 |
| 144 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 145 | All Classes | | | | | | |
| 146 | | | Total Margin | $ 291,797,594 | | Total Margin | $ 429,730,539 |
| 147 | | | Revenue Proof | $ 291,797,594 | | Target Margin | $ 429,730,539 |
| 148 | | | Over/(Under) | $ - | | Over/(Under) | $ - |

**Northern Indiana Public Service Company**
**Residential Customer Monthly Bill Comparison**

| Line No. | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description | January | February | March | April | May | June | July | August | September | October | November | December | Total |
| 2 | Volumes (therms) | 147 | 155 | 118 | 89 | 49 | 26 | 18 | 17 | 17 | 20 | 48 | 119 | 824 |
| 3 | Current Revenues | 90.91 | 94.99 | 75.04 | 59.51 | 37.77 | 24.97 | 20.95 | 20.00 | 20.22 | 21.84 | 37.21 | 75.66 | 579.06 |
| 4 | Proposed Revenues | 102.84 | 107.09 | 86.29 | 70.09 | 47.42 | 34.07 | 29.87 | 28.88 | 29.12 | 30.81 | 46.83 | 86.93 | 700.23 |
| 5 | Difference | 11.93 | 12.10 | 11.24 | 10.58 | 9.65 | 9.10 | 8.93 | 8.89 | 8.90 | 8.96 | 9.62 | 11.27 | 121.16 |
| 6 | Avg. Monthly Increase | 10.10 | | | | | | | | | | | | |

**Residential - Rate 411**

| Line No. | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|
| 7 | (A) | (B) | (C) | (D) | (E) | (F) |
| 8 | | Present | Proposed | | | |
| 9 | | Rates | Rates | | | |
| 10 | Customer Charge | $11.00 | $19.50 | | | |
| 11 | Delivery Charge | $0.09898 | $0.15560 | | | |
| 12 | TDSIC Charge | $0.03337 | $0.00000 | | | |
| 13 | GDSM Charge | $0.00668 | $0.00668 | | | |
| 14 | Average Gas Charg | $0.40352 | $0.40352 | | | |
| 15 | ANNUAL | REVENUE AT | REVENUE AT | | | |
| 16 | CONSUMPTION | PRESENT | PROPOSED | REVENUE | | |
| 17 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 18 | 100 | $ 186 | $ 291 | $ 104 | 56.01% | 7,038 |
| 19 | 200 | $ 241 | $ 347 | $ 107 | 44.34% | 8,924 |
| 20 | 300 | $ 295 | $ 404 | $ 109 | 36.97% | 17,211 |
| 21 | 400 | $ 349 | $ 460 | $ 111 | 31.89% | 31,509 |
| 22 | 500 | $ 403 | $ 517 | $ 114 | 28.18% | 52,393 |
| 23 | 600 | $ 458 | $ 573 | $ 116 | 25.34% | 74,384 |
| 24 | 700 | $ 512 | $ 630 | $ 118 | 23.11% | 87,508 |
| 25 | 800 | $ 566 | $ 687 | $ 121 | 21.31% | 85,821 |
| 26 | 900 | $ 620 | $ 743 | $ 123 | 19.82% | 73,327 |
| 27 | 1,000 | $ 675 | $ 800 | $ 125 | 18.57% | 57,873 |
| 28 | 1,100 | $ 729 | $ 856 | $ 128 | 17.51% | 42,767 |
| 29 | 1,200 | $ 783 | $ 913 | $ 130 | 16.59% | 30,566 |
| 30 | 1,300 | $ 837 | $ 970 | $ 132 | 15.79% | 21,714 |
| 31 | 1,400 | $ 892 | $ 1,026 | $ 135 | 15.09% | 15,236 |
| 32 | 1,500 | $ 946 | $ 1,083 | $ 137 | 14.47% | 10,595 |
| 33 | 1,600 | $ 1,000 | $ 1,139 | $ 139 | 13.92% | 7,362 |
| 34 | 1,700 | $ 1,054 | $ 1,196 | $ 142 | 13.42% | 5,112 |
| 35 | 1,800 | $ 1,109 | $ 1,252 | $ 144 | 12.98% | 3,888 |
| 36 | 1,900 | $ 1,163 | $ 1,309 | $ 146 | 12.57% | 2,707 |
| 37 | 2,000 | $ 1,217 | $ 1,366 | $ 149 | 12.20% | 1,985 |

**Northern Indiana Public Service Company**
**Bill Impacts**

**Multi-Family - Rate 415**

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | Present Rates | Proposed Rates | | | |
| 29 | Customer Charge | $12.50 | $17.50 | | | |
| 30 | Delivery Charge | | | | | |
| 31 | First 45 therms | $0.16526 | $0.17372 | | | |
| 32 | Over 45 therms | $0.11526 | $0.17372 | | | |
| 33 | TDSIC Charge | $0.04871 | $0.00000 | | | |
| 34 | GDSM Charge | $0.00283 | $0.00283 | | | |
| 35 | Average Gas Cost | $0.40352 | $0.40352 | | | |
| 36 | ANNUAL | REVENUE AT | REVENUE AT | REVENUE CHANGE | | |
| 37 | CONSUMPTION | PRESENT | PROPOSED | | | |
| 38 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 39 | 100 | $ 212 | $ 268 | $ 56 | 26.40% | 44 |
| 40 | 500 | $ 456 | $ 500 | $ 44 | 9.67% | 381 |
| 41 | 800 | $ 626 | $ 674 | $ 48 | 7.63% | 509 |
| 42 | 1,000 | $ 742 | $ 790 | $ 48 | 6.50% | 417 |
| 43 | 1,500 | $ 1,029 | $ 1,080 | $ 51 | 4.99% | 1,158 |
| 44 | 2,000 | $ 1,315 | $ 1,370 | $ 55 | 4.20% | 778 |
| 45 | 2,500 | $ 1,602 | $ 1,660 | $ 58 | 3.64% | 429 |
| 46 | 3,000 | $ 1,888 | $ 1,950 | $ 62 | 3.30% | 195 |
| 47 | 3,500 | $ 2,171 | $ 2,240 | $ 69 | 3.20% | 98 |
| 48 | 4,000 | $ 2,458 | $ 2,530 | $ 72 | 2.93% | 50 |
| 49 | 5,000 | $ 3,029 | $ 3,110 | $ 82 | 2.70% | 38 |
| 50 | 6,000 | $ 3,599 | $ 3,690 | $ 92 | 2.54% | 11 |
| 51 | 9,000 | $ 5,310 | $ 5,431 | $ 121 | 2.27% | 14 |

**Northern Indiana Public Service Company**
**Bill Impacts**
**Small General Service - Rate 421**

| Line No. | (a) | (b) | (c) |
|---|---|---|---|
| | | Present Rates | Proposed Rates |
| 52 | Customer Charge | $30.00 | $53.00 |
| 53 | Delivery Charge | $0.09079 | $0.14847 |
| 54 | TDSIC Charge | $0.02302 | $0.00000 |
| 55 | GDSM Charge | $0.00522 | $0.00522 |
| 56 | Average Gas Cost | $0.41063 | $0.41063 |

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| 57 | ANNUAL | REVENUE AT | REVENUE AT | REVENUE CHANGE | | |
| 58 | CONSUMPTION | PRESENT | PROPOSED | | | |
| 59 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 60 | 500 | $ 625 | $ 918 | $ 293 | 46.95% | 8,525 |
| 61 | 1,500 | $ 1,154 | $ 1,482 | $ 328 | 28.41% | 15,556 |
| 62 | 2,500 | $ 1,684 | $ 2,047 | $ 363 | 21.53% | 6,978 |
| 63 | 3,500 | $ 2,214 | $ 2,611 | $ 397 | 17.95% | 4,076 |
| 64 | 4,000 | $ 2,479 | $ 2,893 | $ 415 | 16.73% | 1,486 |
| 65 | 5,000 | $ 3,008 | $ 3,458 | $ 449 | 14.94% | 2,224 |
| 66 | 7,500 | $ 4,332 | $ 4,868 | $ 536 | 12.37% | 3,295 |
| 67 | 10,000 | $ 5,657 | $ 6,279 | $ 623 | 11.01% | 1,936 |
| 68 | 12,000 | $ 6,716 | $ 7,408 | $ 692 | 10.30% | 981 |
| 69 | 14,000 | $ 7,775 | $ 8,537 | $ 761 | 9.79% | 741 |
| 70 | 16,000 | $ 8,835 | $ 9,665 | $ 831 | 9.40% | 569 |
| 71 | 18,000 | $ 9,894 | $ 10,794 | $ 900 | 9.10% | 424 |
| 72 | 19,500 | $ 10,688 | $ 11,640 | $ 952 | 8.91% | 275 |
| 73 | 25,000 | $ 13,602 | $ 14,744 | $ 1,143 | 8.40% | 720 |
| 74 | 30,000 | $ 16,250 | $ 17,566 | $ 1,316 | 8.10% | 450 |
| 75 | 35,000 | $ 18,898 | $ 20,387 | $ 1,489 | 7.88% | 320 |
| 76 | 40,000 | $ 21,546 | $ 23,209 | $ 1,662 | 7.72% | 198 |
| 77 | 45,000 | $ 24,195 | $ 26,030 | $ 1,836 | 7.59% | 184 |
| 78 | 50,000 | $ 26,843 | $ 28,852 | $ 2,009 | 7.48% | 137 |
| 79 | 60,000 | $ 32,140 | $ 34,495 | $ 2,356 | 7.33% | 197 |
| 80 | 70,000 | $ 37,436 | $ 40,139 | $ 2,702 | 7.22% | 135 |
| 81 | 80,000 | $ 42,733 | $ 45,782 | $ 3,049 | 7.13% | 83 |
| 82 | 90,000 | $ 48,030 | $ 51,425 | $ 3,395 | 7.07% | 56 |

