STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM PURSUANT TO IND. CODE § 8-1-2-42(a) TO (A) TIMELY RECOVER CHARGES AND CREDITS FROM REGIONAL TRANSMISSION ORGANIZATIONS AND NIPSCO'S TRANSMISSION REVENUE REQUIREMENTS; (B) TIMELY RECOVER NIPSCO'S PURCHASED POWER COSTS; AND (C) ALLOCATE NIPSCO'S OFF SYSTEM SALES REVENUES; (6) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS, THE ENVIRONMENTAL COST RECOVERY MECHANISM AND THE ENVIRONMENTAL EXPENSE MECHANISM; (7) APPROVAL OF THE CLASSIFICATION OF NIPSCO'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; AND (8) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.* TO THE EXTENT SUCH RELIEF IS NECESSARY TO EFFECT THE RATEMAKING MECHANISMS PROPOSED BY NIPSCO.	)	CAUSE NO. 43526

FILED

AUG 29 2008

INDIANA UTILITY
REGULATORY COMMISSION

Prepared Direct Testimony and Exhibits

of

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Volume 3 of 6

Frank A. Shambo, Robert D. Greneman, Curt A. Westerhausen

August 29, 2008

NIPSCO ELECTRIC RATE CASE – TABLE OF CONTENTS

Case-In-Chief Volume 1

1. Robert C. Skaggs, Jr.
2. Eileen O'Neill Odum
3. Linda E. Miller
4. Mitchell E. Hershberger

Case-In-Chief Volume 2

5. Robert D. Campbell
6. Susanne M. Taylor
7. William Gresham
8. John M. O'Brien
9. Phillip W. Pack
10. Timothy A. Dehring

Case-In-Chief Volume 3

11. Frank A. Shambo
12. Robert D. Greneman
13. Curt A. Westerhausen

Case-In-Chief Volume 4

14. John J. Spanos

Case-In-Chief Volume 5

15. Vincent V. Rea
16. Paul R. Moul
17. John P. Kelly

Case-In-Chief Volume 6

18. John J. Reed
19. Victor F. Ranalletta
20. Bradley K. Sweet
21. Curtis A. Crum
22. Kelly R. Carmichael

Petitioner's Exhibit FAS-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

FRANK A. SHAMBO

VICE PRESIDENT, REGULATORY AND LEGISLATIVE AFFAIRS

VERIFIED DIRECT TESTIMONY OF FRANK A. SHAMBO

1 **I. INTRODUCTION**

2 **Q1. Please state your name and business address.**

3 A1. My name is Frank A. Shambo. My business address is 101 W. Ohio Street, Indianapolis,
4 Indiana 46204.

5 **Q2. What is your role with Northern Indiana Public Service Company ("NIPSCO")?**

6 A2. I am Vice President, Regulatory and Legislative Affairs for NIPSCO.

7 **Q3. Please briefly describe your educational and business experience.**

8 A3. I graduated from Western Illinois University with a Bachelor of Science Degree in
9 Accounting. I also have a Masters of Management Degree in economics and finance
10 from the J.L. Kellogg Graduate School of Management, Northwestern University. During
11 the period 1980 through 1996, I was employed by MidCon, an Occidental Petroleum
12 Company, in various capacities. During the period 1987 through 1996, I was employed in
13 the Marketing Department of Natural Gas Pipeline Company of America ultimately
14 obtaining the position of Director of Marketing for Utility Sales. In 1996, I was a co-
15 founder of mc2, a start-up company and an early entrant into the unregulated retail energy
16 market and served as the Director of Marketing/Finance through 1998 when the company
17 was sold. In 1998 through 2000, I served as Vice President, Finance and Business
18 Development for enable LLC, which was also a start-up company working in concert
19 with utilities across the country on new products and marketing efforts. Beginning in
20 2000, I served as a consultant for various utilities until my employment by NIPSCO as

1 Director, Regulatory and Government Policy in January 2004. I assumed my current
2 position of Vice President, Regulatory and Legislative Affairs on April 1, 2008.

3 **Q4. Have you previously testified before this or any other regulatory commission?**
4 A4. Yes, I have previously testified before the Indiana Utility Regulatory Commission
5 ("Commission") on behalf of NIPSCO in Cause No. 43186, involving NIPSCO's
6 purchased power benchmark; Cause No. 43396, involving NIPSCO's acquisition of the
7 Sugar Creek Generating Facility ("Sugar Creek Facility" or "Facility"); and various fuel
8 adjustment clause ("FAC") proceedings.

9 **Q5. What is the purpose of your direct testimony in this proceeding?**
10 A5. The purpose of my direct testimony is to: (1) provide a brief background of NIPSCO's
11 existing rates; (2) explain certain proforma adjustments made to test year operating
12 results; (3) provide an overview of the principles NIPSCO used in developing the rates
13 proposed in this proceeding; (4) explain key rules used in the development of rates and
14 how those rules align with the established principles; (5) review NIPSCO's Step Two rate
15 increase proposal associated with the Sugar Creek Facility; (6) illustrate the rationale for
16 NIPSCO's proposed Reliability Adjustment ("RA") tracking mechanism; (7) briefly
17 discuss NIPSCO's effort to simplify its tariff structure; and (8) discuss NIPSCO's future
18 steps related to rate offerings.

1 **II. CURRENT RATE STRUCTURE**

2 **Q6. When were NIPSCO's basic rates and charges last established?**

3 A6. NIPSCO's current basic rates and charges were approved by the Commission in its Order
4 dated July 15, 1987 in Cause No. 38045. The Order granted an increase in NIPSCO's
5 basic rates, which was implemented in an across-the-board fashion. Implementation of
6 the rate increase in such a manner was affirmed on reconsideration in the Commission's
7 Order dated March 9, 1988 in Cause No. 38045.

8 **Q7. Did the Commission subsequently investigate NIPSCO's basic rates and charges?**

9 A7. Yes, however, the basic rates and charges established in Cause No. 38045 remain in
10 effect today consistent with the terms of the Settlement Agreement approved by the
11 Commission in its Order dated September 23, 2002 in Cause No. 41746, *affirmed on*
12 *appeal, Citizens Action Coalition of Ind., Inc. v. Northern Ind. Pub. Serv. Co.*, 796
13 N.E.2d 1264 (Ind. Ct. App. 2003).[1]

14 **Q8. Have there been changes in NIPSCO's tariff since NIPSCO's last rate case?**

15 A8. Yes. Various changes have been made to NIPSCO's electric tariff over the last 20 years.
16 For example, additional provisions have been added to implement various adjustments in
17 accordance with tracking mechanisms approved by the Commission, including the

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[1] The Settlement Agreement approved by the Commission in Cause No. 41746 also provides for certain customer bill credits that have continued beyond the initial 49 month term of the settlement but will terminate when the Commission enters a basic rate order that approves revised NIPSCO electric rates.

Environmental Expense Recovery Mechanism ("EERM") and Environmental Cost Recovery Mechanism ("ECRM").

Q9. Please describe the scope of the tariff revisions proposed by NIPSCO in this proceeding.

A9. As discussed in more detail by NIPSCO Witnesses Curt A. Westerhausen and Robert D. Greneman, rather than making minor revisions to the current tariff, which has evolved in a piecemeal fashion over the past two decades, NIPSCO chose to substantially revise its tariff reflecting a complete assessment of ratemaking principles, cost of service and bill impacts.

III. REVENUE ADJUSTMENTS TO TEST YEAR

Q10. Have you reviewed the testimony of NIPSCO Witness Linda E. Miller?

A10. Yes. I will discuss the following five adjustments to test year revenues reflected in Petitioner's Exhibit LEM-2 sponsored by Ms. Miller: (1) an increase in NIPSCO's test year revenue to reflect the fact that certain large industrial customers were receiving discounts from tariff rates under special contracts during the test year; (2) a reduction in NIPSCO's test year revenue for certain customers that had consumption greater than the level that will be available to them in the future; (3) a reduction in NIPSCO's test year revenue to eliminate off-system sales margins; (4) a reduction in NIPSCO's test year revenue to eliminate the net proceeds from the sale of emissions allowances; and (5) a reduction in NIPSCO's test year revenue to eliminate non-firm transmission revenues.

Q11. Please explain the basis for Adjustment REV-3 on Petitioner's Exhibit LEM-2.

A11. Adjustment REV-3 on Petitioner's Exhibit LEM-2 is designed to increase NIPSCO's test year revenue by approximately $80 million to reflect the difference between current tariff rates and the discounted rates currently in place for certain large industrial customers pursuant to special contracts. All of these special contracts have been approved by the Commission over the past few years and some of these special contracts have already expired. The adjustment is primarily related to contracts that have either already expired or are set to expire six months following the implementation of the new basic rates and charges approved in this proceeding in accordance with either the terms of the Commission Orders approving the contracts or the terms of the contracts themselves. NIPSCO has not made an adjustment to its revenue requirement to attempt to recover the difference between the special contract rates and its proposed tariff rates for the six month period between approval of new basic rates and charges and the expiration of the special contracts. Therefore, NIPSCO has imputed revenues for these customers as a proforma adjustment to test year operating revenues.

Q12. Does NIPSCO anticipate that the expiring special contracts will be replaced by new special contracts?

A12. No. NIPSCO's cost allocation and rate design in this proceeding are more reflective of the actual cost to serve these customers. This better alignment of rates should eliminate the need for special contract rates for these customers.

1 **Q13. Please explain the basis for Adjustment REV-6 on Petitioner's Exhibit LEM-2.**

2 A13. Adjustment REV-6 on Petitioner's Exhibit LEM-2 reduces operating revenues for a group
3 of customers that operate under contract rates that limit usage periods. During the test
4 year, these customers requested variances, which NIPSCO granted, from the special
5 contract requirements. NIPSCO has removed $804,136 from test year revenues because
6 these variances were unusual and are not expected to be permitted in the future.
7 NIPSCO's proposed tariff provisions in this proceeding that would be applicable for these
8 customers or similar customers prescribes a better solution to meet their needs.

9 **Q14. Please explain the basis for Adjustment REV-8 on Petitioner's Exhibit LEM-2.**

10 A14. Adjustment REV-8 on Petitioner's Exhibit LEM-2 reduces operating revenues to
11 eliminate off-system sales revenues. During the test year, NIPSCO had off-system sales
12 margins of $29.1 million. NIPSCO is proposing an adjustment to remove both the
13 revenues and associated expenses (FP-5 on Petitioner's Exhibit LEM-2) from the test
14 year operating results because NIPSCO is proposing that 100% of future off-system sales
15 margins up to $15 million annually will be passed back to the ratepayers through the
16 proposed RA mechanism. If NIPSCO's off-system sales margins exceed $15 million in
17 any given year, NIPSCO proposes to pass back 80% of any additional sales margins to its
18 retail customers.

19 **Q15. How did NIPSCO select $15 million as the dividing line between 100% pass-through**
20 **and 80% pass-through of off-system sales margins to retail customers?**

A15. The highest level of margins from off-system sales during the period 2002 through 2006 was $15 million. Off-system sales margins during that period were $9.7 million in 2002, $13.8 million in 2003, $8.7 million in 2004, $15.4 million in 2005, and $14.4 million in 2006. During 2006 and 2007, NIPSCO relied upon block purchases to meet capacity requirements set by the North American Electric Reliability Corporation ("NERC")/ReliabilityFirst Corporation. NIPSCO purchased blocks of power sufficient to meet a percentage of its expected peak demand during a period, which provided an opportunity for higher off-system sales during non-peak periods. The reasonableness of this method as a way of meeting customer reliability needs was at issue in Cause No. 38706-FAC71-S1, wherein NIPSCO agreed to refund $33 million and also agreed to an ongoing benchmark limiting NIPSCO's ability to recover purchased power costs. These requirements were approved in the Commission's January 30, 2008 Order approving the Stipulation and Agreement in Cause No. 38706-FAC71-S1 ("FAC71-S1 Settlement"). Based upon the Commission's approval of the FAC71-S1 Settlement and ongoing discussions with stakeholders, NIPSCO has modified its purchased power practices by acquiring capacity reserves and substantially decreasing block purchases.

Q16. How did NIPSCO select 80% as the appropriate pass-through percentage?

A16. The 80% pass-through percentage is a fair sharing of risk and benefits with customers. By example, if NIPSCO makes $30 million in off-system sales margin in a given year, under this proposal, NIPSCO's customers would receive $27 million as a credit in the RA mechanism (100% x $15 million + 80% of the next $15 million) which is 90% of the

total off-system sales margin). In my opinion, $30 million would be on the high side of potential future off-system sales.

Q17. Please explain the basis for Adjustment REV-9 on Petitioner's Exhibit LEM-2.

A17. Adjustment REV-9 on Petitioner's Exhibit LEM-2 reduces operating revenues generated through the sales of emission allowances. During 2007, NIPSCO had net proceeds from the sale of emission allowances totaling approximately $12 million. As further explained by NIPSCO Witness Philip W. Pack, NIPSCO is proposing to revise its EERM to allow NIPSCO to recover the cost of any emission allowance purchases. To promote symmetry, NIPSCO proposes to use the EERM to pass-through as a credit the net proceeds from any future sales of emission allowances.

Q18. Please explain the basis for Adjustment REV-10 on Petitioner's Exhibit LEM-2.

A18. Adjustment REV-10 on Petitioner's Exhibit LEM-2 reduces operating revenues by $4.7 million. This reduction removes non-firm transmission revenues received from the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") under Schedules 1, 2, 7 and 8. NIPSCO proposes to pass back 100 percent of these net revenues through the RA mechanism. This is appropriate because an ongoing level of transmission revenues cannot be forecasted with any degree of reliability.

1 **IV. RATE POLICY**

2 **Q19. What are the policy objectives that NIPSCO established for this proceeding?**

3 A19. NIPSCO had three overall policy objectives in the development of the rates proposed in
4 this proceeding: (1) the charge for any service rendered is reasonable and just; (2) to the
5 extent possible, the rates should be easy to understand and administer; and (3) the final
6 rates need to consider broader public policy objectives.

7 **Q20. Please further explain the policy objective that rates are just and reasonable.**

8 A20. Reasonableness is a bit of a subjective term, but there are two underlying goals: (1) an
9 appropriate balance between the desire of customers for reasonable rates and NIPSCO's
10 responsibility to its shareholders to design rates that give the Company an opportunity to
11 earn a reasonable return on its investment, which ultimately is also in the customer's best
12 interest; and (2) a reasonable level of equity between customer classes in the final rate
13 design.

14 Obtaining a fair return for investors, in turn, requires that rates be designed based on an
15 appropriate revenue requirement level and that the rate structure provide NIPSCO with a
16 reasonable opportunity to recover that revenue requirement. As discussed by NIPSCO
17 Witness Paul R. Moul, a fair return is critical to NIPSCO's ability to acquire the capital
18 necessary to continue to provide safe and reliable electric service to our customers. One
19 of the biggest challenges in any rate proceeding is balancing equity between customer
20 classes. This is a substantial challenge for NIPSCO in this proceeding. This is the first

time in over 20 years that the revenue allocation, implicit in NIPSCO's rates, has been examined in detail. Additionally, NIPSCO's industrial customers represent an unusually high percentage of annual load when compared to other utilities, accounting for more than 50% of annual energy usage on NIPSCO's system. Many of these industrial customers compete in the world marketplace and have options as to where they will produce their products. Within the last 9 months, at least two industrial customers in NIPSCO's territory, Union Tank and Monaco Coach, have announced that they are either closing or substantially reducing production. On the other hand, NIPSCO is well aware of the challenges facing our residential customers that have had to sustain increases in other energy costs such as gasoline and natural gas. NIPSCO's proposed cost allocation and rate design takes into consideration the characteristics of all customer classes.

NIPSCO is also addressing in its proposed rate design the difference between "peak" and "off-peak" usage. The advent of the Midwest ISO marketplace has provided much clearer signals on the relative value of electricity for all hours. It is clear from reviewing the Midwest ISO's Locational Marginal Prices ("LMPs") that there is a significant value difference between peak hours in the summer and all other hours for the balance of the year. The simple average LMP price at NIPSCO's load node of peak hours in the summer was $72.75 as contrasted with an average price for all other hours for the balance of the year at the same load node of $47.16. This LMP differential reflects the fact that the Midwest ISO is dispatching more costly units as demand rises. NIPSCO believes that its rate design policy should provide more encouragement for customers to move from

1 peak hours to off-peak hours. This is a benefit to all customers in three ways: (1)
2 NIPSCO can reduce production from less efficient units; (2) NIPSCO can reduce
3 purchases from the market that by design reflect the dispatch of higher cost units across
4 the Midwest ISO's footprint as demand rises; and /or (3) NIPSCO can make off-system
5 sales into the Midwest ISO marketplace at the LMP (with the vast majority of these off-
6 system sales margins proposed to be passed back to customers through the RA
7 mechanism).

8 **Q21. Please describe what you mean when you say rates should be easy to understand**
9 **and administer.**

10 A21. It is NIPSCO's belief that all customers want safe and reliable service priced at rates that
11 are easy to understand. We believe our customers are not served well by a complicated
12 tariff that is difficult to understand or complex tariff options that require specialists to
13 evaluate the nuances in detail to find the correct rate for their business. To promote rates
14 that are easy to understand and administer, NIPSCO proposes to reduce the number of
15 rate schedules in its proposed tariff. For example, NIPSCO has reduced the number of
16 Street Lighting rate schedules from 21 to 1.

17 **Q22. Please describe, generally, the notion of offering rates that consider broader public**
18 **policy objectives.**

19 A22. In 2006, the State of Indiana through the Indiana Office of Energy & Defense
20 Development established the Hoosier Homegrown Energy Strategic Plan that encourages

1 energy efficiency investments. This Commission has also conducted hearings on energy
2 efficiency through its investigation of demand side management programs in Cause No.
3 42693. NIPSCO has considered these public policy objectives in the development of its
4 proposed rates in this proceeding and will also do so in a separate case to be filed in the
5 near future that will seek approval of various Demand Side Management ("DSM")
6 programs. This objective does not conflict in any significant way with the other two
7 objectives. These public policy objectives are consistent with revenue allocations that
8 send customers accurate price signals about the cost implications of their consumption
9 decisions, both in terms of revenue allocation among customer classes and rate design.

10 **Q23. Is the Cost of Service Study presented by Mr. Greneman consistent with the**
11 **objectives you describe above?**
12 A23. Yes.

13 **V. KEY RATE DEVELOPMENT DECISIONS**

14 **Q24. Please identify key rate development decisions made by NIPSCO and their**
15 **relationship to the objectives described above.**
16 A24. NIPSCO made a number of decisions in this proceeding to reach the objectives identified
17 above: (1) production costs are allocated based upon 4 Coincident Peaks ("4CP"); (2)
18 fuel costs are removed from base rates to permit recovery of all fuel costs in the FAC; (3)
19 declining block rates are eliminated; (4) certain billing determinants for demand charges
20 have been developed to recognize the difference between peak and off-peak; (5) rates are

1 constructed that encourage lowering peak demand (Rates 526 and 527); (6) the use of
2 Interval Demand Recording ("IDR") meters will be increased for customers served under
3 Rates 523 and 533; (7) interruptible service is continued and expanded; (8) the total
4 number of rate schedules is reduced and the service offerings are simplified so that
5 customers and stakeholders will better understand the options available; (9) the customer
6 charges are increased to better reflect the cost to serve; (10) a new structure has been
7 developed for the Economic Development Rider; and (11) NIPSCO's rate design is
8 adjusted to provide a measured progress toward full cost based rates for certain customer
9 classes in order to avoid rate shock.

10 **Q25. Why did NIPSCO use a 4CP allocation for production costs?**

11 A25. During 2007, NIPSCO's 200 highest demand hours occurred during the four summer
12 months of June through September. In my opinion, the 4CP cost allocation method
13 provides the best alignment between cost causation and rate design for NIPSCO's load
14 profile, as more thoroughly described by Mr. Greneman.

15 **Q26. Please explain in more detail why NIPSCO is proposing to remove all fuel costs**
16 **from its basic rates and instead recover them through the FAC.**

17 A26. To explain why NIPSCO is removing fuel-related costs from its basic rates, I need to
18 briefly recap the evolution of energy markets in the United States. For many years,
19 utilities have forecasted their native load requirements and through economic dispatch
20 principles, determined which of their generating units to dispatch and in what order they

would be dispatched. The cost of fuel for this internal generation was recognized in the ratemaking process. Beginning in the early 1970s, changes in the cost of fuel for this internal generation was recovered through FAC proceedings. Electric utilities then became significantly more interconnected and entered into contracts for purchased power, which allowed utilities to decide whether it was more economical to purchase power from a neighboring utility than to dispatch one of its internal generating units to meet its retail load. This Commission has repeatedly encouraged electric utilities to purchase power from neighboring utilities when such power was less expensive than that of the utility's own internal generating units.[2] In order to encourage this practice and provide customers with the benefit of less expensive resources, the cost of this purchased power was recoverable in the utility's FAC proceedings. NIPSCO is now proposing to remove all fuel costs, including purchased power costs, from its base rates for two reasons: (1) fuel is a variable cost by nature and should not be collected in a fixed component on the bill; and (2) as discussed above, one of NIPSCO's objectives is to simplify its tariff structure and having all fuel costs in one place does simplify the process for customers. In addition, NIPSCO is proposing to remove purchased power and related Midwest ISO costs from the FAC and recover these costs through the RA mechanism. NIPSCO Witnesses Curtis L. Crum and Ms. Miller more fully describe this proposal.

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[2] *Northern Indiana Pub. Serv. Co.*, Cause No. 37343 (IURC 12/27/1983), pp. 4-5. (The Commission found that "it is imperative that [NIPSCO]...commence a program directed toward reducing fuel costs by supplementing internal coal generation of electricity with the purchase of less expensive supplies of electricity from neighboring utilities whenever operating conditions will permit this without adversely affecting the reliability of electrical services.")

1 If the Commission does not accept NIPSCO's proposal and determines that fuel costs
2 (which have been excluded in NIPSCO's rate design) should be included in basic rates, a
3 further adjustment would be necessary in this proceeding to reflect an appropriate level of
4 fuel in basic rates.

5 **Q27. Please explain why NIPSCO has eliminated declining block rates?**

6 A27. Declining block rates cause the per unit cost of energy to decrease as a customer increases
7 its consumption of electricity. NIPSCO believes this rate structure encourages customers
8 to increase energy usage. Given current policies in favor of promoting energy efficiency,
9 NIPSCO proposes to eliminate declining block rates.

10 **Q28. Please explain NIPSCO's rationale for the billing determinants for demand charges**
11 **used in Rates 533 and 534.**

12 A28. In light of public policy objectives and the goal of providing more cost-reflective price
13 signals within classes, NIPSCO is seeking to create greater awareness of seasonal peak
14 versus off-peak usage in the rates proposed in this proceeding. NIPSCO is proposing that
15 the billing determinants for Rates 533 and 534 be set at the higher of 90% of peak usage,
16 defined as the eight-hour period from 11 AM to 7 PM, Monday through Friday, excluding
17 holidays, during the four summer months of June through September, or 80% of all other
18 hours. The billing determinants for a given month will be the highest of the previous 24
19 months using the rule described above. NIPSCO chose a 90% threshold, instead of
20 100%, to avoid overly penalizing a customer which may have had just a handful of high

hours during that period. Using 80% of the off-peak period clearly encourages customers to move higher demand into off-peak hours. This billing determinant approach is also consistent with the use of 4CP for allocating production costs.

Q29. Please explain the nature of Rates 526 and 527 and NIPSCO's rate design for those rates?

A29. Rates 526 and 527, like the billing determinants rules described above, are established to encourage Off-Peak usage.

Rate 526 is specifically identified as Off-Peak Service. This Rate encourages Off-Peak service by setting Billing Demand equal to either 100% of On-Peak hours for the past 12 months or 50% of Off-Peak hours for the past 24 months. On-Peak hours for Rate 526 are defined as 11 AM to 7 PM from April 1 through September 30 and 1 PM to 9 PM from October 1 to March 31, excluding weekends and holidays. Customers with high load during On-Peak hours would pay more on this Rate than under Rate 533 because under Rate 533 only 90% of Peak is used to determine Billing Demand, rather than 100%. By contrast, a Customer whose demand could be migrated to off-peak hours would be encouraged to do so because their Billing Demand would be set at 50%, as compared 80% under Rate 533.

Rate 527 offers lower costs to any customer willing to limit operation during peak hours to two out of five business days. This clearly encourages customers to move demand to off-peak periods, which in turn benefits all customers by more efficiently using

NIPSCO's system and reducing the need for additional capacity. NIPSCO expects that some customers would be at the beginning of the week (Monday and Tuesday) and others at the end of the week (Thursday and Friday), further diversifying NIPSCO's demand requirements. NIPSCO has included specific provisions for situations when these customers need additional power during periods outside of the hours provided in the Rate.

Mr. Greneman discusses the specifics of this rate design and Mr. Westerhausen discusses the specific tariff rules proposed to implement these changes.

Q30. Why does NIPSCO reserve the right to move a customer to Rate 533 or 534 who fails to manage its load within the requirements of certain of the rate schedules?

A30. Some of NIPSCO's proposed rate schedules, including Rates 526 and 527, provide lower rates to customers that manage their load moving demand into Off-Peak periods. For example, Rate 527 is designed to encourage customers to move load to off-peak hours. These lower rates are attributable to costs NIPSCO avoids because of this load shift. Customers who fail to manage their load within the requirements of the applicable Rate Schedule are taking the lower rates without reducing the costs that make those lower rates possible. This unfairly shifts costs to either NIPSCO's other customers or its shareholders.

Q31. Please explain why NIPSCO is proposing to increase the number of IDR meters?

A31. NIPSCO is proposing to add additional IDR meters for our medium and large non-residential customers (Rates 523 and 533) so that the nature of load differences among

1 these customers can be better understood. NIPSCO expects to use this data in the future
2 for a number of purposes, including: (1) better allocation of production costs to these
3 classes; (2) better allocation of energy costs to these classes; (3) development of riders for
4 these rate schedules to provide incentives for lower peak usage; and (4) more accurate
5 knowledge of overall system operations. As discussed further by NIPSCO Witness
6 Timothy A. Dehring, NIPSCO will be establishing processes to read and record the
7 information provided by the meters. This information also will be useful in evaluating
8 the potential value of extending these devices to smaller customer classes.

9 **Q32. Why has NIPSCO limited the applicability of Rate 523?**

10 A32. Rate 523 was designed for customers on the Company's distribution system, many of
11 whom do not currently have IDR meters and therefore the billing determinants are
12 simplified and not appropriate for larger customers.

13 **Q33. Please explain Rate 536 for interruptible service and the rationale for its design and**
14 **the expected volumes used to create the rate schedule.**

15 A33. Interruptible load that conforms to the Midwest ISO interruption requirements will
16 benefit all customers by allowing NIPSCO to avoid building new facilities or paying for
17 capacity to meet reliability standards. NIPSCO's Rate 536 conforms to the Midwest ISO
18 interruption requirements. NIPSCO has allocated only 50% of the capacity costs to this
19 rate schedule because of its ability to interrupt service on short notice.

1 NIPSCO has evaluated the load characteristics of the customers eligible for this tariff to
2 determine the billing determinants used in the proposed rates. This determination was
3 based on those customers that (a) currently are on interruptible service or (b) have self-
4 generation options.

5 **Q34. Why is NIPSCO limiting participation in Rate 536 to 250 MW?**

6 A34. The counterpart to Rate 536 in NIPSCO's current rates and charges (Rate 836) limits the
7 rate's availability to 110 MW. NIPSCO has estimated that the total load of current
8 customers who would benefit from this Rate is 250 MW. NIPSCO is proposing to
9 increase its amount of interruptible service to meet this projected demand, which more
10 than doubles the currently availability, and consequently, NIPSCO seeks to limit the
11 availability of this Rate to 250 MW. Additionally, this limitation serves to protect against
12 the risk associated with earnings erosion if more customers migrate to this rate than what
13 NIPSCO assumed in its Cost of Service Study. Mr. Greneman further explains the
14 implications of the Cost of Service Study.

15 **Q35. Please explain why NIPSCO is reducing the number of customer Rates.**

16 A35. NIPSCO is proposing to reduce the number of customer Rates from 42 to 13.
17 Determining the appropriate number of customer rates is a balance between seeking
18 equitable cost allocation among customers with different characteristics and the
19 simplicity and administrative feasibility of fewer rate offerings with some embedded
20 riders. NIPSCO has decided to move in the direction of simplicity and administrative

1 feasibility in this proceeding. While many of NIPSCO's customers have diverse usage
2 characteristics, NIPSCO's proposed rate restructuring is now able to better align customer
3 load profile with the Company's underlying cost structure.

4 **Q36. Please explain the rationale for NIPSCO's Economic Development Rider.**

5 A36. It is in the best interest of NIPSCO and its customers that NIPSCO promote its service
6 territory as a viable location for new businesses. Competition has become strong within
7 the United States and globally for business expansions. It takes a concerted effort on the
8 part of the state, local communities and utilities to create the best chance to bring new
9 business to the territory. Benefits to NIPSCO customers include an increased tax base
10 from the investment and potential new employment with related income tax, sales tax and
11 property tax benefits.

12 NIPSCO is proposing discounts to non-fuel rates to avoid shifting the burden to other
13 customers. NIPSCO will also assure that the rate will be above the incremental cost to
14 provide service to a new customer. NIPSCO seeks the ability to discount the non-fuel
15 rate for up to 5 years and by up to 50% in the first year declining to 10% by year 5.
16 NIPSCO will evaluate a number of key variables prior to offering the discount, including
17 whether the facility is located in a "brownfield" area. By brownfield, I mean areas of
18 NIPSCO's territory where existing transmission and distribution facilities are not at
19 capacity and limited new facilities would be required for new business. NIPSCO has a
20 number of areas where existing transmission and distribution facilities are not at capacity.

1 Locating new facilities in those areas can be done at the lowest incremental cost.
2 NIPSCO will consider additional criteria in determining the appropriate discounts as
3 defined in the proposed tariff as discussed by Mr. Westerhausen.

4 **Q37. Is NIPSCO proposing to change its new business policy in this proceeding?**
5 A37. Yes.

6 **Q38. Please explain the change and rationale?**
7 A38. NIPSCO is seeking to move away from the simple calculation of 2.5 times revenue to
8 define the appropriate investment level that NIPSCO should make for new business.
9 Revenue is not a good proxy for contribution to a fixed asset business, although I admit it
10 is a simple calculation. NIPSCO is proposing to consider the non-fuel margin and
11 expected non-fuel revenue to determine an appropriate investment level based upon net
12 present value of the revenue stream. Using this methodology, NIPSCO proposes that the
13 appropriate investment level be $3,500 per residential customer. Using the existing 2.5
14 times revenue produces approximately $2,500. This change will assist in encouraging
15 housing growth in NIPSCO's service territory during a period that can certainly use
16 additional encouragement.

17 **Q39. Please explain why NIPSCO is proposing modifications of the cost-based revenue**
18 **allocations and the impact of those modifications?**
19 A39. Upon completion of the class embedded cost study, it was apparent that a substantial cost
20 shift was occurring among the three major customer classes. Because existing rates date

1 back to the early 1980's, there are many possible explanations for the changes, including
2 fundamental shifts in demand in the commercial class that has moved from smaller units
3 to big box operations during this period, and changing residential usage patterns with the
4 major changes in electrical appliances over this period. NIPSCO suspects, but cannot
5 confirm, that the current tariff reflects some social engineering of the rates to shift costs
6 from residential to commercial and industrial customers. Whatever the reason, NIPSCO
7 seeks to move toward rates that rely on cost-based allocations with limited social
8 adjustments. However, moving to cost-based allocations in one step (after 20 years)
9 would result in a 23.2% increase in basic rates for residential customers.

10 NIPSCO is therefore proposing that only one-third of the full cost-based rate increase to
11 the residential Rate be implemented in this proceeding, yielding an average 7.74%
12 increase in basic rates to residential customers.

13 **Q40. Are you familiar with NIPSCO's load research study?**

14 A40. Yes, I am. To improve the allocation of demand costs, NIPSCO conducted additional
15 load research on our customer segments that have lower usage levels, specifically small
16 commercial and residential customers. It should be noted that NIPSCO has detailed
17 meter information (hourly or at least periodic demand) on over 50% of our annual volume
18 including all large industrial customers. The additional load research was performed to
19 better understand the differences between small commercial and residential customers

1 only. The results were provided to Mr. Greneman for his use in allocating demand costs
2 between these classes.

3 **Q41. Are you familiar with NIPSCO's proposal to treat its electric utility business as**
4 **100% jurisdictional?**
5 A41. Yes, I am.

6 **Q42. Please explain the rationale for this proposal.**
7 A42. NIPSCO's system is designed to serve jurisdictional customers. As the Midwest ISO
8 marketplace develops, transmission services, energy sales, and ancillary services can be
9 purchased from the Midwest ISO. In the past, NIPSCO treated a small amount of its
10 business as non-jurisdictional because it provides a small amount of FERC-regulated
11 wholesale service to the City of Argos under a long-term contract, FERC-regulated
12 ancillary services to Indiana Municipal Power Agency ("IMPA") and FERC-regulated
13 transmission service to Wabash Valley Power Association, Inc. ("WVPA"). Given the
14 small size and incidental amount of the non-jurisdictional business, NIPSCO believes its
15 business should be treated as 100% jurisdictional and that revenues from these incidental
16 wholesale ancillary services and transmission services should be credited to retail
17 customers as described in greater detail by Mr. Greneman. NIPSCO will treat these
18 revenues as jurisdictional for purposes of NIPSCO's calculation of compliance with the
19 earnings test in its FAC.

1 **VI. TWO STEP RATE ADJUSTMENT PROPOSAL**

2 **Q43. Please explain NIPSCO's proposal to implement its proposed rate adjustments in**
3 **two steps.**

4 A43. NIPSCO is proposing to adjust its rates and charges in two steps. The first step ("Step
5 One") would adjust NIPSCO's rates to reflect rate base in service as of December 31,
6 2007 and the financial results using the 2007 test year adjusted for fixed, known and
7 measurable changes. Step One would be effective immediately upon the issuance of the
8 Commission Order in this proceeding approving new base rates. The second step ("Step
9 Two") would reflect capital costs and operating expenses relating to the Sugar Creek
10 Facility. Step Two would be implemented when the Sugar Creek Facility becomes
11 dispatchable in the Midwest ISO.

12 **Q44. Please describe the Sugar Creek Facility.**

13 A44. The Sugar Creek Facility is a 535 MW combined cycle combustion turbine generating
14 facility ("CCGT") located near Terre Haute, Indiana. The Sugar Creek Facility was
15 acquired by NIPSCO through the purchase of the equity interests in Sugar Creek Power
16 Company, LLC and the subsequent merger of that company into NIPSCO. NIPSCO
17 acquired the equity interests on May 30, 2008 pursuant to the Commission's Order in
18 Cause No. 43396 dated May 28, 2008 ("CPCN Order") granting NIPSCO a Certificate of
19 Public Convenience and Necessity ("CPCN") for the acquisition and NIPSCO assumed
20 control of the Sugar Creek Facility on that date. The Sugar Creek Facility is capable of
21 connection to either the Midwest ISO or the PJM Interconnection, LLC ("PJM") markets.

1 **Q45. Why is NIPSCO proposing Step Two to reflect the capital costs and operating**
2 **expenses relating to the Sugar Creek Facility?**
3 A45. NIPSCO's Step Two rate adjustment is necessary to resolve a difference between the time
4 when the Sugar Creek Facility can be reflected in NIPSCO's retail rates and the time
5 NIPSCO agreed to initiate this rate proceeding. NIPSCO committed to initiate this rate
6 proceeding by July 1, 2008 in a settlement approved by the Commission's Order dated
7 August 23, 2006 in Cause No. 42824. NIPSCO was not able to acquire control of the
8 Sugar Creek Facility until May 30, 2008. Because the Sugar Creek Facility is committed
9 to the PJM market through May 31, 2010, NIPSCO proposed in Cause No. 43396 a
10 mechanism to pass revenues earned from PJM to retail customers which it believed
11 would render the Sugar Creek Facility sufficiently used and useful to be included in
12 NIPSCO's rate base while committed to PJM. In the CPCN Order, however, the
13 Commission determined that the Sugar Creek Facility would not be deemed "in-service"
14 or "used and useful" to NIPSCO's ratepayers until the Facility is dispatched into the
15 Midwest ISO. Notwithstanding the CPCN Order, NIPSCO did finalize the purchase of
16 the Facility following the issuance of the CPCN Order because it believed acquisition of
17 the Facility was in the best interest of its customers. NIPSCO is proposing the Step Two
18 rate adjustment in this proceeding to incorporate the costs associated with the Sugar
19 Creek Facility once it becomes used and useful as prescribed in the CPCN Order. The
20 CPCN Order provided that a review of "the inclusion of costs of the purchase of the

1 Sugar Creek Facility in NIPSCO's forthcoming rate case . . . (to the extent requested) can
2 occur as part of that proceeding . . . ." CPCN Order, p. 32.

3 **Q46. Why did NIPSCO acquire a generation facility that was committed to PJM through**
4 **May 31, 2010?**

5 A46. NIPSCO initiated two requests for proposals ("RFP") to identify potential sources to meet
6 its generation needs. The first RFP required potential CCGT's be capable of dispatch
7 into the Midwest ISO after January 1, 2009 and a second RFP solicited further CCGT's
8 capable of dispatch into the Midwest ISO by May 31, 2008. Proposals for the Sugar
9 Creek Facility were received in response to both RFPs. Only after NIPSCO commenced
10 its evaluation did it learn through its due diligence process that the Sugar Creek Facility,
11 although physically capable of dispatching load into the Midwest ISO, was committed to
12 the PJM market through May 31, 2010.

13 **Q47. Why did NIPSCO continue evaluating the Sugar Creek Facility as a potential**
14 **generation option?**

15 A47. Notwithstanding the Facility's commitment to PJM, acquisition of the Sugar Creek
16 Facility continued to rank highly in NIPSCO's evaluation of its alternatives. NIPSCO
17 concluded it was inappropriate to exclude from consideration a plant that will provide
18 many decades of service to its customers and offered such favorable economic terms
19 because of a two year commitment to PJM. Investigation of the Sugar Creek Facility
20 continued and NIPSCO eventually executed a purchase agreement for the Facility. In its

1 CPCN Order, the Commission concluded the public convenience and necessity required
2 NIPSCO's acquisition of the Sugar Creek Facility and granted NIPSCO a CPCN to
3 acquire the Sugar Creek Facility. The Commission expressly found that "NIPSCO's
4 purchase of [Sugar Creek] will, *in 2010*, add needed capacity for the benefit of its
5 ratepayers." CPCN Order at 26 (emphasis added).

6 **Q48. Will NIPSCO evaluate withdrawing the Sugar Creek Facility from the PJM**
7 **commitment?**

8 A48. Yes. NIPSCO will explore any opportunities that may arise to terminate the PJM
9 commitment earlier than May 31, 2010. However, there are contractual and regulatory
10 obstacles to such a change. NIPSCO will pursue reasonable options to dispatch the Sugar
11 Creek Facility into the Midwest ISO as soon as possible, but there is no assurance that
12 this can be accomplished earlier than June 1, 2010.

13 **Q49. How does NIPSCO propose to deal with carrying costs and depreciation expense**
14 **relating to the Sugar Creek Facility?**

15 A49. NIPSCO proposes to include deferred depreciation expense and carrying costs relating to
16 its investment in the Sugar Creek Facility in Step Two pursuant to the relief NIPSCO
17 seeks in Cause No. 43396-S1. In that subdocket, NIPSCO proposes an alternative
18 regulatory plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 for this treatment. NIPSCO is
19 proposing to recover the deferred depreciation and carrying costs commencing with the
20 proposed Step Two rate increase. NIPSCO proposes to recover these deferrals over a five

1 year period, after which NIPSCO's rates will be adjusted to remove the recovery of the
2 deferrals. This proposal is consistent with the FAC71-S1 Settlement.

3 **Q50. How does NIPSCO propose to calculate its Step Two rates?**

4 A50. Ms. Miller has calculated the revenue requirement for Step Two. Mr. Greneman then
5 used the same cost allocation method as used in Step One and the same billing
6 determinants in section two of his cost of service study. NIPSCO is not proposing any
7 revision to the fully allocated cost methodology described Mr. Greneman. Petitioner's
8 Exhibit CAW-3 contains the proposed rates for Step Two. In Step Two, NIPSCO is
9 proposing approximately an $80 million increase in basic rates, yielding an average
10 9.05% rate increase in basic rates.

11 **Q51. What procedures does NIPSCO propose in order to implement the Step Two rate**
12 **adjustment?**

13 A51. NIPSCO proposes to implement the Step Two rate adjustment as soon as the Sugar Creek
14 Facility is dispatched into the Midwest ISO market. The latest this will occur is June 1,
15 2010. Ms. Miller has calculated the Step Two rate adjustment based on the revenue
16 requirement relating to the Sugar Creek Facility. NIPSCO will file a written verification
17 with the Commission when the Facility is dispatchable into the Midwest ISO. NIPSCO
18 requests that the Commission authorize NIPSCO to place the Step Two rates in effect
19 immediately upon the submission of the verification. If the Sugar Creek Facility will be
20 dispatched to the Midwest ISO prior to June 1, 2010, NIPSCO will adjust Ms. Miller's

rate calculation for the shorter period over which the amortized costs would be deferred and file a revised tariff reflecting that change. A subsequent tariff filing will be made to remove the portion of the rates recovering the amortized depreciation and carrying costs after those costs have been fully recovered to comport with the terms of the FAC71-S1 Settlement.

Q52. Are you aware of any prior Commission orders approving a rate adjustment similar to the Step Two proposal?

A52. Yes, I am. In its December 3, 1984 Order in Cause No. 37457, the Commission authorized Indiana & Michigan Electric Company ("I&M") to implement a second step rate increase twelve months after the first rate increase went into effect for its Rockport generating station. In its August 24, 1995 Order in Cause No. 39938, the Commission approved a settlement agreement providing for a two phase rate increase for Indianapolis Power & Light Company where the second phase was to go into effect nine months after the first phase to reflect the in-service date of certain environmental control property. In its December 2, 1992 Order in Cause No. 39381, the Commission authorized Crawfordsville Electric Light & Power to implement a two phase rate increase with the second phase going into effect upon placing in service new electric plant. All of these orders were approved under traditional ratemaking principles.

1 **Q53. Is NIPSCO's proposal for a Step Two rate increase in the public interest?**

2 A53. Yes. As recognized by the grant of a CPCN through the CPCN Order, the public
3 convenience and necessity were served by NIPSCO's purchase of the Sugar Creek
4 Facility. The Facility's purchase brought necessary capacity and fuel diversity to
5 NIPSCO's generating mix. NIPSCO's 2007 Integrated Resource Plan demonstrated that
6 NIPSCO would need to either acquire or construct additional generation facilities as part
7 of its strategy to meet its capacity requirements. Acquisition of the Sugar Creek Facility
8 resulted from NIPSCO's thorough RFP process designed to identify the most cost
9 effective options to meet its need for additional generation. The Sugar Creek Facility was
10 the most cost effective alternative for NIPSCO to acquire needed capacity. Had NIPSCO
11 constructed an equivalent facility, the cost to ratepayers would have been two to six times
12 what it is with the Sugar Creek Facility and NIPSCO would have been able to capitalize
13 carrying costs on its investment during the construction period through allowance for
14 funds used during construction. Penalizing NIPSCO for acquiring the lowest cost facility
15 because of its temporary commitment to another Regional Transmission Organization
16 would discourage Indiana utilities from exploring such opportunities. This could result in
17 higher prices for Indiana retail customers.

18 **VII. THE RA MECHANISM**

19 **Q54. What costs and offsetting revenues is NIPSCO seeking to recover through the**
20 **proposed RA mechanism?**

A54. NIPSCO is seeking recovery of all purchased power costs, capacity costs, and all non-FAC MISO costs offset by non-FAC MISO credits and off-system sales margins as detailed by Mr. Crum.

Q55. Please describe why NIPSCO is seeking to recover these costs through the RA.

A55. As Mr. Crum describes, these costs are necessary components to the provision of reliable service. NIPSCO believes that because of the variable nature of these costs, recovery through a tracker is more appropriate than including it as an operating expense when establishing NIPSCO's fair rate of return. These costs will be reviewable on a quarterly basis in the RA mechanism. Including these costs in a tracker assures that NIPSCO will recover no more and no less than the actual costs incurred in connection with these reliability requirements, provides ongoing scrutiny of these costs by the Commission and provides a means to pass through offsetting revenues and credits to retail customers. For example, capacity costs will be greatly reduced when the Sugar Creek Facility dispatches into the Midwest ISO. Recovering these costs in the RA ensures that customers receive the benefits of decreases in any of the costs or increases in the credits described above. It also provides more accurate price signals to our customers. I would also note that inclusion of purchased power costs in the RA is consistent with the FAC71-S1 Settlement Agreement, which provided for recovery of these costs through a Section 42(a) mechanism.

NIPSCO proposes to offset these costs by passing back off-system sales margins, as described above, through this mechanism. Many off-system sales are now made the same way energy is purchased – through the Midwest ISO. Accordingly, it is appropriate to use the RA mechanism to pass these margins back to customers.

