STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, FOR APPROVAL OF REVISED DEPRECIATION RATES, FOR APPROVAL OF TRACKING MECHANISMS PURSUANT TO IND. CODE § 8-1-2-42(a), FOR APPROVAL OF REVISED RULES AND REGULATIONS APPLICABLE TO ELECTRIC UTILITY SERVICE, AND FOR DECLINATION OF JURISDICTION AND APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.*	)	CAUSE NO. 43526

PETITIONER'S SUBMISSION OF REVISED AND SUPPLEMENTAL TESTIMONY

Volume 2 of 2

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 (Revised) contains the cost of service study summary schedules; and Petitioner's Exhibit RDG-4 (Revised) contains the revenue proof under ~~Step One and Step Two~~ the Company's revised 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

- ~~A.~~ Develops a revenue requirement for each customer class based on a target rate of return for that class;
- ~~B.~~ 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;

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

- ~~A.~~ 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 <u>Petitioner's Exhibit LEM-2 (Revised)</u>. 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.

Q7. How is the cost of service study organized?

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

Schedule 1.0 (Revised) provides a rate of return summary for the existing rates in effect;

Schedule 2.0 (Revised) provides a rate of return summary for the proposed service classifications ~~under Step One rates~~;

Schedule 2.1 (Revised) provides the revenue requirement for the proposed service classifications at parity rate of return;

Schedule 2.2 (Revised) shows the unbundled cost of service by proposed classifications at parity rate of return for each class;

Schedule 2.3 (Revised) reports unbundled unit costs by proposed service classifications at parity rate of return;

Schedule 3.0 (Revised) provides a summary of the ~~attendant~~moderated revenue requirement by class ~~for the proposed Step One rates~~ based on the Petitioner's revised filing;

Schedule 3.1 summarizes the unbundled costs for the proposed rates ~~under Step One~~under the revised filing;

Schedule 3.2 summarizes the unit costs ~~for the proposed Step One rates~~ under the revised filing;

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

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

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

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

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

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

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

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

3. Allocation is the process of apportioning each functionalized and classified cost 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. ALLOCATION

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

1. Full requirements service to the town of Argos;

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

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

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

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

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

Non-firm, or opportunity sales, were zeroed out as a pro forma adjustment. Non-firm wheeling was also zeroed out and is proposed to be handled separately as a tracker credit to retail customers. These two components are more fully discussed in the testimony of Ms. Miller.

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

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

Q19. Why did you use this approach?

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

These tests are as follows:

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

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

3. To review the extent to which peak demands in non-peak months exceed peak 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.

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

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

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

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

Q21. How was Transmission allocated to customers?

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

Q22. How were distribution system costs assigned to classes?

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

- Distribution Substations - General;
- Distribution Substations – Railroad;
- Distribution Lines – Primary-Demand;
- Distribution Lines – Secondary-Demand; and
- Line Transformers – Demand.

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

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

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

1. Class demand coincident with the control area peak;

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

3. Sum of maximum customer demands within a class

These demands, which are based on the Company's class load characteristics, generally 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.

Q24. In the Company's last base rate case decided in 1987, the IURC approved a 75 percent discount for interruptible. Why are you now using a 50 percent discount in your cost of service study?

A24. The conditions under which customers can be interrupted under the proposed rate are less restrictive as compared with the existing rate in terms of notice period, duration per interruption and maximum number of interruptions. Under the present rate the Company could interrupt for any reason at any time, not to exceed one event per day or 10 hours per day. Under the proposed rate, interruption is limited to three consecutive days not to exceed one event per day or 16 hours per day or three days in a rolling seven day period, but not to exceed 400 hours per year.

Q25. How were customer-related costs allocated?

A25. Meters, services, meter reading, billing & collecting, customer service & informational expense and sales expenses were generally allocated to customer classes based on weighting factors for each class times the number of customers in the class. The weighting factor for each class was expressed in terms of the cost for that class relative to the cost for residential – this class having a weighting factor of 1.0.

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

Weighting factors for services (Account 369) were developed based on a 50% weighting of number of customers by class and a 50% weighting of the square-root of the average maximum demand per customer times the number of customers in the class. This composite factor was used in recognition of the fact that services, which are typically difficult to identify by customer class, are related to both, number of customers as well as the capacity of the service.