**Northern Indiana Public Service Company**
**Bill Impacts**

**General Service Large - Rate 425**

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | Present Rates | Proposed Rates | | | |
| 83 | Customer Charge | $250.00 | $400.00 | | | |
| | Delivery Charge | | | | | |
| 84 | First 6,000 Therms | $0.05658 | $0.09261 | | | |
| 85 | Next 24,000 Therms | $0.05358 | $0.08261 | | | |
| 86 | Next 60,000 Therms | $0.04658 | $0.06261 | | | |
| 87 | All over 90,000 Therms | $0.04158 | $0.05761 | | | |
| 88 | TDSIC Charge | $0.01227 | $0.00000 | | | |
| 89 | GDSM Charge | $0.00522 | $0.00522 | | | |
| 90 | Average Gas Cost | $0.41063 | $0.41063 | | | |
| 91 | ANNUAL | REVENUE AT | REVENUE AT | REVENUE CHANGE | | |
| 92 | CONSUMPTION | PRESENT | PROPOSED | | | |
| 93 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 94 | 1,250 | $ 3,606 | $ 5,436 | $ 1,830 | 50.74% | 3 |
| 95 | 2,500 | $ 4,212 | $ 6,071 | $ 1,859 | 44.15% | 8 |
| 96 | 5,000 | $ 5,424 | $ 7,342 | $ 1,919 | 35.38% | 3 |
| 97 | 10,000 | $ 7,847 | $ 9,885 | $ 2,038 | 25.97% | 6 |
| 98 | 20,000 | $ 12,694 | $ 14,969 | $ 2,275 | 17.92% | 7 |
| 99 | 30,000 | $ 17,530 | $ 20,016 | $ 2,486 | 14.18% | 5 |
| 100 | 40,000 | $ 22,387 | $ 25,134 | $ 2,748 | 12.27% | 8 |
| 101 | 50,000 | $ 27,212 | $ 30,145 | $ 2,934 | 10.78% | 13 |
| 102 | 60,000 | $ 32,044 | $ 35,181 | $ 3,137 | 9.79% | 25 |
| 103 | 70,000 | $ 36,874 | $ 40,210 | $ 3,335 | 9.04% | 34 |
| 104 | 80,000 | $ 41,676 | $ 45,142 | $ 3,466 | 8.32% | 33 |
| 105 | 90,000 | $ 46,539 | $ 50,282 | $ 3,742 | 8.04% | 41 |
| 106 | 100,000 | $ 51,361 | $ 55,282 | $ 3,921 | 7.63% | 23 |
| 107 | 125,000 | $ 63,429 | $ 67,827 | $ 4,398 | 6.93% | 52 |
| 108 | 150,000 | $ 75,471 | $ 80,289 | $ 4,818 | 6.38% | 54 |
| 109 | 175,000 | $ 87,439 | $ 92,522 | $ 5,083 | 5.81% | 44 |
| 110 | 200,000 | $ 99,556 | $ 105,212 | $ 5,656 | 5.68% | 33 |
| 111 | 250,000 | $ 123,596 | $ 130,006 | $ 6,410 | 5.19% | 47 |
| 112 | 300,000 | $ 147,657 | $ 154,860 | $ 7,203 | 4.88% | 30 |
| 113 | 350,000 | $ 171,395 | $ 178,791 | $ 7,396 | 4.31% | 30 |
| 114 | 400,000 | $ 194,784 | $ 201,725 | $ 6,940 | 3.56% | 11 |
| 115 | 450,000 | $ 219,314 | $ 227,919 | $ 8,605 | 3.92% | 10 |
| 116 | 500,000 | $ 243,016 | $ 251,783 | $ 8,767 | 3.61% | 8 |
| 117 | 550,000 | $ 266,822 | $ 275,873 | $ 9,051 | 3.39% | 7 |
| 118 | 700,000 | $ 337,495 | $ 346,786 | $ 9,291 | 2.75% | 1 |

**Northern Indiana Public Service Company**
**Revenue Proof and Rate Design**

| | | | | | Phase I Proposed Rates | | |
|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| Line No. | Description | 2018 Forecasted Billing Determinants (Bills or Therms) | 400 Series Rate | 2018 Total Revenue ("Margins") | 2018 Forecasted Billing Determinants (Therms/Bills) | Proposed Rate | Total Revenue ("Margins") 2018 |
| 1 | **Residential - Rate 411** | | | | | | |
| 2 | Customer Charge | | | | | | |
| 3 | Customer Charge - 411 | 9,031,590 | $ 11.00 | $ 99,347,489 | 9,031,590 | $ 19.50 | $ 176,116,003 |
| 4 | Customer Charge - 451 | 26,474 | $ 11.00 | $ 291,211 | 26,474 | $ 19.50 | $ 516,238 |
| 5 | Total Customer Charge | 9,058,064 | | $ 99,638,700 | 9,058,064 | | $ 176,632,242 |
| 6 | Delivery Charge | | | | | | |
| 7 | All Therms - 411 | 619,541,105 Therms | $ 0.09898 | $ 61,323,405 | 619,541,105 Therms | $ 0.12840 | $ 79,546,481 |
| 8 | All Therms - 451 | 2,666,152 Therms | $ 0.09898 | $ 263,901 | 2,666,152 Therms | $ 0.12840 | $ 342,323 |
| 9 | Total Delivery Charge | 622,207,258 Therms | | $ 61,587,306 | 622,207,258 Therms | | $ 79,888,804 |
| 10 | Residential - Rate 411 Sales | | | $ 161,226,006 | | | $ 256,521,045 |
| 11 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 4,605,622 | | | |
| 12 | Adjustment of Charges for TDSIC | | | $ 20,761,654 | | | |
| 13 | Total Rider | | | $ 25,367,276 | | | $ - |
| 14 | | | Total Margin | $ 186,593,282 | | Total Margin | $ 256,521,045 |
| 15 | | | Revenue Proof | $ 186,593,282 | | Target Margin | $ 256,521,045 |
| 16 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 17 | **Multi-Family - Rate 415** | | | | | | |
| 18 | Customer Charge | | | | | | |
| 19 | Customer Charge - 415 | 60,765 | $ 12.50 | $ 759,567 | 60,765 | $ 17.50 | $ 1,063,394 |
| 20 | Customer Charge- 451 | 40 | $ 12.50 | $ 495 | 40 | $ 17.50 | $ 692 |
| 21 | Total Customer Charge | 60,805 | | $ 760,062 | 60,805 | | $ 1,064,086 |
| 22 | Delivery Charge | | | | | | |
| 23 | First 45 therms | 2,314,726 Therms | $ 0.16526 | $ 382,537 | 2,314,726 Therms | $ 0.15427 | $ 357,082 |
| 24 | Over 45 therms | 5,247,754 Therms | $ 0.11526 | $ 604,869 | 5,247,754 Therms | $ 0.15427 | $ 809,548 |
| 25 | First 45 Therms - 451 | 2,565 Therms | $ 0.16526 | $ 424 | 2,565 Therms | $ 0.15427 | $ 396 |
| 26 | Over 45 Therms - 451 | 6,942 Therms | $ 0.11526 | $ 800 | 6,942 Therms | $ 0.15427 | $ 1,071 |
| 27 | Total Delivery Charge | 7,571,986 Therms | | $ 988,631 | 7,571,986 Therms | | $ 1,168,097 |
| 28 | Multi-Family - Rate 415 Sales | | | $ 1,748,693 | | | $ 2,232,183 |
| 29 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 53,977 | | | |
| 30 | Adjustment of Charges for TDSIC | | | $ 368,794 | | | |
| 31 | Total Rider | | | $ 422,770 | | | $ - |
| 32 | | | Total Margin | $ 2,171,463 | | Total Margin | $ 2,232,183 |
| 33 | | | Revenue Proof | $ 2,171,463 | | Target Margin | $ 2,232,183 |
| 34 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 35 | **Small General Service - Rate 421** | | | | | | |
| 36 | Customer Charge | | | | | | |
| 37 | Customer Charge - 421 | 794,556 | $ 30.00 | $ 23,836,668 | 794,556 | $ 53.00 | $ 42,111,447 |
| 38 | Customer Charge- 451 | - | $ 30.00 | $ - | - | $ 53.00 | $ - |
| 39 | Total Customer Charge | 794,556 | | $ 23,836,668 | 794,556 | | $ 42,111,447 |
| 40 | Delivery Charge | | | | | | |
| 41 | All Therms | 315,561,686 Therms | $ 0.09079 | $ 28,649,603 | 315,561,686 Therms | $ 0.13101 | $ 41,343,069 |
| 42 | All Therms - 451 | 0 Therms | $ 0.09079 | $ - | 0 Therms | $ 0.13101 | $ - |
| 43 | Total Delivery Charge | 315,561,686 Therms | | $ 28,649,603 | 315,561,686 Therms | | $ 41,343,069 |
| 44 | Small General Service - Rate 421 Sales | | | $ 52,486,271 | | | $ 83,454,516 |
| 45 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 1,910,584 | | | |
| 46 | Gas Demand-Side Management ("GDSM") Rider - Rider 472 | | | $ 52 | | | |
| 47 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 48 | Adjustment of Charges for TDSIC | | | $ 7,263,627 | | | |
| 49 | Total Rider | | | $ 9,174,264 | | | $ - |
| 50 | | | Total Margin | $ 61,660,536 | | Total Margin | $ 83,454,516 |
| 51 | | | Revenue Proof | $ 61,660,536 | | Target Margin | $ 83,454,516 |
| 52 | | | Over/(Under) | $ - | | Over/(Under) | $ - |