VIII. SIMPLIFICATION OF AND REDUCTION IN THE NUMBER OF RATE SCHEDULES

Q56. Please provide an overview of NIPSCO's efforts to simplify and reduce its number of rate schedules.

A56. Currently, NIPSCO has 42 Rate Schedules and is proposing a reduction to 13 rate schedules in this proceeding. NIPSCO continues to provide rate flexibility. For example, Rate 534 (customers over 10 MW) is primarily targeted for transmission level customers but the rate design is set based upon delivery at the primary distribution system. Credit is provided to customers who take service at the transmission level in Rate 534. This rate design allows all customers with load over 10 MW to qualify for the service, not just those on the transmission system. NIPSCO is also seeking to simplify its tariff structure by moving elements of the rate schedules that are common into the general rules and regulations, thereby limiting the rate schedules to the service criteria and pricing. Mr. Westerhausen provides a broader discussion of NIPSCO's rate schedules, riders and rules.

1 **Q57. Please describe the reclassification process used in defining the tariff categories.**

2 A57. Most residential customers will map easily from Rate 811 to the new Rate 511 schedules.
3 NIPSCO is converting two additional residential rates into riders for Rate 511. There are
4 a number of schedules in the commercial/small industrial classes that will be collapsed
5 into just three (3) rate schedules (Rates 521, 523 and 533). Rate 521 is designed for small
6 commercial customers that do not have demand meters. These customers are not likely to
7 have as much energy acquisition sophistication as larger customers. The rate structure is
8 similar to the residential rates with a customer charge and a volumetric per kWh charge.

9 Rate 523 contains a broad grouping of customers, estimated at 11,500, that receive power
10 from the distribution system. This is the first rate schedule that provides a demand
11 charge. Customers were mapped into this rate schedule from Rates 821, 823 and 824
12 based upon a combination of the assets used to serve these customers, demand data from
13 those customers with permanent demand meters and sampling demand meters. This is a
14 difficult grouping because of the variety of loads within this class. In recognition of this
15 difficulty, NIPSCO is planning to expand the use of IDR meters within this group.
16 NIPSCO is also providing a number of riders that can be used to better fit customer needs
17 in this Rate.

18 Rate 533 contains a smaller group of customers, estimated at 900 plus, that take service at
19 the distribution and transmission levels. These customers, by and large, have had demand
20 meters for some time. Customers were mapped into this rate schedule from 817, 820,

821, 823, 824, 826, 832 and 833 based upon a combination of the assets used to serve these customers and demand data from the existing demand meters. NIPSCO will be replacing existing Demand Indicating meters with IDR meters, in this group for better understanding of load characteristics.

Q58. Several of the rate schedules require a separate contract with the customer. Is NIPSCO proposing to negotiate a contract unique to each customer?

A58. No. While certain terms in the contracts will be unique to the customer, NIPSCO will develop standard forms consistent with the tariff. Individual contracts are necessary to identify customer specific data such as usage history.

Q59. Please explain Rider 575?

A59. NIPSCO's current tariff includes three (3) separate space heating rates. Consistent with NIPSCO's effort to simplify its tariff, the three (3) existing rate schedules have been transitioned to one rider, Rider 575. This rider increases the threshold for the discount applicable to the Energy Charge for residential customers to 700 kWh during October through April based upon a review of space heating customer usage.

IX. DSM PROGRAMS

Q60. Is NIPSCO proposing specific DSM programs in this proceeding?

A60. No. After consideration of the complexity of filing its first base rate case in over 20 years, NIPSCO decided that its DSM programs and related concepts should be filed in a separate proceeding. NIPSCO anticipates making this filing in fall 2008, with the hope

1 that approval is received by early 2009 in order to allow for specific programs to be
2 available to customers for the summer of 2009. Given the schedule for this proceeding,
3 an implementation date that early would not be possible if the DSM programs were
4 proposed in the context of this proceeding.

5 **Q61. Is NIPSCO introducing concepts within this proceeding that are consistent with its**
6 **DSM efforts?**

7 A61. Yes. As discussed above, NIPSCO is proposing a number of rate changes to be more
8 consistent with its efforts to expand DSM. Specifically, NIPSCO is removing declining
9 blocks, offering an interruptible rate (Rate 536), offering variations of off-peak rates
10 (Rates 526 and 527) and setting billing determinants for Rates 533 and 534 at 90% of
11 summer peak hours versus 80% of all other hours. Also, as discussed above and by Mr.
12 Dehring, NIPSCO will be introducing IDR meters to a much larger group of customers in
13 an effort to better understand their usage characteristics.

14 **Q62. Does this conclude your prepared direct testimony?**

15 A62. Yes, it does.

VERIFICATION

I, Frank A. Shambo, Vice President, Regulatory and Legislative Affairs for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Frank A. Shambo

Date: August 20, 2008

Petitioner's Exhibit RDG-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

ROBERT D. GRENEMAN

ASSOCIATE DIRECTOR, MANAGEMENT AND MARKET STRATEGY PRACTICE

STONE & WEBSTER MANAGEMENT COUNSULTANTS, INC.

SPONSORING PETITIONER'S EXHIBITS RDG-2 THROUGH RDG-4

VERIFIED DIRECT TESTIMONY OF ROBERT D. GRENEMAN

Q1. Please state your name, occupation and business address.

A1. My name is Robert D. Greneman. I am an Associate Director in the Management and Market Strategy Practice with the firm of Stone & Webster Management Consultants, Inc., 1 Main Street, Cambridge MA.

Q2. Please describe your educational and professional background.

A2. I graduated in 1970 from the City College of New York with a Bachelor of Engineering degree in Electrical Engineering. I have also done graduate work at CCNY. From 1973 through 1978 I was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. As an associate engineer my responsibilities included performing cost of service studies, rate design, load forecasting, depreciation studies, economic feasibility studies, valuation studies, plant inspections and the review of power contracts. In 1978 I joined Stone & Webster Management Consultants, where, as a consultant I have continued to assist utility companies in rate and regulatory matters. From 1983 to 1986 I was employed by the Brooklyn Union Gas Company in the Rate & Regulatory Department where I was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 I rejoined Stone & Webster Management Consultants as an executive consultant in the Rate and Regulatory Services Department.

I have prepared numerous cost of service and rate design studies for clients that range from international energy companies, combination gas and electric vertically integrated North American investor owned utilities, municipal public power companies with multiple services including gas, electric, steam, water and wastewater, electric cooperatives – both distribution and generation and transmission owners, and Canadian crown corporations. These clients have each required attention to a diverse variety of cost of service and rate design issues including equitable treatment for multi-state jurisdictions, allocating shared services for a company that offers multiple services to differing customer bases, aligning costs for isolated island generation and distribution systems, developing costs and rate design for underdeveloped countries, and competitive considerations. The clients have included:

Alpena Power Company (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Centra Gas British Columbia, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires), Gaz Metropolitain, Inc. (Montreal), Green Mountain Power Company, Guyana Electricity Corporation, Halifax Regional Municipality, Holyoke Department of Gas & Electric (MA), ICG Utilities

(Toronto), Jamaica Water Supply Company (NY), Lake Superior District Power Company, Louisville Gas & Electric Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newfoundland & Labrador Hydro, Ltd., Newport Electric Corporation, Northern Indiana Public Service Company, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority (NY), Valley Gas Company (RI), Winnipeg Hydro and Washington Natural Gas Company.

I have provided expert testimony before the Delaware Public Service Commission, the Commonwealth of Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Montana Public Service Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Public Utilities Board of Newfoundland and Labrador, the Nova Scotia Utility and Review Board and the Federal Energy Regulatory Commission.

I am a licensed professional engineer in the states of New York and New Jersey.

Q3. What is the purpose of your testimony?

A3. The purpose of my testimony is to: (1) present the electric cost of service study in support of the rate filing of Northern Indiana Public Service Company ("NIPSCO" or "Company"); (2) describe the development of the Company's proposed rate structure; and (3) to review the results of the FERC Seven-Factor Test application that Stone & Webster Consultants performed for NIPSCO.

Q4. Have you prepared exhibits that accompany your testimony in these areas?

A4. Yes. Petitioner's Exhibit RDG-2 contains schedules that are referenced in my testimony; Petitioner's Exhibit RDG-3 contains the cost of service study summary schedules; and Petitioner's Exhibit RDG-4 contains the revenue proof under Step One and Step Two proposed rates. Additional details including the complete cost of service study will be included in the supporting workpapers to be filed in this Cause.

I. COST OF SERVICE

Q5. Turning first to the cost of service study, what role does this study have in this proceeding?

A5. A fully-allocated cost of service study, which apportions the Company's revenue requirement to customer classes, provides a standard industry yardstick to measure the degree to which the revenues produced by each customer class, in comparison with the cost to serve that class, are equitable and non-discriminatory.

As it is used in this proceeding, the cost of service study

- Develops a revenue requirement for each customer class based on a target rate of return for that class;
- Develops a fully unbundled pro forma revenue requirement for each defined function (generation, transmission, distribution and billing and collecting) as well as sub-functions within each of these main functions) based on the target rate of return for each class;

- Indicates which customer classes are receiving or providing a subsidy to other classes; and

- Develops unit costs by customer class and unbundled function. These unit costs, which are expressed in $/kWh, $/kW and $/customer/month, although not rates per se, serve as an important guide in the rate design process.

Q6. Please provide an overview of the cost of service study.

A6. The cost of service study (or cost study) was based on the audited financial results of the Company's electric operations for the twelve months ended December 31, 2007 and includes pro forma adjustments that are supported by NIPSCO Witness Linda E. Miller, shown in Petitioner's Exhibit LEM-2. The study measures rates of return on original cost rate base.

The cost study was performed under both NIPSCO's current and its proposed service classifications, which are discussed in more detail under the Proposed Rates section of my testimony.

The cost of service study was developed on a gross margin basis, *i.e.*, net of fuel and purchased power, as the Company is proposing to recover all of its fuel through its fuel adjustment clause (FAC). The Company is proposing to recover all purchased power costs through a new Reliability Adjustment ("RA"), which is further discussed by NIPSCO Witnesses Frank A. Shambo, Curtis L. Crum, and Ms. Miller. In this regard, references to "revenues" in my testimony refer to gross margin.

1 **Q7. How is the cost of service study organized?**

2 A7. The cost of service study summary schedules, which are contained in Petitioner's
3 Exhibit RDG-3, are organized into three schedules:

4 Schedule 1.0 provides a rate of return summary for the existing rates in effect;

5 Schedule 2.0 provides a rate of return summary for the proposed service classifications
6 under Step One rates;

7 Schedule 2.1 provides the revenue requirement for the proposed service classifications
8 at parity rate of return;

9 Schedule 2.2 shows the unbundled cost of service by proposed classifications at parity
10 rate of return for each class;

11 Schedule 2.3 reports unbundled unit costs by proposed service classifications at parity
12 rate of return;

13 Schedule 3.0 provides a summary of the attendant revenue requirement by class for the
14 proposed Step One rates;

15 Schedule 3.1 summarizes the unbundled costs for the proposed rates under Step One;

16 Schedule 3.2 summarizes the unit costs for the proposed Step One rates;

17 Schedule 4.0 provides a rate of return summary for the proposed service classifications
18 under Step Two rates;

1 Schedule 4.1 summarizes the revenue requirements for the proposed Step Two rates;
2 and

3 Schedule 4.2 provides a summary of the unit costs for the proposed Step Two rates.

4 The cost of service study, summarized in Schedule 2.0, which does not incorporate
5 NIPSCO's recent purchase of the Sugar Creek Generating Facility, is referred to in my
6 testimony as Step One cost of service. Schedule 3.0 shows the rate of return summary
7 under proposed service classifications when the Sugar Creek plant becomes a part of the
8 Company's revenue requirement in Step Two. Supporting detailed schedules will be
9 included in the supporting workpapers to be filed in this Cause.

10 **Q8. Please describe the general allocation procedures that you used in preparing your**
11 **cost of service study.**

12 A8. The cost of service study uses the traditional three-step approach that consists of
13 functionalization, classification and allocation.

14 1. Functionalization assigns all plant and expenses to the basic steps involved in
15 the process of producing, transmitting, distributing and billing for electricity;

16 2. Classification further assigns costs for each function as being demand-, energy-
17 or customer-related; and

18 3. Allocation is the process of apportioning each functionalized and classified cost
19 component to classes of service based on factors related to cost causation.

The functionalization and classification steps were done together and are contained in the Functionalization section of the cost study. The allocation step is contained in a separate section by that name.

II. FUNCTIONALIZATION

Q9. Please describe the first step, functionalization in greater detail.

A9. The first step, functionalization, is the definition of the major cost groupings that represent the basic steps in the production, transmission, distribution and billing of electricity. The process involves assigning plant, reserve, operation and maintenance, depreciation and tax expense to the appropriate functions involved.

The cost of service study is comprised of 24 functions. The functions used were generally defined for either of the following basic reasons:

1. To identify and track costs by those predefined groupings that are important to understanding the costs associated with each of the services that the company provides; and

2. To separate costs within functional categories that are not allocated in the same way to customer classes. For example, primary and secondary lines are allocated differently to customer class, as are meter reading and billing and collecting.

The functionalization process begins with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, in which plant, depreciation reserve, operation

& maintenance expenses, depreciation expense and taxes other than income taxes are assigned to the individual functional categories, or sub-functions, that are involved in each of the basic activities of producing, transmitting, distributing and billing for electric service. Examples of sub-functions within the distribution function include bulk substations, primary lines, line transformers, secondary lines and services.

Operation and maintenance expenses were functionalized across all functions by primary account based on the plant account to which they pertain. Book depreciation expense and reserve, which are known by primary account, were functionalized based on their corresponding plant account.

General plant, which cannot be directly associated with particular functions, was functionalized on the basis of labor ratios. These ratios were developed by functionalizing the labor in each primary O&M account (excluding A&G) in the same manner as the functional distribution of the corresponding O&M account. The use of labor for the allocation of general plant is a widely accepted industry practice. It might be noted that this methodology allows plant costs associated with customer functions such as meter reading and billing to be captured, as there are not separate plant accounts for these activities.

Administrative and general expenses were generally also functionalized on the basis of labor, except that property insurance was functionalized on applicable plant, and outside services, general advertising, miscellaneous general expense and rents were functionalized on a weighting factor comprised of 50% plant and 50% labor.

Taxes other than income taxes were broken down by type of tax. Each type was functionalized according to its basis for cost causation. For example, property taxes were functionalized on the Company's tax basis for plant, employment-related taxes were functionalized on labor and gross income taxes were assigned to the Revenue Taxes function for allocation to classes in a later phase of the study.

Q10. How was production plant functionalized?

A10. Production was separated into fixed and variable components to capture fixed costs associated with generating plant versus non-fuel variable costs such as fuel handling, boiler maintenance and fuel stock. The breakdown was based on a fixed-variable analysis that was performed by the Company.

Q11. How were distribution lines functionalized between primary and secondary?

A11. An estimate of poles carrying primary versus secondary voltage was made based on a query of NIPSCO's Integrated Mapping System ("NIMS") database, which reported the quantity of poles by height for poles carrying primary only, secondary only, and primary or secondary with various combinations of line transformers and services. As a result of this query it was estimated that 70% of the cost of poles in Account 364 were serving primary and 30% were serving secondary. The analysis also accounted for distribution underbuild on primary poles.

Distribution overhead conductors were functionalized between primary and secondary voltages by reviewing the Company's wire types by the voltage it carried and apportioning costs between primary and secondary based on relative conductor size and

length. Based on this review it was estimated that approximately 89% of conductors carried primary and 11% carried secondary.

Distribution underground conductors, which are primarily associated with new subdivisions, were functionalized between primary and secondary based on a Company analysis of work orders for two recent large subdivisions that were seen as being typical in NIPSCO's system. This analysis showed that approximately 53 percent of the cost was primary and 47 percent secondary.

III. CLASSIFICATION

Q12. Please describe the process of classification.

A12. The second step in the costing process is classification. In this step, each functionalized cost group is separated into demand-, energy- and customer-related components based on the predominant factor for cost causation.

Some costs are related to the quantity of energy produced or sold. These are known as energy-related costs. Costs related to fuel handling and boiler maintenance are examples of energy-related costs.

Demand- or capacity-related costs are those associated with maximum rates of use of energy, or demand. Most capital costs are demand-related because the investment in facilities is related to the size of the facility and facilities are sized to provide service under peak demand conditions. Generating facilities, transmission and distribution lines and line transformers are examples of demand-related costs. However, the peak

demand condition each component is designed to meet may be different for each type of facility.

Customer-related costs are those that are associated with serving customers regardless of either the amount of energy used or the maximum demand. For example, every customer has a meter and a service and the costs associated with metering and billing are not related to consumption. These costs are commonly considered to be allocable on factors that are related to the number of customers.

Functionalization and classification were done in the same step.

Revenue-related costs such as uncollectible accounts and gross income taxes were each assigned to their respective functions, to be functionalized at a later stage based on the sub-total of the functionalized and classified cost of service for each customer class, excluding these costs.

Q13. How did you classify the distribution system?

A13. Primary lines, secondary lines and line transformers were classified as 100 percent demand-related. This was done because the Company's property records are not sufficiently detailed as to reliably support a zero-intercept or minimum system analysis.

IV. <u>ALLOCATION</u>

Q14. Please go on to describe the third step in the costing process.

A14. The third step, allocation of costs, is the process of cost assignment whereby each class of service receives a proportionate cost responsibility for each of the functionalized and

classified cost groups. This is accomplished by means of allocation factors, which are based on the ratio of the amount of demand, energy sold, or number of customers for each customer class to the Company total.

The general approach used to allocate demand-related costs was to develop factors for each type of facility based on a measure of the maximum load imposed on the facility, recognizing: (1) customer load served at each voltage level; (2) an increasing level of diversity associated with upstream facilities; and (3) losses. The demands used in the cost study were based on control area peaks and Company load research data for calendar year 2007.

Q15. What customer classes were included in your study?

A15. The cost of service study summarized in Schedule 1.0 of Petitioner's Exhibit RDG-3, developed rates of return under present rates, as defined by each of the individual rates in the Company's tariff under which customers took service in the test year. The cost of service study summaries in Schedules 2.0 and 3.0 were based on the Company's proposed service classifications, which are described in more detail later in my testimony.

Q16. Where is the wholesale portion of NIPSCO's business shown?

A16. As discussed in the direct testimony of Mr. Shambo, NIPSCO is proposing a sharing mechanism for its off-system sales margins; it is proposing to pass-through the RA mechanism any wheeling revenues paid by Midwest Independent Transmission System

1 Operator, Inc. ("Midwest ISO") under schedules 1, 2, 7, and 8, or its successors, and
2 revenues derived from the following wholesale transactions:

3 1. Full requirements service to the town of Argos;

4 2. Firm wheeling to the Indiana Municipal Power Agency ("IMPA"); comprised of
5 eight customers: Rensselaer, Bremen, Brookston, Chalmers, Etna Green,
6 Kingsford, Walkerton and Winamac; and

7 3. Firm wheeling to Wabash Valley Power Authority ("WVPA") that serves a
8 number of REMCs.

9 These amounts are credited back to Indiana retail customers in my cost of service study
10 based on factors which I will discuss later in my testimony. The cost of service study
11 therefore does not separately identify this segment of the business.

12 **Q17. How did you credit back revenues from these customers to the retail side of the**
13 **business?**

14 A17. In general, Indiana jurisdictional classes received credits in relation to the predominant
15 factor in support of the facilities used in making the sale. For example, revenues from
16 the town of Argos were credited back on the production allocator, and revenues derived
17 from wheeling were credited back on the transmission allocator.

18 Non-firm, or opportunity sales, were zeroed out as a pro forma adjustment. Non-firm
19 wheeling was also zeroed out and is proposed to be handled separately as a tracker

1 credit to retail customers. These two components are more fully discussed in the
2 testimony of Ms. Miller.

3 **Q18. Moving on then, what was the treatment accorded generation?**

4 A18. Plant and expenses functionalized to the generation functions were allocated on the
5 basis of the contribution of each class of service to the four-month (June through
6 September) average control area peak.

7 **Q19. Why did you use this approach?**

8 A19. I have utilized four quantitative tests as a basis for selecting an appropriate demand
9 allocator. The tests, which are consistent with those used by the FERC, provide a
10 measure as to whether the system's demand curve is relatively flat or pronounced over a
11 particular period of months.

12 These tests are as follows:

13 1. To compare the average of the system peaks during the purported peak months
14 as a percentage of the annual peak, to the average of the system peaks during the
15 off-peak months, as a percentage of the annual peak;

16 2. To examine the ratio of the lowest monthly peak to the annual system peak;

17 3. To review the extent to which peak demands in non-peak months exceed peak
18 demands during the peak months; and

4. To review the average of the twelve monthly system peaks as a percentage of the system peak.

Q20. What did the results of these tests show?

A20. Petitioner's Exhibit RDG-2, Schedule 1.0, page 1 of 3, attached to the end of my testimony, contains NIPSCO's peak load data for the test-year 2007 plus five years preceding. This data, which was taken directly from FERC Form 1 in each of the six years, was used to perform the tests. Page 2 of Schedule 1.0 shows the data in graphical form. The results of the four tests are summarized below and on page 3 of this Schedule.

- Test 1 shows that the ratio of: (1) the average of the system peaks during the four-month purported peak period to the system peak; compared to (2) the average of the system peaks during the eight-month off-peak period to the system peak varies from a low of 0.76 to a high of 0.83, with an average of 0.793.

- Test 2, which measures the ratio of the lowest monthly peak to the highest peak, ranges from a low of 0.66 to a high of 0.72, with an average of 0.685.

- Test 3 measures the extent to which peaks in the off-peak period exceed peaks in the on-peak period. The results show that in only one instance, May 2006, the peak for that month exceeded at least one summer peak.

1 o Test 4, which measures the average of the 12 monthly peaks as a percentage of
2 the system peak, shows a range of 0.77 to 0.84, with an average of 0.810.

3 My review of the test results indicates that: (1) the four summer peaks are particularly
4 pronounced with respect to the average; and (2) that over the six-year period reviewed, I
5 am not able to observe a flattening trend.

6 Additionally, in an extensive review of potential electric demand-side management
7 options prepared in 2005 by Stone & Webster for NIPSCO (described in testimony
8 submitted in Cause No. 43396), the focus was on reducing demand during summer
9 rather than winter months.

10 These findings, in my view, support the use of a 4 CP methodology as being a
11 reasonable measure for the allocation of production costs.

12 **Q21. How was Transmission allocated to customers?**

13 A21. Transmission was allocated among retail customers based on the 12-month average of
14 the Company's coincident control area peak demands. 12 CP is the most commonly
15 used method before the FERC. 12 CP rather than a 4 CP methodology is used by
16 Midwest ISO for cost allocation as it is applied to NIPSCO.

17 **Q22. How were distribution system costs assigned to classes?**

18 A22. The Company's distribution system was sub-functionalized into the categories below.

19 • Distribution Substations - General;

1 • Distribution Substations – Railroad;

2 • Distribution Lines – Primary-Demand;

3 • Distribution Lines – Secondary-Demand; and

4 • Line Transformers – Demand.

5 Distribution Substations-General, Distribution Lines-Primary and Line Transformers-
6 Demand were allocated based on the maximum annual class demand, *i.e.*, the maximum
7 diversified demand of all customers within a class without regard to the time of
8 occurrence.

9 Distribution Lines Secondary-Demand was allocated based on the 12-month average
10 maximum class undiversified demand, *i.e.*, the 12-month average of the arithmetic sum
11 of the maximum annual demand of each customer within the class, assuming all
12 customers were demand metered.

13 In all, three types of demand factors were used in the study:

14 1. Class demand coincident with the control area peak;

15 2. Maximum class demand without regard to the control area peak; and

16 3. Sum of maximum customer demands within a class

17 These demands, which are based on the Company's class load characteristics, generally
18 reflect a progressively decreasing level of diversity of load and were applied in the

study to successively lower voltage level facilities. This was done because as voltage level decreases, facilities are sized to serve loads that are progressively more local in nature, and therefore less diversified.

The demands used were adjusted for losses from the customer's meter to reflect the load at the specific facility being allocated. The demand factors also reflect the load of customers that actually take service at that particular voltage level. Voltage level of the customer class was developed with the assistance of a Customer Information System ("CIS") download performed by the Company, which summarized kWh sold by voltage level by customer class for the test-year.

The function Distribution Substations-Railroad was used to directly assign the substations that serve the railroad customer on Rate 844. This direct assignment was made due to the nature of service to the railroad, which involves the hand-off of load among multiple substations.

Q23. How was service to interruptible customers treated in the cost study?

A23. There is currently one interruptible customer taking service under Rate 836. Under the proposed interruptible rate the Company projects that four additional customers totaling 250 MW of interruptible load will commit portions of their load to be subject to interruption under the terms of the proposed interruptible rate. The contracted interruptible generation demand under proposed rates was weighted 50 percent to recognize the interruptible nature of their service.

1 **Q24. In the Company's last base rate case decided in 1987, the IURC approved a 75**
2 **percent discount for interruptible. Why are you now using a 50 percent discount**
3 **in your cost of service study?**
4 A24. The conditions under which customers can be interrupted under the proposed rate are
5 less restrictive as compared with the existing rate in terms of notice period, duration per
6 interruption and maximum number of interruptions. Under the present rate the
7 Company could interrupt for any reason at any time, not to exceed one event per day or
8 10 hours per day. Under the proposed rate, interruption is limited to three consecutive
9 days not to exceed one event per day or 16 hours per day or three days in a rolling seven
10 day period, but not to exceed 400 hours per year.

11 **Q25. How were customer-related costs allocated?**
12 A25. Meters, services, meter reading, billing & collecting, customer service & informational
13 expense and sales expenses were generally allocated to customer classes based on
14 weighting factors for each class times the number of customers in the class. The
15 weighting factor for each class was expressed in terms of the cost for that class relative
16 to the cost for residential – this class having a weighting factor of 1.0.

17 Weighting factors used for meters (Account 370) were based on a Company analysis of
18 the average installed cost of a meter installation by customer class.

19 Weighting factors for services (Account 369) were developed based on a 50%
20 weighting of number of customers by class and a 50% weighting of the square-root of
21 the average maximum demand per customer times the number of customers in the class.

1 This composite factor was used in recognition of the fact that services, which are
2 typically difficult to identify by customer class, are related to both, number of
3 customers as well as the capacity of the service.

4 Meter reading, billing and collections, customer service & informational expenses and
5 sales expenses were developed based on discussions with the Company as to the costs
6 involved. Costs associated with billing larger customers were estimated and directly
7 assigned.

8 **Q26. How were income taxes assigned to classes?**

9 A26. State and Federal income taxes were computed for each class by applying the applicable
10 tax rates to the class taxable income. The class taxable income was computed based on
11 revenues less operating expenses and interest expense and other adjustments for tax
12 purposes.

13 **Q27. What do the results of the allocation phase show?**

14 A27. The results of the allocation phase of the cost of service study are summarized in
15 Petitioner's Exhibit RDG-3, Schedule 1.0, pages 1-3 under the Company's present
16 service classifications and Schedule 2.0, pages 1-2 under the proposed service
17 classifications. They are presented in the form of an income statement that computes
18 the return earned on original cost rate base for each of the classes that comprise the
19 Company's electric operations. They are a measure of the adequacy of the rates that
20 were in effect during the test-year.

1 **V. PROPOSED SERVICE CLASSIFICATIONS AND RATE DESIGN**

2 **Q28. Turning to the Company's proposed service classifications, why are new service**
3 **classifications being proposed?**

4 A28. NIPSCO's existing rates, which number in excess of 20 service classifications,
5 excluding lighting, were established more than two decades ago with additional rates
6 that were added incrementally in the intervening years. Some of these rates are
7 duplicative of one another in terms of eligibility requirements; include provisions that
8 are no longer applicable and are comprised of customers with a diverse mix of metering
9 types that make it difficult to implement new metering technology in a consistent
10 fashion.

11 By way of illustration of the need for a restructuring of service classifications:

12 • The Company's present Rate 821 – General Service Small is a rate without a
13 demand charge, but includes customers that range from minimal monthly use
14 through customers up to the order of 3 MWs. Most of the customers on this rate
15 have energy-only metering.

16 • The Company's Rate 826 – Off-Peak Service, which was originally intended for
17 off-peak service includes a number of high load factor customers such as
18 supermarkets that have relatively high on-peak usage but are advantaged under
19 this rate.

20 • There are 23 rates applicable to traffic, street and highway lighting, a number of
21 which offer different rates for the same service.

As discussed in the direct testimony of Mr. Shambo, the Company is proposing to reorganize and simplify its existing service classifications and to make changes to its rate structure in order to better reflect current customer load profiles and market conditions. To effect the transition, customers were individually mapped from their existing service classification to one of the proposed service classifications based on the mapping criteria for the new rate structure as discussed below.

Q29. Is there an exhibit that sets forth the Company's proposed rates?

A29. Yes, the proposed rates are contained in Petitioner's Exhibit CAW-2 sponsored by NIPSCO Witness Curt A. Westerhausen.

Q30. What was the general philosophy used in designing the proposed rates?

A30. Unit costs in the cost of service are not rates per se, but serve as an important guide in the rate design process, which can encompass other considerations, such as:

- Competitive concerns;
- Conservation of natural and capital resources;
- Economic development;
- Social and political concerns;
- Value of service; and
- Historical rate relationships and gradualism

As is frequently the case, many of these objectives cannot be met simultaneously. One such example is the need to sell versus the need to conserve. Thus, a balance must be

struck between the needs of all stakeholders while maintaining equity among customer classes. It is for this reason that rate design has often been characterized as an art as well as a science.

In terms of placing emphasis on particular rate design goals, the general rate design philosophy that was used in designing the proposed rates are enumerated below.

- There should be a movement towards parity in rates of return across all customer classes and to reduce intraclass cross-subsidies. Gradualism, in terms of the effect on aggregate customers within a class should be recognized;

- Rate structure charges should be reasonably straight fixed-variable in terms of providing an accurate reflection of their basis for cost causation in the cost of service study. That is, demand charges should be reflective of demand costs; customer charges reflective of customer-related costs, etc. Straight fixed-variable rate design acts to reduce intraclass cross-subsidies, as well as to maintain cost-based relationships as market conditions change;

- Rates should encourage economic development;

- Rates should allow NIPSCO's largest customers to operate effectively while remaining cost based rates and encouraging conservation; and

- Service classifications should be reflective of homogeneity of load, metering requirements and customer impact.

The resulting tariff structure is described for the proposed service classifications in the discussion that follows.

VI. OVERVIEW OF THE PROPOSED SERVICE CLASSIFICATIONS AND PROPOSED TARIFF STRUCTURE

Q31. Please describe the proposed service classifications, their characteristics and how they were developed.

A31. The proposed service classifications were developed based on several criteria, including customer size, load profile and end-use.

Rate 511 – Residential is comprised of customers presently served under the existing rates 811 (Residential), 812 (Residential Good Cents) and 813 (Residential Good Cents Multi-family). This rate will serve approximately 398,800 customers.

Each of the three existing residential service classifications has a monthly customer charge that includes 36 kWh of use and three declining energy blocks. Proposed Rate 511 has a monthly customer charge that excludes energy use and a single rate per kWh for all energy usage. Flattening of this rate was seen as important in light of current high energy costs and the movement of many utilities to use rate design as an adjunct to their demand-side management programs to provide price signals for the conservation of natural and capital resources that are more closely aligned with current costs.

Additionally, the present Rate 811 has an electric space heating provision that provides a discount to eligible customers during winter months for all usage over 500 kWh. Under proposed Rider 574, which is applicable to Rate 511, this provision is being

closed to new electric space heating load; grandfathered to existing customers; and the threshold above which the discount goes into effect has been raised to 700 kWh per month – this higher threshold seen as being more closely aligned with space heating usage. In the case of the discount for electric space heating, the Company will decide at the time of its next general rate application whether to maintain or to discontinue the discount for existing electric space heating load.

Similarly, the Company is proposing to eliminate the discount provision for new load applicable to heat pumps in its current Good Cents rates 812 and 813, and to grandfather existing load. The present 700 kWh threshold over which the discount under rate 812 applies will remain the same for existing heat pump usage and the 500 kWh discount threshold under rate 813 is proposed to be raised to 700 kWh during applicable winter months. In contrast with the elimination of the discount for space heating, heat pumps may offer some measure of energy efficiency. The Company has not verified the expected energy savings, and intends to address this issue in its demand side management proceeding.

Rate 521 - General Service Small includes non-demand-metered customers, currently served under Rates 820 (Good Cents Energy Efficient Commercial and General Service), 821 (General Service Small) and 822 (Commercial Space Heating) with an estimated demand of less than 10 kW. There are approximately 41,350 general service customers that meet this criterion.

Present Rate 821 has a customer charge that includes 36 kWh of usage and three declining energy blocks. Under proposed Rate 521 there will be a monthly customer charge that includes no usage and a flat rate per kWh for all energy use.

The Company is also proposing to eliminate the commercial heat pump Rate 820 as well as the commercial electric space heating Rate 822. Those customers will now be served under Rate 521.

Rate 523 - General Service - Medium will be comprised of customers that are currently served under Rates 820, 821, 822, 823, 824, 826 and 848 that range in expected size from 10 kW to 300 kW. This Rate will provide service to approximately 11,600 customers.

Q32. What criteria did you use to establish the upper and lower limits for this rate?

A32. The proposed grouping of service classifications was based on considerations that included: (1) customer size; (2) homogeneity of load characteristics; (3) end use; (4) installed stock of meters by type with an eye towards prospective metering goals; (5) number of customers in each group; and (6) service classifications of other Indiana electric utilities.

Service classifications for demand-metered customers were generally based on maximum demand, similarity of load profile and end-use. To serve as a guide in delineating how service classifications might reasonably be grouped, a form of segmentation analysis was performed. The following procedure was used:

1 a. Annual kWh and peak demand data were collected for all customers for which
2 such data was available. This included data for a population of more than 1,600
3 customers, comprised of all customers with either Demand Indicating or Interval
4 Data Recording ("IDR") meters;

5 b. Customers were sorted in ascending order of peak demand;

6 c. Starting from the customer with the lowest kW demand and working upwards,
7 cumulative load factor was calculated up to the level of each customer as: (1) the
8 sum of annual kWh of all customers from the first customer up through the
9 instant customer divided by 8,760 hours; divided by (2) the sum of maximum
10 kW demand from the first customer up through the instant customer; and

11 d. A graph was then developed showing cumulative load factor versus maximum
12 kW demand.

13 The results show a progressive increase in cumulative load factor through
14 approximately 100 kW of maximum demand, after which the slope of the curve levels
15 off through around 300 kW. Beyond the 300 kW level there was generally a continued
16 increase in load factor, although at a lesser rate.

17 The range 10 kW through 300 kW (proposed Rate 523) was chosen for the initial
18 demand metered rate based on: (1) 10 kW being a generally used threshold in which
19 utilities begin measurement of customer demand; (2) 300 kW being a reasonable ending
20 point for medium general service customers since a majority of customers in this range

have at least a demand-indicating meter and due to the Company's goal to convert those customers with energy-only meters to demand metering over a relatively short time period; and (3) a cost-based demand charge applied to customers under this rate would act to reduce intraclass subsidies among customers with differing load factors.

Rate 523 is proposed to be a three-part rate with a monthly customer charge; demand charge and a flat rate per kWh for all energy use. The billing demand for customers served under this rate is proposed to be their maximum recorded demand in the month. In addition, the demand charge is differentiated by voltage level of service, i.e., primary or secondary.

This Rate will have an energy-only component until such time as the Company implements demand metering for these customers. Their billing will be based on a transitional flat energy provision in the rate, plus the same monthly customer charge that is applicable to demand-metered customers.

The Maximum Demand of 300 kW was based upon the nature of the billing determinants due to the lack of IDR meters on the majority of Rate 523 customers.

Rate 526 – Off-Peak Service is targeted to customers that are able to shift the majority of their load to off-peak hours.

Rate 527 – Limited Production- Large was developed for particularly large special situation customers that can operate on-peak for two weekend days and two weekdays and are able to fully curtail their load during peak periods for three weekdays. Costing

and pricing for this class was based on the probability that their load would be on during the summer peak hours. The rate structure for this rate is otherwise similar to other demand-based rates with a customer charge and a flat energy charge.

Rate 533 – General Service - Large will serve customers currently served under rates 821, 823, 824, 826, 832 and 848 that range in size from 300 kW through 10 MW. This rate is proposed to be a four-part rate that includes a monthly customer charge; demand charge; an energy charge and a power factor correction charge and will provide service to approximately 933 customers. The billing basis will be the greater of: (a) 90% of summer on-peak demand for the past 24 months; or (b) 80% of all other hours for the past 24 months. Summer on-peak is 11 AM - 7 PM in June thru September.

The demand charge will also be differentiated by voltage level of service. In terms of composition of customer metering, approximately 500 customers have demand indicating meters and the remaining customers have IDRs that are capable of measuring kVAR. The Company expects to transition all customers under this rate to IDR meters by the time this rate is expected to go into effect.

Rate 534 – Industrial Service Large (>10 MW). This service classification provides service to the Company's 13 largest customers.

The rate structure for this rate is similar to Rate 533, but these largest, perhaps more sophisticated customers, are those for whom the Company may wish in the future to explore innovative programs.

Q33. What changes are proposed for NIPSCO's lighting tariffs?

A33. NIPSCO currently has 23 rates in effect that deal with traffic, street and highway and dusk-to-dawn area lighting. These rates, which have increased in number over time due to the need to address particular circumstances, have resulted in the present situation in which different rates are being charged for effectively the same service. The Company is taking the first step in this proceeding to significantly simplify these lighting rates. Three classes are being proposed:

- Street and Highway Lighting;
- Traffic and Directive Lighting; and
- Dusk-to-Dawn Area Lighting.

The myriad of current charges applicable to street and highway lighting will be consolidated under proposed Rate 550 and current charges applicable to dusk-to-dawn area lighting will be rolled into Rate 560. Traffic and directive lighting, which is currently contained in a single rate 895, will effectively remain the same but designated as Rate 555.

The rates applicable to street and highway lighting and to dusk-to-dawn area lighting are now proposed to be stated in a menu format. For example, there are separate monthly rates that are applicable to:

- Energy to customer-owned fixtures by size and type of fixture;

1 • Maintenance of customer-owned fixtures by type of fixture; and

2 • Provision of Company-owned fixtures, including maintenance by size and type.

3 It should be noted that as this is the Company's first attempt at performing such a
4 wholesale restructuring of the lighting rates, additional adjustment may be needed in
5 advance of its next rate petition.

6 **Q34. What was done with NIPSCO's current Economic Development Rate?**

7 A34. Economic development discounts will continue to be available to qualified customers,
8 however, rather than having their service provided under a separate rate, they will
9 remain under their otherwise applicable rate.

10 **Q35. Please describe how power factor is incorporated in the proposed rate structure.**

11 A35. Under present rates the method for charging large customers for power factor varies
12 significantly among service classifications. In the proposed rate structure, the provision
13 that charges customers for lagging power factor will be applied uniformly across all
14 applicable service classifications based on each customer's deviation below a 95
15 percent reference power factor. This charge, which is based on NIPSCO's cost to add
16 capacitor banks, is reflected in the rates on a $/kVAR basis. The current power factor
17 provision that charges customers for leading power factor will be maintained. The
18 Company's power factor at the time of its control area peak is estimated to be
19 approximately 96 percent.

1 **Q36. Are any changes being proposed to the primary metering discount?**

2 A36. Yes. Primary metering refers to those situations in which the measurement of
3 electricity for customers that are served from a transformer owned by the Company are
4 metered on the higher voltage side of the transformer rather than the actual point of
5 delivery. This results in higher demand and energy readings than what is actually
6 delivered to the customer. In order to compensate, a provision in NIPSCO's rates
7 provides a discount that reflects losses through the transformer. NIPSCO's current rates
8 have a three percent discount applicable to classes that are energy-only metered and a
9 one percent discount applicable to demand and energy for those classes that also have
10 demand metering.

11 An analysis was prepared that shows losses through NIPSCO's secondary transformers
12 at 60 percent and 100 percent loading. This analysis, which is based on the Company's
13 current purchasing specifications and weighted by number of transformers, is contained
14 in Schedule 3.0 accompanying my testimony. The results show losses of 1.1 percent
15 and 1.4 percent at 60 percent and 100 percent of transformer capacity, respectively. As
16 transformers are typically installed with rated capacity in excess of expected customer
17 peak, the 100 percent loading case would be materially higher than the load imposed
18 during a system peak hour. Moreover, NIPSCO's standards group has indicated that 60
19 percent transformer loading is more representative of the loading that transformers need
20 to carry when system loads are between average and peak levels. In light of this, the 1.1
21 percent loss figure at 60 percent of transformer capacity was rounded up to 1.2 percent

– this being a fair and reasonable primary metering loss percent to be applied to energy and demand billing units across all customer classes.

Also, a secondary metering surcharge provision is now being proposed to recognize the opposite situation in which customers take service at the high side of a transformer but are metered on the low voltage side. It is proposed that these customers be assessed an additional 1.2 percent of their energy and demand billing units. Such situations can occur when the customer owns the intervening transformer.

Q37. Is there a schedule that summarizes the features in each proposed rate?

A37. Yes, a summary of the features of each of the proposed rates is contained in Petitioner's Exhibit CAW-3 sponsored by Mr. Westerhausen.

VII. DEVELOPMENT OF RATES

Q38. Please go on to describe the process you used to develop the proposed rates

A38. There were several steps.

- First, a rate-revenue proof was performed in order to tie out the Company's present rates multiplied by book billing determinants, plus or minus applicable adjustments with revenues reported in FERC Form 1.
    - This calculation included the addition of the fuel adjustment clause (FAC) revenues for each rate in the test-year along with NIPSCO's two environmental trackers and the applicable revenue credit for each rate.

1 o Since the proposed rates are net of fuel costs, a second calculation was
2 performed which was similar to the above, but excluded the FAC tracker
3 and $0.022556 per kWh, representing base fuel costs that are included in
4 the published base rates.

5 o The calculation above, yielded gross margin (revenues less fuel costs)
6 for each rate. A further adjustment was then made that reduced the
7 margin: (1) in each temperature-sensitive rate to recognize that 2007 was
8 a warmer than normal summer; and (2) to reduce kWh for the off-peak
9 metal melters to projected levels in accordance with the provisions of
10 their rate.

11 o These calculations are shown in Schedule 1.0 of Petitioner's Exhibit
12 RDG-4.

13 • The next step was similar to the first, except that a rate-revenue proof was
14 performed under the proposed set of rates.

15 o This step relied on the mapping of individual customer energy, demand
16 and margin from their present rate to their applicable proposed rate based
17 on that rate's applicability criteria.

18 o Each charge under the proposed rate was identified along with its
19 respective billing determinants.

1 o Two sets of computations were performed: (1) In one set, customer,
2 energy and demand charges were developed such that the total calculated
3 gross margin for that rate equaled, in sum, the gross margin that
4 customers mapped into each rate were paying under current rates; and
5 (2) In the second set of computations, customer, energy and demand
6 charges were developed such that the total calculated gross margin for
7 that rate equaled the total gross margin that was targeted by proposed
8 rate.

9 o The gross margin target for each proposed rate would ultimately equal its
10 cost of service for each rate at an overall total company rate of return.
11 However, as the Company is proposing a phase-in of all rates to parity,
12 or equal overall rate of return, the initial gross margin target will be
13 higher or lower than average for particular service classifications.

14 o Individual charges (customer, energy and demand) within each service
15 classification in the second computation, just described, were subject to
16 an iterative process. That is, to the extent that typical bill comparisons
17 and cross-over points among rates indicated that some adjustment was in
18 order.

19 o This rate-revenue proof under proposed rates is contained in Schedule
20 2.0 of Petitioner's Exhibit RDG-4.

- Next, typical bill comparisons were developed, which compared billing under present rates versus under proposed rates, with and without applicable Riders.
    - Typical bills were computed over a range of monthly usage levels as well as for the average customer in the proposed service classification.
    - Amount and percent increase was shown for customers at each usage level.
    - A typical bill comparison was made for every combination of customer on one of the Company's present rates to one of the proposed rates.
    - These typical bill comparisons will be included in the supporting workpapers to be filed in this Cause.
- In the last step, a crossover analysis was done to ensure that customer migration to different rates was minimized:
    - This was accomplished by computing the overall unit cost that the customer would experience across a range of possible consumption levels; and
    - The per unit customer costs of each proposed rate were then compared.

Q39. How was the increase or decrease in rates determined for each of the proposed classes?

A39. First, the increase or decrease was developed for each class needed to bring that class to the overall rate of return proposed by the Company, or rate of return parity across all rate classes. The criterion used to phase-in rates was that for each class for which an increase was indicated, only one-third of that increase was applied and the difference was apportioned among those classes for which a decrease was indicated. A comparison of increases and decreases by rate class to parity with the moderated increases are shown in Schedule 2.1 of Petitioner's Exhibit RDG-3. This schedule also shows for each proposed rate:

- Current gross margin;
- Current return on rate base;
- The index of the return on rate base in relation to the overall return;
- Proposed gross margin;
- Proposed return on rate base; and
- The index of the return on rate base in relation to the overall return.

Comparing the index for each rate under current and proposed rates, it can be seen that there is a significant improvement towards equalizing rates of return across all service classifications.