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

Q26. How were income taxes assigned to classes?

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

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

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

V. PROPOSED SERVICE CLASSIFICATIONS AND RATE DESIGN

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

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

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

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

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

- ~~Σ.~~ There are 23 rates applicable to traffic, street and highway lighting, a number of 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 <u>Petitioner's Exhibit CAW-S2</u> 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:

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

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

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

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

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

The range 10 kW through 300 kW (proposed Rate 523) was chosen for the initial demand metered rate based on: (1) 10 kW being a generally used threshold in which utilities begin measurement of customer demand; (2) 300 kW being a reasonable ending 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;

- Maintenance of customer-owned fixtures by type of fixture; and
- Provision of Company-owned fixtures, including maintenance by size and type.

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

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

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

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

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

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

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

An analysis was prepared that shows losses through NIPSCO's secondary transformers at 60 percent and 100 percent loading. This analysis, which is based on the Company's current purchasing specifications and weighted by number of transformers, is contained in Schedule 3.0 accompanying my testimony. The results show losses of 1.1 percent and 1.4 percent at 60 percent and 100 percent of transformer capacity, respectively. As transformers are typically installed with rated capacity in excess of expected customer peak, the 100 percent loading case would be materially higher than the load imposed during a system peak hour. Moreover, NIPSCO's standards group has indicated that 60 percent transformer loading is more representative of the loading that transformers need to carry when system loads are between average and peak levels. In light of this, the 1.1 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.
    - Since the proposed rates are net of fuel costs, a second calculation was performed which was similar to the above, but excluded the FAC tracker

and $0.022556 per kWh, representing base fuel costs that are included in the published base rates.

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

- These calculations are shown in Schedule 1.0 of Petitioner's Exhibit RDG-4 (Revised).

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

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

  - Each charge under the proposed rate was identified along with its respective billing determinants.

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

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

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

- This rate-revenue proof under proposed rates is contained in Schedule 2.0 of Petitioner's Exhibit RDG-4 (Revised).

• 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.~~Q40.What is the purpose of your testimony relative to the application of the FERC Seven-Factor Test?

~~A41.~~A40.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.~~Q41.Why is NIPSCO seeking to revise its segregation between its transmission and distribution facilities at this time?

~~A42.~~A41In 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.~~Q42. Please provide a description of the NIPSCO electrical network?

~~A43.~~A42. 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.~~Q43. Please provide a brief overview of the actual test guidelines.

~~A44.~~A43.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 the utility. It allows the states to take into consideration traditional uses of facilities as well as specific issues for each system prior to the FERC decision over the separation.

~~Q45.~~Q44. Doesn't the FERC Uniform System of Accounts already delineate what is transmission versus what is distribution?

~~A45.~~A44. Yes, but on narrowly defined criteria. The cost of transmission and distribution facilities is typically booked based solely on operating voltage and there are variations among utilities with respect to what voltages are transmission versus distribution as well as the treatment of substations having both transmission and distribution. The Seven-Factor Test goes further by considering how systems function in a particular utility.

~~Q46.~~Q45.Please review each of the seven factors and discuss each as it pertains to NIPSCO's system.

~~A46.~~A45.The guidelines used by FERC to distinguish between transmission and distribution, and NIPSCO's understanding of each of those indicators, are as follows:

(1) Local distribution facilities are normally in close proximity to retail customers.

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

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

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

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

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

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

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

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

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

(6) <u>Meters are based at the transmission/local distribution interface to measure flows into the local distribution system</u>.

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

(7) <u>Local distribution systems will be of reduced voltage</u>.

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

XII. <u>APPLICATION OF FERC SEVEN-FACTOR TEST</u>

~~Q47.~~<u>Q46.</u>What were NIPSCO's efforts in regard to applying these guidelines to its system?

~~A47.~~<u>A46.</u>NIPSCO formed a working group and retained expert consultants in 2003 to systematically catalog and classify its facilities and to make recommendations with respect to the guidelines. To assist in this effort the Company brought together a cross sectional core resource team of 13 employees, and made available to serve as advisors to this team additional employees and outside consultants with specific expertise. Several functional areas of the Company were represented on the resource team including Planning and Engineering, Rates, Finance, Accounting, Legal and Operations. Calling upon data contained in NIPSCO's Asset

Management System the team and its consultants methodically reviewed and classified components of its transmission and distribution system.