**Northern Indiana Public Service Company**
**Revenue Proof and Rate Design**

| Line No. | Description (A) | (B) 2018 Forecasted Billing Determinants (Bills or Therms) | (C) 400 Series Rate | (D) 2018 Total Revenue ("Margins") | Phase I Proposed Rates (E) 2018 Forecasted Billing Determinants (Therms/Bills) | (F) Proposed Rate | (G) Total Revenue ("Margins") 2018 |
|---|---|---|---|---|---|---|---|
| 53 | **General Service Large - Rate 425** | | | | | | |
| 54 | Customer Charge | | | | | | |
| 55 | Customer Charge - 425 | 8,163 | $ 250 | $ 2,040,705 | 8,163 | $ 400.00 | $ 3,265,128 |
| 56 | Customer Charge- 451 | - | $ 250 | $ - | - | $ 400.00 | $ - |
| 57 | Total Customer Charge | 8,163 | | $ 2,040,705 | 8,163 | | $ 3,265,128 |
| 58 | Delivery Charge | | | | | | |
| 59 | First 6,000 Therms | 42,934,570 Therms | $ 0.05658 | $ 2,429,256 | 42,934,570 Therms | $ 0.08575 | $ 3,681,693 |
| 60 | Next 24,000 Therms | 65,746,788 Therms | $ 0.05358 | $ 3,522,741 | 65,746,788 Therms | $ 0.07575 | $ 4,980,402 |
| 61 | Next 60,000 Therms | 12,302,656 Therms | $ 0.04658 | $ 573,063 | 12,302,656 Therms | $ 0.05575 | $ 685,889 |
| 62 | All over 90,000 Therms | 855,908 Therms | $ 0.04158 | $ 35,589 | 855,908 Therms | $ 0.05075 | $ 43,438 |
| 63 | First 6,000 Therms - Rate 451 | 0 Therms | $ 0.06 | $ - | 0 Therms | $ 0.08575 | $ - |
| 64 | Next 24,000 Therms - Rate 451 | 0 Therms | $ 0.05 | $ - | 0 Therms | $ 0.07575 | $ - |
| 65 | Next 60,000 Therms - Rate 451 | 0 Therms | $ 0.05 | $ - | 0 Therms | $ 0.05575 | $ - |
| 66 | All over 90,000 Therms | 0 Therms | $ 0.04 | $ - | 0 Therms | $ 0.05075 | $ - |
| 67 | Total Delivery Charge | 121,839,923 Therms | | $ 6,560,650 | 121,839,923 Therms | | $ 9,391,422 |
| 68 | General Service Large - Rate 425 Sales | | | $ 8,601,354 | | | $ 12,656,550 |
| 69 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | $ 447,672 | | | |
| 70 | Gas Demand-Side Management ("GDSM") Rider - Rider 472 | | | $ 52 | | | |
| 71 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 72 | Adjustment of Charges for TDSIC | | | $ 1,494,654 | | | |
| 73 | Total Rider | | | $ 1,942,378 | | | $ - |
| 74 | | | Total Margin | $ 10,543,733 | | Total Margin | $ 12,656,550 |
| 75 | | | Revenue Proof | $ 10,543,733 | | Target Margin | $ 12,656,550 |
| 76 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 77 | **LargeTransportation - Rate 428** | | | | | | |
| 78 | Customer Charge | 1,882 | $ 350.00 | $ 658,700 | 1,882 | $ 1,000.00 | $ 1,882,000 |
| 79 | Demand Charge | | | | 83,404,689 | $ 0.12124 | $ 10,111,999 |
| 80 | Administrative Charges for Balancing Services | | | | | | |
| 81 | Category A & C | 335 | $ 1,325.00 | 444,302 | 335 | $ 1,590.00 | 533,163 |
| 82 | Category B | 1,547 | $ 550.00 | 850,850 | 1,547 | $ 660.00 | 1,021,020 |
| 83 | Total Administrative Charges for Balancing Ser | 1,882 | | 1,295,152 | | | 1,554,183 |
| 84 | Transportation charge | | | | | | |
| 85 | First 300,000 Therms | 321,996,061 Therms | $ 0.02565 | 8,257,602 | 321,996,061 Therms | $ 0.02939 | 9,464,884 |
| 86 | All Over 300,000 Therms | 1,985,469,543 Therms | $ 0.00765 | 15,178,997 | 1,985,469,543 Therms | $ 0.00975 | 19,358,328 |
| 87 | Total Transportation Charge | 2,307,465,604 Therms | | 23,436,599 | 2,307,465,604 Therms | | 28,823,212 |
| 88 | Pooling Agreement Fee | 1,792 | $ 50.00 | 89,579 | 1,792 | $ 60.00 | 107,494 |
| 89 | Company Nomination Exchange | 1,711 | $ 10.00 | 17,109 | 1,711 | $ 10.00 | 17,109 |
| 90 | Imbalance Exchange Service Charge | - | $ 10.00 | - | - | $ 10.00 | - |
| 91 | Pool Adminstration Charge - Cat. A | 12 | $ 1,000.00 | 11,528 | 12 | $ 1,000.00 | 11,528 |
| 92 | Pool Adminstration Charge - Cat. B | 133 | $ 500.00 | 66,285 | 133 | $ 500.00 | 66,285 |
| 93 | Pool Adminstration Charge - Cat. C | - | $ 250.00 | - | | $ 250.00 | - |
| 94 | Pool Participation Fee - Cat. A | 127 | $ 2,500.00 | 317,015 | 127 | $ 2,500.00 | 317,015 |
| 95 | Pool Participation Fee - Cat. B | 1,490 | $ 87.50 | 130,373 | 1,490 | $ 87.50 | 130,373 |
| 96 | Pool Participation Fee - Cat. C | 127 | $ 250.00 | 31,702 | 127 | $ 250.00 | 31,702 |