VIII. SUMMARY OF STEP TWO RATE INCREASE

Q40. What is shown on lines 18-22 of Schedule 2.1 of Petitioner's Exhibit RDG-2?

A40. The last lines in this schedule show the effect on revenue requirement by customer class of including the Sugar Creek Generating Facility in the cost of service study (referred to as "Step Two"). If the incremental required revenues associated with Sugar Creek are apportioned in accordance with cost responsibility as indicated in the cost of service study, on top of the moderated increase in Step One, there will be a continued improvement towards parity across all customer classes. The Sugar Creek cost of service summary sheets are shown in Schedule 3 of Petitioner's Exhibit RDG-3.

IX. SEVEN-FACTOR TEST

Q41. What is the purpose of your testimony relative to the application of the FERC Seven-Factor Test?

A41. NIPSCO is seeking approval to revise its segregation between transmission and distribution facilities to be consistent with orders from FERC. My testimony describes: (1) the composition of NIPSCO's transmission and distribution systems; (2) the application of the Seven-Factor Test as it relates to the jurisdictional line between transmission facilities subject to FERC's jurisdiction and distribution facilities subject to state jurisdiction; and (3) the proposed classification of NIPSCO electric facilities into either transmission or distribution categories.

Q42. Why is NIPSCO seeking to revise its segregation between its transmission and distribution facilities at this time?

A42. In Order 888, the FERC claimed jurisdiction over all unbundled transmission and left distribution regulation to the states. FERC deferred to the states to determine the classification of transmission and distribution facilities, consistent with a Seven-Factor Test set out in Order 888. Each state is authorized to approve proposed separation of transmission and distribution functions using the Seven-Factor Test, with FERC retaining authority to review and make a final determination on treatment of assets. This is the first rate review for NIPSCO since the issuance of FERC Order 888, therefore it is the first time NIPSCO has had the opportunity to establish its transmission/distribution segregation before a regulatory body.

X. OVERVIEW OF THE NIPSCO SYSTEM

Q43. Please provide a description of the NIPSCO electrical network?

A43. NIPSCO serves approximately 457,000 electric customers in the northern third of Indiana. This includes 2,500 industrial customers, 52,000 commercial customers and 399,000 residential customers. The 2007 peak control area load was 3,625 MW.

The system has approximately 566 substations that operate at voltage levels of 345 kV, 138 kV, 69 kV, 34.5 kV, 12.5 kV and 4.2 kV. There are approximately 354 circuit miles of 345 kV line, 763 circuit miles of 138 kV line, 1,660 circuit miles of 69 kV line, 425 circuit miles of 34.5 kV line, 8,000 circuit miles of 12.5 kV line, 1,000 circuit miles of 7.2 kV line, and 50 circuit miles of 4.2 kV line.

Circuits at the 345 kV and 138 kV levels operate as part of the interconnected transmission network. The 69 kV networked circuits, predominately located in the east

and south sections of the Company's service territory, serve a transmission function in areas where higher voltage transmission is not available. Flow on these circuits can be bi-directional and as well, participate in power transfers across the Company's system. NIPSCO's transmission system is interconnected with the control areas of five surrounding utilities.

The distribution system is comprised of 12.5 kV circuits, which are all operated as radial lines, and a small amount of 7.2 kV 4.2 kV substations and circuits operated as a network.

XI. OVERVIEW OF THE SEVEN-FACTOR TEST GUIDELINES

Q44. Please provide a brief overview of the actual test guidelines.

A44. The FERC Seven-Factor Test, first put forth by the FERC in its 1996 Order 888, was established as part of FERC action to require electric utilities to provide transmission service on an open access, non-discriminatory basis. Order 888 mandated that utilities provide service over their transmission systems to any credible customer that requested it. The FERC Order issued the Seven-Factor Test guidelines to help utilities and State regulators delineate its transmission and distribution facilities between what is under the FERC jurisdiction and subject to open access rules versus what is under state jurisdiction and not subject to open access. The test is a combination of functional and technical measures designed to help assess the nature of and role of utility assets with regard whether it operates as transmission or distribution. The FERC guidelines allow differentiation between the overall use of electric plant and interpretation on the part of

1 the utility. It allows the states to take into consideration traditional uses of facilities as
2 well as specific issues for each system prior to the FERC decision over the separation.

3 **Q45. Doesn't the FERC Uniform System of Accounts already delineate what is**
4 **transmission versus what is distribution?**

5 A45. Yes, but on narrowly defined criteria. The cost of transmission and distribution
6 facilities is typically booked based solely on operating voltage and there are variations
7 among utilities with respect to what voltages are transmission versus distribution as well
8 as the treatment of substations having both transmission and distribution. The Seven-
9 Factor Test goes further by considering how systems function in a particular utility.

10 **Q46. Please review each of the seven factors and discuss each as it pertains to NIPSCO's**
11 **system.**

12 A46. The guidelines used by FERC to distinguish between transmission and distribution, and
13 NIPSCO's understanding of each of those indicators, are as follows:

14 (1) <u>Local distribution facilities are normally in close proximity to retail customers</u>.

15 NIPSCO considers facilities physically and electrically located where they can
16 be tapped with transformers to serve load in an economical manner to be in
17 close proximity to retail customers. NIPSCO's 12.5, 7.2 and 4.2 kV system is
18 generally built along roads or local rights-of-way and primarily provide service
19 to retail customers.

1 (2) Local distribution facilities are primarily radial in character.

2 NIPSCO considers its 12.5 kV and lower voltage systems to be radial.

3 (3) Power flows into local distribution systems; it rarely, if ever, flows out.

4 NIPSCO's distribution system is mostly without local generation and
5 consequently, power flows in through these lines to serve local load.
6 Occasionally small generating units are connected and may export power out on
7 to the higher voltage system under certain load and generation conditions;
8 however this is an infrequent occurrence.

9 (4) When power enters a local distribution system, it is not re-consigned or
10 transported on to some other market.

11 NIPSCO's 12.5 kV and lower systems are typically used to serve local
12 customers and not as bulk power tie lines facilitating wholesale power
13 transactions to neighboring electrical systems.

14 (5) Power entering a local distribution system is consumed in a comparatively
15 restricted geographical area.

16 Distribution systems supply power in an area that is limited in size to counties,
17 towns or parts of communities. NIPSCO's 12.5 kV and below facilities are
18 typically used to serve local customers and do not transport power long
19 distances.

1 (6) Meters are based at the transmission/local distribution interface to measure
2 flows into the local distribution system.

3 Meters are located on a distribution system where they may measure the
4 aggregate load on that system. NIPSCO measures power flow into the 12.5 kV
5 and below systems at the point of voltage transformation from various higher
6 voltage facilities.

7 (7) Local distribution systems will be of reduced voltage.

8 Transmission facilities rated 69 kV and higher were primarily designed to
9 transmit power over longer regional distances, to supply power to bulk
10 substations for transformation to a lower voltage level and secondarily, to enable
11 wholesale transactions at the transmission level. Lower voltage facilities are
12 most generally used to provide service to retail customer in a more localized
13 area.

14 **XII. APPLICATION OF FERC SEVEN-FACTOR TEST**

15 **Q47. What were NIPSCO's efforts in regard to applying these guidelines to its system?**

16 A47. NIPSCO formed a working group and retained expert consultants in 2003 to
17 systematically catalog and classify its facilities and to make recommendations with
18 respect to the guidelines. To assist in this effort the Company brought together a cross
19 sectional core resource team of 13 employees, and made available to serve as advisors
20 to this team additional employees and outside consultants with specific expertise.
21 Several functional areas of the Company were represented on the resource team

1 including Planning and Engineering, Rates, Finance, Accounting, Legal and Operations.
2 Calling upon data contained in NIPSCO's Asset Management System the team and its
3 consultants methodically reviewed and classified components of its transmission and
4 distribution system.

5 The team accomplished several necessary and useful tasks including:

6 1. Review of industry practices and guidelines and their applicability to this
7 effort;

8 2. Identification and resolution of gray areas where proper classification of
9 facilities was not immediately evident;

10 3. Delineation of land between transmission and distribution;

11 4. Procedure for implementing changes to its plant accounts;

12 5. Creation of categories for those 34.5 and 69 kV lines and substations that
13 could have both transmission and distribution characteristics; and

14 6. Comparison of transmission and distribution facilities by function (per
15 the seven factor guidelines) with FERC primary accounts within each
16 accounting function.

Q48. Please continue.

A48. The team segregated assets into similar types and addressed each separately. For instance, the high voltage system consisting of facilities operating at 138 kV and above were grouped together.

The 69 kV system was divided into seven separate categories depending upon type and function of the various 69 kV facilities. Likewise several different functional types of 34 kV facilities were identified and sorted appropriately according to criteria of the Seven-Factor Test. Also, types of substation functions were identified with resulting classification of assets according to the test. The group at first identified a number of gray areas where treatment of facilities initially was not clearly evident but was resolved as the team effort progressed over time. In addition, the team addressed treatment of land, land rights and common right of ways between the gas and electric sister companies.

Q49. How does NIPSCO classify 345 kV and 138kV facilities?

A49. The NIPSCO 345 kV and 138 kV systems are the major bulk power carriers for the Company. The primary functions of these systems are to transport power over regional distances to load centers where the voltage is reduced in order to distribute the power over a more local area. The systems are located on rights-of-way and do not interconnect directly with retail customers. All 345 kV and 138 kV lines are classified as transmission under the application of the Seven-Factor Test.

1 **Q50. How does NIPSCO classify 69 kV?**

2 A50. 69 kV was classified as transmission. Virtually all of the 69 kV system is networkable
3 and capable of performing a transmission function.

4 **Q51. What was done with 34 kV?**

5 A51. 34 kV, which was classified as distribution in the Seven-Factor Test, were the
6 Company's older sub-transmission voltage lines that were originally used where 69 kV
7 was not available. Over the years, sub-transmission voltages such as 34 kV and 25 kV
8 (in other utilities) tended to operate as distribution as is the case with NIPSCO's older
9 34 kV system.

10 **Q52. How does NIPSCO treat facilities of 12.5 kV and below?**

11 A52. The technical characteristics and function of this type of facility matches the definition
12 of local distribution under the FERC's Seven-Factor Test. These facilities are normally
13 in close proximity to retail customers, typically provide radial service to customers, and
14 are of reduced voltage. Power usually flows only one way into these local systems, is
15 consumed in a relatively small geographical area and is not normally wheeled through
16 the low voltage system to other markets. The application of the FERC Seven-Factor
17 Test on these systems supports that they should be classified as local distribution

18 **Q53. What was NIPSCO's approach with respect to substation assets?**

19 A53. NIPSCO considered a number of criteria, including:

20 • Whether the low side voltage was an industry recognized distribution voltage
21 e.g., 4/12/13 or 34.5 kV.

1 • The distribution circuits are almost always radial (except for distribution
2 networks) and serve many customers.

3 • Occasionally circuits may be dedicated to one or two larger customers.

4 • The load almost always consists of end use customers, is not a wholesale or
5 sales for resale customer, in other words the load only serves its core market.

6 • In instances where sales for resale or a wheeling function is provided, such as in
7 serving REMCs, the contract with the REMC specifically provides that the
8 REMC takes service at the distribution voltage.

9 • The high side of the substation is any voltage greater than the distribution line
10 voltage.

11 • The high side circuit serving the substation can be a radial line, two lines with
12 one operating normally open, or two lines operated as a network.

13 **Q54. What was done with generator leads and generator step-up transformers?**

14 A54. Both of these facilities were classified as generation, consistent with FERC precedence
15 in NIPSCO's recent Open Access Transmission Tariff filing.

16 **Q55. What is shown on Schedule 4.0 accompanying your testimony?**

17 A55. At the conclusion of the Seven-Factor Test a set of rules was developed in the form of
18 an algorithm to be used to reclassify existing transmission and distribution assets in
19 accordance with the results of the Seven-Factor Test. This would be used, as well, as

1 the guideline for booking future plant additions to FERC primary accounts. The
2 procedures are set forth in Schedule 4.0 of my testimony.

3 **Q56. Have transfers among primary accounts been quantified based upon the**
4 **Company's findings?**

5 A56. Yes. The net effect of plant and depreciation reserve transfers among FERC primary
6 accounts at December 31, 2007 are detailed in an exhibit accompanying the testimony
7 of NIPSCO Witness Mitchell E. Hershberger, and for convenience are also shown on
8 Schedule 4.1 of Petitioner's Exhibit RDG-2.

9 **Q57. How are the effects of these transfers reflected in this proceeding?**

10 A57. Although the actual transfers were not made to NIPSCO's plant and reserve accounts
11 until the beginning of 2008, they are incorporated in the cost of service study as a
12 functional reclassification among primary accounts. At year end 2008 they will be
13 reported in their respective primary account in FERC Form 1.

14 **Q58. Does this conclude your prepared direct testimony?**

15 A58. Yes, it does.

VERIFICATION

I, Robert D. Greneman, Associate Director, Management and Market Strategy Practice of Stone & Webster Management Consultants, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Robert D. Greneman

Date: August 26, 2008

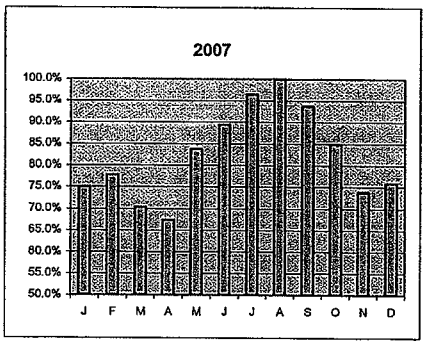
NORTHERN INDIANA PUBLIC SERVICE COMPANY

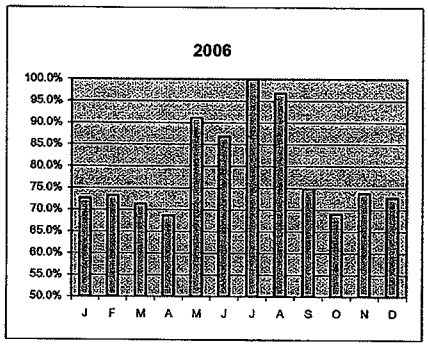
SYSTEM PEAK LOAD DATA AS REPORTED IN FERC FORM 1
TEST-YEAR 2007 AND PRIOR FIVE YEARS

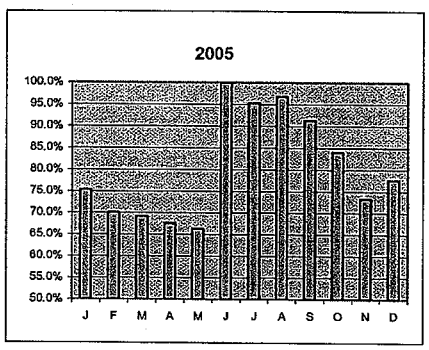
Month	2007	2006	2005	2004	2003	2002
(A)	(B)	(C)	(D)	(E)	(F)	(G)
			----- MW -----			
January	2,723	2,636	2,674	2,593	2,280	2,081
February	2,822	2,659	2,488	2,591	2,243	2,077
March	2,550	2,587	2,457	2,500	2,212	2,061
April	2,441	2,491	2,401	2,380	2,047	2,232
May	3,036	3,304	2,354	2,647	2,130	2,421
June	3,241	3,148	3,549	3,206	2,744	2,864
July	3,494	3,629	3,380	3,289	2,619	2,978
August	3,625	3,511	3,434	3,284	3,054	2,903
September	3,396	2,714	3,242	3,020	2,464	2,859
October	3,075	2,504	2,983	2,476	2,115	2,404
November	2,679	2,678	2,602	2,521	2,185	2,265
December	2,751	2,640	2,756	2,661	2,303	2,310
			----- PERCENT OF MAX MONTH -----			
January	75.1%	72.6%	75.3%	78.8%	74.7%	69.9%
February	77.9%	73.3%	70.1%	78.8%	73.4%	69.7%
March	70.3%	71.3%	69.2%	76.0%	72.4%	69.2%
April	67.3%	68.6%	67.7%	72.4%	67.0%	74.9%
May	83.7%	91.0%	66.3%	80.5%	69.7%	81.3%
June	89.4%	86.7%	100.0%	97.5%	89.8%	96.2%
July	96.4%	100.0%	95.2%	100.0%	85.8%	100.0%
August	100.0%	96.7%	96.8%	99.8%	100.0%	97.5%
September	93.7%	74.8%	91.3%	91.8%	80.7%	96.0%
October	84.8%	69.0%	84.1%	75.3%	69.3%	80.7%
November	73.9%	73.8%	73.3%	76.6%	71.5%	76.1%
December	75.9%	72.7%	77.7%	80.9%	75.4%	77.6%

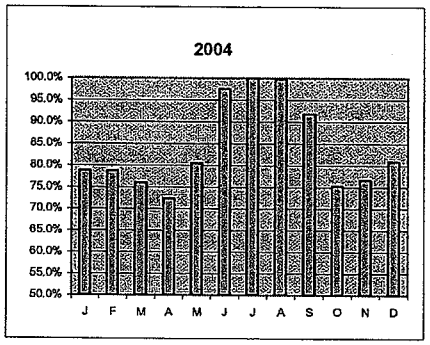
NORTHERN INDIANA PUBLIC SERVICE COMPANY

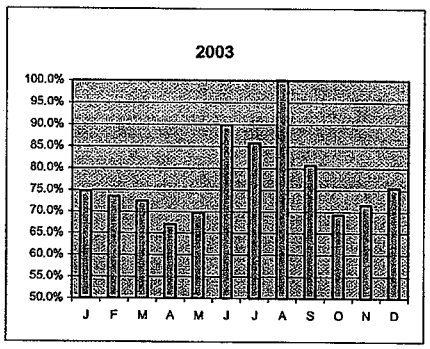
MONTHLY PEAK DEMAND AS PERCENT OF SYSTEM PEAK

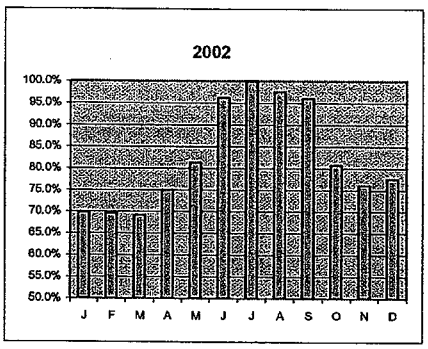












NORTHERN INDIANA PUBLIC SERVICE COMPANY

APPLICATION OF TESTS FOR FLATNESS OR PROUNCIATION OF SYSTEM PEAKS
TEST-YEAR 2007 AND PRIOR FIVE YEARS

	2007	2006	2005	2004	2003	2002	Average
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Test 1							
Average 4 Month to Peak	0.95	0.90	0.96	0.97	0.89	0.97	
Average 8 Month to Peak	0.76	0.74	0.73	0.77	0.72	0.75	
Ratio	1.25	1.21	1.31	1.26	1.24	1.30	
	0.80	0.83	0.76	0.80	0.80	0.77	0.793
Test 2							
Ratio: Lowest Peak to Highest Peak	0.67	0.69	0.66	0.72	0.67	0.69	0.685
Test 3							
Extent to which Peak Demands in off-Peak Exceed Peak Demands in On-Peak							
Minimum in On-Peak	3,241	2,714	3,242	3,020	2,464	2,859	
Maximum in Off-Peak	3,075	3,304	2,983	2,661	2,303	2,421	
Test 4							
Average of 12 Peaks	2,986	2,875	2,860	2,764	2,366	2,455	
System Peak	3,625	3,629	3,549	3,289	3,054	2,978	
Percent	0.82	0.79	0.81	0.84	0.77	0.82	0.810

NORTHERN INDIANA PUBLIC SERVICE COMPANY
EARNED RATES OF RETURN UNDER PROPOSED SERVICE CLASSIFICATIONS - PRO FORMA TEST-YEAR ENDED DECEMBER 31, 2007

	Earned Rate of Return
Rate 511 - Residential	4.20%
Rate 521 - General Service Small	17.64%
Rate 523 - General Service Medium	11.50%
Rate 526 - Off-Peak Service	2.76%
Rate 527 - Limited Production Large	14.76%
Rate 533 - General Service Large	10.14%
Rate 534 - Industrial Service Large	9.51%
Rate 536 - Interruptible Industrial Service	2.64%
Rate 541 - Water Pumping	-1.75%
Rate 544 - Railroad Power Service	12.39%
Rate 550 - Street and Area Lighting	14.81%
Rate 560 - Traffic and Directive Lighting	17.23%
Rate 570 - Dusk-to-Dawn Lighting	-4.19%
Interdepartmental	-2.38%
Total Company	7.74%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPARISON OF EARNED, PARITY AND MODERATED
RATES OF RETURN
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007

		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	**AT EARNED RATE OF RETURN**								
2	PRESENT GROSS MARGIN	867,912,688	280,432,032	43,522,466	146,136,000	7,137,285	10,777,965	182,243,494	154,090,596
3	RATE OF RETURN EARNED	7.74%	4.20%	17.64%	11.50%	2.76%	14.76%	10.14%	9.51%
4	INDEX WITH RESPECT TO OVERALL ROR	1.00	0.54	2.28	1.48	0.36	1.91	1.31	1.23
5									
6	**AT PARITY RATE OF RETURN OF 8.34%**								
7	MARGIN INCREASE TO BASE RATES	23,983,307	65,081,618	-12,717,436	-18,835,873	2,236,060	-2,375,106	-13,655,230	-7,554,132
8	PERCENT MARGIN INCREASE	2.76%	23.21%	-29.22%	-12.89%	31.33%	-22.04%	-7.49%	-4.90%
9	RATE OF RETURN ON RATE BASE	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
10	INDEX WITH RESPECT TO OVERALL ROR	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
11									
12	**AT MODERATED RATE OF RETURN (STEP 1)**								
13	MARGIN INCREASE TO BASE RATES	23,983,307	21,693,873	-575,142	-851,847	745,353	0	-617,554	-341,633
14	PERCENT MARGIN INCREASE	2.76%	7.74%	-1.32%	-0.58%	10.44%	0.00%	-0.34%	-0.22%
15	RATE OF RETURN ON RATE BASE	8.34%	5.58%	17.22%	11.35%	4.62%	14.76%	10.06%	9.46%
16	INDEX WITH RESPECT TO OVERALL ROR	1.00	0.67	2.06	1.36	0.55	1.77	1.21	1.13
17									
18	**EFFECT OF SUGAR CREEK MARGIN INCREASE (STEP 2)**								
19	STEP 2 INCREASE TO BASE RATES	80,723,639	27,459,804	2,052,336	10,965,208	786,804	634,140	15,912,474	18,141,884
20	PERCENT INCREASE STEP 2	9.05%	9.09%	4.78%	7.55%	9.98%	5.88%	8.76%	11.80%
21	ROR ON RATE BASE AFTER STEP 2	8.35%	5.93%	16.31%	10.99%	5.10%	14.12%	9.83%	9.28%
22	INDEX WITH RESPECT TO OVERALL ROR	1.00	0.71	1.95	1.32	0.61	1.69	1.18	1.11

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPARISON OF EARNED, PARITY AND MODERATED
RATES OF RETURN
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007

		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**AT EARNED RATE OF RETURN**							
2	PRESENT GROSS MARGIN	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
3	RATE OF RETURN EARNED	2.64%	-1.75%	12.39%	14.81%	17.23%	-4.19%	-2.38%
4	INDEX WITH RESPECT TO OVERALL ROR	0.34	-0.23	1.60	1.91	2.23	-0.54	-0.31
5								
6	**AT PARITY RATE OF RETURN OF 8.34%**							
7	MARGIN INCREASE TO BASE RATES	9,019,374	1,874,730	-255,277	-1,298,425	-202,510	1,134,940	1,530,572
8	PERCENT MARGIN INCREASE	31.27%	104.47%	-19.08%	-17.38%	-25.35%	61.45%	103.33%
9	RATE OF RETURN ON RATE BASE	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
10	INDEX WITH RESPECT TO OVERALL ROR	1.00	1.00	1.00	1.00	1.00	1.00	1.00
11								
12	**AT MODERATED RATE OF RETURN (STEP 1)**							
13	MARGIN INCREASE TO BASE RATES	3,006,458	624,910	-11,545	-866,084	-153,457	1,329,975	0
14	PERCENT MARGIN INCREASE	10.42%	34.82%	-0.86%	-11.59%	-19.21%	72.01%	0.00%
15	RATE OF RETURN ON RATE BASE	4.54%	1.62%	12.21%	10.49%	10.49%	10.49%	-2.38%
16	INDEX WITH RESPECT TO OVERALL ROR	0.54	0.19	1.46	1.26	1.26	1.26	-0.29
17								
18	**EFFECT OF SUGAR CREEK MARGIN INCREASE (STEP 2)**							
19	STEP 2 INCREASE TO BASE RATES	4,251,891	87,350	45,386	70,837	33,842	21,202	260,480
20	PERCENT INCREASE STEP 2	13.35%	3.61%	3.42%	1.07%	5.24%	0.67%	17.58%
21	ROR ON RATE BASE AFTER STEP 2	5.12%	1.85%	12.04%	10.46%	10.29%	10.48%	-1.05%
22	INDEX WITH RESPECT TO OVERALL ROR	0.61	0.22	1.44	1.25	1.23	1.25	-0.13

NORTHERN INDIANA PUBLIC SERVICE COMPANY
AVERAGE DISTRIBUTION TRANSFORMER EFFICIENCY

KVA	Count	Avg. Efficiency at 60 percent load	Avg. Efficiency at 100 percent load	Percent Losses @ 60% Load	Weighted	Percent Losses @ 100% Load	Weighted
10	3281	98.63%	98.32%	1.37%	0.2304%	1.68%	0.2825%
15	2578	98.76%	98.47%	1.24%	0.1642%	1.53%	0.2021%
25	7453	98.88%	98.56%	1.12%	0.4278%	1.44%	0.5485%
38	1140	99.03%	98.80%	0.97%	0.0567%	1.20%	0.0701%
50	2642	99.05%	98.80%	0.95%	0.1291%	1.20%	0.1624%
75	779	99.01%	98.77%	0.99%	0.0397%	1.23%	0.0492%
100	196	99.25%	99.06%	0.75%	0.0076%	0.94%	0.0094%
150	346	99.06%	98.86%	0.94%	0.0167%	1.14%	0.0202%
167	80	99.27%	99.05%	0.73%	0.0030%	0.95%	0.0039%
225	310	99.15%	98.99%	0.85%	0.0135%	1.01%	0.0161%
250	8	99.29%	99.12%	0.71%	0.0003%	0.88%	0.0004%
300	238	99.20%	99.05%	0.80%	0.0098%	0.95%	0.0116%
500	205	99.29%	99.15%	0.71%	0.0075%	0.85%	0.0089%
750	99	99.29%	99.09%	0.71%	0.0036%	0.91%	0.0046%
1000	66	99.34%	99.15%	0.66%	0.0022%	0.85%	0.0029%
1500	55	99.40%	99.21%	0.60%	0.0017%	0.79%	0.0022%
2000	16	99.41%	99.22%	0.59%	0.0005%	0.78%	0.0006%
2500	18	99.41%	99.23%	0.59%	0.0005%	0.77%	0.0007%
Total	19,510			0.85%	**1.1146%**	1.06%	**1.3963%**
				Average	Weighted	Average	Weighted

Calculated from Certified Test Data from 2001 through 2007 for 19510 transformer records.

Example:
Efficiency at 100% load = Output / Input
kVA*1000 / (kVA*1000 + Losses)
NIPSCO Estimated Efficiency at 60% load
Eff = kVA*1000*0.6 / [kVA*1000*0.6 + NL + LL*(0.6)^2]
(Load Loss varies with square of load), In this example, the load loss at 60% load is 880*(0.6)^2 =316.8
Example 75KVA, NL= 267, LL=880
kVA*1000*0.6 / [kVA*1000*0.6 + NL + LL*(0.6)^2]
75*1000*0.6 / [75*1000*0.6 + 267 + 880*(0.6)^2]
45000/45000+267+316.8
45000/45583.8
=98.72%

Guidelines Used for Applying FERC Seven Factor Test to NIPSCO Equipment

These guidelines have been arranged in a specific order. These five guidelines and their noted exceptions must be considered in total rather than in isolation from one another. If treatment for a piece of equipment falls outside the consideration of an earlier guideline, it has been included in a later guideline or exception.

1. NIPSCO's distribution system includes all circuits that operate at or below 34 kV. NIPSCO's transmission system includes all circuits that operate above 34 kV.

2. All assets associated with substations performing transformations with high and low side voltages >=69kV are part of NIPSCO's transmission system.

3. Assets associated with substations performing only a <=69kV to <=34kV transformation are part of NIPSCO's distribution system.
    a. Exception 1: Any 69kV capacitor banks and associated equipment in these stations are considered part of the transmission system.
    b. Exception 2: The Angola substation performs a 69kV switching function and a 69kV to 12kV transformation. Equipment should be split between transmission and distribution accounts according to Guideline 4 below supplementing 69kV as the transmission high side voltage.
    c. Exception 3: The Norway Hydro and Oakdale Hydro substations perform 2.3kV to 69kV transformations and provide connection to NIPSCO's 69kV transmission system. The Oakdale Hydro substation also performs a 69kV to 12kV transformation for NIPSCO's distribution system. Switchyard equipment at the Norway Hydro substation is considered part of the transmission system. At the Oakdale station, the 69kV to 12kV transformer, its connection to the high side bus, and all low side equipment are considered part of the distribution system. The remaining switchyard equipment is considered part of the transmission system.

4. Assets associated with substations performing a >69kV to <=34kV transformation should be split between distribution and transmission accounts. The transformer, its connection to the high side bus, and all low side equipment are considered part of the distribution system. Equipment on the high side busses is considered part of the transmission system.
    a. Transformers with a tertiary voltage <=34kV and a secondary voltage >=69kV are considered part of the transmission system.

5. Assets associated with substations without voltage transformations should be classified to transmission or distribution following the voltage classifications in Guideline 1.
    a. e.g. Miller 138kV switching, Grand Army 69kV capacitor bank

NORTHERN INDIANA PUBLIC SERVICE COMPANY

NET SEVEN FACTOR STUDY AND OTHER EQUIPMENT TRANSFERS AMONG FERC ACCOUNTS

DECEMBER 31, 2007

		Gross Plant	Depreciation Reserve
	PRODUCTION PLANT		
310-316	STEAM	$ 37,830,713	$ 17,127,252
330-336	HYDRO	0	0
340-346	OTHER	123,784	84,512
	TOTAL PRODUCTION PLANT	37,954,497	17,211,764
	TRANSMISSION PLANT		
350	LAND AND LAND RIGHTS	-791,342	-72,939
352	STRUCTURES & IMPROVEMENTS	-2,833,497	-1,021,541
353	STATION EQUIPMENT	-78,751,378	-31,254,641
354	TOWERS & FIXTURES	-352,968	-333,825
355	POLES & FIXTURES	-28,768,805	-12,002,553
356	OVERHEAD CONDUCTORS & DEVICES	-19,096,002	-10,130,157
357	UNDERGROUND CONDUIT	-492,553	-492,644
358	UNDERGROUND CONDUCTORS & DEV.	-231,787	-33,107
359	ROADS & TRAILS	0	0
	TOTAL TRANSMISSION PLANT	-131,318,334	-55,341,407
	DISTRIBUTION PLANT		
360	LAND AND LAND RIGHTS	831,802	72,939
361	STRUCTURES & IMPROVEMENTS	2,980,598	1,035,348
362	STATION EQUIPMENT	50,768,095	18,434,381
364.1	CUSTOMER STATIONS	-7,279,897	-4,207,980
364.2	POLES TOWERS & FIXTURES	28,998,001	12,625,090
365	OVERHEAD CONDUCTORS	16,514,477	9,709,624
366	UNDERGROUND CONDUIT	472,902	477,093
367	UNDERGROUND CONDUCTORS	93,102	-15,540
368	LINE TRANSFORMERS	-22	-31
369	SERVICES	-15,222	-1,280
370	METERS	0	0
371	INSTALLATIONS ON CUST PREMISES	0	0
373	STREET LIGHTING & SIGNAL SYSTEMS	0	0
	TOTAL DISTRIBUTION PLANT	93,363,837	38,129,642
	TOTAL	$ 0	$ -

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY UNDER PRESENT RATES

Line No		Total Company	Residential Rate 811	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	OPERATING REVENUES	888,318,151	285,300,758	3,006,447	874,314	117,527	128,835,143	664,362	102,529,456
2									
3	OPERATING EXPENSES								
4	OPERATION & MAINTENANCE	352,734,675	131,096,459	1,205,851	417,017	274,463	38,450,451	387,227	34,955,190
5	DEPRECIATION	211,069,605	79,287,325	706,364	238,936	144,637	23,471,951	239,197	22,728,592
6	TAXES OTHER THAN INCOME	54,649,962	20,837,565	193,658	65,446	38,454	6,834,832	68,720	6,080,932
7									
8	TOTAL OPERATING EXPENSES	618,454,242	231,221,349	2,105,872	721,399	457,554	68,757,233	695,144	63,764,714
9									
10	INCOME TAXES	88,580,793	14,152,634	293,946	38,182	-155,003	22,001,687	-40,065	13,420,000
11									
12	NET OPERATING INCOME	181,283,115	39,926,775	606,629	114,732	-185,024	38,076,222	9,283	25,344,741
13									
14	RATE BASE	2,341,480,136	874,324,261	8,002,359	2,679,748	1,943,637	264,277,536	3,114,867	258,024,365
15									
16	RATE OF RETURN - %	7.74%	4.57%	7.58%	4.28%	-9.52%	14.41%	0.30%	9.82%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY UNDER PRESENT RATES

Line No		GS Large Rate 824	Comml GS Sm. Rate 817	Metel Melting Rate 825	Off-Peak Serv. Rate 826	Rate 832	Ind. Pwr Serv. Rate 833	int. Ind. Pwr S. Rate 836	Muni. Power Rate 841
		(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
1	OPERATING REVENUES	113,626,067	40,190	6,956,147	29,325,519	3,854,720	25,285,138	8,135,097	1,767,708
2									
3	OPERATING EXPENSES								
4	OPERATION & MAINTENANCE	35,198,224	117,527	3,404,884	10,976,098	1,198,925	11,153,926	7,909,509	1,087,792
5	DEPRECIATION	21,176,793	90,305	1,898,032	6,507,412	681,341	5,913,724	3,550,114	762,459
6	TAXES OTHER THAN INCOME	5,741,724	18,505	473,524	1,692,673	178,744	1,437,446	804,525	209,961
7									
8	TOTAL OPERATING EXPENSES	62,116,741	226,337	5,776,441	19,176,182	2,059,010	18,505,097	12,264,149	2,060,211
9									
10	INCOME TAXES	18,778,243	-84,396	292,000	3,469,183	661,900	2,176,197	-2,041,333	-204,186
11									
12	NET OPERATING INCOME	32,731,082	-101,750	887,707	6,680,153	1,133,810	4,603,844	-2,087,719	-88,317
13									
14	RATE BASE	236,219,500	1,009,428	20,974,494	72,559,235	7,415,213	64,372,345	41,508,906	9,667,845
15									
16	RATE OF RETURN - %	13.86%	-10.08%	4.23%	9.21%	15.29%	7.15%	-5.03%	-0.91%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY UNDER PRESENT RATES

Line No		WW Pumping Rate 842	Rate 844 Railroad	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Backup & Maint. 2100	Street Lighting	Traffic Lighting	Dusk-to-Dawn	Interdepart-mental
		(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
1	OPERATING REVENUES	33,611	1,354,611	274,484	163,290,848	1,243,311	7,491,655	847,447	1,941,766	1,521,827
2										
3	OPERATING EXPENSES									
4	OPERATION & MAINTENANCE	1,647	332,226	12,424	69,444,558	146,865	2,133,627	528,764	1,267,977	1,033,044
5	DEPRECIATION	899	268,364	5,912	39,843,480	48,618	1,585,813	408,322	831,564	679,451
6	TAXES OTHER THAN INCOME	695	90,403	5,449	8,914,661	27,267	509,716	114,899	150,917	159,246
7										
8	TOTAL OPERATING EXPENSES	3,242	690,992	23,785	118,202,699	222,751	4,229,156	1,051,985	2,250,458	1,871,741
9										
10	INCOME TAXES	12,217	232,752	101,044	14,327,187	408,585	1,241,678	-125,223	-165,168	-211,268
11										
12	NET OPERATING INCOME	18,152	430,867	149,655	30,760,962	611,975	2,020,821	-79,315	-143,524	-138,647
13										
14	RATE BASE	10,104	4,088,872	62,482	444,642,514	563,932	8,906,623	4,769,651	4,512,764	7,829,456
15										
16	RATE OF RETURN - %	179.64%	10.54%	239.52%	6.92%	108.52%	22.69%	-1.66%	-3.18%	-1.77%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY UNDER PROPOSED RATES

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	RATE OF RETURN SUMMARY								
1	OPERATING REVENUES	888,318,151	288,984,827	44,359,213	148,458,007	7,320,390	10,902,737	185,407,037	157,736,115
2									
3	OPERATING EXPENSES								
4	OPERATION & MAINTENANCE	352,734,675	133,558,263	12,516,303	47,511,683	3,931,752	3,540,806	66,374,211	61,124,861
5	DEPRECIATION	211,069,605	82,642,527	7,112,771	30,425,338	2,122,094	1,863,569	39,753,041	34,563,184
6	TAXES OTHER THAN INCOME	54,649,962	21,751,588	2,251,586	8,379,506	530,564	461,086	10,494,610	7,543,418
7									
8	TOTAL OPERATING EXPENSES	618,454,242	237,952,378	21,880,660	86,316,527	6,584,410	5,865,460	116,621,862	103,231,462
9									
10	INCOME TAXES	88,580,793	12,539,853	8,401,296	22,092,282	90,854	1,849,936	23,953,927	18,751,621
11									
12	NET OPERATING INCOME	181,283,115	38,492,596	14,077,257	40,049,198	645,126	3,187,341	44,831,248	35,753,032
13									
14	RATE BASE	2,341,480,136	916,946,449	79,802,590	348,403,373	23,382,016	21,597,859	441,993,328	375,833,873
15									
16	RATE OF RETURN - %	7.74%	4.20%	17.64%	11.50%	2.76%	14.76%	10.14%	9.51%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY UNDER PROPOSED RATES

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	RATE OF RETURN SUMMARY							
1	OPERATING REVENUES	30,171,331	1,836,440	1,352,284	7,511,621	807,214	1,947,317	1,523,617
2								
3	OPERATING EXPENSES							
4	OPERATION & MAINTENANCE	17,549,836	1,225,310	313,791	2,414,413	235,591	1,344,288	1,093,567
5	DEPRECIATION	7,923,832	858,660	244,039	1,793,446	158,470	888,629	720,006
6	TAXES OTHER THAN INCOME	1,975,517	232,627	83,238	564,113	48,023	165,871	168,216
7								
8	TOTAL OPERATING EXPENSES	27,449,185	2,316,597	641,068	4,771,972	442,084	2,398,788	1,981,789
9								
10	INCOME TAXES	284,366	-290,654	255,694	1,004,930	136,103	-229,863	-259,551
11								
12	NET OPERATING INCOME	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
13								
14	RATE BASE	92,342,480	10,846,090	3,675,615	11,714,341	1,329,084	5,284,498	8,328,540
15								
16	RATE OF RETURN - %	2.64%	-1.75%	12.39%	14.81%	17.23%	-4.19%	-2.38%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	EARNED RATE OF RETURN	7.74%	4.20%	17.64%	11.50%	2.76%	14.76%	10.14%	9.51%
1	RATE BASE	2,341,480,137	916,946,449	79,802,590	348,403,373	23,382,016	21,597,859	441,993,328	375,833,873
2									
3	TARGET RATE OF RETURN	0.08340	0.08340	0.08340	0.08340	0.08340	0.08340	0.08340	0.08340
4									
5	REQUIRED RETURN ON RATE BASE	195,279,443	76,473,334	6,655,536	29,056,841	1,950,060	1,801,261	36,862,244	31,344,545
6	EARNED RETURN ON RATE BASE	181,283,115	38,492,596	14,077,257	40,049,198	645,126	3,187,341	44,831,248	35,753,032
7									
8	REQUIRED INCREASE IN RETURN	13,996,328	37,980,738	-7,421,721	-10,992,357	1,304,934	-1,386,079	-7,969,005	-4,408,487
9									
10	ASSOC. INCR IN INCOME TAXES	9,567,992	25,963,909	-5,073,542	-7,514,455	892,062	-947,534	-5,447,670	-3,013,674
11									
12	TOTAL INCREASE IN RETURN & INC TAXES	23,564,320	63,944,646	-12,495,263	-18,506,811	2,196,996	-2,333,613	-13,416,674	-7,422,162
13									
14	INCREASE IN REVENUE-RELATED	418,987	1,136,971	-222,173	-329,061	39,064	-41,493	-238,556	-131,970
15									
16	OPERATING EXPENSES PER COSS	618,454,242	237,952,378	21,880,660	86,316,527	6,584,410	5,865,460	116,621,862	103,231,462
17	INCOME TAXES PER COSS	88,580,793	12,539,853	8,401,296	22,092,282	90,854	1,849,936	23,953,927	18,751,621
18	RETURN PER COSS	181,283,115	38,492,596	14,077,257	40,049,198	645,126	3,187,341	44,831,248	35,753,032
19									
20	TOTAL REVENUE REQUIREMENT	912,301,457	354,066,444	31,641,778	129,622,134	9,556,450	8,527,631	171,751,807	150,181,984
21	LESS OTHER REVENUES	20,405,463	8,552,795	836,747	2,322,007	183,105	124,772	3,163,542	3,645,520
22	REVENUE REQUIREMENT FROM RATES	891,895,994	345,513,649	30,805,030	127,300,127	9,373,345	8,402,859	168,588,264	146,536,464
23									
24	PRESENT RATE REVENUES	867,912,688	280,432,032	43,522,466	146,136,000	7,137,285	10,777,965	182,243,494	154,090,596
25									
26	REVENUE INCREASE TO BASE RATES	23,983,307	65,081,618	-12,717,436	-18,835,873	2,236,060	-2,375,106	-13,655,230	-7,554,132
27	PERCENT REVENUE INCREASE	2.76%	23.21%	-29.22%	-12.89%	31.33%	-22.04%	-7.49%	-4.90%
28									

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	EARNED RATE OF RETURN	2.64%	-1.75%	12.39%	14.81%	17.23%	-4.19%	-2.38%
1	RATE BASE	92,342,480	10,846,090	3,675,615	11,714,341	1,329,084	5,284,498	8,328,540
2								
3	TARGET RATE OF RETURN	0.08340	0.08340	0.08340	0.08340	0.08340	0.08340	0.08340
4					10.494%			
5	REQUIRED RETURN ON RATE BASE	7,701,363	904,564	306,546	976,976	110,846	440,727	694,600
6	EARNED RETURN ON RATE BASE	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
7								
8	REQUIRED INCREASE IN RETURN	5,263,583	1,094,067	-148,976	-757,743	-118,182	662,336	893,221
9								
10	ASSOC. INCR IN INCOME TAXES	3,598,223	747,912	-101,841	-517,998	-80,790	452,777	610,612
11								
12	TOTAL INCREASE IN RETURN & INC TAXES	8,861,806	1,841,979	-250,817	-1,275,741	-198,972	1,115,113	1,503,833
13								
14	INCREASE IN REVENUE-RELATED	157,568	32,751	-4,460	-22,683	-3,538	19,827	26,739
15								
16	OPERATING EXPENSES PER COSS	27,449,185	2,316,597	641,068	4,771,972	442,084	2,398,788	1,981,789
17	INCOME TAXES PER COSS	284,366	-290,654	255,694	1,004,930	136,103	-229,863	-259,551
18	RETURN PER COSS	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
19					9,900,158			
20	TOTAL REVENUE REQUIREMENT	39,190,705	3,711,170	1,097,008	6,213,197	604,704	3,082,257	3,054,189
21	LESS OTHER REVENUES	1,330,908	41,999	14,101	39,094	8,253	100,295	42,324
22	REVENUE REQUIREMENT FROM RATES	37,859,797	3,669,170	1,082,907	6,174,102	596,451	2,981,962	3,011,865
23								
24	PRESENT RATE REVENUES	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
25								
26	REVENUE INCREASE TO BASE RATES	9,019,374	1,874,730	-255,277	-1,298,425	-202,510	1,134,940	1,530,572
27	PERCENT REVENUE INCREASE	31.27%	104.47%	-19.08%	-17.38%	-25.35%	61.45%	103.33%
28								