The team accomplished several necessary and useful tasks including:

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

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

3. Delineation of land between transmission and distribution;

4. Procedure for implementing changes to its plant accounts;

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

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

~~Q48.~~Q47.Please continue.

~~A48.~~A47.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.~~Q48. How does NIPSCO classify 345 kV and 138kV facilities?

~~A49.~~A48. 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.

~~Q50.~~Q49. How does NIPSCO classify 69 kV?

~~A50.~~A49. 69 kV was classified as transmission. Virtually all of the 69 kV system is networkable and capable of performing a transmission function.

~~Q51.~~Q50. What was done with 34 kV?

~~A51.~~A50. 34 kV, which was classified as distribution in the Seven-Factor Test, were the Company's older sub-transmission voltage lines that were originally used where 69 kV was not available. Over the years, sub-transmission voltages such as 34 kV and 25 kV (in other utilities) tended to operate as distribution as is the case with NIPSCO's older 34 kV system.

~~Q52.~~Q51. How does NIPSCO treat facilities of 12.5 kV and below?

~~A52.~~A51. The technical characteristics and function of this type of facility matches the definition of local distribution under the FERC's Seven-Factor Test. These facilities are normally in close proximity to retail customers, typically provide radial service to customers, and are of reduced voltage. Power usually flows only one way into these local systems, is consumed in a relatively small geographical area and is not normally wheeled through the low voltage system to other markets. The application of the FERC Seven-Factor Test on these systems supports that they should be classified as local distribution

~~Q53.~~Q52. What was NIPSCO's approach with respect to substation assets?

~~A53.~~A52. NIPSCO considered a number of criteria, including:

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

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

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

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

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

- The high side of the substation is any voltage greater than the distribution line voltage.

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

~~Q54.~~Q53. What was done with generator leads and generator step-up transformers?

~~A54.~~A53. Both of these facilities were classified as generation, consistent with FERC precedence in NIPSCO's recent Open Access Transmission Tariff filing.

~~Q55.~~Q54. What is shown on Schedule 4.0 accompanying your testimony?

~~A55.~~A54. At the conclusion of the Seven-Factor Test a set of rules was developed in the form of an algorithm to be used to reclassify existing transmission and distribution assets in accordance with the results of the Seven-Factor Test. This would be used, as well, as the guideline for booking future plant additions to FERC primary accounts. The procedures are set forth in Schedule 4.0 of my testimony.

~~Q56.~~Q55. Have transfers among primary accounts been quantified based upon the Company's findings?

~~A56.~~A55. Yes. The net effect of plant and depreciation reserve transfers among FERC primary accounts at December 31, 2007 are detailed in an exhibit accompanying the testimony of NIPSCO Witness Mitchell E. Hershberger, and for convenience are also shown on Schedule 4.1 of Petitioner's Exhibit RDG-2.

~~Q57.~~Q56. How are the effects of these transfers reflected in this proceeding?

~~A57.~~A56. Although the actual transfers were not made to NIPSCO's plant and reserve accounts until the beginning of 2008, they are incorporated in the cost of service study as a functional reclassification among primary accounts. At year end 2008 they will be reported in their respective primary account in FERC Form 1.

~~Q58.~~Q57. Does this conclude your prepared direct testimony?

~~A58.~~A57. Yes, it does.

INDS01 1063033v9

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 (Revised) contains the cost of service study summary schedules; and Petitioner's Exhibit RDG-4 (Revised) contains the revenue proof under the Company's revised 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 (Revised). 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.

Q7. How is the cost of service study organized?

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

Schedule 1.0 (Revised) provides a rate of return summary for the existing rates in effect;

Schedule 2.0 (Revised) provides a rate of return summary for the proposed service classifications;

Schedule 2.1 (Revised) provides the revenue requirement for the proposed service classifications at parity rate of return;

Schedule 2.2 (Revised) shows the unbundled cost of service by proposed classifications at parity rate of return for each class;

Schedule 2.3 (Revised) reports unbundled unit costs by proposed service classifications at parity rate of return;

Schedule 3.0 (Revised) provides a summary of the moderated revenue requirement by class based on the Petitioner's revised filing;

Schedule 3.1 summarizes the unbundled costs for the proposed rates under the revised filing;

Schedule 3.2 summarizes the unit costs under the revised filing;

Supporting detailed schedules will be included in the supporting workpapers to be filed in this Cause.