**Northern Indiana Public Service Company**
**Revenue Proof and Rate Design**

| | | | | | Phase I Proposed Rates | | |
|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| Line No. | Description | 2018 Forecasted Billing Determinants (Bills or Therms) | 400 Series Rate | 2018 Total Revenue ("Margins") | 2018 Forecasted Billing Determinants (Therms/Bills) | Proposed Rate | Total Revenue ("Margins") 2018 |
| 97 | Imbalance Net Throughput Fee | | | | | | |
| 98 | Volumetric Fee - Cat. A & C | 1,706,733,053 Therms | $ 0.00015 | 256,010 | 1,706,733,053 Therms | $ 0.00015 | 256,010 |
| 99 | Volumetric Fee - Cat. B | 301,556,580 Therms | $ 0.00015 | 45,233 | 301,556,580 Therms | $ 0.00015 | 45,233 |
| 100 | LargeTransportation - Rate 428 Sales | | | $ 26,355,285 | | | $ 43,354,143 |
| 101 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 102 | Adjustment of Charges for TDSIC | | | $ 749,464 | | | |
| 103 | Total Rider | | | $ 749,464 | | | $ - |
| 104 | | | Total Margin | 27,104,749 | | Total Margin | 43,354,143 |
| 105 | | | Revenue Proof | $ 27,104,749 | | Target Margin | $ 43,354,143 |
| 106 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 107 | **C&I Off-Peak Interruptible - Rate 434A** | | | | | | |
| 108 | Customer Charge | | | | | | |
| 109 | Customer Charge - 434A | 30 | $ 350.00 | $ 10,500.00 | 30 | $ 637.00 | $ 19,110 |
| 110 | Minimum Charge | | | | 0 | | $ - |
| 111 | Total Customer Charge | 30 | | $ 10,500.00 | 30 | | $ 19,110 |
| 112 | Delivery Charge | | | | | | |
| 113 | Off-Peak Intrrpt Gas | 0 Therms | $ - | 0 | 0 Therms | | $ - |
| 114 | Off-Peak Intrrpt Contract | 2,105,207 Therms | $ 0.17000 | $ 357,885.23 | 2,105,207 Therms | $ 0.15508 | $ 326,469 |
| 115 | Total Delivery Charge | 2,105,207 Therms | | $ 357,885.23 | 2,105,207 Therms | | $ 326,469 |
| 116 | C&I Off-Peak Interruptible - Rate 434A Sales | | | $ 368,385 | | | $ 345,579 |
| 117 | Gas Cost Adjustment Rider (GCA) - Rider 470 | | | | | | |
| 118 | Universal Service Fund Rider - Rider 473 | | | | | | |
| 119 | Total Rider | | | $ - | | | $ - |
| 120 | | | Total Margin | $ 368,385 | | Total Margin | $ 345,579 |
| 121 | | | Revenue Proof | $ 368,385 | | Target Margin | $ 345,579 |
| 122 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 123 | **General Transportation & Balancing - Rate 438** | | | | | | |
| 124 | Customer Charge | 1,128 | $ 250.00 | $ 282,000 | 1,128 | $ 750.00 | $ 846,000 |
| 125 | Administrative Charges for Balancing Services | 1,090 | $ 200.00 | $ 218,069 | 1,090 | $ 365.00 | $ 397,975 |
| 126 | Demand Charge | | | | 2,074,885 | $ 0.3099 | $ 642,944 |
| 127 | Transportation charge | | | | | | |
| 128 | First 6,000 Therms | 6,556,648 Therms | $ 0.05658 | $ 370,978 | 6,556,648 Therms | $ 0.05169 | $ 338,900 |
| 129 | Next 24,000 Therms | 24,063,992 Therms | $ 0.05358 | $ 1,289,359 | 24,063,992 Therms | $ 0.05069 | $ 1,219,754 |
| 130 | Next 60,000 Therms | 18,267,408 Therms | $ 0.04198 | $ 766,874 | 18,267,408 Therms | $ 0.04969 | $ 907,670 |
| 131 | All Over 90,000 Therms | 1,850,590 Therms | $ 0.03698 | $ 68,436 | 1,850,590 Therms | $ 0.04869 | $ 90,101 |
| 132 | Total Transportation Charge | 50,738,639 Therms | | $ 2,495,646 | 50,738,639 Therms | | $ 2,556,425 |
| 133 | General Transportation & Balancing - Rate 438 Sales | | | $ 2,995,715 | | | $ 4,443,344 |
| 134 | Pooling Agreement Fee | 1,006 | $ 50.00 | $ 50,313 | 1,006 | $ 60.00 | $ 60,376 |
| 135 | Company Nomination Exchange | 450 | $ 10.00 | $ 4,500 | 450 | $ 10.00 | $ 4,500 |
| 136 | Pool Administration Charge | 105 | $ 250.00 | $ 26,178 | 105 | $ 250.00 | $ 26,178 |
| 137 | Pool Participation Fee | 877 | $ 25.00 | $ 21,927 | 877 | $ 25.00 | $ 21,927 |
| 138 | Imbalance Net-Admin Charge | 38,330,520 Therms | $ 0.00015 | $ 5,750 | 38,330,520 Therms | $ 0.00015 | $ 5,750 |
| 139 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 140 | Adjustment of Charges for TDSIC | | | $ 251,063 | | | |
| 141 | Total Rider | | | $ 359,731 | | | $ 118,730 |
| 142 | | | Total Margin | $ 3,355,446 | | Total Margin | $ 4,562,074 |
| 143 | | | Revenue Proof | $ 3,355,446 | | Target Margin | $ 4,562,074 |
| 144 | | | Over/(Under) | $ - | | Over/(Under) | $ - |
| 145 | All Classes | | | | | | |
| 146 | | | Total Margin | $ 291,797,594 | | Total Margin | $ 403,126,090 |
| 147 | | | Revenue Proof | $ 291,797,594 | | Target Margin | $ 403,126,090 |
| 148 | | | Over/(Under) | $ - | | Over/(Under) | $ - |

**Northern Indiana Public Service Company**
**Residential Customer Monthly Bill Comparison**

| Line No. | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description | January | February | March | April | May | June | July | August | September | October | November | December | Total |
| 2 | Volumes (therms) | 147 | 155 | 118 | 89 | 49 | 26 | 18 | 17 | 17 | 20 | 48 | 119 | 824 |
| 3 | Current Revenues | 90.91 | 94.99 | 75.04 | 59.51 | 37.77 | 24.97 | 20.95 | 20.00 | 20.22 | 21.84 | 37.21 | 75.66 | 579.06 |
| 4 | Proposed Revenues | 98.83 | 102.88 | 83.08 | 67.65 | 46.07 | 33.37 | 29.37 | 28.43 | 28.65 | 30.26 | 45.52 | 83.69 | 677.81 |
| 5 | Difference | 7.92 | 7.89 | 8.03 | 8.15 | 8.30 | 8.40 | 8.43 | 8.43 | 8.43 | 8.42 | 8.31 | 8.03 | 98.74 |
| 6 | Avg. Monthly Increase | 8.23 | | | | | | | | | | | | |

**Residential - Rate 411**

| Line No. | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|
| 8 | | Present | Proposed | | | |
| 9 | | Rates | Rates | | | |
| 10 | Customer Charge | $11.00 | $19.50 | | | |
| 11 | Delivery Charge | $0.09898 | $0.12840 | | | |
| 12 | TDSIC Charge | $0.03337 | $0.00000 | | | |
| 13 | GDSM Charge | $0.00668 | $0.00668 | | | |
| 14 | Average Gas Charg | $0.40352 | $0.40352 | | | |
| 15 | ANNUAL | REVENUE AT | REVENUE AT | | | |
| 16 | CONSUMPTION | PRESENT | PROPOSED | REVENUE | | |
| 17 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 18 | 100 | $ 186 | $ 288 | $ 102 | 54.55% | 7,038 |
| 19 | 200 | $ 241 | $ 342 | $ 101 | 42.08% | 8,924 |
| 20 | 300 | $ 295 | $ 396 | $ 101 | 34.20% | 17,211 |
| 21 | 400 | $ 349 | $ 449 | $ 100 | 28.77% | 31,509 |
| 22 | 500 | $ 403 | $ 503 | $ 100 | 24.80% | 52,393 |
| 23 | 600 | $ 458 | $ 557 | $ 100 | 21.78% | 74,384 |
| 24 | 700 | $ 512 | $ 611 | $ 99 | 19.39% | 87,508 |
| 25 | 800 | $ 566 | $ 665 | $ 99 | 17.46% | 85,821 |
| 26 | 900 | $ 620 | $ 719 | $ 98 | 15.87% | 73,327 |
| 27 | 1,000 | $ 675 | $ 773 | $ 98 | 14.53% | 57,873 |
| 28 | 1,100 | $ 729 | $ 826 | $ 98 | 13.40% | 42,767 |
| 29 | 1,200 | $ 783 | $ 880 | $ 97 | 12.42% | 30,566 |
| 30 | 1,300 | $ 837 | $ 934 | $ 97 | 11.57% | 21,714 |
| 31 | 1,400 | $ 892 | $ 988 | $ 96 | 10.82% | 15,236 |
| 32 | 1,500 | $ 946 | $ 1,042 | $ 96 | 10.16% | 10,595 |
| 33 | 1,600 | $ 1,000 | $ 1,096 | $ 96 | 9.57% | 7,362 |
| 34 | 1,700 | $ 1,054 | $ 1,150 | $ 95 | 9.04% | 5,112 |
| 35 | 1,800 | $ 1,109 | $ 1,203 | $ 95 | 8.56% | 3,888 |
| 36 | 1,900 | $ 1,163 | $ 1,257 | $ 94 | 8.13% | 2,707 |
| 37 | 2,000 | $ 1,217 | $ 1,311 | $ 94 | 7.73% | 1,985 |

**Northern Indiana Public Service Company**
**Bill Impacts**

**Multi-Family - Rate 415**

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | Present Rates | Proposed Rates | | | |
| 29 | Customer Charge | $12.50 | $17.50 | | | |
| 30 | Delivery Charge | | | | | |
| 31 | First 45 therms | $0.16526 | $0.15427 | | | |
| 32 | Over 45 therms | $0.11526 | $0.15427 | | | |
| 33 | TDSIC Charge | $0.04871 | $0.00000 | | | |
| 34 | GDSM Charge | $0.00283 | $0.00283 | | | |
| 35 | Average Gas Cost | $0.40352 | $0.40352 | | | |
| 36 | ANNUAL | REVENUE AT | REVENUE AT | REVENUE CHANGE | | |
| 37 | CONSUMPTION | PRESENT | PROPOSED | | | |
| 38 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 39 | 100 | $ 212 | $ 266 | $ 54 | 25.48% | 44 |
| 40 | 500 | $ 456 | $ 490 | $ 34 | 7.54% | 381 |
| 41 | 800 | $ 626 | $ 658 | $ 32 | 5.14% | 509 |
| 42 | 1,000 | $ 742 | $ 771 | $ 29 | 3.88% | 417 |
| 43 | 1,500 | $ 1,029 | $ 1,051 | $ 22 | 2.16% | 1,158 |
| 44 | 2,000 | $ 1,315 | $ 1,331 | $ 16 | 1.24% | 778 |
| 45 | 2,500 | $ 1,602 | $ 1,612 | $ 10 | 0.61% | 429 |
| 46 | 3,000 | $ 1,888 | $ 1,892 | $ 4 | 0.21% | 195 |
| 47 | 3,500 | $ 2,171 | $ 2,172 | $ 1 | 0.06% | 98 |
| 48 | 4,000 | $ 2,458 | $ 2,452 | $ (6) | -0.24% | 50 |
| 49 | 5,000 | $ 3,029 | $ 3,013 | $ (16) | -0.51% | 38 |
| 50 | 6,000 | $ 3,599 | $ 3,574 | $ (25) | -0.70% | 11 |
| 51 | 9,000 | $ 5,310 | $ 5,256 | $ (54) | -1.02% | 14 |