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	UNBUNDLED REVENUE REQUIREMENT FROM RATES AT TARGET ROR *(REVENUE-RELATED DISTRIBUTED)*								
1	PRODUCTION								
2	FIXED	434,206,577	155,851,464	11,070,676	59,955,931	4,028,494	2,879,700	85,445,815	94,012,843
3	VARIABLE	73,029,194	15,979,528	1,839,595	9,290,362	968,510	1,235,380	15,234,341	19,178,330
4									
5	TRANSMISSION SUBSTATIONS	83,370,791	22,587,510	2,067,230	11,311,140	974,594	583,280	16,812,953	20,751,463
6	TRANSMISSION LINES	33,851,859	9,187,714	840,512	4,595,910	395,812	236,334	6,828,807	8,417,773
7									
8	DISTRIB. SUBSTATIONS	36,778,130	16,627,617	1,266,322	6,611,176	638,351	990,078	8,912,270	747,124
9	DISTRIB. SUBSTATIONS - RAILROAD	670,949	0	0	0	0	0	0	0
10									
11	DISTRIBUTION LINES PRIMARY - DEMAND	90,407,587	40,863,756	3,113,636	16,254,342	1,569,161	2,435,722	21,912,540	1,837,379
12	DISTRIBUTION LINES SECONDARY - DEMAND	39,002,092	21,167,742	3,395,433	9,693,766	25,391	0	3,914,826	0
13	LINE TRANSFORMERS - DEMAND	22,691,824	12,960,005	984,771	5,000,857	22,255	0	2,996,998	0
14									
15	SERVICES	9,913,128	8,452,262	814,941	549,359	181	0	63,934	0
16	METERS	19,845,628	12,439,853	2,193,306	2,692,421	55,351	6,890	1,906,949	262,209
17	STREET LIGHTING	4,854,669	0	0	0	0	0	0	0
18	DUSK-TO-DAWN LIGHTING	2,404,004	0	0	0	0	0	0	0
19	METER READING	10,396,720	5,763,109	598,282	506,590	40,158	3,649	3,405,833	46,920
20	BILLING & COLLECTING	24,958,536	19,954,267	2,077,544	589,549	613,254	31,817	699,954	818,443
21	CUSTOMER ACCOUNTS OTHER	219,987	188,790	19,590	5,520	5	0	445	6
22	CUSTOMER INFORMATION	1,568,624	262,319	188,136	148,655	41,738	0	444,974	463,869
23	SALES EXPENSE	3,761,296	3,227,713	335,056	94,547	90	8	7,627	105
24	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
27									
28	REVENUE TAXES	0	0	0	0	0	0	0	0
29									
30	TOTAL COST OF SERVICE FROM RATES	891,931,595	345,513,649	30,805,030	127,300,127	9,373,345	8,402,859	168,588,264	146,536,464

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	UNBUNDLED REVENUE REQUIREMENT FROM RATES AT TARGET ROR *(REVENUE-RELATED DISTRIBUTED)*							
1	PRODUCTION							
2	FIXED	18,342,447	446,575	210,829	274,981	175,377	78,013	1,433,433
3	VARIABLE	8,538,696	117,067	80,219	230,674	42,758	65,397	228,337
4								
5	TRANSMISSION SUBSTATIONS	7,724,191	107,280	83,044	96,944	36,727	26,266	208,169
6	TRANSMISSION LINES	3,121,992	43,647	33,722	39,439	14,927	10,694	84,576
7								
8	DISTRIB. SUBSTATIONS	0	519,931	0	174,012	16,227	46,487	228,534
9	DISTRIB. SUBSTATIONS - RAILROAD	0	0	670,949	0	0	0	0
10								
11	DISTRIBUTION LINES PRIMARY - DEMAND	0	1,277,416	0	427,895	39,907	114,196	561,637
12	DISTRIBUTION LINES SECONDARY - DEMAND	0	522,587	0	143,985	13,428	38,440	86,494
13	LINE TRANSFORMERS - DEMAND	0	364,367	0	135,625	12,643	36,251	178,051
14								
15	SERVICES	0	32,453	0	0	0	0	0
16	METERS	113,928	172,920	0	0	0	0	1,800
17	STREET LIGHTING	0	0	0	4,613,286	241,383	0	0
18	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	2,404,004	0
19	METER READING	18,246	9,420	3,677	0	0	0	835
20	BILLING & COLLECTING	252	32,618	458	21,963	1,813	116,605	0
21	CUSTOMER ACCOUNTS OTHER	2	309	0	832	69	4,419	0
22	CUSTOMER INFORMATION	1	17,308	0	254	21	1,349	0
23	SALES EXPENSE	41	5,276	8	14,212	1,173	75,442	0
24	DIRECT TO RETAIL	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
27								
28	REVENUE TAXES	0	0	0	0	0	0	0
29								
30	TOTAL COST OF SERVICE FROM RATES	37,859,797	3,669,170	1,082,907	6,174,102	596,451	3,017,563	3,011,865

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 2.2
Page 2 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	BILLING DETERMINANTS								
1	KWH SALES	16,765,808,626	3,451,355,088	397,251,629	1,999,450,934	229,025,082	295,360,506	3,471,330,760	4,672,758,395
2									
3	AVERAGE MONTH BILLING KW								
4	TRANSMISSION		0	0	581,239	26,840	42,966	707,633	858,143
5	PRIMARY		0	0	581,215	25,626	42,966	689,517	58,956
6	SECONDARY		0	0	562,665	1,045	0	309,141	0
7									
8	AVG. NO. OF CUSTOMERS	464,651	398,826	41,349	11,571	11	1	933	13
9									
10	**UNIT COSTS**							$ 12.85	$ 11.96
11			$/KWH		$/KW/MO.	$/KW/MO.	$/KW/MO.	$/KW/MO.	$/KW/MO.
12	PRODUCTION FIXED		$ 0.04516	$ 0.02787	$ 8.60	$ 12.51	$ 5.59	$ 10.06	$ 9.13
13									
14	PRODUCTION VARIABLE		$ 0.00463	$ 0.00463	$ 0.00465	$ 0.00423	$ 0.00418	$ 0.00439	$ 0.00410
15									
16	TRANSMISSION		$ 0.00921	$ 0.00732	$ 2.28	$ 4.25	$ 1.59	$ 2.78	$ 2.83
17									
18	DISTRIBUTION								
19	PRIMARY		$ 0.01666	$ 0.01103	$ 3.28	$ 7.18	$ 6.64	$ 3.73	$ 3.65
20	SECONDARY		$ 0.00989	$ 0.01103	$ 2.18	$ 3.80	$ -	$ 1.86	$ -
21									
22	DISTRIBUTION TOTAL		$ 0.02655	$ 0.02205	$ 5.45	$ 10.98	$ 6.64	$ 5.59	$ 3.65
23									
24	TOTAL $/KWH		**$ 0.08554**	**$ 0.06187**	**$ 0.00465**	$ 0.00423	$ 0.00418	$ 0.00439	$ 0.00410
25	TOTAL $/KW (@ LOWEST SERVICE LEVEL)		$ -	$ -		$ 27.74	$ 13.82	$ 18.44	$ 15.62
26									
27	CUSTOMER ($/CUSTOMER/MONTH)								
28	SERVICES		$ 1.77	$ 1.64	$ 3.96	$ 1.37	$ -	$ 5.71	$ -
29	METERS		2.60	4.42	19.39	419.32	574.20	170.32	1,680.83
30	STREET LIGHTING		-	-	-	-	-	-	-
31	METER READING		1.20	1.21	3.65	304.23	304.12	304.20	300.77
32	BILLING & COLLECTING		4.17	4.19	4.25	4,645.86	2,651.43	62.52	5,246.43
33	CUSTOMER ACCOUNTS OTHER		0.04	0.04	0.04	0.04	0.04	0.04	0.04
34	CUSTOMER INFORMATION		0.05	0.38	1.07	316.20	0.01	39.74	2,973.52
35	SALES EXPENSE		0.67	0.68	0.68	0.68	0.68	0.68	0.67
36									
37	CUSTOMER TOTAL		**$ 10.51**	**$ 12.55**	**$ 33.03**	**$ 5,687.70**	**$ 3,530.49**	**$ 583.22**	**$ 10,202.25**

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 2.3
Page 1 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Rate 536 Interrupt. Ind. (I)	Rate 541 Water Pumpg (J)	Rate 544 Railroad (K)	Rate 550 Street Lighting (L)	Rate 555 Traffic Lighting (M)	Rate 560 Dusk-to-Dawn (N)	Interdept'l (O)
	BILLING DETERMINANTS							
1	*KWH SALES*	2,084,025,091	25,231,213	18,905,250	48,891,853	9,129,140	14,252,921	48,840,763
2								
3	*AVERAGE MONTH BILLING KW*							
4	*TRANSMISSION*	249,900	0	0	0	0	0	0
5	*PRIMARY*	0	0	0	0	0	0	0
6	*SECONDARY*	0	0	0	0	0	0	0
7								
8	*AVG. NO. OF CUSTOMERS*	5	644	1	1,725	143	9,429	0
9								
10	***UNIT COSTS***							
11		$/KW/MO.	$/KWH/MO.	$/KW/MO.	$/KWH/MO.	$/KWH/MO.	$/KWH/MO.	
12	*PRODUCTION FIXED*	$ 6.12	$ 0.01770	$ -	$ 0.00562	$ 0.01921	$ 0.00547	
13								
14	*PRODUCTION VARIABLE*	$ 0.00410	$ 0.00464	$ 0.00424	$ 0.00472	$ 0.00468	$ 0.00459	
15								
16	*TRANSMISSION*	$ 3.62	$ 0.00598	$ -	$ 0.00279	$ 0.00566	$ 0.00259	
17								
18	*DISTRIBUTION*							
19	*PRIMARY*	$ -	$ 0.07124	$ -	$ 0.01231	$ 0.00615	$ 0.01127	
20	*SECONDARY*	$ -	$ 0.03515	$ -	$ 0.00572	$ 0.00286	$ 0.00524	
21								
22	*DISTRIBUTION TOTAL*	$ -	$ 0.10639	$ -	$ 0.01803	$ 0.00900	$ 0.01651	
23								
24	*TOTAL $/KWH*	$ 0.00410	$ 0.13471	$ 0.00424	$ 0.03116	$ 0.03856	$ 0.02917	
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*	$ 9.73	$ -	$ -	$ -	$ -	$ -	
26								
27	*CUSTOMER ($/CUSTOMER/MONTH)*							
28	*SERVICES*	$ -	$ 4.20	$ -	$ -	$ -	$ -	
29	*METERS*	1,898.80	22.38	-	-	-	-	
30	*STREET LIGHTING*	-	-	-	222.86	140.67	-	
31	*METER READING*	304.11	1.22	306.38	-	-	-	
32	*BILLING & COLLECTING*	4.20	4.22	38.17	1.06	1.06	1.03	
33	*CUSTOMER ACCOUNTS OTHER*	0.04	0.04	0.04	0.04	0.04	0.04	
34	*CUSTOMER INFORMATION*	0.01	2.24	0.01	0.01	0.01	0.01	
35	*SALES EXPENSE*	0.68	0.68	0.69	0.69	0.68	0.67	
36								
37	*CUSTOMER TOTAL*	**$ 2,207.84**	**$ 34.98**	**$ 345.29**	**$ 224.66**	**$ 142.46**	**$ 1.75**	

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industrial Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	EARNED RATE OF RETURN	7.74%	4.20%	17.64%	11.50%	2.76%	14.76%	10.14%	9.51%
1	RATE BASE	2,341,480,137	916,946,449	79,802,590	348,403,373	23,382,016	21,597,859	441,993,328	375,833,873
2									
3	TARGET RATE OF RETURN	0.08340	0.05579	0.17220	0.11352	0.04619	0.14758	0.10061	0.09460
4									
5	REQUIRED RETURN ON RATE BASE	195,279,443	51,152,842	13,741,612	39,552,072	1,080,104	3,187,341	44,470,852	35,553,660
6	EARNED RETURN ON RATE BASE	181,283,115	38,492,596	14,077,257	40,049,198	645,126	3,187,341	44,831,248	35,753,032
7									
8	REQUIRED INCREASE IN RETURN	13,996,328	12,660,246	-335,645	-497,126	434,978	0	-360,396	-199,373
9									
10	ASSOC. INCR IN INCOME TAXES	9,567,992	8,654,636	-229,449	-339,839	297,354	0	-246,369	-136,293
11									
12	TOTAL INCREASE IN RETURN & INC TAXES	23,564,320	21,314,882	-565,095	-836,965	732,332	0	-606,765	-335,665
13									
14	INCREASE IN REVENUE-RELATED	418,987	378,990	-10,048	-14,882	13,021	0	-10,789	-5,968
15									
16	OPERATING EXPENSES PER COSS	618,454,242	237,952,378	21,880,660	86,316,527	6,584,410	5,865,460	116,621,862	103,231,462
17	INCOME TAXES PER COSS	88,580,793	12,539,853	8,401,296	22,092,282	90,854	1,849,936	23,953,927	18,751,621
18	RETURN PER COSS	181,283,115	38,492,596	14,077,257	40,049,198	645,126	3,187,341	44,831,248	35,753,032
19									
20	TOTAL REVENUE REQUIREMENT	912,301,457	310,678,699	43,784,071	147,606,160	8,065,743	10,902,737	184,789,483	157,394,482
21	LESS OTHER REVENUES	20,405,463	8,552,795	836,747	2,322,007	183,105	124,772	3,163,542	3,645,520
22	REVENUE REQUIREMENT FROM RATES	891,895,994	302,125,904	42,947,324	145,284,153	7,882,638	10,777,965	181,625,941	153,748,962
23									
24	PRESENT RATE REVENUES	867,912,688	280,432,032	43,522,466	146,136,000	7,137,285	10,777,965	182,243,494	154,090,596
25									
26	REVENUE INCREASE TO BASE RATES	23,983,307	21,693,873	-575,142	-851,847	745,353	0	-617,554	-341,633
27	PERCENT REVENUE INCREASE	2.76%	7.74%	-1.32%	-0.58%	10.44%	0.00%	-0.34%	-0.22%
28									

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	EARNED RATE OF RETURN	2.64%	-1.75%	12.39%	14.81%	17.23%	-4.19%	-2.38%
1	RATE BASE	92,342,480	10,846,090	3,675,615	11,714,341	1,329,084	5,284,498	8,328,540
2								
3	TARGET RATE OF RETURN	0.04540	0.01615	0.12210	0.14516	0.16830	(0.00016)	(0.02385)
4					10.494%			
5	REQUIRED RETURN ON RATE BASE	4,192,308	175,186	448,785	1,700,450	223,683	-830	-198,621
6	EARNED RETURN ON RATE BASE	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
7								
8	REQUIRED INCREASE IN RETURN	1,754,528	364,689	-6,737	-34,269	-5,345	220,779	0
9								
10	ASSOC. INCR IN INCOME TAXES	1,199,408	249,304	-4,606	-23,426	-3,654	150,926	0
11								
12	TOTAL INCREASE IN RETURN & INC TAXES	2,953,935	613,993	-11,343	-57,695	-8,998	371,704	0
13								
14	INCREASE IN REVENUE-RELATED	52,523	10,917	-202	-1,026	-160	6,609	0
15								
16	OPERATING EXPENSES PER COSS	27,449,185	2,316,597	641,068	4,771,972	442,084	2,398,788	1,981,789
17	INCOME TAXES PER COSS	284,366	-290,654	255,694	1,004,930	136,103	-229,863	-259,551
18	RETURN PER COSS	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
19					10,576,586			
20	TOTAL REVENUE REQUIREMENT	33,177,789	2,461,350	1,340,740	7,452,901	798,056	2,325,630	1,523,617
21	LESS OTHER REVENUES	1,330,908	41,999	14,101	39,094	8,253	100,295	42,324
22	REVENUE REQUIREMENT FROM RATES	31,846,881	2,419,350	1,326,638	7,413,806	789,802	2,225,335	1,481,293
23								
24	PRESENT RATE REVENUES	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
25								
26	REVENUE INCREASE TO BASE RATES	3,006,458	624,910	-11,545	-58,721	-9,158	378,313	0
27	PERCENT REVENUE INCREASE	10.42%	34.82%	-0.86%	-0.79%	-1.15%	20.48%	0.00%
28								

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industrial Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	UNBUNDLED REVENUE REQUIREMENT FROM RATES AT TARGET ROR *(REVENUE-RELATED DISTRIBUTED)*								
1	PRODUCTION								
2	FIXED	435,046,591	136,013,583	15,600,236	68,226,003	3,343,242	3,729,872	92,178,276	98,893,945
3	VARIABLE	73,248,880	15,347,260	2,068,003	9,678,919	917,945	1,347,252	15,599,205	19,490,894
4									
5	TRANSMISSION SUBSTATIONS	83,957,072	19,251,645	3,050,074	13,123,866	782,162	783,098	18,351,710	22,000,122
6	TRANSMISSION LINES	34,131,234	7,617,347	1,303,760	5,450,384	305,158	330,476	7,554,059	9,005,314
7									
8	DISTRIB. SUBSTATIONS	36,799,115	13,468,578	2,042,745	7,978,205	475,853	1,428,164	9,964,740	805,023
9	DISTRIB. SUBSTATIONS - RAILROAD	847,955	0	0	0	0	0	0	0
10									
11	DISTRIBUTION LINES PRIMARY - DEMAND	90,417,314	35,977,050	4,309,679	18,359,517	1,318,427	3,111,411	23,533,881	1,927,063
12	DISTRIBUTION LINES SECONDARY - DEMAND	39,191,454	18,141,614	4,957,799	11,197,858	20,535	0	4,261,799	0
13	LINE TRANSFORMERS - DEMAND	21,873,356	10,188,309	1,665,171	6,166,450	15,871	0	3,395,975	0
14									
15	SERVICES	9,006,897	6,997,523	1,267,269	652,224	139	0	70,772	0
16	METERS	19,620,809	10,912,978	3,058,117	3,050,137	46,283	8,847	2,051,640	275,315
17	STREET LIGHTING	5,712,032	0	0	0	0	0	0	0
18	DUSK-TO-DAWN LIGHTING	1,844,267	0	0	0	0	0	0	0
19	METER READING	10,344,831	5,546,461	668,668	526,618	38,178	3,960	3,482,857	47,641
20	BILLING & COLLECTING	24,400,731	19,108,346	2,354,354	615,959	579,049	34,877	717,887	832,623
21	CUSTOMER ACCOUNTS OTHER	217,927	185,965	20,457	5,602	5	0	449	6
22	CUSTOMER INFORMATION	1,599,826	252,582	209,981	154,455	39,706	0	454,906	470,911
23	SALES EXPENSE	3,682,583	3,116,664	371,011	97,956	86	9	7,784	107
24	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
27									
28	REVENUE TAXES	0	0	0	0	0	0	0	0
29									
30	TOTAL COST OF SERVICE FROM RATES	891,942,874	302,125,904	42,947,324	145,284,153	7,882,638	10,777,965	181,625,941	153,748,962

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 3.1
Page 1 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	UNBUNDLED REVENUE REQUIREMENT FROM RATES AT TARGET ROR *(REVENUE-RELATED DISTRIBUTED)*							
1	PRODUCTION							
2	FIXED	15,128,925	309,604	248,027	351,845	243,156	48,115	731,763
3	VARIABLE	8,060,609	106,102	84,478	249,625	47,676	57,572	193,342
4								
5	TRANSMISSION SUBSTATIONS	6,158,907	69,061	100,072	128,499	53,239	14,588	90,029
6	TRANSMISSION LINES	2,386,116	25,638	41,752	54,335	22,718	5,198	28,979
7								
8	DISTRIB. SUBSTATIONS	0	281,339	0	247,222	25,654	19,929	61,663
9	DISTRIB. SUBSTATIONS - RAILROAD	0	0	847,955	0	0	0	0
10								
11	DISTRIBUTION LINES PRIMARY - DEMAND	0	909,510	0	540,075	54,380	73,078	303,243
12	DISTRIBUTION LINES SECONDARY - DEMAND	0	342,424	0	189,310	19,270	21,903	38,943
13	LINE TRANSFORMERS - DEMAND	0	176,061	0	199,975	20,926	12,952	31,666
14								
15	SERVICES	0	18,969	0	0	0	0	0
16	METERS	94,754	121,787	0	0	0	0	951
17	STREET LIGHTING	0	0	0	5,412,667	299,364	0	0
18	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	1,844,267	0
19	METER READING	17,292	8,583	3,861	0	0	0	714
20	BILLING & COLLECTING	237	29,338	484	23,909	2,037	101,631	0
21	CUSTOMER ACCOUNTS OTHER	2	298	0	854	71	4,216	0
22	CUSTOMER INFORMATION	1	15,789	0	274	23	1,197	0
23	SALES EXPENSE	39	4,848	9	15,215	1,289	67,567	0
24	DIRECT TO RETAIL	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
27								
28	REVENUE TAXES	0	0	0	0	0	0	0
29								
30	TOTAL COST OF SERVICE FROM RATES	31,846,881	2,419,350	1,326,638	7,413,806	789,802	2,272,215	1,481,293

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Total Company (A)	Rate 511 Residential (B)	Rate 521 GS Small (C)	Rate 523 GS Medium (D)	Rate 526 Off-Peak (E)	Rate 527 Ltd. Prod. Lrg (F)	Rate 533 GS large (G)	Rate 534 Industrial Lrg (H)
	BILLING DETERMINANTS								
1	*KWH SALES*	*16,765,808,626*	*3,451,355,088*	*397,251,629*	*1,999,450,934*	*229,025,082*	*295,360,506*	*3,471,330,760*	*4,672,758,395*
2									
3	*AVERAGE MONTH BILLING KW*								
4	*TRANSMISSION*		*0*	*0*	*581,239*	*26,840*	*42,966*	*707,633*	*858,143*
5	*PRIMARY*		*0*	*0*	*581,215*	*25,626*	*42,966*	*689,517*	*58,956*
6	*SECONDARY*		*0*	*0*	*562,665*	*1,045*	*0*	*309,141*	*0*
7									
8	*AVG. NO. OF CUSTOMERS*	*464,651*	*398,826*	*41,349*	*11,571*	*11*	*1*	*933*	*13*
9									
10	***UNIT COSTS***							*$ 13.91*	*$ 12.61*
11			*$/KWH*		*$/KW/MO.*	*$/KW/MO.*	*$/KW/MO.*	*$/KW/MO.*	*$/KW/MO.*
12	*PRODUCTION FIXED*		*$ 0.03941*	*$ 0.03927*	*$ 9.78*	*$ 10.38*	*$ 7.23*	*$ 10.86*	*$ 9.60*
13									
14	*PRODUCTION VARIABLE*		*$ 0.00445*	*$ 0.00521*	*$ 0.00484*	*$ 0.00401*	*$ 0.00456*	*$ 0.00449*	*$ 0.00417*
15									
16	*TRANSMISSION*		*$ 0.00779*	*$ 0.01096*	*$ 2.66*	*$ 3.38*	*$ 2.16*	*$ 3.05*	*$ 3.01*
17									
18	*DISTRIBUTION*								
19	*PRIMARY*		*$ 0.01433*	*$ 0.01599*	*$ 3.78*	*$ 5.83*	*$ 8.80*	*$ 4.05*	*$ 3.86*
20	*SECONDARY*		*$ 0.00821*	*$ 0.01667*	*$ 2.57*	*$ 2.90*	*$ -*	*$ 2.06*	*$ -*
21									
22	*DISTRIBUTION TOTAL*		*$ 0.02253*	*$ 0.03266*	*$ 6.35*	*$ 8.74*	*$ 8.80*	*$ 6.11*	*$ 3.86*
23									
24	*TOTAL $/KWH*		***$ 0.07418***	***$ 0.08810***	***$ 0.00484***	*$ 0.00401*	*$ 0.00456*	*$ 0.00449*	*$ 0.00417*
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*		*$ -*	*$ -*		*$ 22.49*	*$ 18.20*	*$ 20.02*	*$ 16.48*
26									
27	*CUSTOMER ($/CUSTOMER/MONTH)*								
28	*SERVICES*		*$ 1.46*	*$ 2.55*	*$ 4.70*	*$ 1.05*	*$ -*	*$ 6.32*	*$ -*
29	*METERS*		*2.28*	*6.16*	*21.97*	*350.63*	*737.21*	*183.25*	*1,764.84*
30	*STREET LIGHTING*		*-*	*-*	*-*	*-*	*-*	*-*	*-*
31	*METER READING*		*1.16*	*1.35*	*3.79*	*289.23*	*329.96*	*311.08*	*305.39*
32	*BILLING & COLLECTING*		*3.99*	*4.74*	*4.44*	*4,386.73*	*2,906.45*	*64.12*	*5,337.33*
33	*CUSTOMER ACCOUNTS OTHER*		*0.04*	*0.04*	*0.04*	*0.04*	*0.04*	*0.04*	*0.04*
34	*CUSTOMER INFORMATION*		*0.05*	*0.42*	*1.11*	*300.80*	*0.01*	*40.63*	*3,018.66*
35	*SALES EXPENSE*		*0.65*	*0.75*	*0.71*	*0.65*	*0.73*	*0.70*	*0.68*
36									
37	*CUSTOMER TOTAL*		***$ 9.64***	***$ 16.02***	***$ 36.75***	***$ 5,329.13***	***$ 3,974.41***	***$ 606.14***	***$ 10,426.94***

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 3.2
Page 1 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind. (I)	Rate 541 Water Pumpg (J)	Rate 544 Railroad (K)	Rate 550 Street Lighting (L)	Rate 555 Traffic Lighting (M)	Rate 560 Dusk-to-Dawn (N)	Interdept'l (O)
	BILLING DETERMINANTS							
1	*KWH SALES*	2,084,025,091	25,231,213	18,905,250	48,891,853	9,129,140	14,252,921	48,840,763
2								
3	*AVERAGE MONTH BILLING KW*							
4	*TRANSMISSION*	249,900	0	0	0	0	0	0
5	*PRIMARY*	0	0	0	0	0	0	0
6	*SECONDARY*	0	0	0	0	0	0	0
7								
8	*AVG. NO. OF CUSTOMERS*	5	644	1	1,725	143	9,429	0
9								
10	***UNIT COSTS***							
11		$/KW/MO.	$/KWH/MO.	$/KW/MO.	$/KWH/MO.	$/KWH/MO.	$/KWH/MO.	
12	*PRODUCTION FIXED*	$ 5.04	$ 0.01227	$ -	$ 0.00720	$ 0.02664	$ 0.00338	
13								
14	*PRODUCTION VARIABLE*	$ 0.00387	$ 0.00421	$ 0.00447	$ 0.00511	$ 0.00522	$ 0.00404	
15								
16	*TRANSMISSION*	$ 2.85	$ 0.00375	$ -	$ 0.00374	$ 0.00832	$ 0.00139	
17								
18	*DISTRIBUTION*							
19	*PRIMARY*	$ -	$ 0.04720	$ -	$ 0.01610	$ 0.00877	$ 0.00653	
20	*SECONDARY*	$ -	$ 0.02055	$ -	$ 0.00796	$ 0.00440	$ 0.00245	
21								
22	*DISTRIBUTION TOTAL*	$ -	$ 0.06775	$ -	$ 0.02406	$ 0.01317	$ 0.00897	
23								
24	*TOTAL $/KWH*	$ 0.00387	$ 0.08798	$ 0.00447	$ 0.04011	$ 0.05335	$ 0.01777	
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*	$ 7.89	$ -	$ -	$ -	$ -	$ -	
26								
27	*CUSTOMER ($/CUSTOMER/MONTH)*							
28	*SERVICES*	$ -	$ 2.45	$ -	$ -	$ -	$ -	
29	*METERS*	1,579.24	15.76	-	-	-	-	
30	*STREET LIGHTING*	-	-	-	261.48	174.45	-	
31	*METER READING*	288.20	1.11	321.72	-	-	-	
32	*BILLING & COLLECTING*	3.96	3.80	40.34	1.16	1.19	0.90	
33	*CUSTOMER ACCOUNTS OTHER*	0.04	0.04	0.04	0.04	0.04	0.04	
34	*CUSTOMER INFORMATION*	0.01	2.04	0.01	0.01	0.01	0.01	
35	*SALES EXPENSE*	0.65	0.63	0.72	0.74	0.75	0.60	
36								
37	*CUSTOMER TOTAL*	$ 1,872.08	$ 25.83	$ 362.83	$ 263.43	$ 176.45	$ 1.54	

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 3.2
Page 2 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY WITH SUGAR CREEK (STEP 2)

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	RATE OF RETURN SUMMARY								
1	OPERATING REVENUES	888,318,151	288,984,880	44,359,220	148,458,023	7,320,390	10,902,740	185,407,037	157,736,054
2									
3	OPERATING EXPENSES								
4	OPERATION & MAINTENANCE	362,123,096	135,542,691	12,739,759	48,685,078	4,054,883	3,696,831	68,335,416	63,698,047
5	DEPRECIATION	233,530,891	90,694,524	7,682,589	33,502,804	2,329,106	2,011,575	44,149,995	39,489,307
6	TAXES OTHER THAN INCOME	55,782,205	22,183,524	2,288,366	8,544,324	541,627	470,792	10,706,437	7,736,923
7									
8	TOTAL OPERATING EXPENSES	651,436,192	248,420,739	22,710,713	90,732,206	6,925,616	6,179,198	123,191,847	110,924,276
9									
10	INCOME TAXES	72,088,287	7,186,787	7,985,660	19,874,770	-76,504	1,702,156	20,678,982	14,944,837
11									
12	NET OPERATING INCOME	164,793,672	33,377,355	13,662,847	37,851,047	471,278	3,021,386	41,536,207	31,866,941
13									
14	RATE BASE	2,704,703,893	1,046,244,653	89,065,663	398,197,935	26,764,333	24,010,556	513,087,403	455,524,597
15									
16	RATE OF RETURN - %	6.09%	3.19%	15.34%	9.51%	1.76%	12.58%	8.10%	7.00%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION SUMMARY WITH SUGAR CREEK (STEP 2)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	RATE OF RETURN SUMMARY							
1	OPERATING REVENUES	30,171,308	1,836,443	1,352,284	7,511,622	807,214	1,947,317	1,523,618
2								
3	OPERATING EXPENSES							
4	OPERATION & MAINTENANCE	18,668,562	1,235,399	322,712	2,431,387	240,479	1,349,589	1,122,262
5	DEPRECIATION	8,880,001	880,108	254,433	1,803,978	167,291	891,915	793,266
6	TAXES OTHER THAN INCOME	2,025,823	237,225	84,796	573,418	48,865	168,022	172,066
7								
8	TOTAL OPERATING EXPENSES	29,574,386	2,352,732	661,941	4,808,783	456,635	2,409,526	2,087,594
9								
10	INCOME TAXES	-715,851	-308,321	245,730	988,307	128,964	-234,699	-312,532
11								
12	NET OPERATING INCOME	1,312,773	-207,968	444,613	1,714,533	221,614	-227,510	-251,445
13								
14	RATE BASE	108,448,358	11,219,650	3,856,805	11,950,661	1,474,868	5,354,332	9,504,079
15								
16	RATE OF RETURN - %	1.21%	-1.85%	11.53%	14.35%	15.03%	-4.25%	-2.65%

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 4.0
Page 2 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 2 REVENUE REQUIREMENT AT TARGET ROR

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	EARNED RATE OF RETURN	6.09%	3.19%	15.34%	9.51%	1.76%	12.58%	8.10%	7.00%
2									
3	RATE BASE	2,704,703,894	1,046,244,653	89,065,663	398,197,935	26,764,333	24,010,556	513,087,403	455,524,597
4									
5	TARGET RATE OF RETURN	8.35%	5.93%	16.31%	10.99%	5.10%	14.12%	9.83%	9.28%
6									
7	REQUIRED RETURN ON RATE BASE	225,899,208	62,062,765	14,524,917	43,753,066	1,365,424	3,391,462	50,462,112	42,254,923
8	EARNED RETURN ON RATE BASE	164,793,671	33,377,355	13,662,847	37,851,047	471,278	3,021,386	41,536,207	31,866,941
9									
10	REQUIRED INCREASE IN RETURN	61,105,535	28,685,410	862,070	5,902,019	894,146	370,075	8,925,905	10,387,982
11									
12	ASSOC. INCR IN INCOME TAXES	41,772,188	19,609,555	589,317	4,034,663	611,245	252,986	6,101,814	7,101,300
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	102,877,723	48,294,966	1,451,388	9,936,681	1,505,391	623,062	15,027,719	17,489,282
15									
16	INCREASE IN REVENUE-RELATED	1,829,223	858,711	25,806	176,680	26,767	11,078	267,201	310,969
17									
18	OPERATING EXPENSES PER COSS	651,436,192	248,420,739	22,710,713	90,732,206	6,925,616	6,179,198	123,191,847	110,924,276
19	INCOME TAXES PER COSS	72,088,287	7,186,787	7,985,660	19,874,770	-76,504	1,702,156	20,678,982	14,944,837
20	RETURN PER COSS	164,793,671	33,377,355	13,662,847	37,851,047	471,278	3,021,386	41,536,207	31,866,941
21									
22	TOTAL REVENUE REQUIREMENT	993,025,096	338,138,558	45,836,414	158,571,385	8,852,547	11,536,880	200,701,956	175,536,305
23	LESS OTHER REVENUES	20,405,463	8,552,849	836,754	2,322,024	183,105	124,775	3,163,542	3,645,459
24	REVENUE REQUIREMENT FROM RATES	972,619,634	329,585,709	44,999,660	156,249,361	8,669,442	11,412,105	197,538,414	171,890,847
25									
26	PRESENT RATE REVENUES	867,912,688	280,432,032	43,522,466	146,136,000	7,137,285	10,777,965	182,243,494	154,090,596
27									
28	REVENUE INCREASE TO BASE RATES	104,706,946	49,153,677	1,477,194	10,113,361	1,532,157	634,140	15,294,920	17,800,251
29	PERCENT REVENUE INCREASE	12.06%	17.53%	3.39%	6.92%	21.47%	5.88%	8.39%	11.55%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 2 REVENUE REQUIREMENT AT TARGET ROR

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	EARNED RATE OF RETURN	1.21%	-1.85%	11.53%	14.35%	15.03%	-4.25%	-2.65%
2								
3	RATE BASE	108,448,358	11,219,650	3,856,805	11,950,661	1,474,868	5,354,332	9,504,079
4								
5	TARGET RATE OF RETURN	5.12%	1.85%	12.04%	10.45%	10.45%	10.45%	-1.05%
6								
7	REQUIRED RETURN ON RATE BASE	5,548,645	207,697	464,362	1,249,333	154,184	559,747	-99,432
8	EARNED RETURN ON RATE BASE	1,312,773	-207,968	444,613	1,714,533	221,614	-227,510	-251,445
9								
10	REQUIRED INCREASE IN RETURN	4,235,873	415,665	19,749	-465,199	-67,430	787,257	152,013
11								
12	ASSOC. INCR IN INCOME TAXES	2,895,674	284,152	13,501	-318,014	-46,096	538,175	103,917
13								
14	TOTAL INCREASE IN RETURN & INC TAXES	7,131,546	699,817	33,250	-783,213	-113,526	1,325,432	255,930
15								
16	INCREASE IN REVENUE-RELATED	126,803	12,443	591	-13,926	-2,019	23,567	4,551
17								
18	OPERATING EXPENSES PER COSS	29,574,386	2,352,732	661,941	4,808,783	456,635	2,409,526	2,087,594
19	INCOME TAXES PER COSS	-715,851	-308,321	245,730	988,307	128,964	-234,699	-312,532
20	RETURN PER COSS	1,312,773	-207,968	444,613	1,714,533	221,614	-227,510	-251,445
21								
22	TOTAL REVENUE REQUIREMENT	37,429,657	2,548,703	1,386,125	6,714,483	691,670	3,296,316	1,784,098
23	LESS OTHER REVENUES	1,330,884	42,003	14,101	39,095	8,253	100,295	42,324
24	REVENUE REQUIREMENT FROM RATES	36,098,773	2,506,700	1,372,024	6,675,388	683,416	3,196,021	1,741,773
25								
26	PRESENT RATE REVENUES	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
27								
28	REVENUE INCREASE TO BASE RATES	7,258,349	712,260	33,841	-797,139	-115,544	1,348,999	260,480
29	PERCENT REVENUE INCREASE	25.17%	39.69%	2.53%	-10.67%	-14.46%	73.04%	17.58%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 2 UNIT COSTS AT TARGET RATE OF RETURN

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	BILLING DETERMINANTS								
1	*KWH SALES*	16,765,808,626	3,451,355,088	397,251,629	1,999,450,934	229,025,082	295,360,506	3,471,330,760	4,672,758,395
2									
3	*AVERAGE MONTH BILLING KW*								
4	*TRANSMISSION*		0	0	581,239	26,840	42,966	707,633	858,143
5	*PRIMARY*		0	0	581,215	25,626	42,966	689,517	58,956
6	*SECONDARY*		0	0	562,665	1,045	0	309,141	0
7									
8	*AVG. NO. OF CUSTOMERS*	464,651	398,826	41,349	11,571	11	1	933	13
9									
10	***UNIT COSTS***								
11			$/KWH	$/KWH	$/KW/MO.	$/KW/MO.	$/KW/MO.	$/KW/MO.	$/KW/MO.
12	*PRODUCTION FIXED*		$ 0.04575	$ 0.04551	$ 11.29	$ 12.06	$ 8.39	$ 12.53	$ 11.09
13									
14	*PRODUCTION VARIABLE*		$ 0.00507	$ 0.00575	$ 0.00542	$ 0.00458	$ 0.00507	$ 0.00505	$ 0.00470
15									
16	*TRANSMISSION*		$ 0.00808	$ 0.01083	$ 2.67	$ 3.53	$ 2.15	$ 3.07	$ 3.04
17									
18	*DISTRIBUTION*								
19	*PRIMARY*		$ 0.01464	$ 0.01549	$ 3.72	$ 6.01	$ 8.60	$ 4.01	$ 3.84
20	*SECONDARY*		$ 0.00843	$ 0.01611	$ 2.53	$ 3.02	$ -	$ 2.04	$ -
21									
22	*DISTRIBUTION TOTAL*		$ 0.02307	$ 0.03160	$ 6.24	$ 9.03	$ 8.60	$ 6.05	$ 3.84
23									
24	*TOTAL $/KWH*		$ 0.08197	$ 0.09369	$ 0.00542	$ 0.00458	$ 0.00507	$ 0.00505	$ 0.00470
25	*TOTAL $/KW (@ LOWEST SERV. LEVEL)*		$ -	$ -		$ 24.63	$ 19.14	$ 21.65	$ 17.98
26									
27	*CUSTOMER ($/CUSTOMER/MONTH)*								
28	*SERVICES*		$ 1.50	$ 2.46	$ 4.60	$ 1.09	$ -	$ 6.24	$ -
29	*METERS*		2.32	5.99	21.67	359.82	722.02	181.74	1,756.58
30	*STREET LIGHTING*		-	-	-	-	-	-	-
31	*METER READING*		1.17	1.33	3.78	291.53	327.93	310.60	305.67
32	*BILLING & COLLECTING*		4.02	4.69	4.42	4,424.19	2,884.91	63.97	5,338.79
33	*CUSTOMER ACCOUNTS OTHER*		0.04	0.04	0.04	0.04	0.04	0.04	0.04
34	*CUSTOMER INFORMATION*		0.05	0.42	1.11	303.17	0.01	40.57	3,021.55
35	*SALES EXPENSE*		0.66	0.74	0.70	0.66	0.73	0.69	0.68
36									
37	*CUSTOMER TOTAL*		$ 9.76	$ 15.68	$ 36.33	$ 5,380.50	$ 3,935.64	$ 603.85	$ 10,423.30

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 2 UNIT COSTS AT TARGET RATE OF RETURN

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Lighting	Rate 555 Traffic Lighting	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	BILLING DETERMINANTS							
1	*KWH SALES*	2,084,025,091	25,231,213	18,905,250	48,891,853	9,129,140	14,252,921	48,840,763
2								
3	*AVERAGE MONTH BILLING KW*							
4	*TRANSMISSION*	249,900	0	0	0	0	0	0
5	*PRIMARY*	0	0	0	0	0	0	0
6	*SECONDARY*	0	0	0	0	0	0	0
7								
8	*AVG. NO. OF CUSTOMERS*	5	644	1	1,725	143	9,429	0
9								
10	***UNIT COSTS***							
11		$/KW/MO.	$/KWH	$/KW/MO.	$/KWH	$/KWH	$/KWH	
12	*PRODUCTION FIXED*	$ 5.90	$ 0.01366	$ -	$ 0.00720	$ 0.02460	$ 0.00702	
13								
14	*PRODUCTION VARIABLE*	$ 0.00444	$ 0.00481	$ 0.00500	$ 0.00545	$ 0.00542	$ 0.00531	
15								
16	*TRANSMISSION*	$ 3.01	$ 0.00385	$ -	$ 0.00317	$ 0.00644	$ 0.00295	
17								
18	*DISTRIBUTION*							
19	*PRIMARY*	$ -	$ 0.04800	$ -	$ 0.01360	$ 0.00680	$ 0.01248	
20	*SECONDARY*	$ -	$ 0.02103	$ -	$ 0.00648	$ 0.00324	$ 0.00595	
21								
22	*DISTRIBUTION TOTAL*	$ -	$ 0.06903	$ -	$ 0.02008	$ 0.01004	$ 0.01842	
23								
24	*TOTAL $/KWH*	$ 0.00444	$ 0.09135	$ 0.00500	$ 0.03590	$ 0.04650	$ 0.03370	
25	*TOTAL $/KW (@ LOWEST SERV. LEVEL)*	$ 8.91	$ -	$ -	$ -	$ -	$ -	
26								
27	*CUSTOMER ($/CUSTOMER/MONTH)*							
28	*SERVICES*	$ -	$ 2.50	$ -	$ -	$ -	$ -	
29	*METERS*	1,632.54	15.98	-	-	-	-	
30	*STREET LIGHTING*	-	-	-	235.84	149.02	-	
31	*METER READING*	291.61	1.11	321.14	-	-	-	
32	*BILLING & COLLECTING*	4.01	3.81	40.24	1.09	1.09	1.06	
33	*CUSTOMER ACCOUNTS OTHER*	0.04	0.04	0.04	0.04	0.04	0.04	
34	*CUSTOMER INFORMATION*	0.01	2.05	0.01	0.01	0.01	0.01	
35	*SALES EXPENSE*	0.65	0.63	0.72	0.70	0.70	0.68	
36								
37	*CUSTOMER TOTAL*	**$ 1,928.86**	**$ 26.13**	**$ 362.15**	**$ 237.68**	**$ 150.87**	**$ 1.80**	

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 4.2
Page 2 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

NORTHERN INDIANA PUBLIC SERVICE COMPANY
SUMMARY OF PROPOSED RATE REVENUE PROOF

		Calculated Margin or Base Revenues with Rate Change		Calculated Margin or Base Revenue after Rate Change including Adjustment Factor
Step Two Proposed Rate 511 - Residential Service	$	330,785,551	$	329,584,800
Step Two Proposed Rate 521 - General Service Small	$	45,161,787	$	44,997,850
Step Two Proposed Rate 523 - General Service Medium	$	156,924,973	$	156,250,205
Step Two Proposed Rate 526 - Off-Peak Service	$	8,699,413	$	8,667,834
Step Two Proposed Rate 527 - Limited Production Large	$	11,451,859	$	11,410,288
Step Two Proposed Rate 533 - General Service Large	$	198,309,129	$	197,539,157
Step Two Proposed Rate 534 - Industrial Large Service	$	172,515,317	$	171,889,087
Step Two Proposed Rate 536 - Interruptible Industrial Service	$	36,229,421	$	36,097,908
Step Two Proposed Rate 541 - Water Pumping Service	$	2,515,935	$	2,506,802
Step Two Proposed Rate 544 - Railroad Power Service	$	1,377,279	$	1,372,280
Step Two Proposed Rate 550 - Traffic Lighting	$	6,675,388	$	6,658,342
Step Two Proposed Rate 555 - Street Lighting	$	683,416	$	683,604
Step Two Proposed Rate 560 - Dusk to Dawn Lighting	$	3,196,021	$	3,210,030
Interdepartmental	$	11,741,773	$	1,741,773
Totals	$	986,267,262	$	972,609,960
Target Margin			$	972,609,960
Over / Under			$	-

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 511 - Residential Service

		At Step One Proposed Earned Margin 1,2/				At Step Two Proposed Margin 1/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		4,813,076	$ 10.25	$ 49,334,029	$ 10.50	$ 50,537,298
2							
3	Energy Charge						
4	All kWh (Excl. Space Heating)		3,378,833,787	$ 0.074010	$ 250,067,489	$ 0.081700	$ 276,050,720
5	Space Heating 811 (Over 700 kWh)		57,265,740	$ 0.052720	$ 3,019,050	$ 0.057880	$ 3,314,541
6	Space Heating 812 & 813 (Over 700 kWh)		15,255,561	$ 0.052720	$ 804,273	$ 0.057880	$ 882,992
7							
8	Total Energy Weather Adjusted)		3,451,355,088		$ 253,890,812		$ 280,248,253
9							
10	Total Calculated Margin				$ 303,224,841		$ 330,785,551
11							
12	Adjustment Factor				0.996370		0.996370
13							
14	Total Adjusted Margin				$ 302,124,134		$ 329,584,800
15	Target Margin				$ 302,125,904		$ 329,585,709
16	Over / <Under>				$ (1,770)		$ (909)
17	Percent Incr./<Decr.> vs. 800 Series						17.53%
18	Percent Incr./<Decr.> vs. Step One 500 Series						9.79%
19							
20	1/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
21	2/ Existing margin under proposed step one rates						

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 521 - General Service Small