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

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

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

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

3. Allocation is the process of apportioning each functionalized and classified cost 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. <u>FUNCTIONALIZATION</u>

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. ALLOCATION

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

1. Full requirements service to the town of Argos;

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

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

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

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

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

Non-firm, or opportunity sales, were zeroed out as a pro forma adjustment. Non-firm wheeling was also zeroed out and is proposed to be handled separately as a tracker credit to retail customers. These two components are more fully discussed in the testimony of Ms. Miller.

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

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

Q19. Why did you use this approach?

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

These tests are as follows:

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

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

3. To review the extent to which peak demands in non-peak months exceed peak 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.

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

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

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

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

Q21. How was Transmission allocated to customers?

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

Q22. How were distribution system costs assigned to classes?

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

- Distribution Substations - General;
- Distribution Substations – Railroad;
- Distribution Lines – Primary-Demand;
- Distribution Lines – Secondary-Demand; and
- Line Transformers – Demand.

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

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

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

1. Class demand coincident with the control area peak;

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

3. Sum of maximum customer demands within a class

These demands, which are based on the Company's class load characteristics, generally 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.

Q24. In the Company's last base rate case decided in 1987, the IURC approved a 75 percent discount for interruptible. Why are you now using a 50 percent discount in your cost of service study?

A24. The conditions under which customers can be interrupted under the proposed rate are less restrictive as compared with the existing rate in terms of notice period, duration per interruption and maximum number of interruptions. Under the present rate the Company could interrupt for any reason at any time, not to exceed one event per day or 10 hours per day. Under the proposed rate, interruption is limited to three consecutive days not to exceed one event per day or 16 hours per day or three days in a rolling seven day period, but not to exceed 400 hours per year.

Q25. How were customer-related costs allocated?

A25. Meters, services, meter reading, billing & collecting, customer service & informational expense and sales expenses were generally allocated to customer classes based on weighting factors for each class times the number of customers in the class. The weighting factor for each class was expressed in terms of the cost for that class relative to the cost for residential – this class having a weighting factor of 1.0.

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

Weighting factors for services (Account 369) were developed based on a 50% weighting of number of customers by class and a 50% weighting of the square-root of the average maximum demand per customer times the number of customers in the class. This composite factor was used in recognition of the fact that services, which are typically difficult to identify by customer class, are related to both, number of customers as well as the capacity of the service.

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

Q26. How were income taxes assigned to classes?

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

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

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

V. PROPOSED SERVICE CLASSIFICATIONS AND RATE DESIGN

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

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

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

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

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

- There are 23 rates applicable to traffic, street and highway lighting, a number of 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-S2 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:

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

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

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

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

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

The range 10 kW through 300 kW (proposed Rate 523) was chosen for the initial demand metered rate based on: (1) 10 kW being a generally used threshold in which utilities begin measurement of customer demand; (2) 300 kW being a reasonable ending 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;

- Maintenance of customer-owned fixtures by type of fixture; and
- Provision of Company-owned fixtures, including maintenance by size and type.

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

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

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

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

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

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

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

An analysis was prepared that shows losses through NIPSCO's secondary transformers at 60 percent and 100 percent loading. This analysis, which is based on the Company's current purchasing specifications and weighted by number of transformers, is contained in Schedule 3.0 accompanying my testimony. The results show losses of 1.1 percent and 1.4 percent at 60 percent and 100 percent of transformer capacity, respectively. As transformers are typically installed with rated capacity in excess of expected customer peak, the 100 percent loading case would be materially higher than the load imposed during a system peak hour. Moreover, NIPSCO's standards group has indicated that 60 percent transformer loading is more representative of the loading that transformers need to carry when system loads are between average and peak levels. In light of this, the 1.1 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.
    - Since the proposed rates are net of fuel costs, a second calculation was performed which was similar to the above, but excluded the FAC tracker

and $0.022556 per kWh, representing base fuel costs that are included in the published base rates.