**Northern Indiana Public Service Company**
**Bill Impacts**
**Small General Service - Rate 421**

| Line No. | (a) | (b) | (c) |
|---|---|---|---|
| | | Present Rates | Proposed Rates |
| 52 | Customer Charge | $30.00 | $53.00 |
| 53 | Delivery Charge | $0.09079 | $0.13101 |
| 54 | TDSIC Charge | $0.02302 | $0.00000 |
| 55 | GDSM Charge | $0.00522 | $0.00522 |
| 56 | Average Gas Cost | $0.41063 | $0.41063 |

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| 57 | ANNUAL | REVENUE AT | REVENUE AT | REVENUE CHANGE | | |
| 58 | CONSUMPTION | PRESENT | PROPOSED | | | |
| 59 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 60 | 500 | $ 625 | $ 909 | $ 285 | 45.55% | 8,525 |
| 61 | 1,500 | $ 1,154 | $ 1,456 | $ 302 | 26.14% | 15,556 |
| 62 | 2,500 | $ 1,684 | $ 2,003 | $ 319 | 18.94% | 6,978 |
| 63 | 3,500 | $ 2,214 | $ 2,550 | $ 336 | 15.19% | 4,076 |
| 64 | 4,000 | $ 2,479 | $ 2,823 | $ 345 | 13.91% | 1,486 |
| 65 | 5,000 | $ 3,008 | $ 3,370 | $ 362 | 12.03% | 2,224 |
| 66 | 7,500 | $ 4,332 | $ 4,738 | $ 405 | 9.35% | 3,295 |
| 67 | 10,000 | $ 5,657 | $ 6,105 | $ 448 | 7.92% | 1,936 |
| 68 | 12,000 | $ 6,716 | $ 7,198 | $ 482 | 7.18% | 981 |
| 69 | 14,000 | $ 7,775 | $ 8,292 | $ 517 | 6.65% | 741 |
| 70 | 16,000 | $ 8,835 | $ 9,386 | $ 551 | 6.24% | 569 |
| 71 | 18,000 | $ 9,894 | $ 10,480 | $ 586 | 5.92% | 424 |
| 72 | 19,500 | $ 10,688 | $ 11,300 | $ 612 | 5.72% | 275 |
| 73 | 25,000 | $ 13,602 | $ 14,308 | $ 706 | 5.19% | 720 |
| 74 | 30,000 | $ 16,250 | $ 17,042 | $ 792 | 4.88% | 450 |
| 75 | 35,000 | $ 18,898 | $ 19,776 | $ 878 | 4.65% | 320 |
| 76 | 40,000 | $ 21,546 | $ 22,511 | $ 964 | 4.48% | 198 |
| 77 | 45,000 | $ 24,195 | $ 25,245 | $ 1,050 | 4.34% | 184 |
| 78 | 50,000 | $ 26,843 | $ 27,979 | $ 1,136 | 4.23% | 137 |
| 79 | 60,000 | $ 32,140 | $ 33,448 | $ 1,308 | 4.07% | 197 |
| 80 | 70,000 | $ 37,436 | $ 38,917 | $ 1,480 | 3.95% | 135 |
| 81 | 80,000 | $ 42,733 | $ 44,385 | $ 1,653 | 3.87% | 83 |
| 82 | 90,000 | $ 48,030 | $ 49,854 | $ 1,825 | 3.80% | 56 |

**Northern Indiana Public Service Company**
**Bill Impacts**

**General Service Large - Rate 425**

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | Present Rates | Proposed Rates | | | |
| 83 | Customer Charge | $250.00 | $400.00 | | | |
| | Delivery Charge | | | | | |
| 84 | First 6,000 Therms | $0.05658 | $0.08575 | | | |
| 85 | Next 24,000 Therms | $0.05358 | $0.07575 | | | |
| 86 | Next 60,000 Therms | $0.04658 | $0.05575 | | | |
| 87 | All over 90,000 Therms | $0.04158 | $0.05075 | | | |
| 88 | TDSIC Charge | $0.01227 | $0.00000 | | | |
| 89 | GDSM Charge | $0.00522 | $0.00522 | | | |
| 90 | Average Gas Cost | $0.41063 | $0.41063 | | | |
| 91 | ANNUAL | REVENUE AT | REVENUE AT | REVENUE CHANGE | | |
| 92 | CONSUMPTION | PRESENT | PROPOSED | | | |
| 93 | (Therms) | RATES | RATES | AMOUNT | PERCENT | Customers |
| 94 | 1,250 | $ 3,606 | $ 5,427 | $ 1,821 | 50.50% | 3 |
| 95 | 2,500 | $ 4,212 | $ 6,054 | $ 1,842 | 43.74% | 8 |
| 96 | 5,000 | $ 5,424 | $ 7,308 | $ 1,885 | 34.75% | 3 |
| 97 | 10,000 | $ 7,847 | $ 9,816 | $ 1,969 | 25.09% | 6 |
| 98 | 20,000 | $ 12,694 | $ 14,832 | $ 2,138 | 16.84% | 7 |
| 99 | 30,000 | $ 17,530 | $ 19,810 | $ 2,280 | 13.01% | 5 |
| 100 | 40,000 | $ 22,387 | $ 24,860 | $ 2,473 | 11.05% | 8 |
| 101 | 50,000 | $ 27,212 | $ 29,803 | $ 2,591 | 9.52% | 13 |
| 102 | 60,000 | $ 32,044 | $ 34,769 | $ 2,725 | 8.51% | 25 |
| 103 | 70,000 | $ 36,874 | $ 39,730 | $ 2,855 | 7.74% | 34 |
| 104 | 80,000 | $ 41,676 | $ 44,593 | $ 2,918 | 7.00% | 33 |
| 105 | 90,000 | $ 46,539 | $ 49,665 | $ 3,125 | 6.72% | 41 |
| 106 | 100,000 | $ 51,361 | $ 54,596 | $ 3,235 | 6.30% | 23 |
| 107 | 125,000 | $ 63,429 | $ 66,970 | $ 3,541 | 5.58% | 52 |
| 108 | 150,000 | $ 75,471 | $ 79,261 | $ 3,790 | 5.02% | 54 |
| 109 | 175,000 | $ 87,439 | $ 91,323 | $ 3,884 | 4.44% | 44 |
| 110 | 200,000 | $ 99,556 | $ 103,841 | $ 4,285 | 4.30% | 33 |
| 111 | 250,000 | $ 123,596 | $ 128,292 | $ 4,696 | 3.80% | 47 |
| 112 | 300,000 | $ 147,657 | $ 152,803 | $ 5,146 | 3.49% | 30 |
| 113 | 350,000 | $ 171,395 | $ 176,391 | $ 4,996 | 2.92% | 30 |
| 114 | 400,000 | $ 194,784 | $ 198,983 | $ 4,198 | 2.16% | 11 |
| 115 | 450,000 | $ 219,314 | $ 224,834 | $ 5,520 | 2.52% | 10 |
| 116 | 500,000 | $ 243,016 | $ 248,355 | $ 5,339 | 2.20% | 8 |
| 117 | 550,000 | $ 266,822 | $ 272,103 | $ 5,281 | 1.98% | 7 |
| 118 | 700,000 | $ 337,495 | $ 341,987 | $ 4,493 | 1.33% | 1 |