		At Step One Proposed Earned Margin 3,4/				At Step Two Proposed Margin 3/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		496,188	$ 12.55	$ 6,227,155	$ 12.55	$ 6,227,155
2							
3	Energy Charge						
4							
5	kWh	100.0%	397,251,629	$ 0.092830	$ 36,876,869	$ 0.098010	$ 38,934,632
6							
7	Total Energy Weather Adjusted)	100.0%	397,251,629		$ 36,876,869		$ 38,934,632
8							
9	Total Calculated Margin				$ 43,104,023		$ 45,161,787
10							
11	Adjustment Factor				0.996370		0.996370
12							
13	Total Adjusted Margin				$ 42,947,556		$ 44,997,850
14	Target Margin				$ 42,947,324		$ 44,999,660
15	Over / <Under>				$ 232		$ (1,811)
16	Percent Incr./<Decr.> vs. 800 Series						3.39%
17	Percent Incr./<Decr.> vs. Step One 500 Series						4.71%
18							

19 3/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
20 4/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 523 - General Service Medium

	(A)	At Step One Proposed Earned Margin 5,6/ Percent Distribution (B)	Pro forma Billing Determinants (Bills, kWh, kW) (C)	Rate (D)	"Margin" or Base Revenues (E)	At Step Two Proposed Margin 5/ Proposed Rate (F)	Proposed "Margin" or Base Revenues (G)
1	Customer Charge		138,859	$ 33.00	$ 4,582,336	$ 33.00	$ 4,582,336
2							
3	Demand Metered Customers						$ 4,582,336
4	Energy Charge						
5	kWh	100.0%	1,103,832,368	$ 0.005345	$ 5,899,984	$ 0.006031	$ 6,657,329
6	Thermal Storage kWh		2,957,137	$ 0.005345	$ 15,806	$ 0.006031	$ 17,835
7							
8	Sub-Total Energy	100.0%	1,106,789,505		$ 5,915,790		$ 6,675,164
9							
10	Demand Charge						
11	Transmission Service Level		3,102,086	$ 14.00	$ 43,413,693	$ 15.53	$ 48,187,772
12	Primary Service Level		3,102,086	$ 4.25	$ 13,191,621	$ 4.14	$ 12,840,868
13	Secondary Service Level		173,216	$ 2.89	$ 500,812	$ 2.82	$ 487,649
14	Thermal Storage kW		93,044	$ 21.14	$ 1,966,842	$ 22.49	$ 2,092,446
15							
16	Total Demand		3,102,086		$ 59,072,968		$ 63,608,735
17							
18	Non-Demand Metered Customers						
19	Energy Charge (all kWh)		892,661,429	$ 0.085513	$ 76,333,710	$ 0.091926	$ 82,058,739
20							
21	Total Energy		2,002,408,071		$ 82,249,500		$ 88,733,902
22							
23							
24	Total Calculated Margin				$ 145,904,805		$ 156,924,973
	Thermal Storage Discount				$ 99,132		$ 105,514
	Total Revenue less Thermal Storage				$ 145,805,672		$ 156,819,459
25							
26	Adjustment Factor				0.996370		0.996370
27							
28	Total Adjusted Margin				$ 145,276,398		$ 156,250,205
29	Target Margin				$ 145,284,153		$ 156,249,361
30	Over / <Under>				$ (7,755)		$ 844
31	Percent Incr./<Decr.> vs. 800 Series						6.92%
32	Percent Incr./<Decr.> vs. Step One 500 Series						7.50%
33							

34 5/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
35 6/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 526 - Off-Peak Service

		At Step One Proposed Earned Margin 7,8/				At Step Two Proposed Margin 7/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		132	$ 5,500.00	$ 726,000	$ 5,550.00	$ 732,600
2							
3	Energy Charge						
5	All kWh	100.0%	229,025,082	$ 0.004010	$ 918,391	$ 0.0045800	$ 1,048,935
6							
7	Total Energy Weather Adjusted)	100.0%	229,025,082		$ 918,391		$ 1,048,935
8							
9	Demand Charge						
10	Transmission Service Level		322,085	$ 13.76	$ 4,431,883	$ 15.60	$ 5,024,518
11	Primary Service Level		307,510	$ 5.83	$ 1,792,784	$ 6.01	$ 1,848,136
12	Secondary Service Level		12,542	$ 2.90	$ 36,406	$ 3.02	$ 37,874
14	**Power Factor Correction Charge**						
15	Transmission Customers		0	$ 1.60	$ -	$ 1.60	$ -
16	Primary & Secondary Customers		18,373	$ 0.40	$ 7,349	$ 0.40	$ 7,349
17	Transmission Metering Credit		-	$ -	-	$ -	-
18	Primary Metering Credit		-	$ -	-	$ -	-
19							
20	Total Demand		322,085		$ 6,268,422		$ 6,917,878
21							
22	Total Calculated Margin				$ 7,912,813		$ 8,699,413
23							
24	Adjustment Factor				0.996370		0.996370
25							
26	Total Adjusted Margin				$ 7,884,089		$ 8,667,834
27	Target Margin				$ 7,882,638		$ 8,669,442
28	Over / <Under>				$ 1,451		$ (1,609)
29	Percent Incr./<Decr.> vs. 800 Series						21.47%
30	Percent Incr./<Decr.> vs. Step One 500 Series						11.03%
31							

32 7/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
33 8/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 527 - Limited Production Large

		At Step One Proposed Earned Margin 9,10/					At Step Two Proposed Margin 9/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		12	$ 3,525.00	$ 42,300	$ 3,525.00	$ 42,300
2							
3	Energy Charge						
4							
5	kWh	100.0%	295,360,506	$ 0.00351	$ 1,036,715	$ 0.00401	$ 1,184,396
6							
7	Total Energy	100.0%	295,360,506		$ 1,036,715		$ 1,184,396
8							
9	Demand Charge						
10	Transmission Service Level		515,592	$ 9.39	$ 4,841,409	$ 10.57	$ 5,449,807
11	Primary Service Level		515,592	$ 8.80	$ 4,537,210	$ 8.60	$ 4,434,091
12	Secondary Service Level		-	$ -	$ -	$ -	$ -
13	**Power Factor Correction Charge**						
14	Transmission Customers		0	$ -	$ -	$ -	$ -
15	Primary & Secondary Customers		568,774	$ 0.60	$ 341,264	$ 0.60	$ 341,264
16	Transmission Metering Credit		515,592	$ -	-	$ -	-
17	Primary Metering Credit		-	$ -	-	$ -	-
18							
19	Total Demand		515,592		$ 9,719,883		$ 10,225,163
20							
21	Total Calculated Margin				$ 10,798,898		$ 11,451,859
22							
23	Adjustment Factor				0.996370		0.996370
24							
25	Total Adjusted Margin				$ 10,759,698		$ 11,410,288
26	Target Margin				$ 10,777,965		$ 11,412,105
27	Over / <Under>				$ (18,267)		$ (1,817)
28	Percent Incr./<Decr.> vs. 800 Series						5.88%
29	Percent Incr./<Decr.> vs. Step One 500 Series						5.88%
30							
31	9/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
32	10/ Existing margin under proposed step one rates						

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 533 - General Service Large

	(A)	At Step One Proposed Earned Margin 11,12/ Percent Distribution (B)	Pro forma Billing Determinants (Bills, kWh, kW) (C)	Rate (D)	"Margin" or Base Revenues (E)	At Step Two Proposed Margin 11/ Proposed Rate (F)	Proposed "Margin" or Base Revenues (G)
1	Customer Charge		11,327	$ 580.00	$ 6,569,937	$ 580.00	$ 6,569,937
2							
3	Energy Charge						
4	Thermal Storage kWh		12,255,201	$ 0.004484	$ 54,952	$ 0.005033	$ 61,678
5	kWh	100.0%	3,459,075,559	$ 0.004484	$ 15,510,282	$ 0.005033	$ 17,408,936
6							
7	Total Energy Weather Adjusted)	100.0%	3,471,330,760		$ 15,565,234		$ 17,470,614
8							
9	Demand Charge						
10	Transmission Service Level		8,491,593	$ 13.89	$ 117,958,602	$ 15.59	$ 132,365,543
11	Primary Service Level		8,274,198	$ 4.04	$ 33,465,263	$ 4.00	$ 33,132,419
12	Secondary Service Level		3,709,696	$ 2.06	$ 7,641,973	$ 2.04	$ 7,567,779
	Thermal Storage kW		43,646	20.00	$ 872,742	21.63	$ 944,164
13	**Power Factor Correction Charge**						
14	Transmission Customers		24,952	$ 1.14	$ 28,445	$ 1.14	$ 28,445
15	Primary & Secondary Customers		383,711	$ 0.60	$ 230,227	$ 0.60	$ 230,227
16	Transmission Metering Credit		-	$ -	-	$ -	-
17	Primary Metering Credit		-	$ -	-	$ -	-
18							
19	Total Demand		8,491,593		$ 160,197,251		$ 174,268,577
20							
21	Total Calculated Margin				$ 182,332,422		$ 198,309,129
	Thermal Storage Discount				$ 46,385		$ 50,292
	Total Revenue less Thermal Storage				$ 182,286,038		$ 198,258,837
22							
23	Adjustment Factor				0.996370		0.996370
24							
25	Total Adjusted Margin				$ 181,624,339		$ 197,539,157
26	Target Margin				$ 181,625,941		$ 197,538,414
27	Over / <Under>				$ (1,601)		$ 743
28	Percent Incr./<Decr.> vs. 800 Series						8.39%
29	Percent Incr./<Decr.> vs. Step One 500 Series						8.73%
30							

31 11/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
32 12/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 534 - Industrial Large Service

		At Step One Proposed Earned Margin 13,14/				At Step Two Proposed Margin 13/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		152	$ 10,200.00	$ 1,552,087	$ 10,200.00	$ 1,552,087
2							
3	Energy Charge						
4							
5	kWh	100.0%	4,672,758,395	$ 0.003620	$ 16,915,385	$ 0.004090	$ 19,111,582
6							
7	Total Energy	100.0%	4,672,758,395		$ 16,915,385		$ 19,111,582
8							
9	Demand Charge						
10	Transmission Service Level		10,297,716	$ 12.60	$ 129,751,222	$ 14.16	$ 145,815,659
11	Primary Service Level		707,472	$ 3.94	$ 2,787,440	$ 3.86	$ 2,730,842
12	Secondary Service Level		-	$ -	-	$ -	-
13	**Power Factor Correction Charge**						
14	Transmission Customers		2,004,572	$ 1.60	$ 3,207,316	$ 1.60	$ 3,207,316
15	Primary & Secondary Customers		244,580	$ 0.40	$ 97,832	$ 0.40	$ 97,832
16	Transmission Metering Credit		-	$ -	-	$ -	-
17	Primary Metering Credit		-	$ -	-	$ -	-
18							
19	Total Demand		10,297,716		$ 135,843,809		$ 151,851,648
20							
21	Total Calculated Margin				$ 154,311,282		$ 172,515,317
22							
23	Adjustment Factor				0.996370		0.996370
24							
25	Total Adjusted Margin				$ 153,751,132		$ 171,889,087
26	Target Margin				$ 153,748,962		$ 171,890,847
27	Over / <Under>				$ 2,169		$ (1,760)
28	Percent Incr./<Decr.> vs. 800 Series						11.55%
29	Percent Incr./<Decr.> vs. Step One 500 Series						11.77%
30							

31 13/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
32 14/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 536 - Interruptible Industrial Service

		At Step One Proposed Earned Margin 15,16/				At Step Two Proposed Margin 15/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		60	$ 2,200.00	$ 132,000	$ 2,200.00	$ 132,000
2							
3	Energy Charge						
4							
5	kWh	100.0%	2,084,025,091	$ 0.003920	$ 8,169,378	$ 0.004500	$ 9,378,113
6							
7	Total Energy Weather Adjusted)	100.0%	2,084,025,091		$ 8,169,378		$ 9,378,113
8							
9	Demand Charge						
10	Transmission Service Level		2,998,800	$ 7.89	$ 23,660,532	$ 8.91	$ 26,719,308
11							
12	Total Demand		2,998,800		$ 23,660,532		$ 26,719,308
13							
14	Total Calculated Margin				$ 31,961,910		$ 36,229,421
15							
16	Adjustment Factor				0.996370		0.996370
17							
18	Total Adjusted Margin				$ 31,845,889		$ 36,097,908
19	Target Margin				$ 31,846,881		$ 36,098,773
20	Over / <Under>				$ (993)		$ (865)
21	Percent Incr./<Decr.> vs. 800 Series						25.17%
22	Percent Incr./<Decr.> vs. Step One 500 Series						14.75%
23							

24 15/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
25 16/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 541 - Water Pumping Service

		At Step One Proposed Earned Margin 17,18/					At Step Two Proposed Margin 17/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		7,728	$ 35.00	$ 270,480	$ 35.00	$ 270,480
2	Customer Charge (non metered)		60	$ 45.00	$ 2,700	$ 45.00	$ 2,700
3							
4	Energy Charge						
	Residential Pumps		953	$ 2.48	$ 2,363	$ 2.23	$ 2,125
5	Commercial Pumps		38	$ 2.88	$ 109	$ 2.59	$ 98
6	kWh	100.0%	25,231,213	$ 0.085430	$ 2,155,502	$ 0.088800	$ 2,240,532
7							
8	Total Energy Weather Adjusted)	100.0%	25,231,213		$ 2,157,975		$ 2,242,755
9							
10	Demand Charge						
11	Transmission Service Level		105,695	$ -	-	$ -	-
12	Primary Service Level		105,695	$ -	-	$ -	-
13	Secondary Service Level		81,354	$ -	-	$ -	-
14							
15	Total Demand		105,695		$ -		$ -
16							
17	Total Calculated Margin				$ 2,431,155		$ 2,515,935
18							
19	Adjustment Factor				0.996370		0.996370
20							
21	Total Adjusted Margin				$ 2,422,330		$ 2,506,802
22	Target Margin				$ 2,419,350		$ 2,506,700
23	Over / <Under>				$ 2,980		$ 102
24	Percent Incr./<Decr.> vs. 800 Series						39.69%
25	Percent Incr./<Decr.> vs. Step One 500 Series						4.87%
26							

27 17/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
28 18/ Existing margin under proposed step one rates

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP TWO REVENUE PROOF - PROPOSED RATES

Proposed Rate 544 - Railroad Power Service

		At Step One Proposed Earned Margin 19,20/				At Step Two Proposed Margin 19/	
		Percent Distribution	Pro forma Billing Determinants (Bills, kWh, kW)	Rate	"Margin" or Base Revenues	Proposed Rate	Proposed "Margin" or Base Revenues
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Customer Charge		12	$ 345.00	$ 4,140	$ 345.00	$ 4,140
2							
3	Energy Charge						
4							
5	kWh	100.0%	18,905,250	$ 0.004789	90,528	$ 0.007303	138,072
6							
7	Total Energy Weather Adjusted)	100.0%	18,905,250		$ 90,528		$ 138,072
8							
9	Demand Charge						
10	Transmission Service Level		79,171	$ 8.00	633,368	$ 8.00	633,368
11	Primary Service Level		79,171	$ 4.40	348,352	$ 4.40	348,352
12	Secondary Service Level		79,171	$ 3.20	253,347	$ 3.20	253,347
13							
14	Total Demand		79,171		$ 1,235,068		$ 1,235,068
15							
16	Total Calculated Margin				$ 1,329,735		$ 1,377,279
17							
18	Adjustment Factor				0.996370		0.996370
19							
20	Total Adjusted Margin				$ 1,324,908		$ 1,372,280
21	Target Margin				$ 1,326,638		$ 1,372,024
22	Over / <Under>				$ (1,730)		$ 256
23	Percent Incr./<Decr.> vs. 800 Series						2.53%
24	Percent Incr./<Decr.> vs. Step One 500 Series						3.39%
25							
26	19/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
27	20/ Existing margin under proposed step one rates						

Petitioner's Exhibit CAW-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

CURT A. WESTERHAUSEN

MANAGER OF RATES AND CONTRACTS

SPONSORING PETITIONER'S EXHIBITS CAW-2 THROUGH CAW-4

VERIFIED DIRECT TESTIMONY OF CURT A. WESTERHAUSEN

Q1. Please state your name and business address.

A1. My name is Curt A. Westerhausen. My business address is 801 E. 86th Avenue, Merrillville, Indiana, 46410.

Q2. By whom are you employed and in what capacity?

A2. I am employed by NiSource Corporate Services ("NCS"), which is a subsidiary of NiSource Inc. ("NiSource"). My current position is Manager of Rates and Contracts in the Rates and Regulatory Finance Department for the Northern Indiana Energy business unit, which is comprised of Northern Indiana Public Service Company ("NIPSCO" or the "Company"), Northern Indiana Fuel & Light Company, Inc, and Kokomo Gas and Fuel Company, all of which are subsidiaries of NiSource. I am submitting this testimony on behalf of NIPSCO.

Q3. What is your educational background?

A3. I received a Bachelor of Science degree in Electrical Engineering from Valparaiso University and a Masters of Business Administration from Indiana University. I am also a Licensed Professional Engineer in the State of Indiana.

Q4. Please describe your professional experience.

A4. I began my employment with NIPSCO in 1978 in the Plant Engineering Department. Since joining NIPSCO, I have held various engineering positions in the Plant Engineering, Plant Construction and the Power Engineering Departments. Since 2000, I

have been a Principal in the Competitive and Regulatory Development Department, Lead Regulatory Analyst in the Rates Department and Manager of Commercial and Industrial Products of NiSource.

Q5. What are your current duties as they relate to NIPSCO?

A5. The Rates and Contracts group is responsible for rates and contract administration for all of NIPSCO's electric and gas rate, rules and contract filings with the Indiana Utility Regulatory Commission ("IURC" or "Commission"). My responsibilities also include the interpretation, application and administration of NIPSCO's rates, rules and regulations, terms and conditions of service and tariffs filed with the IURC for retail electric service. I am also responsible for recommending tariff revisions, preparing and coordinating filings with regulatory agencies, implementing and complying with state and federal regulatory orders and assisting in the interpretation and implementation of state and federal regulatory requirements regarding utilities.

Q6. Have you previously testified before this or any other regulatory commission?

A6. Yes, most recently in NIPSCO's Cause No. 42150-ECR-11 proceeding.

Q7. What is the purpose of your direct testimony?

A7. The purpose of my direct testimony is to describe NIPSCO's proposed Tariff, including the Schedules of Rates ("Rates"), Riders and General Rules and Regulations ("Rules"). I also explain how the proposed Tariff differs from NIPSCO's current Tariff.

Q8. Are you sponsoring any exhibits?

A8. Yes, I am sponsoring Petitioner's Exhibit CAW-2, which is the Northern Indiana Public Service Company, IURC Electric Service Tariff, Original Volume No. 11 ("Tariff"); Petitioner's Exhibit CAW-3, which is a matrix summarizing the Rates; and Petitioner's Exhibit CAW-4, which contains the Rates for Step Two.

Q9. Please provide a general background on NIPSCO's current electric rates.

A9. NIPSCO's current electric Tariff was developed from NIPSCO's last base rate case dating back to the mid-1980's. In the ensuing years, a number of additional tariff changes, as well as adjustments and updates to existing Rates have been made. In addition, NIPSCO entered into contracts with certain individual customers. The Tariff and contracts in existence today were based on the demographics and energy needs within NIPSCO's service territory over the past twenty years. NIPSCO's residential basic rates have remained constant for more than twenty years.

Q10. What are the advantages of developing new electric Rates?

A10. The development of a new electric rate structure will provide customers with a simplified structured approach. This approach was used in all phases of the ratemaking process in order to reflect current conditions and with an eye toward future changes.

Q11. Please summarize the Company's objectives in developing NIPSCO's proposed electric Rates.

A11. As discussed by NIPSCO Witness Frank A. Shambo, NIPSCO has three main objectives in the development of a new rate structure. First, rates should be constructed so that the charge for services is reasonable and just. Mr. Shambo further discusses this objective. Second, clarification, simplification and standardization of the Tariff including the Rules was necessary to improve the ease of use and understanding by our customers of the Company's services and associated charges. Third, NIPSCO wanted to design rates to meet the needs of our customers, as well as to be responsive to changing environmental conditions and the need for energy conservation. Mr. Shambo further elaborates on NIPSCO's approach to rate design. In addition, the rate design developed by NIPSCO Witness Robert D. Greneman has been incorporated comprehensively into the Tariff.

Q12. Regarding the Company's rate design objectives stated above, how does NIPSCO's proposed electric rate structure clarify, simplify and standardize the Tariff?

A12. As part of the redesign of rates, NIPSCO reduced the overall number of Rates. For example, there are currently 42 Rates, 23 of which are lighting-related. Our proposed Tariff has been reduced to 13 Rates, three of which are lighting-related.

In NIPSCO's current rate structure, many of the terms and conditions are repeated in each individual Rate. This duplication of language for common items has been removed from the individual Rates and now appears in NIPSCO's proposed Riders section. This results in descriptions of each Rate that are more concise, consistent and easier to understand. All Rates will have applicable Riders and a uniform set of Rules, which are discussed further below. In addition, in consideration of customer feedback received

over the years regarding the existing Tariff, many of NIPSCO's Rates have been updated to provide a clearer understanding and meaning as to intent, interpretation and applicability of the specific Rule being addressed. We have also added a definitions section in the Rules to define terms utilized throughout the Tariff.

Complementing the simplification and clarification theme used in the development of NIPSCO's proposed Tariff, similar attempts were made to standardize terms used in NIPSCO's Tariff. For example, the Power Factor Charge, which varies by Rate and methodology throughout the existing electric Rates, has been standardized in the proposed Tariff. The result is a uniform metric in determining the normal leading and lagging power factor and the billing adjustments associated therewith across all affected Rates. In addition, similar language was standardized throughout the Rates or relocated to the Rules. Where possible, common terms for billing determinants were used to facilitate an understanding of the nature and terms of energy service.

In the many Rate classes in the current Tariff, the customer is billed for energy via a declining block pricing mechanism. This means that the per unit price declines as higher levels of energy are consumed, discouraging energy conservation. NIPSCO has eliminated this declining block rate structure, as Mr. Shambo explains further.

1 **Q13. Please summarize the convention used to distinguish NIPSCO's proposed electric**
2 **Rates.**
3 A13. NIPSCO's proposed electric Rates will replace the current eight hundred series of Rates
4 ("800 Series") with a five hundred series of Rates ("500 Series"). As described earlier,
5 the new 500 Series clarify, simplify and standardize Rates as well as promote energy
6 conservation.

7 **Q14. Please describe NIPSCO's proposed electric Rates.**
8 A14. NIPSCO's proposed electric Rates are summarized below. Petitioner's Exhibit CAW-3
9 summarizes the charges, terms, and applicable Riders for each Rate. These summaries
10 are provided in general terms only and specific details, terms and conditions, rules, etc.,
11 applicable to each Rate are contained in Petitioner's Exhibit CAW-2.

12 **Rate 511 – Rate for Electric Service, Residential**

13 NIPSCO previously had three residential Rates in the 800 Series and has created one
14 residential Rate in the 500 Series available to residential and farm customers. Residential
15 electric heating, including electric heat pumps, will be covered by Rider 575 "Electric
16 Spaceheating Rider to Residential Service."

17 **Rates 521 and 523 – Rates for Electric Service, General Service ("GS") Small (521)**
18 **and Medium (523)**

19 NIPSCO proposes the following GS rates: Rate 521 – GS Small ("GSS"), and Rate 523
20 – GS Medium ("GSM"). GSS is an energy only rate and is available to customers with a
21 rolling twelve month average energy consumption less than 5,000 kilowatt hours

("kWh") per month. GSM is a demand and energy metered rate and is available to customers with demand greater than 10 kilowatts ("kW") but less than 300 kW. NIPSCO Witness Timothy A. Dehring describes the Company's efforts to ensure that all GSM customers will have appropriately installed demand meters. A transitional energy only rate will be used to bill these customers during the interim period.

Rate 526 – Rate for Electric Service, Off-Peak Service ("OPS")

Customers that have demands greater than 300 kW can benefit by shifting their demand from on-peak to off-peak periods by utilizing NIPSCO's proposed OPS. The customer's billing demands are based on the greater of 100% on-peak demand within the last 12 months up, to and including the current month or 50% off-peak demand within the last 24 months, up to and including the current month. A three-year contract is required for service under OPS.

Rate 527 – Rate for Electric Service, Limited Production Large ("LPL")

LPL offers a Rate to customers that have the ability to creatively manage their production in both an on- and off-peak and days-of-the-week fashion. This Rate is available to customers with demands greater than 20,000 kW and the flexibility to utilize the system predominately in the off-peak. The energy used during non-production hours must be less than 2.5% of the energy used during production hours. If a customer defaults on this condition, the customer will be moved to an appropriate rate. A three-year contract is required for service under LPL.

1 **Rate 533 – Rate for Electric Service, General Service Large ("GSL")**

2 GSL is for customers with demands between 300 kW and 10,000 kW. All customers
3 taking service under GSL will be required to have Indicating Demand Recording ("IDR")
4 meters. This is a seasonal rate where all hours outside of the four summer months (June
5 through September) are considered off-peak for demand billing purposes. A customer's
6 monthly billing demand will be based on the higher of 90% of the highest demand during
7 the summer on-peak period within the last 24 months up to and including the current
8 month or 80% of the highest demand at any other time within the last 24 months up to
9 and including the current month.

10 **Rate 534 – Rate for Electric Service, Industrial Service Large ("ISL")**

11 ISL is for customers with demands greater than 10,000 kW. This is also a seasonal rate
12 where all hours outside of the four summer months (June through September) are
13 considered off-peak for demand billing purposes. A three-year contract is required for
14 service under ISL. A customer's monthly billing demand will be based on the higher of
15 90% of the highest demand during the summer on-peak period within the last 24 months
16 up to and including the current month or 80% of the highest demand at any other time
17 within the last 24 months up to and including the current month or 80% of the contract
18 demand.

1 **Rate 536 – Rate for Electric Service, Interruptible Industrial Service ("IIS")**

2 IIS is for Customers who have the ability to interrupt and/or curtail electric demand with
3 10 minute notice. Interruptions will be done on an economic basis while curtailment will
4 be done in regard to bulk electric system reliability. A customer may continue to receive
5 service upon being interrupted, but will be billed at the Midwest ISO Locational Marginal
6 Price ("LMP") at the NIPSCO load node. A three-year contract is required for service
7 under IIS. A customer's monthly billing demand will be based on the contract demand.

8 **Rate 541 – Rate for Electric Service, Water Pumping ("WP")**

9 WP is available on a metered basis to Municipalities, the Indiana Department of Natural
10 Resources, Corporations or Persons operating under an exclusive franchise in furnishing
11 water service at retail, and on an unmetered basis to applicable residential and small
12 commercial customers pumping sewage water and waste. Energy consumption on the
13 non-metered pumps is estimated for the purposes of allocating applicable Riders.

14 **Rate 544 – Rate for Electric Service, Railroad Power Service ("RR")**

15 RR is available only to existing railroads or to a non-profit commuter transportation
16 district operating said railroads. Electricity will be supplied for the operation of trains on
17 a continuous electrified right-of-way of the customer.

18 **Rate 550 – Rate for Electric Service, Street Lighting ("SL")**

19 SL is available for street, highway and billboard lighting service. Twenty separate
20 lighting rates from the 800 Series are combined into SL. Billing is based upon type,

ownership and responsible maintaining party of the lighting fixture. New to SL is the applicability of various Riders to pre-allocated amounts of electric usage based on specific light fixture sizes and types. Also new to SL is the elimination of the geographic-specific billing metric.

Rate 555 – Rate for Electric Service, Traffic and Directive Lighting ("TDL")

TDL will be closely related to existing Rate 895, Traffic and Directive Lighting of the 800 Series and will remain applicable to traffic, directive, and similar lighting.

Rate 560 – Rate for Electric Service, Dusk to Dawn Area Lighting ("DDAL")

DDAL is similar to SL. Customers taking service under DDAL will be billed based on estimated energy usage by type of fixture. Also, DDAL will be subject to the same various Riders as SL. A one-year contract is required for service under DDAL.

Q15. Does this complete the general description of NIPSCO's proposed electric Rates?

A15. Yes.

Q16. Please describe NIPSCO's proposed Riders.

A16. NIPSCO's proposed Riders are summarized below. As described earlier, the proposed Riders apply to specific Rates. This summary is provided in general terms only and the actual specific details, terms and conditions, rules, etc., applicable to each Rider are listed in Petitioner's Exhibit CAW-2.

Rider 570 – Adjustment of Charges for Cost of Fuel Rider ("FAC")

The cost of fuel has been removed from base rates and will be recovered fully via the FAC mechanism. The cost of purchased power has been removed and will be recovered via the Reliability Adjustment. Mr. Shambo and NIPSCO Witness Curtis A. Crum discuss these proposals more fully.

Rider 571 – Reliability Adjustment ("RA")

The RA is a new mechanism proposed to be utilized to recover all non-FAC Midwest ISO charges and credits, all purchased power costs, including capacity and to share off-system sales margins with customers. Messrs. Shambo and Crum, and NIPSCO Witness Linda E. Miller discuss the RA in greater detail.

Rider 572 – Environmental Cost Recovery Mechanism ("ECRM")

The ECRM is applicable to various Rates and will be updated semi-annually. The ECRM will reflect updated production allocators from Mr. Greneman's Cost of Service Study. NIPSCO Witness Philip W. Pack and Ms. Miller further describe the ECRM and proposed changes to its scope.

Rider 573 – Environmental Expense Recovery Mechanism ("EERM")

The EERM is applicable to various Rates, is currently filed annually and will reflect both the updated production and energy allocators from Mr. Greneman's cost of service study. The new filing period for the proposed EERM will be on a semi-annual period concurrent

with the ECRM. Mr. Pack and Ms. Miller further describe the EERM and proposed changes to its scope.

Rider 574 – Adjustment of Charges for Power Factor ("PF")

The PF Rider is applicable to on-peak demands in the proposed electric Rates and incents the customer's efficient use of service. The 800 Series rates had four separate metrics for determining power factor charges. The proposed 500 Series Rider standardizes these different calculations into a single method. Mr. Greneman discusses the new power factor adjustment calculation in greater detail.

Rider 575 – Electric Spaceheating Rider to Residential Service ("ES")

ES is applicable to Residential Customers that currently have permanently installed electric space heating or electric heat pumps. Rider ES offers a reduced charge for monthly energy consumption over 700 kWh during the months from October through April.

Rider 576 – Thermal Storage Rider (TS)

Rider TS is applicable to current customers with thermal storage equipment capable of meeting 40% of the total btu requirements for their air-conditioned space during the on-peak daily demand. The discount has been modified from a discount of off-peak energy and demand to a straight 5% discount of the non-fuel portion of the customer's bill.

1 **Rider 577 – Purchases From Cogeneration and Small Power Production Facilities**

2 Rider 577 is available to a Qualifying Facility, as defined in the Rules. A contract is
3 required between the Company and each Qualifying Facility, setting forth all terms and
4 conditions governing the purchase of electric power. Availability of back-up and
5 maintenance power is also addressed in Rider 577.

6 **Rider 578 – Interconnection Standards**

7 Rider 578 is provided in accordance with the applicable standards, rules and regulations
8 of the Commission's Rules as specified in the Indiana Administrative Code.

9 **Rider 579 – Net Metering**

10 Similar to Rider 578, Rider 579 is provided in accordance with the applicable standards,
11 rules and regulations of the Commission's Rules as specified in the Indiana
12 Administrative Code.

13 **Rider 580 – Economic Development Rider ("EDR")**

14 The EDR is available to non-residential Customers upon demonstrating the fulfillment of
15 certain new production, increased load and other economic-related characteristics that
16 would otherwise have not occurred absent the availability of this EDR. Mr. Shambo
17 further discusses the EDR.

1 **Q17. Does this complete the general description of NIPSCO's proposed new electric**
2 **Riders?**
3 A17. Yes.

4 **Q18. Please summarize the development strategy used in NIPSCO's proposed Rules.**
5 A18. As mentioned earlier, the Rules are applicable to the Rates and Riders previously
6 described. The Rules clarify, simplify, and standardize the overall rules and subject
7 matter as contained therein.

8 **Q19. Please summarize the significant changes from the current Rules to NIPSCO's**
9 **proposed Rules.**
10 A19. NIPSCO's proposed Rules are summarized below. This summary is provided in general
11 terms only and the actual specific details, terms and conditions, rules, regulations,
12 subject, etc., applicable to the Rules are listed in Petitioner's Exhibit CAW-2. Rule 14
13 (Miscellaneous and Non-reoccurring Charges) reflects an increase in the charges for
14 reconnection service based on the Company's analysis of actual costs incurred to perform
15 such services. This is further described below and the details of this analysis can be
16 found in the workpapers to be filed in this proceeding. No other charges within
17 NIPSCO's proposed Rules have changed.

18 **Rule 1 – Definitions**

19 The definition section in Rule 1 is new and is intended to assist customers in fully
20 understanding the terms used in the proposed Rates, Riders and Rules. It also contains

1 the definitions of the new seasonal On-Peak and Off-Peak Hours that are utilized in the
2 proposed Rates and Riders, which are discussed further by Mr. Shambo.

3 **Rule 2 – Rates, Rules and Regulations**

4 The proposed Rule 2 revises current Rule 1 to clarify that if there are conflicts with the
5 language between Contracts, Rates, Riders and Rules, which will prevail.

6 **Rule 3 – Character of Service**

7 Rule 3.1 is a new rule to clarify the standard Company installations to provide service.
8 Rule 3.2 revises current Rule 37 to reflect the proposed change of defining 34 kV as a
9 primary service voltage pursuant to the FERC Seven-Factor Study as discussed by Mr.
10 Greneman.

11 **Rule 4 – Application, Service Request or Contract**

12 The proposed Rule 4 is a combination of current Rules 2, 3 and 21. There were no
13 significant changes made to these rules.

14 **Rule 5 – Prediction of Rate Schedule Selection**

15 The proposed Rule 5 is a combination of current Rules 10, 11 and 12. There were no
16 significant changes made to these rules.

17 **Rule 6 – Service Extensions and Modification**

18 The proposed Rule 6 is a combination of current Rules 22, 30, 33, 41 and 42. This new
19 rule includes the proposed modifications to NIPSCO's method of determining the amount

1 of contributions and guaranteed minimums required from customers when NIPSCO
2 extends basic service facilities to provide standard electric service. These proposed
3 modifications will also be used to determine the amount of advances required to be paid
4 by builders and developers prior to their sites receiving service. This proposed Rule is
5 further discussed by Mr. Shambo.

6 **Rule 7 – Customer Installation**

7 The proposed Rule 7 is a combination of current Rules 23 and 32. There were no
8 significant changes to these rules.

9 **Rule 8 – Company Equipment on Customer's Premises**

10 The proposed Rule 8 is a combination of current Rules 4, 5, 17, 24, 28 and 36. There
11 were no significant changes to these rules.

12 **Rule 9 – Metering**

13 The proposed Rule 9 is a combination of current Rules 16, 25 and 26. Rule 9.4 was
14 added for additional clarification.

15 **Rule 10 – Customer Service Deposits**

16 The proposed Rule 10 is a combination of current Rules 9A and 9B. There were no
17 significant changes to these rules.

1 **Rule 11 – Rendering and Payments of Bills**

2 The proposed Rule 11 is a combination of current Rules 6A, 6B and 7. The Senior
3 Citizen Payment Plan has been expanded to include the legally disabled and people
4 receiving social security benefits and is now the Senior Citizen and Disability Payment
5 Plan. If the customer meets the criteria, their due date can be extended up to ten calendar
6 days.

7 **Rule 12 – Disconnection and Reconnection of Service**

8 The proposed Rule 12 is a combination of current Rules 8, 15 and 19. There were no
9 significant changes to these rules.

10 **Rule 13 – Service Interruptions and Curtailments**

11 The proposed Rule 13 is a combination of current Rules 34 and 35. This rule has been
12 modified to incorporate the changes to our Curtailment and Interruption procedures as a
13 result of being a member of the Midwest ISO, which is discussed in more detail by Mr.
14 Crum.

15 **Rule 14 – Miscellaneous and Non-reoccurring Charges**

16 The proposed Rule 14 includes (1) reconnection fees and (2) a charge to reimburse the
17 Company for non-sufficient and returned payment fees. Reconnection fees are calculated
18 to cover the cost of reconnection of service and vary depending on when the service is
19 provided (during normal working hours, after normal working hours or holidays), as well
20 as whether the reconnection is done at the meter or at the pole. The distinction between

where the reconnection is done is an expansion of the existing rule. The current rule also changes the former non-sufficient funds fees to encompass both paper and electronic payment transactions.

Q20. Does this complete the general description of NIPSCO's proposed Rules?

A20. Yes.

Q21. Are there any other exhibits that you are sponsoring?

A21. Yes. I have prepared Petitioner's Exhibit CAW-4, which summarizes the proposed charges that will apply to each Rate reflecting the Step Two changes. NIPSCO is not proposing any other modifications to the Rates as a result of Step Two.

Q22. Please summarize your testimony.

A22. I have presented and explained NIPSCO's proposed new Tariff, including its Rates, Riders and Rules applicable to its electric service. In addition, I described the Company's goal to improve ease of use for our customers through the simplification and clarification of NIPSCO's Tariff.

Q23. Does this conclude your prepared direct testimony?

A23. Yes, it does.

VERIFICATION

I, Curt A. Westerhausen, Manager Rates and Contracts for NiSource Corporate Services, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Curt A. Westerhausen

Date: August 29, 2008

INDS01 1062883v1

Petitioner's Exhibit CAW-2
Northern Indiana Public Service Company
Cause No. 43526

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC ELECTRIC SERVICE TARIFF

ORIGINAL VOLUME NO. 11

SCHEDULE OF RATES APPLICABLE TO ELECTRIC SERVICE

IN

CITIES, TOWNS AND UNINCORPORATED COMMUNITIES

TABLE OF CONTENTS

Rate/Rider	Code	Description	Sheet Nos.
		Index of Cities, Towns and Unincorporated Communities Furnished Electric Service	3, 4
		General Rules and Regulations Applicable to Electric Service	5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36
Rate 511	RS	Residential	37
Rate 521	GSS	General Service Small	38, 39
Rate 523	GSM	General Service Medium	40, 41, 42
Rate 526	OPS	Off-Peak Service	43, 44, 45
Rate 527	LPL	Limited Production Large	46, 47, 48, 49
Rate 533	GSL	General Service Large	50, 51, 52
Rate 534	ISL	Industrial Service Large	53, 54, 55, 56
Rate 536	IIS	Interruptible Industrial Service	57, 58, 59, 60
Rate 541	WP	Water Pumping	61, 62, 63, 64
Rate 544	RR	Railroad Power Service	65, 66
Rate 550	SL	Street Lighting	67, 68, 69, 70, 71, 72, 73
Rate 555	TDL	Traffic and Directive Lighting	74
Rate 560	DDAL	Dusk to Dawn Area Lighting	75, 76, 77, 78
Rider 570	FAC	Adjustment of Charges for Cost of Fuel Rider	79
Rider 571	RA	Reliability Adjustment	80
Rider 572	ECRM	Adjustment of Charges for Environmental Cost Recovery Mechanism	81
Rider 573	EERM	Adjustment of Charges for Environmental Expense Recovery Mechanism	82
Rider 574	PF	Adjustment of Charges for Power Factor	83, 84
Rider 575	ES	Electric Spaceheating Rider to Residential Service	85
Rider 576	TS	Thermal Storage Rider	86
Rider 577	COG	Purchases from Cogeneration and Small Power Production Facilities	87, 88, 89, 90
Rider 578	IS	Interconnection Standards	91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101, 102, 103, 104, 105
Rider 579	NM	Net Metering	106, 107
Rider 580	EDR	Economic Development Rider	108, 109, 110
Appendix A		Applicable Riders	111
Appendix B		Fuel Cost Charge	112
Appendix C		Reliability Adjustment Factor	113
Appendix D		Environmental Cost Recovery Mechanism Factor	114
Appendix E		Environmental Expense Recovery Mechanism Factor	115

INDEX OF CITIES, TOWNS AND UNINCORPORATED COMMUNITIES FURNISHED ELECTRIC SERVICE

Adams Lake
Ade
Ainsworth
Aldine
Ambia
Angola
Ashley
Atwood
Barbee Lakes
Bass Lake
Beaver Dam Lake
Belshaw
Benton
Beverly Shores
Big Long Lake
Boone Grove
Boswell
Bourbon
Brighton
Brimfield
Bristol
Brook
Brunswick
Buffalo
Burket
Burnettsville
Burns Harbor
Burr Oak
Cedar Lake
(LaGrange County)
Cedar Lake
(Lake County)
Chapman Lake
Chase
Chesterton
Claypool
Clear Lake
Clunette
Corunna
Cromwell
Crooked Lake
Crown Point
Crystal Lake
Culver
Deep River
Delong
Demotte
Denham
Dewart Lake
Dixon Lake
Donaldson
Door Village
Dune Acres
Duneland Beach
Dyer
Earl Park
East Chicago
Emmatown
Enos
Etna
Fish Lake
(LaGrange County)
Fish Lake
(LaPorte County)
Flint Lake
Foraker
Foresman
(Newton County)
Fowler
Francesville
Freeman Lake
Fremont
Gary
Goodland
Goshen
Grass Creek
Griffith
Grovertown
Hamlet
Hammond
Hanna
Hebron
Helmer
Hibbard
Highland
Hobart
Hoffman
Howe
Hudson
Idaville
Independence Hill
Inwood
Jimtown
Kentland
Kewanna
Kingsbury
Knox
Koontz Lake
Kouts
LaCrosse
LaGrange
Lake Bruce
Lake Dale Carlia
Lake Gage
Lake George
Lake James
Lake Maxinkuckee
Lake of Silver Lake
Lake of the Woods
(LaGrange County)
Lake of the Woods
(Marshall County)
Lake Station
Lake Village
LaPorte
Leesburg
Leiters Ford
Leroy
Lochiel
Long Beach
Long Lake
(Porter County)
Lowell
Malden
Medaryville
Mentone
Merrillville
Michiana Shores
Michigan City
Middlebury
Milford
Mill Creek

INDEX OF CITIES, TOWNS AND UNINCORPORATED COMMUNITIES FURNISHED ELECTRIC SERVICE

Millersburg
Mongo
Monon
Monterey
Monticello
Morocco
Mount Ayr
Munster
Nappanee
Nevada Mills
New Chicago
New Elliott
New Paris
North Judson
North Liberty
North Webster
Norway
Oak
Ober
Ogden Dunes
Oliver Lake
Ontario
Ora
Orland
Oswego
Otis
Palestine
Palmer
Pierceton
Pine Village
Pinhook
Pinola
Pleasant Lake
Plymouth
Portage
Porter
Pottawattamie Park
Pretty Lake
(LaGrange County)
Pretty Lake
(Marshall County)
Pulaski
Raub
Ray
Remington
Rexville
Reynolds
Riverdale
Rome City
Roselawn
Ross
St. John
Salem Center
Salem Heights
San Pierre
Schererville
Schneider
Scott
Seafield
Sedley
Shafer Lake
Shelby
Shipshewanna
Shipshewanna Lake
Shoe Lake
Silver Lake
Smithson
South Haven
South Milford
Star City
Stillwell
Stone Lake
Stroh
Sumava
Swanington
Syracuse
Talbot
Talma
Teegarden
Tefft
Thayer
The Pines
Tippecanoe
Tippecanoe Lake
Topeka
Toto
Tracy
Trail Creek
Twin Lakes
(LaGrange County)
Tyner
Union Center
Union Mills
Valentine
Valparaiso
Wabee Lake
Wadena
Wahob Lake
Wakarusa
Wanatah
Warsaw
Waterford
Waterford Mills
Waterloo
Wawaka
Wawasee
Webster Lake
Westboro
Westville
Wheatfield
Wheeler
Whiting
Winfield
Winona Lake
Wolcott
Wolcottville
Woodland
Woodville
Wyatt
Yellow Creek Lake
Yeoman

Also effective in rural territories furnished electric service by Company.

Issued Date
Date

Effective Date
Date

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

Table of Contents

RULE	SUBJECT	SHEET NO.
1.	Definitions	6, 7, 8, 9, 10, 11
2.	Rates, Rules and Regulations	12
3.	Character of Service	13, 14
4.	Application, Service Request, or Contract	15
5.	Predication of Rate Schedule Selection	16, 17, 18
6.	Service Extensions and Modifications	19, 20, 21, 22
7.	Customer Installation	23
8.	Company Equipment on Customer's Premise	24, 25
9.	Metering	26, 27
10.	Customer Service Deposits	28
11.	Rendering and Payments of Bills	29
12.	Disconnection and Reconnection of Service	30, 31
13.	Service Interruptions and Curtailments	32, 33, 34
14.	Miscellaneous and Non-reoccurring Charges	35, 36

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. DEFINITIONS

Unless otherwise specified in the Rate Schedule, the following terms shall have the meanings defined below when used in this Tariff for Electric Service:

A. Billing Demand – That Demand, stated in kilowatts, upon which the Demand Charge in the bill is determined in any given month.

B. Billing Period – The Billing Period is defined as the period for which a Customer has been billed. The Billing Period is the duration from the bill's start date to the bill's end date.

C. Cogeneration Facility – (1) A facility that simultaneously generates electricity and useful thermal Energy and meets the Energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3, in effect November 9, 1978. (2) The land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility. (3) The transmission or distribution facility necessary to conduct the Energy produced by the facility to a user located at or near the project site.