## Northern Indiana Public Service Company
## Class Cost of Service Study
## Phase II Test Year Ending 12/31/2018

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. DP 428a | Large Transp. HP 428b | C&I Off-Peak Interruptible 434 | General Transp. 438 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| | **Rate Base** | | | | | | | | | |
| 1 | Plant in Service | $ 2,931,233,313 | $ 1,830,942,419 | $ 16,025,307 | $ 518,537,316 | $ 80,180,483 | $ 143,137,746 | $ 317,900,535 | $ 198,060 | $ 24,311,447 |
| 2 | Accumulated Reserve | (1,524,896,207) | (1,070,451,405) | (8,944,369) | (270,977,202) | (35,265,899) | (49,652,774) | (80,219,617) | (116,344) | (9,268,595) |
| 3 | Other Rate Base Items | 113,872,189 | 64,802,307 | 614,649 | 32,300,618 | 10,261,569 | 1,695,408 | 3,916,436 | 1,914 | 279,289 |
| 4 | Total Rate Base | $ 1,520,209,295 | $ 825,293,322 | $ 7,695,586 | $ 279,860,732 | $ 55,176,153 | $ 95,180,380 | $ 241,597,354 | $ 83,630 | $ 15,322,140 |
| | **Margin at Current Rates** | | | | | | | | | |
| 5 | Delivery Sales Margin | 253,890,377 | 161,226,006 | 1,748,693 | 52,486,271 | 8,601,429 | 6,258,922 | 20,096,362 | 368,385 | 3,104,307 |
| 6 | TDSIC Margin | 30,889,257 | 20,761,654 | 368,794 | 7,263,627 | 1,494,654 | 78,273 | 671,191 | - | 251,063 |
| 7 | Other Riders Exlcuding TDSIC | 7,017,960 | 4,605,622 | 53,977 | 1,910,637 | 447,724 | - | - | - | 0 |
| 8 | Miscellaneous Revenues Margin | 6,653,764 | 4,277,223 | 46,343 | 980,929 | 159,243 | 133,000 | 1,022,750 | 2,109 | 32,167 |
| 9 | Total Margin | $ 298,451,358 | $ 190,870,506 | $ 2,217,806 | $ 62,641,465 | $ 10,703,051 | $ 6,470,196 | $ 21,790,303 | $ 370,494 | $ 3,387,538 |
| 10 | Total Margin Exlcuding Misc. Revenues | $ 291,797,594 | $ 186,593,282 | $ 2,171,463 | $ 61,660,536 | $ 10,543,808 | $ 6,337,196 | $ 20,767,553 | $ 368,385 | $ 3,355,371 |
| 11 | Gas Costs (Trackable) | 316,748,872 | $ 207,808,679 | $ 2,403,993 | $ 84,370,019 | $ 20,731,302 | $ 1,434,877 | $ - | $ - | $ - |
| 12 | Total Sales Revenue | $ 615,200,230 | $ 398,679,185 | $ 4,621,799 | $ 147,011,484 | $ 31,434,353 | $ 7,905,073 | $ 21,790,303 | $ 370,494 | $ 3,387,538 |
| | **Expenses at Current Rates** | | | | | | | | | |
| 13 | Operation and Maintenance | 201,760,740 | 139,383,666 | 1,168,501 | 35,128,025 | 4,423,958 | 6,346,646 | 13,066,430 | 65,456 | 2,178,060 |
| 14 | Amortization and Depreciation Expense | 75,739,074 | 50,795,598 | 423,433 | 12,616,872 | 1,767,496 | 3,065,114 | 6,523,809 | 5,304 | 541,449 |
| 15 | Taxes Other Than Income | 26,901,840 | 17,573,018 | 161,851 | 4,933,996 | 720,673 | 949,287 | 2,283,428 | 14,808 | 264,780 |
| 16 | Other Tax Adjustments | - | - | - | - | - | - | - | - | - |
| 17 | Income Taxes | (10,106,527) | (9,535,723) | 95,403 | 1,419,293 | 821,641 | (1,676,312) | (1,350,412) | 84,052 | 35,530 |
| 18 | Total Expenses - Current | $ 294,295,128 | $ 198,216,559 | $ 1,849,189 | $ 54,098,186 | $ 7,733,768 | $ 8,684,735 | $ 20,523,255 | $ 169,618 | $ 3,019,818 |
| 19 | Operating Income - Current | $ 4,156,230 | $ (7,346,053) | $ 368,618 | $ 8,543,279 | $ 2,969,283 | $ (2,214,539) | $ 1,267,048 | $ 200,876 | $ 367,719 |
| 20 | Current Rate of Return | 0.27% | -0.89% | 4.79% | 3.05% | 5.38% | -2.33% | 0.52% | 240.20% | 2.40% |
| | **Present Revenue Requirement at Equal Rates of Return** | | | | | | | | | |
| 21 | Present Return | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% | 0.27% |
| 22 | Present Operating Income @ Equal Return | $ 4,156,230 | $ 2,256,340 | $ 21,040 | $ 765,135 | $ 150,851 | $ 260,222 | $ 660,524 | $ 229 | $ 41,891 |
| 23 | Income Taxes | (10,106,527) | (5,486,645) | (51,161) | (1,860,546) | (366,817) | (632,770) | (1,606,167) | (556) | (101,863) |
| 24 | Other Expenses | 304,401,655 | 207,752,282 | 1,753,785 | 52,678,893 | 6,912,127 | 10,361,047 | 21,873,666 | 85,567 | 2,984,288 |
| 25 | Total Margin @ Equal Rates of Return | $ 298,451,358 | $ 204,521,977 | $ 1,723,664 | $ 51,583,482 | $ 6,696,160 | $ 9,988,498 | $ 20,928,023 | $ 85,239 | $ 2,924,315 |
| 26 | Delivery Margin @ Equal Rates of Return | $ 291,797,594 | $ 200,244,753 | $ 1,677,320 | $ 50,602,552 | $ 6,536,917 | $ 9,855,498 | $ 19,905,273 | $ 83,131 | $ 2,892,149 |
| 27 | Present (Subsidies)/Excesses | $ (0) | $ (13,651,471) | $ 494,143 | $ 11,057,983 | $ 4,006,891 | $ (3,518,302) | $ 862,280 | $ 285,255 | $ 463,222 |

**Northern Indiana Public Service Company**
**Class Cost of Service Study**
**Phase II Test Year Ending 12/31/2018**

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. DP 428a | Large Transp. HP 428b | C&I Off-Peak Interruptible 434 | General Transp. 438 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| | **Revenue Requirement at Equal Rates of Return** | | | | | | | | | |
| 28 | Required Return | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% | 6.90% |
| 29 | Required Operating Income | $ 104,894,469 | $ 56,945,254 | $ 530,996 | $ 19,310,396 | $ 3,807,156 | $ 6,567,448 | $ 16,670,222 | $ 5,770 | $ 1,057,228 |
| 30 | Operating Income (Deficiency) / Surplus | $ (100,738,239) | $ (64,291,307) | $ (162,378) | $ (10,767,117) | $ (837,873) | $ (8,781,987) | $ (15,403,174) | $ 195,105 | $ (689,509) |
| | **Expenses at Required Return** | | | | | | | | | |
| 31 | Operation and Maintenance | $ 201,760,740 | $ 139,383,666 | $ 1,168,501 | $ 35,128,025 | $ 4,423,958 | $ 6,346,646 | $ 13,066,430 | $ 65,456 | $ 2,178,060 |
| 32 | Uncollectible Account Increase | 419,808 | $ 372,244 | $ 2,499 | $ 43,691 | $ 1,331 | $ 27 | $ 16 | $ - | $ - |
| 33 | Amortization and Depreciation Expense | 75,739,074 | 50,795,598 | 423,433 | 12,616,872 | 1,767,496 | 3,065,114 | 6,523,809 | 5,304 | 541,449 |
| 34 | Taxes Other Than Income | 26,901,840 | 17,573,018 | 161,851 | 4,933,996 | 720,673 | 949,287 | 2,283,428 | 14,808 | 264,780 |
| 35 | Other Tax Adjustments | - | - | - | - | - | - | - | - | - |
| 36 | Tax Increases | 2,117,717 | 1,344,797 | 14,586 | 437,792 | 71,745 | 52,206 | 167,625 | 3,073 | 25,893 |
| 37 | Income Taxes | 24,751,913 | 13,437,353 | 125,299 | 4,556,668 | 898,373 | 1,549,719 | 3,933,667 | 1,362 | 249,474 |
| 38 | Total Expenses - Required | $ 331,691,093 | $ 222,906,676 | $ 1,896,169 | $ 57,717,043 | $ 7,883,576 | $ 11,962,998 | $ 25,974,974 | $ 90,001 | $ 3,259,655 |
| 39 | Total Revenue Requirement at Equal Return | $ 436,585,562 | $ 279,851,930 | $ 2,427,164 | $ 77,027,439 | $ 11,690,732 | $ 18,530,446 | $ 42,645,196 | $ 95,772 | $ 4,316,883 |
| 40 | Current Miscellaneous Revenues Margin | $ 6,653,764 | $ 4,277,223 | $ 46,343 | $ 980,929 | $ 159,243 | $ 133,000 | $ 1,022,750 | $ 2,109 | $ 32,167 |
| 41 | Additional Miscellaneous Revenues Margin | $ 201,259 | $ 189,400 | $ 1,324 | $ 10,504 | $ 16 | $ 2 | $ - | $ 9 | $ 3 |
| 42 | Delivery Margin @ Equal Rates of Return | $ 429,730,539 | $ 275,385,307 | $ 2,379,497 | $ 76,036,005 | $ 11,531,473 | $ 18,397,444 | $ 41,622,446 | $ 93,653 | $ 4,284,714 |
| 43 | Revenue (Deficiency)/Surplus | $ (138,134,204) | $ (88,792,025) | $ (208,034) | $ (14,375,470) | $ (987,665) | $ (12,060,248) | $ (20,854,893) | $ 274,732 | $ (929,343) |
| 44 | Rate Schedule Margin as Proposed | $ 429,730,539 | $ 273,450,242 | $ 2,379,497 | $ 88,962,126 | $ 13,491,823 | $ 10,805,325 | $ 35,409,990 | $ 368,385 | $ 4,863,150 |
| 45 | Miscellaneous Revenues Margin | 6,855,023 | 4,466,623 | 47,668 | 991,434 | 159,259 | 133,002 | 1,022,750 | 2,118 | 32,169 |
| 46 | Total Margin as Proposed | $ 436,585,562 | $ 277,916,865 | $ 2,427,164 | $ 89,953,560 | $ 13,651,082 | $ 10,938,328 | $ 36,432,739 | $ 370,504 | $ 4,895,320 |
| 47 | Current Revenue to Cost Ratio | 0.68 | 0.68 | 0.91 | 0.81 | 0.91 | 0.34 | 0.50 | 3.93 | 0.78 |
| 48 | Current Parity Ratio | 1.00 | 1.00 | 1.34 | 1.19 | 1.35 | 0.51 | 0.73 | 5.79 | 1.15 |
| 49 | Proposed Revenue to Cost Ratio | 1.00 | 0.99 | 1.00 | 1.17 | 1.17 | 0.59 | 0.85 | 3.93 | 1.14 |
| 50 | Proposed Margin Increase | $ 138,134,204 | $ 86,856,960 | $ 208,034 | $ 27,301,591 | $ 2,948,015 | $ 4,468,129 | $ 14,642,436 | $ - | $ 1,507,779 |
| 51 | Precent Margin Change | 47.34% | 46.55% | 9.58% | 44.28% | 27.96% | 70.51% | 70.51% | 0.00% | 44.94% |
| 52 | 2018 Estimated Gas Costs - See Attach. 15-H | $ 434,107,206 | $ 253,286,838 | $ 3,081,831 | $ 128,440,152 | $ 47,569,477 | | | $ 864,453 | $ 864,453 |
| 53 | Total Bill Before Increase | $ 698,800,051 | $ 439,880,120 | $ 5,253,294 | $ 190,100,688 | $ 58,113,285 | | | $ 1,232,839 | $ 4,219,824 |
| 54 | Percent Total Bill Increase | 19.77% | 19.75% | 3.96% | 14.36% | 5.07% | | | 0.00% | 35.73% |
| 55 | Income Prior to Taxes | $ 101,805,970 | $ 53,179,615 | $ 513,926 | $ 31,615,761 | $ 5,645,120 | $ (1,235,789) | $ 9,921,881 | $ 280,317 | $ 1,601,678 |
| 56 | Income Taxes | $ 24,751,913 | $ 12,929,470 | $ 124,950 | $ 7,686,686 | $ 1,372,489 | $ (300,455) | $ 2,412,290 | $ 68,153 | $ 389,413 |
| 57 | Operating Income | $ 104,894,469 | $ 55,518,072 | $ 531,344 | $ 29,106,498 | $ 5,293,391 | $ 825,503 | $ 11,979,142 | $ 213,711 | $ 1,495,725 |
| 58 | **Proposed Return** | **6.90%** | **6.73%** | **6.90%** | **10.40%** | **9.59%** | **0.87%** | **4.96%** | **255.54%** | **9.76%** |