D. Commission – Indiana Utility Regulatory Commission, or its successor.

E. Company – Northern Indiana Public Service Company.

F. Company Standards – Electric Standards established by the Company and posted on the Company's website.

G. Contract Capacity – A Customer's specified load requirements expressed in kWs for which a Customer contracts.

H. Contract Year – Twelve consecutive Billing Periods used in the application of Rate Schedules.

I. Curtailment – The reduction of a Customer's load at the request of the Company pursuant to the Company's Rate Schedules for reliability reasons.

J. Customer – Any person, firm, corporation, municipality or other government agency in whose name service is rendered at a single premise by the Company.

K. Customer Charge – The dollar amount set forth in each Rate Schedule.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. DEFINITIONS (continued)

L. Day-Ahead LMP – As defined in the Midwest ISO Open Access Transmission and Energy Markets Tariff ("TEMT") or its successor at the established NIPSCO Load Commercial Pricing Node(s).

M. Delinquent Bill – A Customer bill that has remained unpaid for the period set forth in the IURC Rules (170 IAC 4-1-13), or its successor.

N. Demand – The rate at which Energy is used by the Customer from the Company's system within an interval of time, stated in kWs.

O. Demand Charge – The portion of a Customer bill for electric service based on the Customer's Maximum Demand, in kW, and calculated based on the Billing Demand charges under the applicable Rate Schedule.

P. Demand Indicating Meter (DI Meter) – A meter capable of measuring and recording the maximum kW Demand, kVAR Demand and kWh within a specific range of time.

Q. Distribution Line – Any distribution line of the Company operated at a nominal voltage less than 69,000 volts.

R. Energy – The active component of the quantity of supply expressed in kWh.

S. Energy Charge – The portion of a Customer's bill for electric service based on the Customer's Energy consumption, in kWh, under the applicable Rate Schedule.

T. FERC – Federal Energy Regulatory Commission.

U. Fuel Adjustment – The additional charges or credits the Company includes in a Customer bill to offset the variance in the price of the fuel used to generate electricity. This adjustment is represented as cents per kWh.

V. General Service - Service provided to non-residential Customers.

W. Gross Margin – Revenues minus cost of fuel and purchased power.

X. Interruption – The reduction of a Customer's load at the request of the Company pursuant to the Company's Rate Schedules for economic reasons.

Y. Interval Data Recorders (IDR) – A meter capable of measuring and recording kW Demand and kVAR Demand on a sub-hour time interval and hourly integrated basis and measuring Energy in kWh on a cumulative basis.

Z. IURC – Indiana Utility Regulatory Commission, or its successor.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. DEFINITIONS (continued)

AA. IURC Rules - Rules and regulations for electric utilities promulgated by the IURC, codified in Title 170 of the Indiana Administrative Code (IAC), Article 4.

BB. Kilovolt-Ampere (kVA) - A measurement of total power - active power, measured in kWs, and reactive power, kVAR. The kVA is defined as the current that is required to electrify the system to reduce resistance and line loss. The equivalent of one kW when the Power Factor is one hundred percent (100%), or is at unity.

$$kVA = \sqrt{kW^2 + kVAR^2}$$

CC. Kilovolt-Ampere Reactive Power (kVAR) – A measurement of reactive power.

DD. Kilowatt (kW) – A measurement of active power. One kilowatt is equivalent to one thousand watts.

EE. Kilowatt-hour (kWh) - The Energy consumed by the use of one kW steadily for one hour.

FF. Lagging Power Factor - The power factor of inductive loads is referred to as lagging, or less than 100%, based upon the power factor ratio.

GG. Load Factor – The kWh divided by the product of the average hours per month (730 hours) times the kW maximum load in the month, expressed as a percentage.

HH. Locational Marginal Pricing (LMP) - The market clearing price for Energy, established by the Midwest ISO on a day ahead and real time basis, at the established NIPSCO Load Commercial Pricing Node(s).

II. Maximum Demand – A Customer's Maximum Demand in any month shall be determined by the Customer's metering device. The Maximum Demand of electric Energy supplied in any month shall be taken as the highest average load in kWs occurring during any 30 consecutive minutes of the month.

JJ. Maximum Summer Peak Hour Demand – The Maximum Demand during the On-Peak Hours of the months of June through September.

KK. Maximum Non-Summer Peak Hour Demand – The Maximum Demand during the months January through May and October through December and the Off-Peak Hours of the months of June through September.

LL. Megawatt (MW) – A measurement of active power. One megawatt is equivalent to one million watts.

MM. Midwest ISO – Midwest Independent Transmission System Operator, Inc.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. **DEFINITIONS (continued)**

NN. National Electric Code – The standard for the safe installation of electrical wiring and equipment. It is part of the National Fire Codes series published by the National Fire Protection Association (NFPA).

OO. Non-Sufficient Funds – An account shall be considered to have Non-Sufficient Funds for the following reasons:

1. The Customer's payment is considered delinquent by the banking institution.
2. The Customer has supplied the incorrect bank account number.
3. The Customer's bank account number is no longer available.
4. The Customer has issued a stop payment by the banking institution to the Company.
5. The Customer pays electronically, and a chargeback is subsequently assessed by the Customer's financial institution.

PP. Off-Peak Demand – The Demand taken during Off-Peak Hours.

QQ. Off-Peak Hours - All hours not defined as On-Peak Hours shall be considered Off-Peak hours.

RR. On-Peak Demand - The Demand taken during On-Peak Hours.

SS. On-Peak Hours – Defined as the hours listed below:

Winter classified as October 1 through March 31

On-Peak Hours are those commencing at 1:00 p.m. Central Standard Time (C.S.T.) and ending at 9:00 p.m., Central Standard Time (C.S.T.), Monday through Friday excluding the holidays set forth below.

Summer classified as April 1 through September 30

On-Peak Hours are those commencing at 11:00 a.m. Central Standard Time (C.S.T.) and ending at 7:00 p.m., Central Standard Time (C.S.T.), Monday through Friday excluding the holidays set forth below.

Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day and are considered to be Off-Peak Hours for the entire twenty-four hours. If the holidays listed above occur on a Saturday and the preceding Friday is a legally observed holiday, the entire twenty four hours of such Friday will be considered off-peak hours. If the holiday listed occurs on a Sunday and the following Monday is legally observed as a holiday, the entire twenty-four hours of such Monday will be considered as off-peak hours.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. **DEFINITIONS (continued)**

TT. Peak Power Factor – The Power Factor at the time of the Customer's Maximum On-Peak Demand for the month.

UU. Power Factor – The ratio of real power to apparent power.

VV. Premise - The main residence, or living quarters for the use of a single family, or main building of a non-residential Customer, which includes the outlying or adjacent buildings used by the Customer provided the use of the service in the outlying or adjacent buildings is supplemental to the service used in the main residence or building.

WW. Present Value – The current value of a future payment, or stream of payments, discounted at the rate of return allowed by the IURC at the time the Company's Rate Schedules go into effect.

XX. Primary Line - Any distribution line of the Company operated at a nominal voltage between 600 volts and 34,500 volts.

YY. Qualifying Facility – A cogeneration or alternate energy production facility of eighty (80) MWs capacity or less which is owned not more than fifty percent (50%) in equity interest by a person primarily engaged in the generation or retail sale of electricity, gas, or thermal energy, as defined in the IURC Rules (170 IAC 4-4.1-1), or its successor.

ZZ. Rate Schedule - A part of the Tariff setting forth the availability and charges for service supplied to a particular group of Customers, as filed with and approved by the IURC.

AAA. Real-Time LMP – As defined in the Midwest ISO Open Access Transmission and Energy Markets Tariff ("TEMT") or its successor at the established NIPSCO Load Commercial Pricing Node(s).

BBB. Residential Service - Customers in whose name service is rendered exclusively for residential purposes, as defined by the IURC Rules (170 IAC 4-1-1), or its successor.

CCC. Rider - A part of the Tariff setting forth supplemental provisions applicable to specific Rate Schedules, as filed with and approved by the IURC.

DDD. Rules – A part of the Tariff setting forth the General Rules and Regulations Applicable to Electric Service, as filed with and approved by the IURC.

EEE. Secondary Line – Any distribution line of the Company operated at a nominal voltage of 600 volts or less.

FFF. Substation – The electric equipment, structures, land and land rights, including transformers, switches, protective devices and other apparatus necessary to transform Energy from a Transmission or Primary Line voltage.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. **DEFINITIONS (continued)**

GGG. Tariff – The entire body of Rules, Rate Schedules and Riders.

HHH. Transmission Line – Any transmission line of the Company operated at a nominal voltage of 69,000 volts or greater.

III. Watt-Hour Meter – A meter capable of measuring and recording the amount of kWh supplied to the Customer.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

2. RATES, RULES AND REGULATIONS

2.1 Rules & Regulations on File

A copy of all rates, rules and regulations under which service will be supplied is posted or filed for the convenience of the Public in the office of the Company and with the IURC. The IURC has continuing jurisdiction over the Tariff in its entirety. The Tariff, or any part thereof, may be revised, amended, or otherwise changed from time to time and any such changes, when approved by the IURC, will supersede the present Tariff.

2.2 Special Conditions and Provisions

The Rules set forth the conditions under which service is to be rendered, and govern all Rate Schedules to the extent applicable. In case of conflict between any provision of a contract, Rate Schedule, Rider and/or the Rules, the order of priority in interpretation shall be the (1) contract, (2) Rate Schedule, (3) Rider, and (4) Rules.

The Company shall have the right to execute contracts for service under any Rate Schedule or Rider. The Company shall also have the right to execute other contracts for service provided, however, such contracts requiring IURC approval shall be contingent upon receipt of such approval.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

3. CHARACTER OF SERVICE

3.1 Standard Installation

The Company shall provide, as a standard installation, facilities required to supply service at a single point of delivery for a single premise. These facilities shall include one transformation, where required, and metering adequate to measure the Demand and Energy consumption of the Premise. Arrangements may be made with the Company in the case of facility requests outside the scope of a standard installation pursuant to Rule 6. A Distribution Line or Secondary Line, to be installed, owned and maintained by the Company, will be provided when the Customer meets the requirements listed in Rule 6.

3.1.1 Secondary Service (600 volts or less)

A Standard Secondary Service Installation includes a Secondary Line up to 135 feet in length from the easement line (or property line if no easement exists). Service in excess of 135 feet in length will be installed and owned by the Company pursuant to Rule 6. Service for industrial or commercial service entrance sizes, in excess of 400 amps, single or combined, of like voltage or phases, shall be considered large, and therefore shall be owned, installed, and maintained by the Customer pursuant to Rule 6.

When a Customer installs its own secondary service, the Company shall assume no responsibility for such service.

3.1.2 Primary Service (over 600 volts)

3.1.2A Overhead

A Standard Primary Service Installation includes an overhead Primary Line, transformer/transformers, transformer pole/poles, and metering equipment that will be provided by the Company pursuant to Rule 6. The Customer is required to install, own, and maintain any additional line and supporting poles.

3.1.2B Underground

Underground Distribution Lines will be installed only where, in the opinion of the Company, such installation is necessary or where it is required by the IURC Rules. The decision whether such lines shall be installed "underground" or "overhead" shall be made by the Company where the matter rests in the Company's sole discretion. Underground primary service is not a standard installation as it relates to Rule 6.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

3. CHARACTER OF SERVICE (continued)

3.2 Voltages

The standard nominal service voltages within the Company's service area are:

SECONDARY		PRIMARY	TRANSMISSION
Single Phase	Three Phase	Three Phase	Three Phase
120 volts	120/208 volts	12,470/7,200 volts	69,000 volts
120/240 volts	240 volts	34,500 volts	138,000 volts
120/208 volts	277/480 volts		
240/480 volts	480 volts		

The availability and application of these voltages will be determined by the Company under the applicable Rate Schedule. Exceptions to the above standard nominal voltages are a 4,160/2,400 volt system and a 13,800 volt system, which are limited to existing Customers that are in the process of being converted to the Company's standard voltage.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

4. APPLICATION, SERVICE REQUEST OR CONTRACT

4.1 Written Application or Contract Required

A written application for service or properly executed contract may be required from a Customer before the Company will be obligated to supply service. The Company shall have the right to reject any application or contract for valid reason. When special construction or equipment expense is necessary to furnish service, the Company may require a contract for a suitable period of time and reasonable guarantees pursuant to Rule 6. Certain Rate Schedules specify a minimum term of contract. In the absence of such a requirement in any Rate Schedule, the Company may require a term of contract commensurate with the size of the Customer's load that the Company is obligated to serve and/or the cost to the Company of making service available.

4.2 Service to be Furnished

4.2.1 New Customers

The Customer shall provide the Company with the load and Demand characteristics to be served. This information will be used by the Company to determine the character of the service and the conditions under which it will be served.

4.2.2 Existing Customers: Notify Company Before Increasing Load

The service connections, transformers, meters and equipment supplied by the Company have definite capacity. No addition to the Customer's equipment or connected load in excess of the defined capacity provided will be allowed except upon written consent from the Company. The Customer shall request any increase in load 60 days prior to the contract period expiration and will be allowed only with written consent from the Company.

4.3 Modification of Contract

No promises, agreements or representation of any agent of the Company shall be binding upon the Company unless the same shall have been incorporated in a written contract before such contract is signed and approved by an agent of the Company authorized to sign such contract on behalf of the Company.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

5. PREDICATION OF RATES AND RATE SCHEDULE SELECTION

5.1 Single Premise

The Rate Schedules are predicated upon the supply of service to the Customer separately for each Premise and for the ultimate usage of such separate Premise. The combining of service of two or more separate classifications through a single meter, or of two or more Premises, or of two or more separate living quarters of the same Premise, will be permitted only under the Rules. An outlying or adjacent building of the Customer, if located on the same Premise, may be served from the supply to the main residence or building, provided the use of such supply to the outlying or adjacent building is supplementary to the usage in the main building.

5.2 Premise Containing Two Meters

If the Customer chooses not to supply the outlying or adjacent buildings by the main service, the Company will install a separate service. The installed service shall be classified under one of the Rate Schedules based on the Customer's load characteristics.

5.3 Building Containing Two or More Separate Living Quarters

Where Residential Service is supplied through one meter to an apartment house or to a building containing two or more separate living quarters, the Customer shall have the option, by written application to the Company, of electing whether:

a. The service shall be classed as Residential Service, in which case, for billing purposes, the Customer Charge and minimum payment of the residential Rate Schedule shall be multiplied by the number of living quarters served through the meter.

b. The service shall be classed as General Service, in which case, for billing purposes, the General Service Rate Schedules shall be applied on the basis of a single Customer.

The election made by the Customer shall continue for a period of twelve (12) months and thereafter until the Customer notifies the Company, in writing, of its election to change the selected classification of such service. Each such election subsequent to the initial election shall continue for a twelve (12) months and thereafter until the Customer again notifies the Company, in writing, of its election to change the selected classification of such service.

The Customer may arrange the wiring at Customer's own expense, so as to separate the combined service and permit the Company to install a separate meter for each separate living quarter. In each such case, the readings of each such meter shall be billed separately under Rate 511. In such case, the wiring shall be arranged to provide for the grouping of all meters at the service entrance.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

5. PREDICATION OF RATES AND RATE SCHEDULE SELECTION (continued)

This rule has no application to rooming houses.

5.4 Combined Residential and Non-Residential Service

Where both residential and non-residential service are supplied through one service and one meter to the same Customer on the same Premise and where the principal use of Energy will be for residential purposes, but a small amount of Energy will be used for non-residential purposes, the Customer will be billed under Rate 511 only when the equipment for such non-residential use is within the capacity of one 120 volt, 30 ampere branch circuit (or is less than 3,000 watts capacity). When the non-residential equipment exceeds the above-stated maximum limit, the entire non-residential wiring may be separated from the residential wiring, so that the residential and non-residential loads may be metered separately. If the separation is accomplished, the residential and non-residential consumption will be billed under the appropriate Rate Schedule. In the event the Customer elects not to separate the residential and non-residential wiring, the total metered consumption will be billed under the appropriate Rate Schedule.

5.5 Choice of Optional Rate

Where optional Rate Schedules are available for the same class of service, the Customer shall designate the desired Rate Schedule. Where selection of the most favorable Rate Schedule is difficult to pre-determine, the Customer will be given an opportunity to change to another Rate Schedule, provided, however, that after one such change is made, the Customer may not make a further change in Rate Schedule until twelve (12) months have elapsed.

The Company will, at the request of the Customer, assist the Customer in its choice of the most advantageous Rate Schedule, but the Company does not guarantee that the Customer will at all times be served under the most favorable Rate Schedule, nor will the Company make refunds representing the difference in charges between the Rate Schedule under which service has actually been billed and another Rate Schedule applicable to the same class of service.

5.6 Resale of Service

Service will not be furnished under any Rate Schedule to any Customer for the purpose of reselling any or all of such service.

5.7 General Service

A Customer will be considered a General Service Customer when so designated by the applicable Rate Schedule or when either of the following service characteristics are present:

a. The Customer operates an electric motor on the premises with a rating in excess of ten (10) horsepower, or

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

5. PREDICATION OF RATES AND RATE SCHEDULE SELECTION (continued)

b. The required transformer capacity exceeds 100 kVA.

5.7.1 Residential

A Residential Customer, at the Customer's option, and in accordance with current provisions of the National Electric Code, may have a General Service in addition to its Residential Service billed separately under applicable Rate Schedules.

5.7.2 Non-Residential

A non-residential Customer, at its option, and in accordance with current provisions of the National Electric Code, may have at a single delivery point, two services billed separately under applicable Rate Schedules.

5.8 Default Schedule for Large Use General Service or Industrial Customers

Notwithstanding the conditions of service under Rate 533, in the absence of a contract between a Rates 526, 527, 534 or 536 Customer and the Company, the rates and charges under Rate 533 will be applicable to any such Customer requiring service from the Company.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

6. SERVICE EXTENSIONS AND MODIFICATIONS

6.1 Extension of Lines and Services Beyond Standard Installations

Upon request by a Customer taking service at a Primary or Secondary voltage level, the Company will provide necessary facilities for rendering standard service. A contribution, a Letter of Credit in a form satisfactory to the Company, or minimum guarantee will be necessary when facilities beyond the Standard Installation pursuant to Company Rule 3.1 are required to serve the Customer prior to facilities installation. Once the Customer comes online, the Customer shall be entitled to any excess of the estimated direct installed costs of the facilities installed less the Customer's estimated Present Value of Gross Margin for a 6 year period. Any such funds acquired under these conditions will be netted against any required Customer deposit before rendering service.

6.1.1 For each Customer, exclusive of the initial applicants considered in the making of an extension, connected to such an extension within the period of six years from the completion of such extension, the electric utility shall refund to such initial applicants, in proportion to their respective contributions toward the cost of such extension, an amount equal to the Present Value of Gross Margin over a 6 year period of each meter when each meter comes on line, less the cost to service such new customer, but the total of all refunds to any such applicant shall in no event exceed the aforesaid contribution of such applicant.

6.2 Company Rule 6.1 does not apply to Customers taking service at Transmission voltage levels. Facilities installations for Customers taking service at Transmission voltage levels shall be considered on a case-by-case basis requiring mutual agreement between the Customer and the Company.

6.3 New Residential Development Procedures

Any Developer of a residential subdivision must choose one of the following investment guarantees before the Company will undertake facility investment with regard to any subdivision or phase thereof:

Option #1. Total estimated expense, excluding overheads, paid upfront by the Developer and guaranteed over six years with the Developer being reimbursed by the Company for the estimated Present Value of Gross Margin over a 6 year period for each meter when each meter comes online.

Option #2. Developer pays prime interest rate as reported in the Wall Street Journal on total amount of estimated expenses, including overheads, at the end of each year for six years. The interest rate is applied to the remaining balance (total estimated expenses minus estimated Present Value of Gross Margin over a 6 year period for each meter when each meter comes online) at the end of each year. Any remaining balance at the end of year six, including any applicable interest charges, will be paid to the Company by Developer.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

6. SERVICE EXTENSIONS AND MODIFICATIONS (continued)

Option #3. Developer furnishes a satisfactory Letter of Credit in a form satisfactory to the Company providing for a periodic draw-down by the Company at the end of each period for three 18-month periods. The periodic draw-down will be equal to one-third of the estimated costs, without overheads, after deducting estimated Present Value of Gross Margin over a 6 year period for each meter when each meter comes online.

Option #4. Developer pays interest expense based upon the prime interest rate upfront on the total amount of estimated expenses, without overheads, with the prime rate applied to the remaining balance (total estimated expense minus estimated Present Value of Gross Margin over a 6 year period for each meter when each meter comes online) at the start of each period for a three 18-month period, with the full balance of estimated expenses paid to the Company at the end of the three periods.

Option #5. At the beginning of each period of a three 18-month period, Developer pays a periodic amount equal to one-half of the Company's weighted cost of capital, as computed annually, multiplied by the remaining estimated expenses, excluding overheads, minus the estimated expense. At the end of the three 18-month periods, Developer pays the remaining estimated expenses after reduction for the estimated Present Value of Gross Margin over a 6 year period for each meter when each meter comes online.

Developers must enter into a contract with the Company designating which of the above options Developer selects. Once a selection is made by Developer, that selection will remain in place for either the entire subdivision development or if designated by Developer, the entire phase of the subdivision development.

6.4 Temporary Service

The charge for temporary service, where existing facilities can be utilized to supply single phase 120 or 120/240 volt service no larger than 100 amps, is consistent with the cost filings submitted annually to the Commission pursuant to 170 IAC 4-1-27. The applicable Rate Schedule shall apply for service furnished. The charge for temporary service other than those stated above shall be determined by estimating the cost of construction and removal of facilities, including labor, material, stores freight and handling, and job order overhead, less any estimated salvage value of material recovered.

6.5 Auxiliary Service

Auxiliary Service is herein defined as electric service rendered by the Company to a Customer wherein such Customer's premises are supplied with electricity from a source of supply other than the Company, or whose electric requirements are wholly or partially at any time relieved by other power generating equipment. The Customer, where service is rendered under such circumstances, shall have the privilege of using the Company's electrical service as reserve or auxiliary service in connection with its alternative

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

6. SERVICE EXTENSIONS AND MODIFICATIONS (continued)

or other source of supply upon the conditions herein prescribed.

A. Where total connected load to be supplied by Company's service does not exceed 15 kilowatts:

A suitable contract shall be entered into with the Customer, listing the apparatus and connected load in kilowatts of the equipment to be supplied auxiliary service.

The Customer shall agree to pay for all Energy used computed under any rate the Customer shall select in effect for the location and for the class of service rendered, except that the minimum monthly payment for such auxiliary service shall be calculated on the basis of $10.00 per month for the first 3 kilowatts or less of total connected load and $3.00 per month for each additional kilowatt or fraction thereof of total connected load; provided, however, that the minimum monthly payment for such auxiliary service so calculated shall not in any case be less than the monthly minimum payment called for in the Rate Schedule or contract.

For the purpose of determining the Demand of the total connected load contracted for, the Company may install a meter capable of measuring Demand which shall measure the highest average load in kilowatts occurring during any thirty (30) consecutive minutes of the month; provided, further that if the Customer's load is three-phase, the Maximum Demand shall not be less than eighty percent (80%) of the product of the actual voltage multiplied by the maximum amperes in any phase multiplied by 1.73. If such measured Maximum Demand exceeds the connected load contracted to be supplied with auxiliary service, then such measured Demand shall be used in calculating the minimum charge in the current and subsequent month's billing until exceeded by a higher measured Demand.

The Company further reserves the right to require the Customer to provide, at his own expense, suitable apparatus to reasonably limit any intermittence or fluctuations of the Customer's requirement, where in the Company's judgment such apparatus is necessary to prevent undue interference with the service of the Company, and the Company further reserves the right to refuse, at any time, service where electric welding machines or other equipment producing high and intermittent fluctuations constitute a part of the Customer's connected load. Paralleled operations of the Company's and the Customer's electric generating equipment shall not be permitted hereunder.

The term of the contract shall be for a period of not less than one (1) year from the beginning of service thereunder. If the parties continue thereafter to furnish and accept the electrical service thereunder, it shall operate to renew and continue the service by yearly periods until cancelled by sixty (60) days notice being given by one party to the other, prior to any such yearly expiration, of such party's election to discontinue the service.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

6. SERVICE EXTENSIONS AND MODIFICATIONS (continued)

B. Where total connected load to be supplied by Company's service exceeds 15 kilowatts:

In such cases, auxiliary service shall be furnished only upon execution of a contract.

6.6 Excess Facilities

In the event service facilities in excess of those required to provide standard service are requested by the Customer or are required to serve the Customer's load, the Company may extend such facilities therefor, subject to the following conditions:

a. The type, extent, and location of such service facilities shall be determined by the agreement between the Company and the Customer;

b. Such service facilities shall be the property of the Company;

c. The Customer shall agree to pay to the Company a monthly rental equal to two percent (2%) of the estimated installed cost of the excess facilities;

d. The monthly rental shall be appropriately adjusted if a change is made in the excess facilities provided by the Company; and

e. such others as are reasonably necessary due to special conditions of service

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

7. CUSTOMER INSTALLATION

7.1 Inside Wiring and Entrance Equipment

Applicants for service must at their own expense equip their premises with all wiring and entrance equipment, all of which shall be constructed and maintained, subject to the approval of any authorized inspectors, and in accordance with the Company's Rules. The Company shall be under no duty to inspect the wiring and equipment of the Customer.

The applicant shall at all times maintain the service entrance and the wires inside the building.

7.2 Exclusive Service on Installation Connection

Except for emergency generating equipment approved by the Company, no other electric light or power service shall be used by the Customer on the same installation in conjunction with the Company's service, either by means of a "throw-over" switch or any other connection, except under a contract for auxiliary service or net metering.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

8. COMPANY EQUIPMENT ON CUSTOMER'S PREMISE

8.1 Company's Property and Protection Thereof

All meters, or other appliances and equipment furnished by and at the expense of the Company, which may at any time be on or in the Customer's Premise, shall, unless otherwise expressly provided, be and remain the property of the Company, and the Customer shall protect such property from loss or damage, and no one who is not an agent of the Company shall be permitted to remove such property or tamper therewith. If Company equipment is damaged or destroyed, the cost of necessary repairs or replacements shall be paid by the Customer.

8.2 Location of Company Transformers, Meters, and Equipment

If the form of service requires, the Customer shall provide free of expense to the Company, and at a location satisfactory to the Company, a suitable place for necessary transformers, meters, or other equipment which may be furnished by the Company.

8.3 Equipment Location Permit

If the Customer is not the owner of the premises served or of intervening property between such premises and the Company's equipment, the Customer shall obtain from such owner, or owners, in form satisfactory to Company, such permits or easements as are, in the opinion of the Company, necessary for the installation and maintenance on such premises and on such intervening property, all poles, wires, or other equipment as may be necessary or convenient for the supplying of electric service to the Customer.

8.4 Access to Premises

Authorized agents of the Company shall have the right to enter upon the premises of the Customer at all reasonable times for the purpose of inspecting, reading, testing, repairing or replacing the meter or meters, appliances and equipment used in connection with its service and removing the same on the termination of the contract or the discontinuance of the service.

8.5 Tampering, Fraud, Theft or Unauthorized Use

When the Company detects fraudulent or unauthorized use of electricity, or that the Company's regulation, measuring equipment or other service facilities have been tampered with, the Company may reasonably assume that the Customer or other user has benefited by such fraudulent or unauthorized use or such tampering and, therefore, is responsible for payment of the reasonable cost of the service used during the period such fraudulent or unauthorized use or tampering occurred or is reasonably assumed to have occurred and is responsible for the cost of field calls and for the cost of effecting repairs necessitated by such use and/or tampering. In any event, the Company may require Customer payment for such out-of-pocket costs. Under circumstances of fraud, theft, unauthorized use of electricity, tampering or alteration of the Company's regulation, measuring equipment and/or other service facilities, the Company

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

8. COMPANY EQUIPMENT ON CUSTOMER'S PREMISE (continued)

may disconnect service without notice and is not required to reconnect the service until a deposit and all the aforementioned charges, or an estimate of such charges are paid in full, subject to any provision of the IURC rules to the contrary. In the event of fraud, theft or unauthorized use of electricity which is not upon or connected with a Customer's premises, the ultimate user of the service shall be liable in the same manner as a Customer for electric service used, the incurred costs of field calls and the cost of effecting repairs, and disconnection without notice.

8.6 Customer's Equipment

Where any of the Customer's utilization equipment has characteristics which, in the Company's judgment, may cause interference with service to other Customers or result in operation at a low power factor, the Customer shall, at the request of the Company, provide suitable facilities to preclude such interference or improve such power factor, or both, as the case may be. Otherwise, the Company shall have the right to provide, at the expense of the Customer, the facilities necessary to preclude such condition or conditions.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

9. METERING

9.1 Meters to be Installed by Company

The electrical Energy, unless otherwise specified, shall be measured by a meter or meters of standard manufacture, installed by the Company. If more than one meter is installed for a Customer that is charged under two or more Rate Schedules, each meter shall be considered by itself in calculating the amount of any bills. Where building codes or other governmental regulation require a separate service for lighting or indicating exits of buildings, each meter shall be considered by itself in calculating the amount of any bills.

When for the convenience of the Company more than one meter is installed at the same Premise for the same Customer, the sum of the registration shall in all cases be taken as the total registration.

9.2 Meter Testing

The Company will test meters used for billing Customers in accordance with the IURC Rules. A copy of these Rules can be found at the IURC's website.

9.3 Failure of Meter

Whenever it is discovered that a meter is not recording within the limits of accuracy as prescribed in the IURC Rules, an adjustment shall be made in accordance with such Rules.

9.4 Demand Metering

The electric Energy to be used under the terms of schedules requiring an IDR, shall be measured at the delivery voltage as to Maximum Demand, use of electric Energy and Power Factor determination through meters to be located in a building or buildings approved by the Company, and furnished by the Customer on the Customer's premises. The Company shall own, furnish and install the necessary metering equipment. All bills, other than bills for the minimum payments, shall be calculated upon the registration of these meters. The meters installed on the Customer's premises, by the Company under this schedule, shall remain the property of the Company and shall be safely kept and protected by the Customer.

The Company shall, at all times, have the right to inspect and test meters, and if found to be defective or inaccurate, to repair or replace them at its option; provided that notice shall be given to the Customer before testing the meters so that the Customer may have its representative present, if desired. Any meter tested and found to be not more than one (1) percent inaccurate shall be considered accurate and correct but shall be adjusted to be as nearly correct as possible. If, as a result of any test hereunder, any meter shall be found inaccurate or incorrect in excess of one percent (1%), such meter shall be adjusted to be as nearly correct as possible, and the reading of such meter previously taken shall be corrected to the percentage of inaccuracy so found, but no such correction shall, without the consent of both parties,

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

9. METERING (continued)

extend back beyond one-half of the period between the date of such test and the date of the last prior test showing the meter to be within one percent (1%) accurate, nor more than forty-five (45) days, whichever is shorter. The Company shall repair or replace a defective or inaccurate meter within a reasonable time after discovery of such defect or inaccuracy. During the time there is no meter in service or the meter in service is not registering, it shall be assumed that the Energy consumed is the same as the daily average for the most recent period of similar operation with respect to usage of Energy preceding the time the meter is out of service. The Customer shall also have the right to require a test of meters at reasonable intervals upon giving notice of its desire to have such test made by the Company.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

10. CUSTOMER SERVICE DEPOSITS

10.1 Residential Customers

The Company shall determine the credit-worthiness of an applicant or an existing Customer in an equitable non-discriminatory method and may require a deposit to insure payment of bills in accordance with 170 IAC 4-1-15, or its successor.

10.2 Commercial and Industrial Customers

The Company may require from any applicant or an existing Customer, as a guarantee against the non-payment of bills, a cash deposit, letter of credit in a form that is acceptable to the Company, or combination thereof equal to the amount payable for service for a 60-day period as estimated by the Company. In all cases, where the monthly amount payable is in excess of that covered by the deposit, the Company may increase the amount of deposit required, but such deposit shall not exceed the estimated amount payable for a sixty-day period.

10.3 Interest on Customer Deposit:

Deposits for Residential service held more than twelve (12) months will earn interest from the date of deposit at a rate of six percent (6%) per annum or at such a rate of interest as the Commission may prescribe, consistent with the requirements of 170 IAC 4-1-15. Upon discontinuance of service, the amount of the final bill will be deducted from the sum of the deposit and any interest payable, and the balance, if any, shall be remitted to the depositor.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

11. RENDERING AND PAYMENT OF BILLS

11.1 Payment of Bills

Bills will be issued monthly and must be paid by the due date specified on the Customer's Bill at an office or an established collection agency of the Company. Bills rendered on estimated readings for service in months in which meters are not read shall have the same force and effect as those based on actual meter readings.

11.2 Payment After Due Date of Service Bill

A bill is delinquent unless payment is received by the due date printed on the bill. The due date is seventeen (17) days from the next business day of the statement date printed on the bill. A delinquent bill may be assessed a late payment charge equal to ten percent (10%) of the first three dollars ($3) and three percent (3%) of the remaining amount that is delinquent and the Company may disconnect service after complying with any applicable IURC Rules.

Failure to receive the bill shall not entitle the Customer to relief from the deferred payment provisions of the rate if the Customer fails to make payment within said seventeen-day period, nor shall it affect the right of the Company to disconnect service for non-payment as above provided.

Once in each half calendar year, but not more often, the Company may upon the Customer's request waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of net amount of the next succeeding month's bill.

11.3 Social Security Payment Plan

The Company may, upon request, extend the due date by ten (10) calendar days, provided that the Customer applies for and is accepted by the Company as a participant in the Social Security Payment Plan. In order to participate in the Social Security Payment Plan, the Customer must meet the following conditions:

a. The Customer must be taking Residential service, which must be in the Customer's name; and

b. The Customer must be retired or be legally disabled and must show proof of receiving monthly social security benefits; and

c. The Customer's normal due date falls either on or between the first and the fourth day, or on or between the twenty-first and last day of the month.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

12. DISCONNECTION AND RECONNECTION OF SERVICE

12.1 Customer Request for Disconnection

The Customer shall be responsible and pay for all electric service supplied to the Customer's premises until the third business day following the requested disconnection date given by the Customer at the office of the Company to discontinue service.

12.2 Company's Right to Disconnect Service Without Notice

The Company reserves the right to disconnect the supply of all service to all or any part of the Customer's Premises without notice in accordance with applicable IURC Rules (if any) for any of the following reasons:

a. if a condition dangerous or hazardous to life, physical safety or property exists; or

b. upon order or direction by any court, the IURC or other duly authorized public authority; or

c. if fraudulent or unauthorized use of electricity is detected and the Company has reasonable grounds to believe the affected Customer is responsible for such fraudulent or unauthorized use; or

d. if the Company's regulating or measuring equipment has been tampered with and the Company has reasonable grounds to believe that the affected Customer is responsible for such tampering.

No discontinuance shall invalidate any contract with the Customer and the Company shall have the right to enforce any contract notwithstanding such discontinuance.

12.3 Company's Right to Disconnect Service With Notice

The Company may disconnect the supply of all service to the Customer's Premises (and refuse to serve any other member of the same household or firm at the same Premises) in accordance with applicable IURC Rules (if any) or other applicable law and with reasonable notice provided to such Customer at the address shown upon the Company's records for any of the following reasons:

a. for violation of any of the Company Rules or contract terms applicable to the service, or

b. for repairs; or

c. for non-payment of bills or failure to post a required security deposit or collateral; or

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

12. DISCONNECTION AND RECONNECTION OF SERVICE (continued)

d. for want of supply; or

e. for failure by the Customer to allow access by employees of the Company to the Customer's meter or other facilities; or

f. for any other lawful reason.

12.4 Reconnection Charges

Whenever service has been discontinued (1) for non-payment of charges; (2) for failure to provide a deposit or collateral; (3) at the request of a Customer more often than once at the same location in a twelve-month period; or (4) for any other reason authorized under the Company Rules and caused by the Customer's actions, a charge will be made by the Company to cover the cost of reconnection of service, in accordance with reconnection charges listed in Company Rule 14.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

13. SERVICE INTERRUPTIONS AND CURTAILMENTS

13.1 Force Majeure

The Company will use reasonable diligence to provide a regular and uninterrupted supply of electric energy but does not guarantee such supply. Neither the Company nor the Customer shall be liable to the other for damages caused by the interruption, suspension, reduction or curtailment of the delivery of electric energy hereunder due to, occasioned by or in consequence of, any of the following causes or contingencies, viz: acts of God, the elements, storms, hurricanes, tornadoes, cyclones, sleet, floods, lightning, earthquakes, landslides, washouts or other revulsions of nature, epidemics, accidents, fires, collisions, explosions, strikes, lockouts, differences with workmen or other industrial disturbances, vandalism, sabotage, riots, inability to secure cars, coal, fuel, or other materials, supplies or equipment, breakage or failure of machinery, generating equipment, electrical lines or equipment, wars, insurrections, blockades, acts of the public enemy, arrests and restraints of rulers and people, civil disturbances, federal, state or other governmental laws, orders, decrees, restraints or regulations, and any other causes or contingencies, whether of the kind herein enumerated or otherwise.

The Company shall not be responsible in damages for any failure to supply electric service or reversal of the supply of electrical energy, or for defective wiring on the Customer's Premises, or for damages resulting to a Customer or to third persons from the use of electricity or the presence of the Company's equipment on the Customer's premises, unless due to gross negligence on the part of the Company.

13.2 Emergency Curtailment Without Regard to Priority

Company reserves the right to order electric service Curtailment without regard to the priority of service when in its judgment such Curtailment is required to forestall imminent and irreparable injury to life, property, or the electric system. Curtailment may include Interruption of selected distribution circuits. A Curtailment pursuant to this Rule shall not exceed 72 consecutive hours but may be extended by Order of the IURC.

13.3 Interruption or Curtailment of Service

The Demand Charges will not be reduced for any billing month because of any Interruption, suspension, reduction or Curtailment of the delivery of electric Energy, unless due to gross negligence on the part of the Company. In any such event, the Demand Charge shall be reduced for such billing month in an amount determined as follows:

a. With respect to reductions or Curtailments of the delivery of electric Energy below the Billing Demand established during the immediately preceding billing month, in the

13. SERVICE INTERRUPTIONS AND CURTAILMENTS (continued)

proportion that the reduction or Curtailment in kilowatts multiplied by the number of hours such reduction or Curtailment was in force, bears to the Billing Demand established during the immediately preceding billing month multiplied by the number of hours in the billing month, but excluding reductions or Curtailments during such month not aggregating more than eight (8) hours in length; and

b. With respect to Interruptions and suspensions of the delivery of electric Energy, in the proportion that the length of time of all such service Interruptions and suspensions during the billing month bears to the total number of hours in the billing Month, but excluding Interruptions during such month not aggregating more than eight (8) hours in length, and also excluding scheduled Interruptions.

The Company reserves the right to interrupt service at any time when necessary to make emergency repairs. For the purpose of making other than emergency repairs or extensions to its lines, the Company reserves the right to cut off the Customer's supply of electric Energy for four (4) consecutive hours on any Sunday, or such other day or days as may be agreed to by the Customer and the Company, provided forty-eight (48) hours' notification previous to the hour of cut-off is given to the Customer. Such Interruptions being scheduled Interruptions referred to above.

13.4 Curtailment Procedures

In the event Company encounters or anticipates a power supply Interruption, fuel shortage, or transmission/distribution emergency, or any other situation that would render Company unable to meet existing and reasonably anticipated Demands for Electric Service, which determinations shall be within Company's reasonable discretion, Company shall have the right to implement these Curtailment Procedures to maintain and restore service to the extent possible under the circumstances.

The Curtailment procedures to follow shall comply with the Midwest ISO Standards for Curtailment, or their successors.

13.4.1 Curtailment Initiation

In the event a Curtailment is required in the sole judgment of the Company, Company shall have the right to curtail Electric Service to its Customers. Such Curtailment shall be effective as of the date and time specified by Company. Company shall implement its Capacity Electric System Emergency Plan for Load Curtailment to maintain and restore service to the extent possible under the circumstances. When necessary in the sole opinion of Company and to the extent possible, Electric Service shall be maintained to Human Needs Customers or other Customers who would otherwise be curtailed, to the extent necessary and practicable under the circumstances.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

13. SERVICE INTERRUPTIONS AND CURTAILMENTS (continued)

13.4.2 Curtailment Notification

If advance notification is possible, Company shall give notification of Curtailment in the most effective manner possible and with as much advance notice as reasonably possible, considering the circumstances and the number of Customers to be notified.

13.4.3 Lifting of Curtailment

Service shall be restored to Customers pursuant to its Electric System Emergency Plan for Load Curtailment.

A Customer who is mandated to curtail Energy use, either by order of an appropriate governmental agency or under application of these rules and regulations, and who solely because of the mandate becomes subject to the ratchet provisions of an applicable Rate Schedule, will for the period during which the mandate is in effect be excluded from meeting the provisions of the ratchet requirements of the Rate Schedule.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

14. MISCELLANEOUS AND NON-REOCCURRING CHARGES

14.1 Reconnection Charges

Whenever the service has been turned off by the Company in accordance with Company Rule 11, a charge will be made by the Company to cover the cost of reconnection of service, which charge shall be as follows:

14.1.1 Reconnection at the meter

A.	Reconnect during normal working hours (8:00 AM to 5:00 PM)	$ 69.85
B.	Reconnect after normal working hours (Monday through Friday) Saturday	$ 82.55
C.	Reconnect on Sunday and Holidays	$ 95.26

14.1.2 Reconnection at the pole

A.	Reconnect during normal working hours (8:00 AM to 5:00 PM)	$ 152.75
B.	Reconnect after normal working hours (Monday through Friday) Saturday	$ 182.13
C.	Reconnect on Sunday and Holidays	$ 211.52

14.1.3 Reconnection at the pole with an easement

A.	Reconnect during normal working hours (8:00 AM to 5:00 PM)	$ 208.15
B.	Reconnect after normal working hours (Monday through Friday) Saturday	$ 249.44
C.	Reconnect on Sunday and Holidays	$ 290.74

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

14. MISCELLANEOUS AND NON-REOCCURRING CHARGES (continued)

14.3 Non-Sufficient Funds

A charge of $20.00 to reimburse the Company for its cost incident to Non-Sufficient Funds will be assessed.

RATE 511
RATE FOR ELECTRIC SERVICE
RESIDENTIAL

TO WHOM AVAILABLE

Available for service to Residential and farm Customers located on the Company's Distribution Lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single phase, at a voltage of 120/240 volts three-wire, or 120/208 volts three-wire, as designated by the Company.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this Rate shall be measured as to Energy consumption by a Watt-Hour meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge and applicable Riders. The Customer Charge and Energy Charge are as follows:

Customer Charge

$10.25 per month

Energy Charge

$0.07401 per kilowatt hour for all kilowatt hours used per month

MINIMUM CHARGE

The Customer's Minimum Charge under this Rate shall be the Customer Charge.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 521
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE SMALL

TO WHOM AVAILABLE

Available to non-residential General service Customers for electric service who are located on the Company's Distribution Lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules. Customers served by Transmission Lines shall not take service under this Rate Schedule.

Customers electing this Rate Schedule shall have a rolling twelve month average Energy consumption less than 5,000 kWh per month. If no historical information is available, the usage shall be estimated by the Company.

If the Company determines that the Customer is no longer eligible for the rate the Company will notify the Customer before moving them to a different Rate Schedule.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and one standard secondary voltage or the available primary voltage as it has in the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this Rate shall be measured as to an Energy consumption by a Watt-Hour meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge and applicable Riders. The Customer Charge, and Energy Charge are as follows:

Customer Charge

$12.55 per month

Energy Charge

$0.09283 per kilowatt hour for all kilowatt hours used per month

ADJUSTMENTS

Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:

If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge.

MINIMUM MONTHLY CHARGE

The Customer's Minimum Charge under this rate shall be the Customer Charge.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 523
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE MEDIUM

TO WHOM AVAILABLE

Available to General Service Customers for electric service who are located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules. Customers served by Transmission Lines shall not take service under this Rate Schedule.

A Customer requesting service hereunder shall be required to have a Demand no greater than 300 kW in two (2) or more of the previous twelve (12) Months and

A. A Demand of 10 kW or greater in at least two (2) month periods in the previous twelve (12) months, or

B. A twelve (12) month rolling average Energy consumption of 5,000 kWh or greater.

If the Company determines that the Customer is no longer eligible for the rate the Company will notify the Customer before moving them to a different Rate Schedule.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and one standard secondary voltage or the available primary voltage in the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand and Energy consumption by an IDR Meter or a DI Meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$33.00 per month

Demand Charge

$21.14 per kilowatt of Billing Demand per month

Customers that have recently migrated to Rate 523 and do not yet have a meter capable of measuring Demand shall not pay a Demand Charge.

Energy Charge

$0.00535 per kilowatt hour for all kilowatt hours used per month

Customers that have recently migrated to Rate 523 and do not yet have a meter capable of measuring Demand shall pay the following Energy Charge:

$0.08551 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

The Billing Demand for the month shall be the Maximum Demand for the month.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

For Watt-hour Metered Customers not yet having a Demand Meter installed

If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge.