# Northern Indiana Public Service Company
## Proposed Test Year Without Gas
## Functional Revenue Requirement

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. DP 428a | Large Transp. HP 428b | C&I Off-Peak Interruptible 434 | C&I Off-Peak Interruptible 434 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (h) | (h) |
| | **Storage** | | | | | | | | | |
| 1 | Demand | $ 7,530,294 | $ 4,814,947 | $ 57,966 | $ 2,213,118 | $ 444,262 | $ - | $ - | $ - | $ - |
| 2 | Commodity | $ 7,123,913 | $ 3,934,082 | $ 38,517 | $ 2,330,198 | $ 821,116 | $ - | $ - | $ - | $ - |
| 3 | Customer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 4 | Sub-total | $ 14,654,206 | $ 8,749,029 | $ 96,483 | $ 4,543,317 | $ 1,265,378 | $ - | $ - | $ - | $ - |
| | **LNG** | | | | | | | | | |
| 5 | Demand | $ 7,582,353 | $ 4,767,828 | $ 56,996 | $ 2,221,918 | $ 535,610 | $ - | $ - | $ - | $ - |
| 6 | Commodity | $ 3,188,678 | $ 1,760,903 | $ 17,240 | $ 1,043,001 | $ 367,533 | $ - | $ - | $ - | $ - |
| 7 | Customer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | Sub-total | $ 10,771,031 | $ 6,528,731 | $ 74,236 | $ 3,264,920 | $ 903,143 | $ - | $ - | $ - | $ - |
| | **Transmission** | | | | | | | | | |
| 9 | Demand | $ 81,968,293 | $ 25,681,066 | $ 307,758 | $ 12,041,978 | $ 3,012,662 | $ 7,364,087 | $ 32,383,311 | $ - | $ 1,177,429 |
| 10 | Commodity | $ 2,115,016 | $ 383,948 | $ 4,672 | $ 194,725 | $ 75,184 | $ 148,708 | $ 1,275,169 | $ 1,299 | $ 31,310 |
| 11 | Customer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | Sub-total | $ 84,083,309 | $ 26,065,014 | $ 312,431 | $ 12,236,703 | $ 3,087,847 | $ 7,512,795 | $ 33,658,480 | $ 1,299 | $ 1,208,739 |
| | **Distribution** | | | | | | | | | |
| 13 | Demand | $ 71,735,186 | $ 36,714,514 | $ 427,733 | $ 16,064,536 | $ 3,613,608 | $ 8,255,951 | $ 5,538,039 | $ 15,341 | $ 1,105,464 |
| 14 | Commodity | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | Customer | $ 255,341,830 | $ 201,794,642 | $ 1,516,281 | $ 40,917,963 | $ 2,820,756 | $ 2,761,699 | $ 3,448,676 | $ 79,132 | $ 2,002,680 |
| 16 | Sub-total | $ 327,077,015 | $ 238,509,156 | $ 1,944,014 | $ 56,982,499 | $ 6,434,364 | $ 11,017,650 | $ 8,986,715 | $ 94,473 | $ 3,108,144 |
| | **TOTAL** | | | | | | | | | |
| 17 | Demand | $ 168,816,125 | $ 71,978,355 | $ 850,454 | $ 32,541,551 | $ 7,606,142 | $ 15,620,038 | $ 37,921,350 | $ 15,341 | $ 2,282,893 |
| 18 | Commodity | $ 12,427,607 | $ 6,078,934 | $ 60,429 | $ 3,567,925 | $ 1,263,833 | $ 148,708 | $ 1,275,169 | $ 1,299 | $ 31,310 |
| 19 | Customer | $ 255,341,830 | $ 201,794,642 | $ 1,516,281 | $ 40,917,963 | $ 2,820,756 | $ 2,761,699 | $ 3,448,676 | $ 79,132 | $ 2,002,680 |
| 20 | TOTAL REVENUE REQUIREMENT | $ 436,585,562 | $ 279,851,930 | $ 2,427,164 | $ 77,027,439 | $ 11,690,732 | $ 18,530,446 | $ 42,645,196 | $ 95,772 | $ 4,316,883 |
| | Functional Revenue Requirement After Other Revenue Credit | | | | | | | | | |
| | Other Revenue | $ 6,855,023 | $ 4,466,623 | $ 47,668 | $ 991,434 | $ 159,259 | $ 133,002 | $ 1,022,750 | $ 2,118 | $ 32,169 |
| | **TOTAL** | | | | | | | | | |
| 21 | Demand | $ 166,089,213 | $ 70,829,533 | $ 833,751 | $ 32,122,703 | $ 7,502,526 | $ 15,507,925 | $ 37,011,891 | $ 15,002 | $ 2,265,881 |
| 22 | Commodity | $ 12,234,345 | $ 5,981,910 | $ 59,243 | $ 3,522,001 | $ 1,246,616 | $ 147,641 | $ 1,244,587 | $ 1,270 | $ 31,076 |
| 23 | Customer | $ 251,406,981 | $ 198,573,865 | $ 1,486,503 | $ 40,391,301 | $ 2,782,330 | $ 2,741,877 | $ 3,365,968 | $ 77,381 | $ 1,987,756 |
| 24 | TOTAL REVENUE REQUIREMENT | $ 429,730,539 | $ 275,385,307 | $ 2,379,497 | $ 76,036,005 | $ 11,531,473 | $ 18,397,444 | $ 41,622,446 | $ 93,653 | $ 4,284,714 |