2. **Deduction for Primary Service:**

If service is taken by the Customer at a primary voltage (as defined in Company Rule 3) and if the Customer supplies and maintains all transformation equipment (primary voltage to utilization voltage), the monthly Demand Charge will be reduced by $2.89 per kilowatt of the monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the Customer Charge.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 526
RATE FOR ELECTRIC SERVICE
OFF-PEAK SERVICE

TO WHOM AVAILABLE

Available to non-Residential Customers who are located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Customers electing this Rate Schedule shall have a Maximum Demand of at least 300 kW in at least two (2) months in the previous twelve (12) months.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard secondary voltage, or the available primary or transmission voltage at the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

The Customer will supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support any protecting, switching, relaying, or metering equipment that may be supplied by the Company

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system, or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and kVAR by an IDR Meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$5,500.00 per month

Demand Charge

$22.49 per kilowatt per month

Energy Charge

$0.00401 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current Month shall be the greatest of the following Demands:

1. Maximum Demand in On-Peak Hours for the past twelve (12) months up to and including the current Month.
2. 50% of the Maximum Demand in Off-Peak Hours for the past twenty four (24) months up to and including the current month.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

3. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

4. **Deduction for Primary Service:**

If service is taken by the Customer at a primary voltage (as defined in Company Rule 3) and if the Customer supplies and maintains all transformation equipment (primary voltage to utilization voltage), the monthly Demand Charge will be reduced by $2.90 per kilowatt of the monthly Billing Demand.

5. **Deduction for Transmission Service:**

If service is taken by the Customer at a transmission voltage as defined in Company Rule 3, and if the Customer supplies and maintains all transformation equipment (transmission voltage to utilization voltage), the monthly Demand Charge will be reduced by $8.73 per kilowatt of monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of not less than three years.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 527
RATE FOR ELECTRIC SERVICE
LIMITED PRODUCTION LARGE

TO WHOM AVAILABLE

Available to non-Residential Customers who are located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

A Customer requesting service hereunder is required to have a Maximum Demand of at least 20 Megawatts in at least two (2) of the past twelve (12) previous Months.

A Customer requesting service hereunder shall take service only during Production Hours as designated by the Company below. If the Customer's energy during Non-Production Hours is greater than 2.5% of the Customer's energy taken during Production Hours (a "Non-Production Hour Infraction") during any month, the Company may place the Customer on another Rate Schedule for which the Customer qualifies for a minimum of eighteen (18) months.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard primary voltage, or the available primary or transmission voltage at the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

The Customer will supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support any protecting, switching, relaying, or metering equipment that may be supplied by the Company.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system, or be subject to termination of service.

HOURS OF SERVICE: NON-PRODUCTION HOURS

Winter classified as October 1st through March 31st

Non-Production Hours of service are those commencing at 1:00 p.m. Central Standard Time (C.S.T.) and ending at 9:00 p.m., Central Standard Time (C.S.T.), for the days Monday through Wednesday or Wednesday through Friday as designated by the Company excluding the Holidays listed below. All other hours are the Production Hours.

Summer classified as April 1st through September 30th

Non-Production Hours are those commencing at 11:00 a.m. Central Standard Time (C.S.T.) and ending at 7:00 p.m., Central Standard Time (C.S.T.), for the days Monday through Wednesday or Wednesday through Friday as designated by the Company excluding Holidays. All other hours are the Production Hours.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and Reactive Kilovolt-Amperes by an IDR Meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$3,525.00 per month

Demand Charge

$18.19 per kilowatt

Energy Charge

$0.00351 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current Month shall be the greatest of the following Demands:

1. Maximum Demand in Production Hours for the current Month if a Non-Production Hour Infraction has occurred in the Month.
2. 50% of the Maximum Demand in Non-Production Hours for the past twenty four (24) months up to and including the current Month.
3. The highest Billing Demand in the past twenty four (24) months up to and including the current month.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

2. **Deduction for Transmission Service:**

   If service is taken by the Customer at a transmission voltage as defined in as defined in Company Rule 3, and if the Customer supplies and maintains all transformation equipment (transmission voltage to utilization voltage), the monthly Demand Charge will be reduced by $8.80 per kilowatt of monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

CUSTOMER LOAD INFORMATION

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of August each year a statement of its estimates of the Customer's future load on the Company by months for a subsequent Period of thirty (30) months.

The Customer shall make a reasonable effort to provide the Company in writing with a reasonably accurate hourly load forecast on a daily basis.

The Customer shall include with each such annual statement, and more often if changes occur, the plans of the Customer to increase or decrease its electrical generating or conversion equipment, or any major change by the Customer which will affect the Customer's load or load factor on the Company. The Customer shall also advise the Company when it plans to order such equipment, the estimated date construction shall begin, and the estimated date the equipment will be in service.

The Customer shall advise the Company in writing of any change in the operation of its generating and conversion equipment which will affect the Customer's load on the Company as such changes occur.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its generating operations.

Failure to comply with requested information on an ongoing basis may result in Customer being moved to another Rate Schedule.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of not less than three years.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 533
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE LARGE

TO WHOM AVAILABLE

Available to non-Residential Customers whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Customers electing this Rate Schedule shall have a Maximum Demand of 300 kW or greater for at least two (2) of the past twelve (12) Months.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard secondary voltage, or the available primary or transmission voltage at the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the premises of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, relaying equipment that may be supplied by the Company.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and Reactive Kilovolt-Amperes by an IDR Meter to be installed by the Company.

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$580.00 per month

Demand Charge

$20.00 per kilowatt of Billing Demand per month

Energy Charge

$0.00448 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

For Customers with IDR Meters, the Billing Demand for the month shall be the greatest of the following Demands:

1. 90% of the Maximum Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.
2. 80% of the Maximum Non-Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.

For Customers with DI Meters, the Billing Demand for the month shall be the 85% of the Maximum Demand for the current month until such time as Company installs IDR meter.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

2. **Deduction for Primary Service:**

If service is taken by the Customer at a primary voltage (as defined in as defined in Company Rule 3) and if the Customer supplies and maintains all transformation equipment (primary voltage to utilization voltage), the monthly Demand Charge will be reduced by $2.06 per kilowatt of the monthly Billing Demand.

3. **Deduction for Transmission Service:**

If service is taken by the Customer at a transmission voltage as defined in as defined in Company Rule 3, and if the Customer supplies and maintains all transformation equipment (transmission voltage to utilization voltage), the monthly Demand Charge will be reduced by $6.10 per kilowatt of monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

CUSTOMER LOAD INFORMATION

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of August each year a statement of its estimates of the Customer's future load on the Company by months for a subsequent period of thirty (30) months.

The Customer shall include with each such annual statement, and more often if changes occur, the plans of the Customer to increase or decrease its electrical generating or conversion equipment, or any major change by the Customer which will affect the Customer's load or load factor on the Company. The Customer shall also advise the Company when it plans to order such equipment, the estimated date construction shall begin, and the estimated date the equipment will be in service.

The Customer shall advise the Company in writing, of any change in the operation of its generating and conversion equipment which will affect the Customer's load on the Company as such changes occur.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its generating operations.

Failure to comply with requested information on an ongoing basis may result in Customer being moved to another Rate Schedule.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 534
RATE FOR ELECTRIC SERVICE
INDUSTRIAL SERVICE LARGE

TO WHOM AVAILABLE

Available to Non-Residential Customers whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Customers electing this Rate Schedule shall have a Maximum Demand of 10,000 kW or greater in at least two (2) of the past twelve (12) previous Months.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard primary or transmission voltage at the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the premises of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, relaying equipment that may be supplied by the Company.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and Reactive Kilovolt-Amperes by an IDR Meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$10,200.00 per month

Demand Charge

$16.54 per kilowatt per month

Energy Charge

$0.00362 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

The Billing Demand for the month shall be the greatest of the following Demands:

1. 90% of the Maximum Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.
2. 80% of the Maximum Non Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.
3. 80% of the Contract Demand.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

2. **Deduction for Transmission Service:**

If service is taken by the Customer at a transmission voltage as defined in Company Rule 3, and if the Customer supplies and maintains all transformation equipment (transmission voltage to utilization voltage), the monthly Demand Charge will be reduced by $3.94 per kilowatt of monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

CUSTOMER LOAD INFORMATION

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of August each year a statement of its estimates of the Customer's future load on the Company by months for a subsequent Period of thirty (30) months.

The Customer shall make a reasonable effort to provide the Company in writing with a reasonably accurate hourly load forecast on a daily basis.

The Customer shall include with each such annual statement, and more often if changes occur, the plans of the Customer to increase or decrease its electrical generating or conversion equipment, or any major change by the Customer which will affect the Customer's load or load factor on the Company. The Customer shall also advise the Company when it plans to order such equipment, the estimated date construction shall begin, and the estimated date the equipment will be in service.

The Customer shall advise the Company in writing of any change in the operation of its generating and conversion equipment which will affect the Customer's load on the Company as such changes occur.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its generating operations.

Failure to comply with requested information on an ongoing basis may result in Customer being moved to another Rate Schedule.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of not less than three years.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 536
RATE FOR ELECTRIC SERVICE
INTERRUPTIBLE INDUSTRIAL SERVICE

TO WHOM AVAILABLE

Available to non-Residential transmission Customers whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rate Schedule and the Company Rules. The total capacity to be made available under this rate is limited to 250 MW.

The Company shall provide ten (10) minutes of advance notice before Curtailing or Interrupting service. Customers electing this Rate Schedule shall be required to have the ability to Curtail electric service at the stated notice by the Company and meet the applicable Load Modifying Resource requirements pursuant to Midwest ISO Tariff or any successor.

Customers electing this Rate Schedule shall have a Demand of 5,000 kW or greater in two (2) of the past twelve (12) Months. The Company shall not be obligated to supply interruptible capacity in excess of that specified in the contract.

Customers electing this Rate Schedule shall also contract for non-interruptible service under Rates 533 or 534 for any power taken above the Interruptible Contract Demand and other charges related to provision of electric service.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard transmission voltage at the location where service is required. Any applicant requiring service differing from that to be supplied by the Company as herein provided shall provide proper converting, transforming, regulating or other equipment upon his own premises and at his own expense. (See Company Rule 3 for the Company's standard voltages.)

The Customer will supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support any protecting, switching, relaying, or metering equipment that may be supplied by the Company.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system, or be subject to termination of service.

CURTAILMENTS OR INTERRUPTIONS

Curtailments and Interruptions shall be limited to the following:

1. No more than one (1) per day;
2. No more than sixteen (16) hours per day;
3. No more than three (3) consecutive days;
4. No more than three (3) days in any rolling seven day week; and
5. No more than 400 hours per rolling 365 days.

Whenever a Curtailment or Interruption is requested, it shall be requested ratably among Customers taking service under this rate according to each Customer's Interruptible Contract Demand divided by total Interruptible Contract Demand in aggregate on this rate.

The Company shall provide ten (10) minutes of advance notice before Curtailing or Interrupting service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and Reactive Kilovolt-Amperes by an IDR Meter to be installed by the Company

RATE

Rates charged for service rendered under this Rate Schedule are based upon the measurement of electric Energy at the voltage supplied to the Customer.

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, a Demand Charge, an Energy Charge and applicable Riders. The Customer Charge, Demand Charge and Energy Charge are as follows:

Customer Charge

$2,200.00 per month

Demand Charge

$7.89 per kilowatt per month.

Energy Charge

$0.00392 per kilowatt hour for all kilowatt hours used per month

For Economic Interruptions, all kilowatt hours used above the current interruptible load less the Demand requested to be interrupted shall be subject to the greater of:

1. Day-Ahead LMP; or
2. Real-Time LMP

For a Reliability Curtailment, if the Customer fails to Curtail, the Customer will be migrated to Rate 533 or 534 and will not be eligible for this Rate schedule for a period of three (3) years.

In addition to the above LMP charges, the Customer shall be liable for any charges and/or penalties from any outside agencies including Midwest ISO, FERC and Reliability First Corporation for failure to Curtail service. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a Load Modifying Resource.

CUSTOMER LOAD INFORMATION

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of August each year a statement of its estimates of the Customer's future load on the Company by months for a subsequent period of thirty (30) months.

The Customer shall make a reasonable effort to provide the Company in writing with a reasonably accurate hourly load forecast on a daily basis.

The Customer shall include with each such annual statement, and more often if changes occur, the plans of the Customer to increase or decrease its electrical generating or conversion equipment, or any major change by the Customer which will affect the Customer's load or load factor on the Company. The Customer shall also advise the Company when it plans to order such equipment, the estimated date construction shall begin, and the estimated date the equipment will be in service.

The Customer shall advise the Company in writing, of any change in the operation of its generating and conversion equipment which will affect the Customer's load on the Company as such changes occur.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its generating operations.

Failure to comply with requested information on an ongoing basis may result in Customer being moved to another Rate Schedule.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

NOTIFICATION OF CURTAILMENT OR INTERRUPTION

The Company shall provide ten (10) minutes of advance notice before Curtailing or Interrupting service.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED INTERRUPTIONS OR CURTAILMENT

A Customer is deemed to have failed to Interrupt or Curtail load when the Customer's current integrated Demand, as measured by the meters installed by the Company, has not been reduced within ten (10) minutes after notification of Interruption or Curtailment.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of not less than three years and an Interruptible Contract Demand of 5,000 Kw or greater. A Customer shall not exceed its Interruptible Contract Demand at any time under this Rate. All load exceeding Interruptible Contract Demand will be billed under the applicable non-interruptible Rate. Customers' load under this Rate will always be measured on a first through the meter basis.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 541
RATE FOR ELECTRIC SERVICE
WATER PUMPING

TO WHOM AVAILABLE

1. Metered Service

Metered service is available to municipalities, the Indiana Department of Natural Resources and to corporations or persons operating under exclusive franchise to furnish water service at retail within a municipality such electric power service to be used for waterpumping purposes; who enter into a written contract for electric service in accordance with this Rate Schedule and who are located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Lighting Service will be supplied under this Rate Schedule only if it is incidental to the power load served and the lighting service in kilowatt Demand and kilowatt hour usage is less than 15 percent of the kilowatt hours respectively of the power load.

2. Un-metered Service

Un-metered service is available to private or governmental entities to provide power to systems for the pumping and removal of residential and small commercial sewage water and waste at multiple locations to a central waste water treatment facility. This rate is available only for an integrated system consisting of individual distributed pumping units which operate intermittently. No single pump may exceed 1.1 horsepower Energy rating or have a maximum Energy consumption exceeding 200 kilowatt hours per year. The distributed pumps comprising the wastewater pumping system must be located in the service territory of the Company on electric facilities suitable and adequate for supplying the service required.

Prior to installing new pumping devices, Customer must notify Company the time and date of the proposed installations so that Company may verify the number of pumps installed for billing purposes. Customer agrees to allow the Company to audit the records of the Waste Water Pumping System, two (2) times per year, to verify the number and size of the pumps located on the Company's lines. Company also reserves the right to install metering devices on one or more pumps from time to time, to verify the Demand and Energy consumption levels of installed pumps. Customer may not install pumps that do not meet the size restrictions of Company lines, Customer will remove, at its own costs and expense, any such pump.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and voltage as it has available in the location where service is required, and if transformation of voltage is desired by the Customer, will transform its primary voltage to one standard secondary voltage. (See Company Rule 3 for the Company's standard voltages.)

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The metered electric service to be supplied under this rate shall be measured with an Energy consumption by a Watt-Hour meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge and Energy Charge are as follows:

1. **Metered Service**

Customer Charge

$35.00 per month

Energy Charge

$0.08543 per kilowatt hour for all metered electric Energy used per month.

2. **Un-metered Service**

Customer Charge

There shall be a single Customer Charge of $45.00 per monthly bill, regardless of the total number of pumps in the Customer's system. The Customer may elect to have the Company aggregate all the pump locations in one integrated system for billing purposes, and the monthly Customer Charge of $45.00 will be applied once to that bill.

Pump Charge

Residential un-metered service under this Rate Schedule shall be $2.48 per month per point of connection with the residential facilities of the Company. If more than one pump is installed at any one point of connection, the rate for that connection shall be $2.48 per month for each pump installed at that location. This rate is not available for installations of more than four pumps at any one point of connection.

Commercial un-metered service under this Rate Schedule shall be $2.88 per month per point of connection with the commercial facilities of the Company. If more than one pump is installed at any one point of connection, the rate for that connection shall be $2.88 per month for each pump installed at that location. This rate is not available for installations of more than four pumps at any one point of connection.

For un-metered service, the estimated kWh per month is 8 kWh for Residential pumps and 9.5 kWh for Commercial pumps.

MINIMUM CHARGE

1. **Metered Service**

   The Customer's Monthly Minimum Charge under this rate shall be the Customer Charge.

2. **Un-metered Service**

   The Customer's Monthly Minimum Charge under this rate shall be the single Customer Charge for each bill rendered, plus the charges set forth above for each point of connection with the facilities of the pumping.

ADJUSTMENT FOR METERING AT DIFFERENT VOLTAGE LEVELS OTHER THAN THE VOLTAGE AT WHICH SERVICE IS TAKEN

If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge.

OWNERSHIP OF SYSTEM – SERVICE LINES FOR UN-METERED SERVICE

The ownership of the property comprising a distributed wastewater pumping system, including pumps, piping, wiring, meter socket extension adapters, gauges and other appliances and structures is and shall remain with the Customer. Company shall own the Watt-Hour Meter, service point connections, poles, wires, transformers, and other facilities used to serve residential and small commercial premises where distributed pumping facilities are installed. Company will repair and maintain all equipment owned by Company, and Customer will repair and maintain all equipment owned by Customer. The Customer shall notify the Company, if, in the process of repairing Customer owned equipment, it is necessary to break the Company meter seal.

All connections to secondary voltage wires, meters, meter sockets, or other facilities of the Company used by Customer to power the distributed pumping system shall be performed by Customer at Customer's expense, in full compliance with the National Electric Safety Code, the National Electric Code, and all other applicable standards, rules and regulations.

The connections scheme shall be as follows: Company will make any connections at the service point if the Customer elects to use the additional weatherhead method of connection. Otherwise, if an adapter is used at the meter socket, Customer will make such connections. All connections will comply with the then applicable engineering standards of the Company.

Where such connections are made, Customer agrees to save and hold harmless Company from any and all claims, losses, damages or costs, including attorney fees, arising, or alleged to arise, from the connection of Customer's pumping system, or from the procedures, workmanship, materials, facilities, or other equipment used to effect such connections, with the facilities of the Company.

GENERAL TERMS AND CONDITIONS OF SERVICE – CONTRACT FOR UN-METERED SERVICE

Any Customer requesting un-metered service under this rate shall enter into a written contract for an initial period of not less than three years.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, the number and type of pumps, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 544
RATE FOR ELECTRIC SERVICE
RAILROAD POWER SERVICE

TO WHOM AVAILABLE

This rate is available only to existing railroads or to a non-profit commuter transportation district operating said railroads, subject to the conditions set forth in this Rate Schedule and the Company Rules. Electricity will be supplied hereunder for the operation of trains on a continuous electrified right-of-way of the Customer and the associated requirements furnished through the eight existing substations which were in service on December 31, 2007; provided, however, that electricity will not be furnished hereunder for resale.

CHARACTER OF SERVICE

The points of delivery shall be limited to the following substations as of the effective date of this Tariff; Hammond substations at Columbia and at Carroll St., Gary substation at Third and Madison, Wickliffe substation, Furnessville substation and Michigan City substations, East Port I, East Port II, and Meer Road. The Energy supplied by the Company shall be alternating current and at such voltages as currently supplied by the Company to the Customer.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system, or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand and Energy consumption by an IDR Meter or a Demand Indicating Meter to be installed by the Company.

RATE

Rates charged for service rendered under this Rate Schedule are based upon the measurement of electric Energy at the voltage supplied to the Customer.

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Demand Charge and Energy Charge are as follows:

Customer Charge

$345.00 per month

Demand Charge

$15.60 per kilowatt of Maximum Demand per month

Energy Charge

$0.00479 per kilowatt hour for all kilowatt hours used per month

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge, Demand Charge and the Energy Charge.

DETERMINATION OF DEMAND

The Customer's Demand of electric Energy supplied shall be determined for each one-hour interval of the month. The phrase "one-hour interval" shall mean sixty (60) minute period beginning or ending on a numbered clock hour as indicated by the clock controlling the metering equipment.

DETERMINATION OF BILLING DEMAND

The Billing Demand for the month shall be the greatest of the following Demands:

1. The maximum one-hour Demand registered for the month.
2. Eighty percent (80%) of the highest Billing Demand established in the immediately preceding twenty three (23) months, adjusted, if the Company's obligation to serve is increased or decreased. Each time the Company's obligation to serve is increased or decreased, the highest Billing Demand established in the immediately preceding twenty three (23) months shall be adjusted by a ratio of the Company's current obligation to serve and the Company's obligation to serve in the month of the highest Billing Demand before multiplying by eighty percent (80%).

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 550
RATE FOR ELECTRIC SERVICE
STREET LIGHTING

TO WHOM AVAILABLE

Available for street, highway and billboard lighting service to Customers for lighting systems located on electric supply lines of the Company which are suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

RATE OPTIONS

1. **Lamp Charge: Customer-Owned Equipment Maintained by the Customer**

   Applicable to Customers with Customer-owned equipment maintained by the Customer.

2. **Lamp Charge: Customer-Owned Equipment Maintained by the Company**

   Applicable to Customers with Customer-Owned equipment for the purposes of maintenance under the following rule:

   Company will repair and/or replace and maintain all equipment owned by Company which may be necessary to provide a continuous supply of electrical Energy to the point of connection of Company's property with the lighting system of Customer.

   Company shall also replace at its own cost and expense, on request of the Customer, all defective or burned-out lamps and all broken glassware of the street lighting system owned by Customer, and such replacement lamps and glassware shall be the property of Customer, but Company will not maintain at its own cost and expense any other part of the street lighting system of Customer.

   Company will, where practicable, furnish necessary materials and do the work of maintaining any other part of the lighting system whenever the Customer shall by written order request Company so to do. The cost and expense of such materials and work shall be borne by the Customer.

3. **Lamp Charge: Company-Owned Equipment Maintained by the Company**

   Applicable to Customers with Company-owned equipment maintained by the Company.

LIGHTING HOURS - OPTIONS

1. **Company-Owned Systems**

   Dusk to Dawn
   The lighting hours for the lighting system shall be on a "dusk to dawn" schedule which provides the lamps to be lit from sunset to sunrise each day of the year.

2. **Customer-Owned Systems**

Dusk to Dawn
The lighting hours for the lighting system shall be on a "dusk to dawn" schedule which provides the lamps to be lit from sunset to sunrise each day of the year.

All-night
The lighting hours for the lighting system shall be on an "all night" schedule which provides that lamps are to be lit from approximately one-half (1/2) hour after sunset until approximately one-half (1/2) hour before sunrise each day of the year.

Dusk to Midnight
The lighting hours for the lighting system shall be on a "dusk to midnight" schedule which provides the lamps to be lit from sunset to midnight C.S.T. each day of the year.

OWNERSHIP

1. **Company-Owned Lighting Systems**
The ownership of the property comprising of street and highway lighting systems served hereunder, including the poles, posts, wires, cables, conductors, conduit, fixtures, lamps, brackets, insulators, guys, anchors and other appliances and structures, is and shall remain in the Company. The Company shall own the distribution transformers, photo-electric controls and required associated equipment.

Company shall erect the service lines necessary to supply electrical Energy to the point of connection with the street and highway lighting system of Customer within the limits of the public structures, public streets and highways or on private property as mutually agreed upon by Company and Customer, provided, however, that where such extension exceeds two spans Customer shall pay to Company a sum equal to the estimated cost of constructing such excess of service lines to supply electrical Energy to the street or highway lighting system.

2. **Customer-Owned Lighting Systems**

The ownership of the property comprising of street, highway and billboard lighting systems served hereunder, including the poles, posts, wires, cables, conductors, conduit, fixtures, lamps, brackets, insulators, guys, anchors and other appliances and structures, is and shall remain in the Customer. The Company shall own the distribution transformers and required associated equipment.

Company shall erect the service lines necessary to supply electrical Energy to the point of connection with the street, highway and billboard lighting system of Customer within the limits of the public structures, public streets and highways or on private property as mutually agreed upon by Company and Customer, provided, however, that where such extension exceeds two spans Customer shall pay to Company a sum equal to the estimated cost of constructing such excess of service lines to supply electrical Energy to the street, highway or billboard lighting system.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Lamp Charge, an Energy Charge, and applicable Riders. The Lamp Charge and Energy Charge are as follows:

Lamp Charge - Per lamp per month:

Lamp Type	Company Owned	Customer Owned-Company Maintained
175 Watt Mercury Vapor*	$8.00 per month	n/a
250 Watt Mercury Vapor*	n/a	$3.15 per month
400 Watt Mercury Vapor*	$9.00 per month	n/a
100 Watt High Pressure Sodium	$8.40 per month	$2.60 per month
150 Watt High Pressure Sodium	$8.75 per month	n/a
250 Watt High Pressure Sodium	$9.00 per month	$2.80 per month
400 Watt High Pressure Sodium	$9.00 per month	$2.85 per month

*Available to existing Customers only

For Customer-Owned – Customer Maintained Lamps, the Lamp Charge shall be $1.20 per lamp per month.

Company-Owned Equipment

Company owned monthly lamp charges apply to lights installed with a standard setup. For Customers that desire additional equipment beyond a standard setup, a non-refundable contribution will be required to be unconditionally made to the Company prior to installation equal to the difference between the installed cost and a standard set-up. A standard set up includes an appropriate sized wood pole and related equipment for the lamp type selected by the Customer.

Energy Charge

$0.03379 per kilowatt hour for all kilowatt hours used per month

The following tables will be utilized to calculate the monthly Energy Charge, along with the applicable Riders. These tables represent the lamp burning hours, in kWh.

Dusk to Dawn Usage Hours:

(kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lamp Type													
150 Watt Mercury Vapor	82	80	66	66	56	51	45	49	55	61	71	76	757
175 Watt Mercury Vapor	89	86	80	71	62	55	51	53	60	68	77	85	837
250 Watt Mercury Vapor	144	140	117	116	98	90	80	86	97	107	125	133	1,333
400 Watt Mercury Vapor	234	228	211	189	165	145	135	141	158	180	204	224	2,214
100 Watt High Pressure Sodium	66	64	53	53	45	41	37	39	44	49	57	61	609
150 Watt High Pressure Sodium	89	86	72	71	60	55	49	53	60	66	77	82	820
250 Watt High Pressure Sodium	141	137	114	114	96	87	79	84	95	105	122	130	1,304
400 Watt High Pressure Sodium	230	224	187	186	157	143	128	138	155	171	200	213	2,132

All-Night Usage Hours:

(kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lamp Type													
100 Watt Mercury Vapor	53	45	44	37	34	31	33	37	41	48	51	55	509
175 Watt Mercury Vapor	89	86	80	71	62	55	51	53	60	68	77	85	837
250 Watt Mercury Vapor	132	128	107	106	90	82	73	79	89	98	115	122	1,221
400 Watt Mercury Vapor	234	228	211	189	165	145	135	141	158	180	204	224	2,214
175 Watt Metal Halide	91	76	75	63	58	52	56	63	69	81	86	93	863
250 Watt Metal Halide	125	104	104	88	80	72	77	86	95	112	119	128	1,190
400 Watt Metal Halide	192	160	159	134	122	110	118	133	146	171	182	197	1,824
1500 Watt Metal Halide	700	585	580	491	447	401	431	484	535	626	665	720	6,665
55 Watt Low Pressure Sodium	36	35	30	29	25	23	20	22	24	27	32	34	337
90 Watt Low Pressure Sodium	60	58	49	48	41	37	33	36	40	44	52	55	553
135 Watt Low Pressure Sodium	73	71	59	59	50	45	41	44	49	54	64	67	676
70 Watt High Pressure Sodium	45	44	36	36	31	28	25	27	30	33	39	41	415
100 Watt High Pressure Sodium	66	64	53	53	45	41	37	39	44	49	57	61	609
150 Watt High Pressure Sodium	89	86	72	71	60	55	49	53	60	66	77	82	820
200 Watt High Pressure Sodium	105	103	86	85	72	65	59	63	71	78	92	97	976
250 Watt High Pressure Sodium	128	125	104	104	88	80	72	77	86	95	112	119	1,190
310 Watt High Pressure Sodium	170	165	138	137	116	105	95	101	114	129	147	157	1,574
400 Watt High Pressure Sodium	230	224	187	186	157	143	128	138	155	171	200	213	2,132
1000 Watt High Pressure Sodium	513	500	417	414	350	318	286	308	346	382	447	475	4,756

Dusk to Midnight Usage:

(kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lamp Type													
175 Watt Mercury Vapor	41	40	33	33	28	25	23	24	27	30	35	38	377
250 Watt Mercury Vapor	60	58	48	48	41	37	33	35	40	44	52	55	551
400 Watt Mercury Vapor	108	105	87	87	73	67	60	64	72	80	93	99	995
150 Watt High Pressure Sodium	40	39	32	32	27	25	22	24	27	30	35	37	370

Unlisted Fixture Usage:

For any lamp type not listed in the usage tables above, the monthly Energy shall be calculated based on the lamp wattage with associated losses and the hours of operation based upon the table below:

Hours of Operation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Dusk to Dawn	462	388	388	332	306	277	296	329	359	416	439	474	4,466
Dusk to Midnight	225	188	168	136	124	109	114	131	151	182	222	237	1,986

MINIMUM CHARGE

The Customer's Minimum Charge per lamp under this rate shall be the Lamp Charge, an Energy Charge and applicable Riders.

TERMS AND CONDITIONS

1. The Customer shall furnish to the Company, without cost to the Company and on forms suitable to it, all rights, permits and easements necessary to permit the installation and maintenance of the Company's facilities on, over, under and across private property where and as needed by the Company in providing service hereunder.

2. The Company shall adjust the automatic control on each installation of Company-owned equipment to provide lighting service to the appropriate lighting hours as listed in this Rate Schedule. For Customers under maintenance schedules, lamp replacements and repairs will be made within a reasonable period of time, during regular working hours, after Customer's notification of the need for such maintenance.

3. The facilities installed by the Company shall remain the property of the Company and may be removed by the Company if service is discontinued.

4. Underground service is available, provided, that the Customer pay to the Company a sum equal to the estimated cost of constructing such underground service line to supply electrical Energy to the lighting fixture.

5. The facilities owned by the Company in this rate apply to wood-pole mounted lighting. Customers requesting ornamental lighting to be installed and owned by the Company are subject to a non-refundable contribution being unconditionally made to the Company prior to such installation for each lighting unit to be installed and to which this rate is applicable equal to the difference in the investment required per such unit of the ornamental system as installed and that of a comparable overhead wood-pole mounted Company owned lighting installation of same unit lumen rating.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 555
RATE FOR ELECTRIC SERVICE
TRAFFIC AND DIRECTIVE LIGHTING

TO WHOM AVAILABLE

Available to any Customer for electric Energy for non-metered traffic directive lights located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single phase, at a voltage of approximately 115 volts two-wire, or 115-230 volts three-wire.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Service Drop Charge, an Energy Charge and applicable Riders. The Service Drop Charge and Energy Charge are as follows:

Service Drop Charge

$16.62 per month

Energy Charge

$0.04231 per kilowatt hour for all kilowatt hours used per month.

The average kilowatts burning shall be determined from the indications of a suitable Demand measuring instrument and shall be taken as the average load in watts during a 15 consecutive minute interval of time. Such determination shall be taken during a period of normal operation. The measured Demand will be converted to a monthly usage in kilowatt hours based on the number of hours in the month.

MINIMUM CHARGE

The Customer's Minimum Charge per service drop under this rate shall be the Service Drop Charge, an Energy Charge and applicable Riders.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 560
RATE FOR ELECTRIC SERVICE
DUSK TO DAWN AREA LIGHTING

TO WHOM AVAILABLE

Available for dusk to dawn area lighting service to Customers for Company-owned lighting systems located on electric supply lines of the Company which are suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

MAINTENANCE

Company will repair and/or replace and maintain all equipment owned by Company which may be necessary to provide a continuous supply of electrical Energy to the point of connection of Company's property

LIGHTING HOURS

Dusk to Dawn

The lighting hours for the lighting system shall be on a "dusk to dawn" schedule which provides the lamps to be lighted from sunset to sunrise each day of the year.

OWNERSHIP

This Rate Schedule is only applicable to Company-owned lighting systems.

RATE

The electric service and Energy supplied hereunder shall be billed under a two-part rate consisting of a Lamp and Equipment Charge, an Energy Charge and applicable Riders. Subject to the adjustments herein provided, said rate is as follows:

Lamp and Equipment Charges - Per unit of equipment per month:

Lamp Type	Company Owned
175 Watt Mercury Vapor*	$13.00 per month
400 Watt Mercury Vapor*	$18.25 per month
100 Watt High Pressure Sodium Dusk to Dawn Fixture	$13.00 per month
250 Watt High Pressure Sodium Dusk to Dawn Fixture	$14.25 per month
400 Watt High Pressure Sodium Dusk to Dawn Fixture	$15.00 per month
150 Watt High Pressure Sodium Floodlight	$15.00 per month
250 Watt High Pressure Sodium Floodlight	$15.00 per month
400 Watt High Pressure Sodium Floodlight	$15.50 per month
30 ft wood pole and span of secondary	$3.35 per month
35 ft wood pole and span of secondary	$4.60 per month
40 ft wood pole and span of secondary	$6.07 per month
Guy and anchor set	$1.56 per month
Extra span of secondary	$1.53 per month

***Available to existing Customers only**

Energy Charge –

$0.03379 per kilowatt hour for all kilowatt hours used per month for each lamp.

The following table will be utilized to calculate the monthly Energy usage per lamp, along with the applicable Riders.

Dusk to Dawn Usage

(kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lamp Type													
175 Watt Mercury Vapor	89	86	80	71	62	55	51	53	60	68	77	85	837
400 Watt Mercury Vapor	234	228	211	189	165	145	135	141	158	180	204	224	2,214
100 Watt High Pressure Sodium Dusk to Dawn Fixture	66	64	53	53	45	41	37	39	44	49	57	61	609
250 Watt High Pressure Sodium Dusk to Dawn Fixture	141	137	114	114	96	87	79	84	95	105	122	130	1,304
400 Watt High Pressure Sodium Dusk to Dawn Fixture	230	224	187	186	157	143	128	138	155	171	200	213	2,132
150 Watt High Pressure Sodium Floodlight	89	86	72	71	60	55	49	53	60	66	77	82	820
250 Watt High Pressure Sodium Floodlight	141	137	114	114	96	87	79	84	95	105	122	130	1,304
400 Watt High Pressure Sodium Floodlight	230	224	187	186	157	143	128	138	155	171	200	213	2,132

MINIMUM CHARGE

The Customer's Minimum Charge per lamp under this rate shall be the applicable Lamp and Equipment Charges, an Energy Charge and applicable Riders.

TERMS AND CONDITIONS

1. The Customer shall furnish to the Company, without cost to the Company and on forms suitable to it, all rights, permits and easements necessary to permit the installation and maintenance of the Company's facilities on, over, under and across private property where and as needed by the Company in providing service hereunder.

2. The facilities installed by the Company shall remain the property of the Company and may be removed by the Company if service is discontinued.

3. Underground service is available, provided, that the Customer pay to the Company a sum equal to the estimated cost of constructing such underground service line to supply electric Energy to the outdoor lighting fixture.

4. The facilities owned by the Company in this rate apply to wood-pole mounted lighting. Customers requesting Ornamental Street Lights to be installed and owned by the Company are subject to a non-refundable contribution being unconditionally made to the Company prior to such installation for each street lighting unit to be installed and to which this rate is applicable equal to the difference in the investment required per such unit of the Ornamental system as installed and that of a comparable Overhead wood-pole mounted Company owned lighting installation of same unit lumen rating.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RIDER 570
ADJUSTMENT OF CHARGES FOR COST OF FUEL RIDER

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

RATE

A. Energy use under all Rate Schedules included in this rider are subject to charges for fuel cost and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

$$\text{Adjustment Factor} = \frac{F}{S}$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month immediately following the twenty-day period allowed by the Commission in IC 8-1-2-42 (b) and consisting of the following costs:

   (a) the average cost of fossil fuel consumed in the Company's own plants, such cost being only those items listed in Account 151 of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees; and

   (b) Other costs approved by the Commission for recovery.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:

   (a) net generation; and
   (b) Energy losses and Company use

B. The fuel cost charge as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the fuel cost charge revenues.

C. The fuel cost charge shall be further modified to reflect the difference in the estimated incremental fuel cost billed and the incremental fuel cost actually experienced during the first and succeeding billing cycle month(s) or calendar months(s) in which such estimated incremental fuel cost was billed for those months not previously reconciled.

D. See Appendix B for fuel cost charge.

RIDER 571
RELIABILITY ADJUSTMENT

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

CHARGES FOR RELIABILITY ADJUSTMENT FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges to reflect the recovery of non-FAC MISO costs and purchased power costs, including energy and capacity and the return of non-FAC MISO credits and sharing of off-system sale margins. Such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

$$\text{Reliability Factor ("RF")} = ((D \times P) + (E \times Pe)) / S$$

Where:

"RF" is the rate adjustment for each Rate Schedule.
"D" equals the total Demand related expenses including but not limited to capacity purchases.
"P" represents the Production Demand Allocation percentage for each Rate Schedule.
"E" equals the total Energy related expenses including but not limited to purchased power, off system sales margins and non-FAC MISO charges and credits.
"Pe" represents the Production Energy Allocation percentage for each Rate Schedule.
"S" is the forecast 3-month KWH sales forecast for each Rate Schedule.

RELIABILITY ADJUSTMENT FACTOR

The above rates are subject to an Reliability Adjustment Factor set forth in accordance with the Order of the Commission approved [Date], in Cause No.43526. The Reliability Adjustment Factor stated in Appendix C is applicable hereto and is issued and effective at the dates shown on Appendix C.

The RA as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the RA revenues and later reconciled with actual sales and revenues.

See Appendix C for RA's per KWH charge for each Rate Schedule.

RIDER 572
ENVIRONMENTAL COST RECOVERY MECHANISM

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges approved by the Commission to reflect rate base treatment for qualified pollution control property, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Cost Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Cost Recovery Mechanism Factor stated in Appendix D is applicable hereto and is issued and effective at the dates shown on Appendix D.

Environmental Cost Recovery Mechanism Factor ("ECRM") = (RxP)/S

Where:

"ECRM" is the rate adjustment for each Rate Schedule representing the ratemaking treatment for qualified pollution control property.
"R" equals the total revenue requirement based upon the costs for the qualified pollution control property.
"P" represents the Production Demand Allocation percentage for the Rate Schedule.
"S" is the forecast 6-month KWH sales for the Rate Schedule.

The ECRM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the ECRM revenues and later reconciled with actual sales and revenues.

See Appendix D for ECRM's per KWH charge for each Rate Schedule.

RIDER 573
ENVIRONMENTAL EXPENSE RECOVERY MECHANISM

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges to reflect the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Environmental Expense Recovery Mechanism Factor ("EERM") = ((D x P) + (O&M x Pc)) / S

Where:

"EERM"	is the rate adjustment for each Rate Schedule representing the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service.
"D"	equals the total six (6)-month depreciation expense for the qualified pollution control property placed in service.
"P"	represents the Production Demand Allocation percentage for each Rate Schedule.
"O&M"	equals the total six (6)-month operation and maintenance expense for the qualified pollution control property placed in service and net emission allowance purchases.
"Pc,"	a percentage value, equals a composite allocation based on: x(%) times P defined in (c) above for each Rate Schedule; and (1-x)(%) times "Te," where:
"Te"	represents the Energy Allocation Percentage for each Rate Schedule; and
"S"	is the forecast six (6)-month KWH sales for each Rate Schedule.

ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Expense Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Expense Recovery Mechanism Factor stated in Appendix E is applicable hereto and is issued and effective at the dates shown on Appendix E.

The EERM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the EERM revenues and later reconciled with actual sales and revenues.

See Appendix E for EERM's per KWH charge for each Rate Schedule.

RIDER 574
ADJUSTMENT OF CHARGES FOR POWER FACTOR

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

A Customer requesting service for the applicable Rate Schedules shall be subject to an adjustment of charges for Power Factor based on the criteria listed in this Rider.

RATE

POWER FACTOR CALCULATION

Determination of Lagging Reactive Kilovolt Amperes

The Customer's requirements in Lagging Reactive Kilovolt Amperes shall be determined for each half-hour (1/2 hour) interval of the month and shall be two (2) times the number of Lagging Kilovolt Amperes recorded during such half-hour (1/2 hour) interval.

Determination of Lagging Power Factor

The Power Factor shall be calculated for each half-hour (1/2 hour) interval for the month from the kilowatt-hours "A", as obtained from the metering equipment, and the Lagging Reactive Kilovolt Ampere Hours "B", as defined above, which are used in the same half-hour (1/2 hour) interval, by the following formula:

$$PowerFactor = \frac{A}{\sqrt{A^2 + B^2}}$$

The Peak Power Factor (PPF) is defined as the Power Factor at the time of the Customer's Maximum On-Peak Demand for the month, as defined in Company Rule 1.

Adjustment for Power Factor

For Peak Power Factors of less than 95% lagging, an amount equal to:

$$\$\text{–}Voltage\ Factor \times B - (A \times .32868)$$

shall be added to the Customer's bill.

The $-Voltage Factors are as follows for delivery voltage of:

Transmission - $1.14 Distribution - $0.60

For Peak Power Factors equal to or in excess of 95% lagging, no adjustment shall be made to the Customer's bill.

The Customer shall not operate its system so as to cause or perpetuate a leading Power Factor. If, however, Customer has a leading Power Factor during the Off-Peak hours, an additional amount equal to the product of the half-hour (1/2 hour) Off-Peak Maximum Leading Reactive Kilovolt Amperes times the applicable $-Voltage Factor shall be added to the Customer's bill.

CUSTOMERS TAKING SERVICE UNDER RATE SCHEDULE 536

For customers taking service under Rate Schedule 536, the adjustment for Power Factor shall be calculated from the sum of the meter readings for both the firm and interruptible rates for the Customer and the Power Factor charge shall be applicable to the Customer's Rate Schedule.

RIDER 575
ELECTRIC SPACEHEATING RIDER TO RESIDENTIAL SERVICE

TO WHOM AVAILABLE

This Residential electric spaceheating rider is available for Residential Customers located on the Company's Distribution Lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the accompanying Company Rules.

This rider is only available to existing electric spaceheating Customers as of [Date of Order] classified as Residential Customers with permanently installed electric spaceheating equipment or a permanently installed Company accepted heat pump which operates as the primary heating /cooling device for the residence.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single phase, at a voltage of 120/240 volts three-wire, or 120/208 volts three-wire, as designated by the Company.

RATE

The electric service and Energy supplied hereunder shall be billed along with the Customer Charge and Energy Charge on Rate Schedule 511. All applicable Riders and terms under Rate 511 shall be applicable under this rider.

During any Month more than half of which is within any calendar month from October to April, inclusive, the Energy rate will be modified as follows:

$0.05272 per kWh for all use in excess of 700 kWh per month

RIDER 576
THERMAL STORAGE RIDER

TO WHOM AVAILABLE

This Rider shall be applicable to existing thermal storage Customers as of [Date of Order].

CHARACTER OF SERVICE

In order to qualify as thermal storage use under this Rate Schedule, the thermal storage system must be capable of supplying at least forty (40) percent of the Btu's required for the conditioned space during the On-Peak daily period.

RATE

Thermal Storage Discount

A Customer qualifying for this Rider shall receive a five (5) percent discount off of the Customer's Demand Charge and Energy Charge related to thermal storage for the current Month.

RULES AND REGULATIONS

Service hereunder shall be subject to Company Rules and the IURC Rules.

RIDER 577
PURCHASES FROM COGENERATION AND SMALL POWER PRODUCTION FACILITIES

TO WHOM AVAILABLE

Available to cogeneration and/or small power production facilities which qualify under the IURC Rules (170 IAC 4-4.1 *et seq.*). A contract shall be required between the Company and each cogenerator or small power producer (Qualifying Facility), setting forth all terms and conditions governing the purchase of electric power from the Qualifying Facility.

INTERCONNECTION STANDARDS

The cogenerator or small power producer shall comply with the interconnection standards as defined in Rider 578 Interconnection Standards Rider.

PURCHASE RATES

	Current Rate Per KWH
Summer period (May - Sept.)	
on-peak (1)	4.425 cents
off-peak (2)(5)	2.662 cents
Winter period (Oct. - Apr.)	
on-Peak (3)	4.144 cents
off-Peak (4)(5)	3.237 cents

(1) Monday through Saturday 8 a.m. to 11 p.m.
(2) Monday through Saturday 11 p.m. to midnight and midnight to 8 a.m. and all day Sunday.
(3) Monday through Friday 8 a.m. to 11 p.m.
(4) Monday through Friday 11 p.m. to midnight and midnight to 8 a.m. and all day Saturday and Sunday.
(5) The twenty-four (24) hours of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day will be included in the Off-Peak period.

For those qualifying facilities for whom metering not capable of recognizing different rating periods is installed:

	Current Rate Per KWH
Summer Period	3.606 cents
Winter Period	3.645 cents

Energy metered during any month more than half of which is in any month of May to September, inclusive, shall be calculated under the summer rates listed above. Energy credited during other periods of the year shall be calculated under the winter rates listed above.

Current Capacity Component

$ 10.43 per KW per month.

The monthly capacity component shall be adjusted by the following factor:

$$F = \frac{E_p}{K(T_P)}$$

Where F = Capacity component adjustment factor.

E_P = Kilowatt-hours delivered to the Company during the on-peak period defined as:

Summer - Monday through Saturday 8 a.m. to 11 p.m.
Winter - Monday through Friday 8 a.m. to 11 p.m.
The twenty-four (24) hours of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day will not be included in the On-Peak period.

K = Kilowatts of capacity the qualifying facility contracts to provide.

T_P = Number of hours in the peak period.

The KW capacity available and the kilowatt-hours in the peak period shall be determined by a suitable recording type instrument.

For intended purchases of 72,000 kilowatt-hours or more per month from a Qualifying Facility, the Company and the Qualifying Facility may agree to increase or decrease the rate for Energy purchase in recognition of the following factors:

1. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the Company generation facilities; or
2. The relationship of the availability of Energy from the Qualifying Facility to the ability of the Company to avoid costs, particularly as is evidenced by the Company's ability to dispatch the qualifying facility; or
3. The usefulness of Energy from the qualifying facility during system emergencies, including the ability of the Qualifying Facility to separate its load from its generation.

The Company and Qualifying Facility may negotiate a rate for Energy or capacity purchase which differs from this filed rate.

DETERMINATION OF AMOUNT OF ENERGY PURCHASED

To properly record the number of kilowatt-hours, and where applicable, kilowatts of purchases, the Company and the Qualifying Facility shall mutually agree on the metering configuration to be utilized in accordance with 170 IAC 4-4.1 Section 7 (b). The metering facilities shall be installed and will be owned by the Company, and the Qualifying Facility will be required to reimburse the Company for the installed cost of said metering equipment. The Company need not purchase at the time of a system emergency.

GENERAL TERMS AND CONDITIONS FOR PURCHASE

1. **Contract**

Any cogenerator or small power producer requesting service under this rate shall enter into a written contract for an initial period of not less than oe year.

2. **Curtailment of Purchase**

The Company reserves the right to Curtail the purchase at any time when necessary to make emergency repairs. For the purpose of making other than emergency repairs, the Company reserves the right to disconnect the Qualifying Facility's electric system for four (4) consecutive hours on any Sunday, or such other day or days as may be agreed to by the Qualifying Facility and the Company, provided forty-eight (48) hours' notification previous to the hour of cut-off is given the Qualifying Facility of such intention.

3. **Additional Load**

The Qualifying Facility shall notify the Company in writing of any substantial additions to or alterations in the equipment supplying electric Energy to the Company and such additions or alterations shall not be connected to the system until such notice shall have been given by the Qualifying Facility and received by the Company.

4. **Discontinuance of Purchase**

The Company shall have the right to cut off and discontinue the purchase of electric Energy and remove its metering equipment and other property when there is a violation by the Qualifying Facility of any of the terms or conditions of the contract.

5. **Back-up and Maintenance Power**

Back-up and maintenance power is electrical Energy and capacity provided by the Company to a Qualified Facility to replace Energy, ordinarily generated by the Qualifying Facility, during a scheduled or unscheduled outage of the Qualifying Facility.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Qualified Facility requesting service under this rate shall enter into a written contract for an initial period of not less than three years. The Qualified Facility has the right to have back-up service or scheduled maintenance outages not to exceed the hours selected to a combined maximum of 1,000 hours in each consecutive contract year period. Any additional Energy taken by the Qualified Facility will be billed under an appropriate Rate Schedule.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Qualified Facility with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RIDER 578
INTERCONNECTION STANDARDS

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

In accordance with 170 IAC 4-4.3 of the Commission Rules, as the same may be revised from time to time by the Commission, applicable to Customer-generator Interconnection Standards, ("Rule 4.3") eligible Customers may own, operate, and interconnect generation equipment to the NIPSCO electric system after meeting the requirements of Rule 4.3, these rules and the approval process is defined.

DEFINITIONS

A Customer shall initiate the approval process by submitting the appropriate application (see Interconnection Agreements below) and fees based on the size and type of the generating unit as defined by the following:

Level 1: Inverter-based Customer-generator facilities with a name plate rating of 10kW or less which meet certification requirements of section 5 of Rule 4.3.

Level 2: Customer-based generator facilities with a name plate rating for 2 MW or less which meet the certification requirements of section 5 of Rule 4.3.

Level 3: Customer-based generator facilities which do not qualify for either Level 1 or Level 2.

RATE

The interconnection review fees shall be as follows:

Level 1: There is no charge.

Level 2: The charge for a Level 2 interconnection review is fifty dollars ($50) plus one dollar ($1) per kW of the Customer-generator facility's name plate capacity.

Level 3: The charge for a Level 3 review is one hundred dollars ($100) plus two dollars ($2) per kW of the Customer-generator facility's name plate capacity, as well as one hundred dollars ($100) per hour for engineering work performed as part of any impact or facilities study. The cost of additional facilities in order to accommodate the interconnection of the Customer-generator facility shall be the responsibility of the applicant.

PROCEDURES:

The interconnection review procedures are prescribed by the following sections of Commission Rule 4.3:

Level 1: Section 6

Level 2: Section 7

Level 3: Section 8

Before the Company may allow interconnection with an eligible Customer's facility, the Customer shall be required to enter into an interconnection agreement with the Company applicable to the facility. See below for the appropriate agreement.

The above stated agreements and associated applications are found below, as follows:

1. Interconnection Agreement For Interconnection and Parallel Operation of Certified Inverter-Based Equipment 10 KW or Smaller
2. Interconnection Agreement for Level 2 or Level 3 Facilities,
3. Application For Interconnection – Level 1, Certified Inverter Based Generation Equipment of 10 kW or Smaller
4. Application For Interconnection – Level 2 or Level 3.
5. Set forth in IS Exhibit A

RIDER 578
INTERCONNECTION STANDARDS

Application For Interconnection

Level 1 - Certified* Inverter-Based Generation Equipment**
10kW or Smaller

Customer Name: _____

Customer Address: _____

Home/Business Phone No.: _____ Daytime Phone No.: _____

Email Address (Optional): _____

Type of Facility:
☐ Solar Photovoltaic ☐☐ Wind Turbine ☐☐ Other (specify) _____
Inverter Power Rating: _____Quantity: _____ Total Rated "AC" Output:_____
Inverter Manufacturer and Model Number: _____
Name of Contractor/Installer: _____
Address: _____
Phone No.: _____ Email Address (Optional): _____

* Certified as defined in 170 Indiana Administrative Code 4-4.3-5.
** Level 1 as defined in 170 Indiana Administrative Code 4-4.3-4(a).

RIDER 578
INTERCONNECTION STANDARDS

Application For Interconnection
Level 2 or Level 3****

Customer Name: _____
Customer Address: _____
Project Contact Person: _____
Phone No.: _____ Email Address (Optional): _____

Provide names and contact information for other contractors and engineering firms involved in the design and installation of the generation facilities:

_____
_____

Total Generating Capacity of Customer-Generator Facility: _____

Type of Generator: ☐ Inverter-Based ☐ Synchronous ☐ Induction

Power Source: ☐ Solar ☐ Wind ☐ Diesel-fueled Reciprocating Engine
☐ Gas-Fueled Reciprocating Engine ☐ Gas Turbine ☐ Microturbine
☐ Other (Specify) _____

Is the Equipment "Certified" as defined by 170 Indiana Administrative Code ("IAC") 4-4.3-5
☐ Yes ☐ No

Indicate all possible operating modes for this generator facility:
☐ Emergency / Standby – Operated when Northern Indiana Public Service Company ("NIPSCO") service is not available. Paralleling is for short durations.
☐ Peak Shaving – Operated during peak Demand periods. Paralleling is for extended times.
☐ Base Load Power – Operated continuously at a pre-determined output. Paralleling is continuous.
☐ Cogeneration – Operated primarily to produce thermal Energy. Paralleling is extended or continuous.
☐ Renewable non-dispatched – Operated in response to an available renewable resource such as solar or wind. Paralleling is for extended times.
☐ Other – Describe: _____

Will the Customer-Generator Facility export power? ☐ Yes ☐ No If yes, how much? _____

Level of Interconnection Review Requested:
☐ Level 2**
☐ Level 3**

Issued Date
Date

Effective Date
Date

RIDER 578
INTERCONNECTION STANDARDS

Application For Interconnection
Level 2** or Level 3** (continued)

FEES

For this application to be considered complete, adequate documentation and information must be submitted that will allow NIPSCO to determine the impact of the generation facilities on NIPSCO's electric system and to confirm compliance by Customer with the provisions of 170 IAC 4-4.3 and other applicable requirements. Typically this should include the following:

1. Single-line diagram of the Customer's system showing all electrical equipment from the generator to the point of interconnection with NIPSCO's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, and current transformers.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. For Certified* equipment, documentation confirming that a nationally recognized testing and certification laboratory has listed the equipment.
7. A description of how the generator system will be operated including all modes of operation.

For inverters, the manufacturer name, model number, and AC power rating, Operating manual or link to manufacture's web site containing such manual.

8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, X'd, & X''d).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

This application is subject to further consideration and study by NIPSCO and the possible need for additional documentation and information from Customer.

Mail to:
NIPSCO
Attn: Business Link, 801 E. 86th Avenue, Merrillville, IN 46410
** Level 2 and Level 3 as defined in 170 Indiana Administrative Code 4-4.3-4(a).

Issued Date
Date

Effective Date
Date

RIDER 578
INTERCONNECTION STANDARDS

INTERCONNECTION AGREEMENT
FOR INTERCONNECTION AND PARALLEL OPERATION
OF CERTIFIED INVERTER-BASED EQUIPMENT 10 kW OR SMALLER

THIS INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this _____day of _____, 2___, by and between Northern Indiana Public Service Company ("Company"), and_____ ("Customer").

Customer is installing, or has installed, inverter-based Customer-generator facilities and associated equipment ("Generation Facilities") to interconnect and operate in parallel with Company's electric distribution system, which Generation Facilities are more fully described as follows:

Location: _____

Type of facility: ☐Solar ☐☐Wind ☐☐Other _____

Inverter Power Rating: _____ (Must have individual inverter name plate capacity of 10kW or less.)

Inverter Manufacturer and Model Number: _____

Description of electrical installation of the Generation Facilities, including any field adjustable voltage and frequency settings:
☐As shown on a single line diagram attached hereto as "Exhibit A" and incorporated herein by this reference; or
☐Described as follows:

_____
_____
_____.

Customer represents and agrees that the Generation Facilities are, or will be prior to operation, certified as complying with:

(i) The requirements of the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547-2003, "Standard for Interconnecting Distributed Resources with Electric Power Systems", as amended and supplemented as of the date of this Agreement, which standard is incorporated herein by this reference ("IEEE Standard 1547-2003"); or

(ii) The requirements of the Underwriters Laboratories ("UL") Standard 1741 concerning Inverters, Converters and Controllers for Use in Independent Power Systems, as amended and supplemented as of the date of this Agreement, which standard is incorporated herein by this reference.

Customer further represents and agrees that:

(i) The Generation Facilities are, or will be prior to operation, designed and installed to meet all applicable requirements of IEEE Standard 1547-2003, the National Electrical Code and local building codes, all as in effect on the date of this Agreement;

(ii) The voltage and frequency settings for the Generation Facilities are fixed or, if field adjustable, are as stated above; and

(iii) If requested by Company, Customer will install and maintain, at Customer's expense, a disconnect switch located outside and accessible by Company personnel.

Customer agrees to maintain reasonable amounts of insurance coverage against risks related to the Generation Facilities for which there is a reasonable likelihood of occurrence, as required by the provisions of 170 Indiana Administrative Code ("IAC") 4-4.3-10, as the same may be revised from time to time by the Commission ("Commission"). Prior to execution of this Agreement and from time to time after execution of this Agreement, Customer agrees to provide to Company proof of such insurance upon Company's request. With respect to the Generation Facilities and their interconnection to Company's electric system, Company and Customer, whichever is applicable, (the "Indemnifying Party") shall indemnify and hold the other harmless from and against all claims, liability, damages and expenses, including attorney's fees, based on any injury to any person, including the loss of life, or damage to any property, including the loss of use thereof, arising out of, resulting from, or connected with, or that may be alleged to have arisen out of, resulted from, or connected with, an act or omission by the Indemnifying Party, its employees, agents, representatives, successors or assigns in the construction, ownership, operation or maintenance of the Indemnifying Party's facilities, as required by the provisions 170 IAC 4-4.3-10(b)(2), as the same may be revised from time to time by the Commission.

Company agrees to allow Customer to interconnect and operate the Generation Facilities in parallel with Company's electric system in accordance with the provisions of 170 IAC 4-4.3, as the same may be revised from time to time by the Commission, which provisions are incorporated herein by this reference.

In the event that Customer and Company are unable to agree on matters relating to this Agreement, either Customer or Company may submit a complaint to the Commission in accordance with the Commission's applicable rules. For purposes of this Agreement, the term "certify" (including variations of that term) has the meaning set forth in 170 IAC 4-4.3-5, as the same may be revised from time to time by the Commission, which provision is incorporated herein by this reference.

Customer's use of the Generation Facilities is subject to the Companying Rules and Regulations, as contained in Company's Retail Electric Tariff, as the same may be revised from time to time with the approval of the Commission.

Both Company and this Agreement are subject to the jurisdiction of the Commission. To the extent that Commission approval of this Agreement may be required now or in the future, this Agreement and Company's commitments hereunder are subject to such approval.

IN WITNESS WHEREOF, Customer and Company have executed this Agreement, effective as of the date first above written.

Issued Date
Date

Effective Date
Date

_____	CUSTOMER
By: _____	By: _____
Printed Name: _____	Printed Name: _____
Title: _____	Title: _____

Mail To:
NIPSCO
Attn: Business Link
801 E. 86th Avenue
Merrillville, IN 46410

Issued Date
Date

Effective Date
Date

RIDER 578
INTERCONNECTION STANDARDS

INTERCONNECTION AGREEMENT
FOR LEVEL 2 OR LEVEL 3 FACILITIES

THIS INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this _____ day of _____, ____, by and between Northern Indiana Public Service Company ("Company"), and _____ ("Customer"). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties".

WITNESSETH:

WHEREAS, Customer is installing, or has installed, generation equipment, controls, and protective relays and equipment ("Generation Facilities") used to interconnect and operate in parallel with Company's electric system, which Generation Facilities are more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: _____
Generator Size and Type: _____

NOW, THEREFORE, in consideration thereof, Customer and Company agree as follows:

1. Application. It is understood and agreed that this Agreement applies only to the operation of the Generation Facilities described above and on Exhibit A.

2. Interconnection. Company agrees to allow Customer to interconnect and operate the Generation Facilities in parallel with Company's electric system in accordance with any operating procedures or other conditions specified in Exhibit A. By this Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the Generation Facilities. The Generation Facilities installed and operated by or for Customer shall comply with, and Customer represents and warrants their compliance with: (a) the National Electrical Code and the National Electrical Safety Code, as each may be revised from time to time; (b) Companying Rules including Company Rule 6.5 – Excess Facilities each as contained in Company's Retail Electric Tariff and as each may be revised from time to time with the approval of the Commission ("Commission"); (c) the rules and regulations of the Commission, including the provisions of 170 Indiana Administrative Code 4-4.3, as such rules and regulations may be revised from time to time by the Commission; and (d) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time.

   Customer shall install, operate, and maintain, at Customer's sole cost and expense, the Generation Facilities in accordance with the manufacturer's suggested practices for safe, efficient and reliable operation of the Generation Facilities in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the Generation Facilities. Customer shall be responsible for protecting, at Customer's sole cost and expense, the Generation

Facilities from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges. Customer agrees that, without the prior written permission from Company, no changes shall be made to the configuration of the Generation Facilities, as that configuration is described in Exhibit A, and no relay or other control or protection settings specified in Exhibit A shall be set, reset, adjusted or tampered with, except to the extent necessary to verify that the Generation Facilities comply with Company approved settings.

3. Operation by Customer. Customer shall operate the Generation Facilities in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the Generation Facilities are being operated in parallel with Company's electric system, Customer shall so operate the Generation Facilities in such a manner that no disturbance will be produced thereby to the service rendered by Company to any of its other Customers or to any electric system interconnected with Company's electric system. Customer understands and agrees that the interconnection and operation of the Generation Facilities pursuant to this Agreement is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its Customers.

   Customer's control equipment for the Generation Facilities shall immediately, completely, and automatically disconnect and isolate the Generation Facilities from Company's electric system in the event of a fault on Company's electric system, a fault on Customer's electric system, or loss of a source or sources on Company's electric system. The automatic disconnecting device included in such control equipment shall not be capable of reclosing until after service is restored on Company's electric system. Additionally, if the fault is on Customer's electric system, such automatic disconnecting device shall not be reclosed until after the fault is isolated from Customer's electric system. Upon Company's request, Customer shall promptly notify Company whenever such automatic disconnecting devices operate.

   Customer shall coordinate the location of any disconnect switch required by Company to be installed and maintained by Customer.

4. Access by Company. Upon reasonable advance notice to Customer, Company shall have access at reasonable times to the Generation Facilities whether before, during or after the time the Generation Facilities first produce Energy, to perform reasonable on-site inspections to verify that the installation and operation of the Generation Facilities comply with the requirements of this Agreement and to verify the proper installation and continuing safe operation of the Generation Facilities. Company shall also have at all times immediate access to breakers or any other equipment that will isolate the Generation Facilities from Company's electric system. The cost of such inspection(s) shall be at Company's expense; however, Company shall not be responsible for any other cost Customer may incur as a result of such inspection(s).

   The Company shall have the right and authority to isolate the Generation Facilities at Company's sole discretion if Company believes that:

(a) continued interconnection and parallel operation of the Generation Facilities with Company's electric system creates or contributes (or will create or contribute) to a system emergency on either Company's or Customer's electric system;

(b) the Generation Facilities are not in compliance with the requirements of this Agreement, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or

(c) the Generation Facilities interfere with the operation of Company's electric system. In non-emergency situations, Company shall give Customer reasonable notice prior to isolating the Generating Facilities.

5. Rates and Other Charges. This Agreement does not constitute an agreement by Company to purchase or wheel power produced by the Generation Facilities, or to furnish any backup, supplemental or other power or services associated with the Generation Facilities, and this Agreement does not address any charges for excess facilities that may be installed by Company in connection with interconnection of the Generation Facilities. It is understood that if Customer desires an agreement whereby Company wheels power, or purchases Energy and/or capacity, produced by the Generation Facilities, or furnishes any backup, supplemental or other power or services associated with the Generation Facilities, then Company and Customer may enter into another mutually acceptable separate agreement detailing the charges, terms and conditions of such purchase or wheeling, or such backup, supplemental or other power or services. It is also understood that if any such excess facilities are required, including any additional metering equipment, as determined by Company, in order for the Generation Facilities to interconnect with and operate in parallel with Company's electric system, then a separate Excess Facilities Agreement shall be executed by Company and Customer in accordance with Company's Rule 6.5 contained in Companying Rules, which details the charges and terms of such excess facilities, as the same may be revised from time to time with the approval of the Commission.

6. Insurance. Customer shall procure and keep in force during all periods of parallel operation of the Generation Facilities with Company's electric system, the following insurance to protect the interests of Company under this Agreement, with insurance carriers acceptable to Company, and in amounts not less than the following:

Coverage Limits
Comprehensive General Liability
Contractual Liability (To be inserted depending upon the nature
Bodily Injury and size of the Generation Facilities.)
Property Damage

At least fifteen (15) days prior to any interconnection of the Generation Facilities with Company's electric system, and thereafter as requested by Company. Customer shall deliver a CERTIFICATE OF INSURANCE verifying the required coverage to:

NIPSCO
Attention: Corporate Insurance
801 E. 86th Avenue
Merrillville, IN 46410_____

If Customer is sufficiently creditworthy, as determined by Company, then, in lieu of obtaining all or part of the above-specified required insurance coverage from insurance carriers acceptable to Company, Customer may self insure all or part of such required insurance coverage provided that Customer agrees to defend Company and to provide on a self insurance basis insurance benefits to Company, all to the same extent as would have been provided under this Agreement pursuant to the above insurance provisions of this Section 6. By utilizing self insurance to provide all or part of the above-specified required insurance, Customer shall be deemed to have agreed to the provisions of the previous sentence of this Section 6.

7. Indemnification. Each Party (the "Indemnifying Party") shall indemnify and hold harmless the other Party from and against all claims, liability, damages and expenses, including attorney's fees, based on any injury to any person, including the loss of life, or damage to any property, including the loss of use thereof, arising out of, resulting from, or connected with, or that may be alleged to have arisen out of, resulted from, or connected with, an act or omission by the Indemnifying Party, its employees, agents, representatives, successors or assigns in the construction, ownership, operation or maintenance of the Indemnifying Party's facilities used in connection with this Agreement. Upon written request of the Party seeking relief under this Section 7, the Indemnifying Party shall defend any suit asserting a claim covered by this Section 7. If a Party is required to bring an action to enforce its rights under this Section 7, either as a separate action or in connection with another action, and said rights are upheld, the Indemnifying Party shall reimburse such Party for all expenses, including attorney's fees, incurred in connection with such action.

8. Effective Term and Termination Rights. This Agreement shall become effective when executed by both Parties and shall continue in effect until terminated in accordance with the provisions of this Agreement. This Agreement may be terminated for the following reasons:

   (a) Customer may terminate this Agreement at any time by giving Company at least sixty (60) days' prior written notice stating Customer's intent to terminate this Agreement at the expiration of such notice period;
   (b) Company may terminate this Agreement at any time following Customer's failure to generate Energy from the Generation Facilities in parallel with Company's electric system within twelve (12) months after completion of the interconnection provided for by this Agreement;
   (c) either Party may terminate this Agreement at any time by giving the other Party at least sixty (60) days' prior written notice that the other Party is in default of any of the material terms and conditions of this Agreement, so long as the notice specifies the basis for termination and there is reasonable opportunity for the Party in default to cure the default; or
   (d) Company may terminate this Agreement at any time by giving Customer at least sixty (60) days' prior written notice in the event that there is a change in an applicable rule or statute affecting this Agreement.

9. Termination of Any Applicable Existing Agreement. From and after the date when service commences under this Agreement, this Agreement shall supersede any oral and/or written agreement or understanding between Company and Customer concerning the service covered by this Agreement and

any such agreement or understanding shall be deemed to be terminated as of the date service commences under this Agreement.

10. Force Majeure. For purposes of this Agreement, the term "Force Majeure" means any cause or event not reasonably within the control of the Party claiming Force Majeure, including, but not limited to, the following: acts of God, strikes, lockouts, or other industrial disturbances; acts of public enemies; orders or permits or the absence of the necessary orders or permits of any kind which have been properly applied for from the government of the United States, the State of Indiana, any political subdivision or municipal subdivision or any of their departments, agencies or officials, or any civil or military authority; unavailability of a fuel or resource used in connection with the generation of electricity; extraordinary delay in transportation; unforeseen soil conditions; equipment, material, supplies, labor or machinery shortages; epidemics; landslides; lightning; earthquakes; fires; hurricanes; tornadoes; storms; floods; washouts; drought; arrest; war; civil disturbances; explosions; breakage or accident to machinery, Transmission Lines, pipes or canals; partial or entire failure of utilities; breach of contract by any supplier, contractor, subcontractor, laborer or materialman; sabotage; injunction; blight; famine; blockade; or quarantine. If either Party is rendered wholly or partly unable to perform its obligations under this Agreement because of Force Majeure, both Parties shall be excused from whatever obligations under this Agreement are affected by the Force Majeure (other than the obligation to pay money) and shall not be liable or responsible for any delay in the performance of, or the inability to perform, any such obligations for so long as the Force Majeure continues. The Party suffering an occurrence of Force Majeure shall, as soon as is reasonably possible after such occurrence, give the other Party written notice describing the particulars of the occurrence and shall use commercially reasonable efforts to remedy its inability to perform; provided, however, that the settlement of any strike, walkout, lockout or other labor dispute shall be entirely within the discretion of the Party involved in such labor dispute.

11. Dispute Resolution. In the event that Customer and Company are unable to agree on matters relating to this Agreement, either Customer or Company may submit a complaint to the Commission in accordance with the Commission's applicable rules.

12. Commission Jurisdiction and Company Rules. Both Company and this Agreement are subject to the jurisdiction of the Commission. To the extent that Commission approval of this Agreement may be required now or in the future, this Agreement and Company's commitments hereunder are subject to such approval. Customer's use of the Generation Facilities is subject to the Companying Rules, as contained in Company's Retail Electric Tariff, as the same may be revised from time to time with the approval of the Commission.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Northern Indiana Public Service
Company

By:_____
(Title)_____

"Customer"_____
By:_____
(Title)_____

Mail To:
NIPSCO
Attn: Business Link
801 E. 86th Avenue
Merrillville, IN 46410

Issued Date
Date

Effective Date
Date

RIDER 578
INTERCONNECTION STANDARDS

EXHIBIT A
Interconnection Agreement – (Customer Name)

Exhibit A should include:

(i) Single Line Diagram;
(ii) Relay Settings;
(iii) Description of Generator and Interconnection Facilities; and
(iv) Conditions of Parallel Operation.

RIDER 579
NET METERING

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

REQUIREMENTS

In accordance with 170 IAC 4-4.2 of the Commission Rules applicable to net metering, residential and K-12 school Customers may own and operate a solar, wind or hydro electrical generating facility ("Facility") and may be considered an eligible net metering Customer if the Customer is in good standing and the Facility:

1. has a total nameplate capacity less than or equal to ten (10) kilowatts (KW);
2. is located on the eligible net metering Customer's premises and operated by the Customer; and
3. is used primarily to offset all or part of the eligible net metering Customer's own electricity requirements

The Company may offer net metering to other Customers at the Company's discretion.

An eligible net metering Customer whose account is not more than thirty (30) days in arrears and who does not have any legal orders outstanding pertaining to any account with the Company is qualified as an eligible net metering Customer in good standing.

The aggregate amount of net metering capacity allowable to all eligible Customers under this rule shall be determined by the sum of each Facility's nameplate capacity and shall not exceed one tenth of one percent (0.1%) of the most recent summer peak retail load of the Company.

Before the Company will allow interconnection with an eligible net metering Customer's Facility and before net metering service may begin, the Customer will be required to enter into an interconnection agreement applicable to the Facility as set forth in Rider 577 – Interconnection Standards.

The eligible net metering Customer shall install, operate and maintain the Facility in accordance with the manufacturer's suggested practice for safe, efficient and reliable operation interconnected to the Company's electric system.

The Company will determine an eligible net metering Customer's monthly bill as follows:

1. Rates and adjustments will be in accordance with the Company's electric service Tariff and general rules that would apply if the eligible net metering Customer did not participate in net metering.

2. The Company will measure the difference between the amount of electricity delivered by the Company to the eligible net metering Customer and the amount of electricity generated by the eligible net metering Customer and delivered to the Company during the Month, in accordance with the Company's normal metering practices. If the kilowatt hours (kWh) delivered by the Company to the

eligible net metering Customer exceed the kWh delivered by the eligible net metering Customer to the Company during the Month, the eligible net metering Customer will be billed for the kWh difference at the rate applicable to the eligible net metering Customer if it was not an eligible net metering Customer. If the kWh generated by the eligible net metering Customer and delivered to the Company exceeds the kWh supplied by the Company to the eligible net metering Customer during the Month, the eligible net metering Customer shall be credited in the next billing cycle for the kWh difference.

3. When eligible net metering Customer elects to no longer participate in net metering under this Rule, any unused credit shall revert to the Company.

Before the Company may allow interconnection with an eligible Customer's facility, the Customer shall be required to enter into an interconnection agreement with the Company applicable to the facility. See Rider 577 – Interconnection Standards for the appropriate agreement.

RIDER 580
ECONOMIC DEVELOPMENT RIDER

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

This Economic Development Rider is available to Industrial and Commercial Customers for new or increased service requirements that result in increased employment opportunities, which are new to the State of Indiana and whose plants are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements. Applicants must demonstrate that, absent the availability of this Rider, this new service requirement and any related employment opportunities would be located outside the Company's electric service territory. Increased service requirements which displace or duplicate existing load in the Company's service territory or are brought about by the shutdown of cogeneration facilities will not qualify under this Rider. Service under this Rider shall commence with the effective date of the contract providing for service under the appropriate Rate Schedule between the Customer and the Company and shall terminate at the earlier of (1) sixty (60) months from the commencement of the initial billing under the Rider or (2) when new base rates are in effect as a resulting from a Commission Order in a base rate case.

CONTRACT

Service under this Rider requires a contract between the Customer and the Company. The contract shall set forth monthly base period kilowatts and kilowatt hours, which shall be deemed those actually used during the preceding twelve (12) months. If new or increased Company facilities are required, the Customer shall be responsible for same in compliance with the Company's New Business Policy in effect at the time of the contract execution.

RATE

For qualifying existing Customers with electric service and Energy supplied by the Company, other than that accounted for in a completed contract under the terms and conditions of this Economic Development Rider (where applicable), the existing Energy requirements shall be deemed the Customer's base load and will be billed on the appropriate Rate Schedule. For the Energy requirements of qualifying new Customers, and for the non-base load service and Energy requirements of existing Customers, a discount on monthly billings for all applicable purchases shall be applied in accordance with the following criteria for bills issued during the respective months starting from contract commencement date:

Year 1 Contract	Up to 50% of the increased base rate charges
Year 2 Contract	Up to 40% of the increased base rate charges
Year 3 Contract	Up to 30% of the increased base rate charges
Year 4 Contract	Up to 20% of the increased base rate charges
Year 5 Contract	Up to 10% of the increased base rate charges

In no event, however, shall the incremental revenues derived from the discounted base rate charges, as stated above for serving the new or increased load, be allowed by the Company to be less than the Company's

marginal Energy costs, plus the marginal capacity costs, to serve said load or the minimum billing provisions of the base rate.

At the completion of the Rider contract term, the Energy supplied in accordance with this Rider will be furnished under the appropriate Rate Schedule in accordance with the contract between the Company and the Customer.

The size and duration of discounts on monthly bills will be determined on an individual Customer basis given the degree of fulfillment of the following criteria. The determination of monthly discounts to be applied will be at the sole discretion of the Company, but such discounts will vary with the number and extent to which the listed criteria are met by Customer's proposed new or expanded load. The Company will monitor the awarding of all contracts to insure the fulfillment by the Customer of all terms and conditions of the contract associated with the award. Nonfulfillment of contract terms and conditions is grounds for reopening and reevaluation of all contract terms and conditions. Confidentiality shall be maintained regarding the terms and conditions of any completed contract as well as all Customer negotiations, successful or otherwise.

ELIGIBILITY THRESHOLDS

Unless otherwise noted, the criteria listed as follows will be used in determining the eligibility for the awarding of incentives under the terms and conditions of this Rider. Flexibility in the use of these criteria is at the sole discretion of the Company.

1. New electrical Demand: minimum 100 Kw.

2. Customer documentation/certification to be provided noting "Customer is considering other specific electric service territories as alternate locations for their planned new facility or expansion."

QUALIFYING CRITERIA

Incentives awarded under the terms and conditions of this Rider to eligible Customers as determined by the Company using the guidelines as listed above in Eligibility Thresholds shall be dependent upon the number and degree of fulfillment attained of the following criteria. The Company shall have the final determination of all incentives based on the determination of issues deemed most beneficial to all stakeholders.

1. **Economic and/or Environmental Distress**

   a. Brown field site development. For purposes of this Rider, a brownfield shall be areas of NIPSCO's territory where existing transmission and distribution facilities are not at capacity and limited new facilities would be required for new business.
   b. Above-county-average wage to be paid by prospect.
   c. Other Indiana "Accelerating Growth" Guidelines, or Future State of Indiana Economic Development Goals.
   d. Any federal, state or local incentives and the degree thereof.

2. **Power Use Characteristics**

   a. High-efficiency, end-use equipment and construction technologies.
   b. "Clean Power" usage considerations.
   c. High load-factor operations

3. **Site Specific Discounts**

   a. Community master plan compliance.
   b. Industrial park location where municipal utilities, zoning and streets already exist.
   c. Utilization of existing industrial sites.
   d. Proximity to existing Company facilities.
   e. Loading of existing Company facilities.

4. **Number of Jobs Created**

   Full-time equivalent job creation per project.

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 570	FAC	Adjustment of Charges for Cost of Fuel Rider	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 571	RA	Reliability Adjustment	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 572	ECRM	Adjustment of Charges for Environmental Cost Recovery Mechanism	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 573	EERM	Adjustment of Charges for Environmental Expense Recovery Mechanism	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 574	PF	Adjustment of Charges for Power Factor	526, 527, 533, 534, 536
Rider 575	ES	Electric Spaceheating Rider to Residential Service	511
Rider 576	TS	Thermal Storage Rider	521, 523, 533
Rider 577	COG	Purchases from Cogeneration and Small Power Production Facilities	511, 521, 523, 526, 527, 533, 534, 536
Rider 578	IS	Interconnection Standards Rider	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 579	NM	Net Metering Rider – Residential Service and K-12 Schools	511, 521, 523, 533
Rider 580	EDR	Economic Development Rider	523, 533, 534

APPENDIX B
FUEL COST CHARGE

The charges in Rates Schedules 511, 521, 523, 526, 533, 534 536, 541, 544, 550, 555 and 560 are subject to the Fuel Cost Charge computed in accordance with Rider 570 – Adjustment of Charges for Cost of Fuel Rider.

Effective for all bills rendered during the [ ] billing months, the Fuel Cost Charge shall be:

A charge of $0.004693 per kilowatt hour

APPENDIX C
RELIABILITY ADJUSTMENT FACTOR

The Reliability Adjustment Factor in Rates 511, 521, 523, 524, 526, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of Qualified Pollution Control Property, set forth in Rider 571 and in accordance with the Order of the IURC approved [Date] in Cause No. 43526, as follows:

Effective for bills rendered beginning with Date billing, the Reliability Adjustment Factor shall be:

RATE SCHEDULES

Rate		Charge
Rate 511	A charge of $	per kwh used per month
Rate 521	A charge of $	per kwh used per month
Rate 523	A charge of $	per kwh used per month
Rate 526	A charge of $	per kwh used per month
Rate 533	A charge of $	per kwh used per month
Rate 534	A charge of $	per kwh used per month
Rate 536	A charge of $	per kwh used per month
Rate 541	A charge of $	per kwh used per month
Rate 544	A charge of $	per kwh used per month
Rate 550	A charge of $	per kwh used per month
Rate 555	A charge of $	per kwh used per month
Rate 560	A charge of $	per kwh used per month

APPENDIX D
ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The Environmental Cost Recovery Mechanism Factor in Rates 511, 521, 523, 524, 526, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control property, set forth in Rider 572 and in accordance with the Order of the IURC approved November 26, 2002, in Cause No. 42150, as follows:

Effective for bills rendered beginning with the [ ] 20XX billing, the Environmental Cost Recovery Mechanism Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511 A charge of $	per kwh used per month
Rate 521 A charge of $	per kwh used per month
Rate 523 A charge of $	per kwh used per month
Rate 526 A charge of $	per kwh used per month
Rate 533 A charge of $	per kwh used per month
Rate 534 A charge of $	per kwh used per month
Rate 536 A charge of $	per kwh used per month
Rate 541 A charge of $	per kwh used per month
Rate 544 A charge of $	per kwh used per month
Rate 550 A charge of $	per kwh used per month
Rate 555 A charge of $	per kwh used per month
Rate 560 A charge of $	per kwh used per month

APPENDIX E
ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The Environmental Expense Recovery Mechanism Factor in Rates 511, 521, 523, 526, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control property, set forth in Rider 573 in accordance with the Order of the IURC approved November 26, 2002, in Cause No. 42150, as follows:

Effective for bills rendered beginning with [ ] 2008 billing, the Environmental Expense Recovery Mechanism Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511 A charge of $	per kwh used per month
Rate 521 A charge of $	per kwh used per month
Rate 523 A charge of $	per kwh used per month
Rate 526 A charge of $	per kwh used per month
Rate 533 A charge of $	per kwh used per month
Rate 534 A charge of $	per kwh used per month
Rate 536 A charge of $	per kwh used per month
Rate 541 A charge of $	per kwh used per month
Rate 544 A charge of $	per kwh used per month
Rate 550 A charge of $	per kwh used per month
Rate 555 A charge of $	per kwh used per month
Rate 560 A charge of $	per kwh used per month

NDS01 CEARLS 1063702v1

Proposed Rate Summary

	Rate	511	521	523	526	527
	Name	Residential Service	General Service Small	General Service Medium	Off-Peak Service	Limited Production Large
	Code	RS	GSS	GSM	OPS	LPL
	Customer Charge	Yes	Yes	Yes	Yes	Yes
	Demand Charge	No	No	Yes	Yes	Yes
	Energy Charge	Yes	Yes	Yes	Yes	Yes
	Adjustment for Metering Voltage vs Service Voltage	No	Yes	Yes	Yes	Yes
	Deduction for Primary Service	No	No	Yes	Yes	No
	Deduction for Transmission Service	No	No	No	Yes	Yes
	Pump Charge	No	No	No	No	No
	Lamp Charge	No	No	No	No	No
	Service Drop Charge	No	No	No	No	No
	Demand Range			10kW to 300 kW	300 kW or Greater	20,000 kW or Greater
	Contract Term				3YR	3YR
	Riders					
570	Adjustment of Charges of Cost of Fuel	Yes	Yes	Yes	Yes	Yes
571	Reliability Adjustment	Yes	Yes	Yes	Yes	Yes
572	Environmental Cost Recovery Mechanism	Yes	Yes	Yes	Yes	Yes
573	Environmental Expense Recovery Mechanism	Yes	Yes	Yes	Yes	Yes
574	Adjustment of Charges for Power Factor	No	No	No	Yes	Yes
575	Electric Spaceheating Rider	Yes	No	No	No	No
576	Thermal Storage Rider	No	No	Yes	No	No
577	Cogenerator Rider	Yes	Yes	Yes	Yes	Yes
578	Interconnection Standards Riders	Yes	Yes	Yes	Yes	Yes
579	Net Metering Rider	Yes	Yes	Yes	No	No
580	Economic Development Rider	No	No	Yes	No	No
	Billing Demand			The Greater Of: 100% of Max Demand	The Greater Of: 100% of Previous 12 months (included current month) On-Peak Max 50% of Previous 24 months (included current month) Off-Peak Max	The Greater Of: Max Demand in Production Hours for current Month if a Non-Production Hour infraction occurred 100% of Previous 24 months Billing Demand 50% of Previous 24 months Non Production Hours Max

Proposed Rate Summary

Rate	533	534	536	541	544
Name	General Service Large	Industrial Service Large	Interruptible Industrial Service	Water Pumping	Railroad Power Service
Code	GSL	ISL	IIS	WP	RR
Customer Charge	Yes	Yes	Yes	Yes	Yes
Demand Charge	Yes	Yes	Yes	No	Yes
Energy Charge	Yes	Yes	Yes	Yes	Yes
Adjustment for Metering Voltage vs Service Voltage	Yes	Yes	Yes	Yes	No
Deduction for Primary Service	Yes	No	No	No	No
Deduction for Transmission Service	Yes	Yes	No	No	No
Pump Charge	No	No	No	Yes	No
Lamp Charge	No	No	No	No	No
Service Drop Charge	No	No	No	No	No
Demand Range	300 kW or Greater	10,000 kW or Greater	5,000 kW or Greater		n/a
Contract Term		3YR	3YR	3 YR - Non Metered	
Riders					
570 Adjustment of Charges of Cost of Fuel	Yes	Yes	Yes - @ CD adj for Curtailment	Yes	Yes
571 Reliability Adjustment	Yes	Yes	Yes	Yes	Yes
572 Environmental Cost Recovery Mechanism	Yes	Yes	Yes	Yes	Yes
573 Environmental Expense Recovery Mechanism	Yes	Yes	Yes	Yes	Yes
574 Adjustment of Charges for Power Factor	Yes	Yes	Yes	No	No
575 Electric Spaceheating Rider	No	No	No	No	No
576 Thermal Storage Rider	Yes	No	No	No	No
577 Cogenerator Rider	Yes	Yes	Yes	No	No
578 Interconnection Standards Riders	Yes	Yes	Yes	Yes	Yes
579 Net Metering Rider	Yes	No	No	No	No
580 Economic Development Rider	Yes	Yes	No	No	No
Billing Demand	**The Greater Of:** 90% of Previous 24 months Summer On-Peak Max 80% of Previous 24 months Non-Summer Peak Hour Max	**The Greater Of:** 90% of Previous 24 months Max Summer Hour Peak Demand 80% of Previous 24 months Max Non Summer Peak Hour Demand 80% of the Contract Demand	Contract Demand		**The Greater Of:** 100% Max Demand for month 80% of Previous 23 months Billing Demand

Energy Pricing at Time of Interruption
RT LMP, DA LMP
Failure to Curtail:
Penalty = The greater of the DA or RT LMP plus penalties

Curtailment/Interruption Limitations
Limited to the following:
1 per day
16 hours per day
3 Consecutive Days
3 days in a rolling 7 day period
400 hours per year

Proposed Rate Summary

	Rate	550	555	560
	Name	Street Lighting	Traffic and Directive Lighting	Dusk to Dawn Area Lighting
	Code	SL	TDL	DDAL
	Customer Charge	No	No	No
	Demand Charge	No	No	No
	Energy Charge	Yes	Yes	Yes
	Adjustment for Metering Voltage vs Service Voltage	No	No	No
	Deduction for Primary Service	No	No	No
	Deduction for Transmission Service	No	No	No
	Pump Charge	No	No	No
	Lamp Charge	Yes	No	Yes
	Service Drop Charge	No	Yes	No
	Demand Range			
	Contract Term			
	Riders			
570	Adjustment of Charges of Cost of Fuel	Yes	Yes	Yes
571	Reliability Adjustment	Yes	Yes	Yes
572	Environmental Cost Recovery Mechanism	Yes	Yes	Yes
573	Environmental Expense Recovery Mechanism	Yes	Yes	Yes
574	Adjustment of Charges for Power Factor	No	No	No
575	Electric Spaceheating Rider	No	No	No
576	Thermal Storage Rider	No	No	No
577	Cogenerator Rider	No	No	No
578	Interconnection Standards Riders	Yes	Yes	Yes
579	Net Metering Rider	No	No	No
580	Economic Development Rider	No	No	No
	Billing Demand			

Step II Proposed Rate Charges

	Rate 511	Rate 521	Rate 523	Rate 526	Rate 527	Rate 533	Rate 534	Rate 536	Rate 541	Rate 544
Customer-Related Charges										
Customer Charge	$10.50	$12.55	$33.00	$5,550.00	$3,525.00	$580.00	$10,200.00	$2,200.00	$35.00	$345.00
Un-Metered Customer Charge									$40.50	
Energy-Related Charges										
Energy Charge	$0.08170	$0.09801	$0.00603	$0.00458	$0.00401	$0.00503	$0.00409	$0.00450	$0.08880	$ 0.007303
Rider 575 Energy Charge above 700 kWh	$0.05788									
Non-Demand Meter			$0.09193							
Residential Pump Charge									$2.23	
Commercial Pump Charge									$2.59	
Demand Charge			$22.49	$24.63	$19.17	$21.63	$18.02	$8.91		$15.60
Service Discounts										
Primary Service Discount			$2.82	$3.02		$2.04				$3.20
Transmission Service Discount				$9.03	$8.60	$6.04	$3.86			$7.60

Step II Proposed Rate Charges - Lighting

Rate 550:

Lamp Type	Lamp Charge: Company Owned	Lamp Charge: Customer Owned Company Maintained	Lamp Charge: Customer Owned Customer Maintained
175 Watt Mercury Vapor	$8.00		
250 Watt Mercury Vapor		$3.15	
400 Watt Mercury Vapor	$9.00		
100 Watt High Pressure Sodium	$8.40	$2.60	
150 Watt High Pressure Sodium	$8.75		
250 Watt High Pressure Sodium	$9.00	$2.80	
400 Watt High Pressure Sodium	$9.00	$2.85	
Unlisted Fixture			$1.20

Energy Charge per kWh $0.03359

Rate 555:

Service Drop Charge	$16.62
Energy Charge per kWh	$0.04702

Rate 560:

Lamp Type/Equipment Type	Lamp and Equipment Charge
175 Watt Mercury Vapor	$13.00
400 Watt Mercury Vapor	$18.25
100 Watt High Pressure Sodium Dusk to Dawn Fixture	$13.00
250 Watt High Pressure Sodium Dusk to Dawn Fixture	$14.25
400 Watt High Pressure Sodium Dusk to Dawn Fixture	$15.00
150 Watt High Pressure Sodium Floodlight	$15.00
250 Watt High Pressure Sodium Floodlight	$15.00
400 Watt High Pressure Sodium Floodlight	$15.50
30 ft wood pole and span of secondary	$3.35
35 ft wood pole and span of secondary	$4.60
40 ft wood pole and span of secondary	$6.07
Guy and anchor set	$1.56
Extra span of secondary	$1.53

Energy Charge per kWh $0.03359