## Northern Indiana Public Service Company
## Proposed Test Year Without Gas
## Unit Costs

| Line No. | Description | Total Company | Res 411 | Multi-Fam 415 | Gen. Serv. Small 421 | Gen. Serv. Large 425 | Large Transp. DP 428a | Large Transp. HP 428b | C&I Off-Peak Interruptible 434 | C&I Off-Peak Interruptible 434 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (h) | (h) |
| | **Storage** | | | | | | | | | |
| 1 | Demand (per Design Day) | $ 0.3517 | $ 0.6197 | $ 0.6310 | $ 0.6161 | $ 0.5291 | $ - | $ - | $ - | $ - |
| 2 | Commodity (per therm) | $ 0.0021 | $ 0.0063 | $ 0.0051 | $ 0.0074 | $ 0.0067 | $ - | $ - | $ - | $ - |
| 3 | Customer (per customer per month) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 4 | Demand and Commodity (per therm) | $ 0.0043 | $ 0.0141 | $ 0.0127 | $ 0.0144 | $ 0.0104 | $ - | $ - | $ - | $ - |
| | **Transmission** | | | | | | | | | |
| 5 | Demand (per Design Day) | $ 3.8281 | $ 3.3051 | $ 3.3503 | $ 3.3523 | $ 3.5880 | $ 3.5595 | $ - | $ - | $ - |
| 6 | Commodity (per therm) | $ 0.0006 | $ 0.000617 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 |
| 7 | Customer (per customer per month) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | Demand and Commodity (per therm) | $ 0.0245 | $ 0.0419 | $ 0.0413 | $ 0.0388 | $ 0.0253 | $ 0.0312 | $ 0.0163 | $ 0.0006 | $ 0.0238 |
| | **Distrubition** | | | | | | | | | |
| 9 | Demand (per Design Day) | $ 3.3502 | $ 4.7251 | $ 4.6563 | $ 4.4722 | $ 4.3037 | $ 3.9906 | $ - | $ - | $ - |
| 10 | Commodity (per therm) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | Customer (per customer per month) | $ 25.73 | $ 22.28 | $ 24.94 | $ 51.50 | $ 345.56 | $ 2,328.58 | $ 4,954.99 | $ 2,637.72 | $ 1,775.43 |
| 12 | Demand and Commodity (per therm) | $ 0.0209 | $ 0.0590 | $ 0.0565 | $ 0.0509 | $ 0.0297 | $ 0.0343 | $ 0.0027 | $ 0.0073 | $ 0.0218 |
| | **TOTAL** | | | | | | | | | |
| 13 | Demand (per Design Day) | $ 7.5299 | $ 8.6498 | $ 8.6376 | $ 8.4406 | $ 8.4208 | $ 7.5501 | $ - | $ - | $ - |
| 14 | Commodity (per therm) | $ 0.0027 | $ 0.0069 | $ 0.0057 | $ 0.0080 | $ 0.0074 | $ 0.0006 | $ 0.0006 | $ 0.0006 | $ 0.0006 |
| 15 | Customer (per customer per month) | $ 25.73 | $ 22.28 | $ 24.94 | $ 51.50 | $ 345.56 | $ 2,328.58 | $ 4,954.99 | $ 2,637.72 | $ 1,775.43 |
| | Demand and Customer (per customer per | $ 42.07 | $ 29.74 | $ 38.16 | $ 91.26 | $ 1,259.96 | $ 15,387.69 | $ 58,014.17 | $ 3,079.43 | $ 3,770.96 |
| 16 | Demand and Commodity (per therm) | $ 0.0497 | $ 0.1150 | $ 0.1105 | $ 0.1041 | $ 0.0654 | $ 0.0654 | $ 0.0190 | $ 0.0079 | $ 0.0456 |
| 17 | DESIGN DAY PEAK | 21,412,453 | 7,770,154 | 91,861 | 3,592,121 | 839,647 | 2,068,842 | 6,759,882 | 0 | 289,945 |
| 18 | TOTAL THROUGHPUT | 3,427,490,303 | 622,207,258 | 7,571,986 | 315,561,686 | 121,839,923 | 240,989,554 | 2,066,476,050 | 2,105,207 | 50,738,639 |
| 19 | NO. OF CUSTOMERS * 12 | 9,924,627 | 9,058,064 | 60,805 | 794,556 | 8,163 | 1,186 | 696 | 30 | 1,128 |

**Northern Indiana Public Service Company**
**Revenue Requirement Mitigation - Alternative**
**Phase II Test Year Ending 12/31/2018**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Class** | | **Pro Forma Rate Schedule Margin Including Riders** | **Proposed Margin for Equal Rates of Return** | **Revenue to Cost Ratio** | **ACOSS Proposed Increase (Decrease) @ 6.74% ROR** | **ACOSS Rate Increase** | **Proposed Increase (Decrease) - Post Apportionment** | **Proposed Revenue to Cost Ratio** | **Proposed Margin Increase %** | **Proposed Margin** | **Less Pooling and Nomination Revenues** | **Targeted Base Rate Margin** |
| 1 | Large Transp. | 428 | 27,104,749 | 60,019,889 | 0.45 | 32,915,140 | 121.44% | 19,110,566 | 0.77 | 70.51% | 46,215,315 | 875,254 | 45,340,061 |
| 2 | Large Transp. - DP | 428a | 6,337,196 | $ 18,397,444 | 0.34 | 12,060,248 | 190.31% | 4,468,129 | 0.59 | 70.51% | 10,805,325 | 547,419 | 10,257,906 |
| 3 | Large Transp. - HP | 428b | 20,767,553 | $ 41,622,446 | 0.50 | 20,854,893 | 100.42% | 14,642,436 | 0.85 | 70.51% | 35,409,990 | 327,835 | 35,082,154 |
| 4 | 428a and 428b Total | | 27,104,749 | 60,019,889 | | 32,915,140 | | 19,110,566 | | | 46,215,315 | 875,254 | 45,340,061 |
| 5 | Delta | | - | 0 | | 0 | | - | | | - | (0) | - |

Note: Column C and D are from ACOSS Results.
The total proposed margin includes revenues from pooling and nomination charges which is not discernable between the distribution pressure and high pressure customers.
This amount was credited to the distribution pressure and high pressure customers prior to setting the Targeted Base Rate Margin for each group.

| Line No. | (A) Description | (B) 2018 Forecasted Billing Determinants (Bills or Therms) | (C) 400 Series Rate | (D) 2018 Total Revenue ("Margins") | (E) 2018 Forecasted Billing Determinants (Therms/Bills) | (F) Proposed Rate | (G) Total Revenue ("Margins") 2018 |
|---|---|---|---|---|---|---|---|
| 1 | **LargeTransportation - Rate 428 - Distribution Pressure** | | | | | | |
| 2 | Customer Charge | 1177 | $ 350.00 | $ 411,977 | 1177 | $ 1,000.00 | $ 1,177,078 |
| 3 | Demand Charge | | | | 9,765,042 | $ 0.2332 | $ 2,277,058 |
| 4 | Administrative Charges for Balancing Services | | | | | | |
| 5 | Category A & C | 53 | $ 1,325.00 | 69,994 | 53 | $ 1,590.00 | 83,992 |
| 6 | Category B | 1,124 | $ 550.00 | 617,967 | 1,124 | $ 660.00 | 741,560 |
| 7 | Total Administrative Charges for Balancin | 1,176 | | 687,960 | 1,176 | | 825,553 |
| 8 | Transportation charge | | | | | | |
| 9 | First 300,000 Therms | 169,479,808 Therms | $ 0.02565 | 4,346,317 | 169,479,808 Therms | $ 0.03020 | 5,118,904 |
| 10 | All Over 300,000 Therms | 71,509,746 Therms | $ 0.00765 | 546,695 | 71,509,746 Therms | $ 0.01104 | 789,575 |
| 11 | Total Transportation Charge | 240,989,554 Therms | | 4,893,012 | 240,989,554 Therms | | 5,908,479 |
| 12 | Pooling Agreement Fee | 1,162 | $ 50.00 | 58,115 | 1,162 | $ 60.00 | 69,738 |
| 24 | LargeTransportation - Rate 428 Sales | | | $ 6,051,065 | | | $ 10,257,906 |
| 25 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 26 | Adjustment of Charges for TDSIC | 240,989,554 Therms | 0.000325 | $ 78,273 | | | |
| 27 | Total Rider | | | $ 78,273 | | | $ - |
| 28 | | | Total Margin | 6,129,338 | | Total Margin | 10,257,906 |
| 29 | | | | | | Target Margin | $ 10,257,906 |
| 30 | | | | | | Over/(Under) | $ - |
| 31 | **LargeTransportation - Rate 428 - High Pressure** | | | | | | |
| 32 | Customer Charge | 705 | $ 350.00 | $ 246,723 | 705 | $ 1,000.00 | $ 704,922 |
| 33 | Demand Charge | | | | 73,639,646 | $ 0.1069 | $ 7,871,899 |
| 34 | Administrative Charges for Balancing Services | | | | | | |
| 35 | Category A & C | 282 | $ 1,325.00 | 374,309 | 282 | $ 1,590.00 | 449,171 |
| 36 | Category B | 423 | $ 550.00 | 232,883 | 423 | $ 660.00 | 279,460 |
| 37 | Total Administrative Charges for Balancin | 706 | | 607,192 | 706 | | 728,630 |
| 38 | Transportation charge | | | | | | |
| 39 | First 300,000 Therms | 152,516,253 Therms | $ 0.02565 | 3,911,286 | 152,516,253 Therms | $ 0.03020 | 4,605,961 |
| 40 | All Over 300,000 Therms | 1,913,959,797 Therms | $ 0.00765 | 14,632,302 | 1,913,959,797 Therms | $ 0.01104 | 21,132,987 |
| 41 | Total Transportation Charge | 2,066,476,050 Therms | | 18,543,588 | 2,066,476,050 Therms | | 25,738,948 |
| 42 | Pooling Agreement Fee | 629 | $ 50.00 | 31,463 | 629 | $ 60.00 | 37,756 |
| 54 | LargeTransportation - Rate 428 Sales | | | $ 19,428,966 | | | $ 35,082,154 |
| 55 | Universal Service Fund Rider - Rider 473 | | | $ - | | | |
| 56 | Adjustment of Charges for TDSIC | 2,066,476,050 Therms | 0.000325 | $ 671,191 | | | |
| 57 | Total Rider | | | $ 671,191 | | | $ - |
| 58 | | | Total Margin | 20,100,157 | | Total Margin | 35,082,154 |
| 59 | | | | | | Revenue Proof | $ 35,082,154 |
| 60 | | | | | | Over/(Under) | $ - |
| 61 | **LargeTransportation - Rate 428 - Distribution Pressure** | | | 6,129,338 | | | 10,257,906 |
| 62 | **LargeTransportation - Rate 428 - High Pressure** | | | 20,100,157 | | | 35,082,154 |
| 63 | **428 Pooling and Nomination Revenue** | | | $ 875,254 | | | $ 875,254 |
| 64 | | | Total | **27,104,749** | | | **46,215,315** |