- The calculation above, yielded gross margin (revenues less fuel costs) for each rate. A further adjustment was then made that reduced the margin: (1) in each temperature-sensitive rate to recognize that 2007 was a warmer than normal summer; and (2) to reduce kWh for the off-peak metal melters to projected levels in accordance with the provisions of their rate.
- These calculations are shown in Schedule 1.0 of Petitioner's Exhibit RDG-4 (Revised).

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

- This step relied on the mapping of individual customer energy, demand and margin from their present rate to their applicable proposed rate based on that rate's applicability criteria.
- Each charge under the proposed rate was identified along with its respective billing determinants.
- Two sets of computations were performed: (1) In one set, customer, energy and demand charges were developed such that the total calculated gross margin for that rate equaled, in sum, the gross margin that customers mapped into each rate were paying under current rates; and (2) In the

second set of computations, customer, energy and demand charges were developed such that the total calculated gross margin for that rate equaled the total gross margin that was targeted by proposed rate.

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

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

  - This rate-revenue proof under proposed rates is contained in Schedule 2.0 of Petitioner's Exhibit RDG-4 (Revised).

- 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.

VIII. SUMMARY OF STEP TWO RATE INCREASE

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IX. SEVEN-FACTOR TEST

Q40. What is the purpose of your testimony relative to the application of the FERC Seven-Factor Test?

A40. 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.

Q41. Why is NIPSCO seeking to revise its segregation between its transmission and distribution facilities at this time?

A41In 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

Q42.Please provide a description of the NIPSCO electrical network?

A42. 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

Q43. Please provide a brief overview of the actual test guidelines.

A43.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 the utility. It allows the states to take into consideration traditional uses of facilities as well as specific issues for each system prior to the FERC decision over the separation.

Q44. Doesn't the FERC Uniform System of Accounts already delineate what is transmission versus what is distribution?

A44. Yes, but on narrowly defined criteria. The cost of transmission and distribution facilities is typically booked based solely on operating voltage and there are variations among utilities with respect to what voltages are transmission versus distribution as well as the treatment of substations having both transmission and distribution. The Seven-Factor Test goes further by considering how systems function in a particular utility.

Q45.Please review each of the seven factors and discuss each as it pertains to NIPSCO's system.

A45.The guidelines used by FERC to distinguish between transmission and distribution, and NIPSCO's understanding of each of those indicators, are as follows:

(1) Local distribution facilities are normally in close proximity to retail customers.

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

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

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

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

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

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

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

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

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

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

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

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

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

XII. APPLICATION OF FERC SEVEN-FACTOR TEST

Q46.What were NIPSCO's efforts in regard to applying these guidelines to its system?

A46.NIPSCO formed a working group and retained expert consultants in 2003 to systematically catalog and classify its facilities and to make recommendations with respect to the guidelines. To assist in this effort the Company brought together a cross sectional core resource team of 13 employees, and made available to serve as advisors to this team additional employees and outside consultants with specific expertise. Several functional areas of the Company were represented on the resource team including Planning and Engineering, Rates, Finance, Accounting, Legal and Operations. Calling upon data contained in NIPSCO's Asset

Management System the team and its consultants methodically reviewed and classified components of its transmission and distribution system.

The team accomplished several necessary and useful tasks including:

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

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

3. Delineation of land between transmission and distribution;

4. Procedure for implementing changes to its plant accounts;

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

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

Q47.Please continue.

A47.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.

Q48. How does NIPSCO classify 345 kV and 138kV facilities?

A48. 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.

Q49. How does NIPSCO classify 69 kV?

A49. 69 kV was classified as transmission. Virtually all of the 69 kV system is networkable and capable of performing a transmission function.

Q50. What was done with 34 kV?

A50. 34 kV, which was classified as distribution in the Seven-Factor Test, were the Company's older sub-transmission voltage lines that were originally used where 69 kV was not available. Over the years, sub-transmission voltages such as 34 kV and 25 kV (in other utilities) tended to operate as distribution as is the case with NIPSCO's older 34 kV system.

Q51. How does NIPSCO treat facilities of 12.5 kV and below?

A51. The technical characteristics and function of this type of facility matches the definition of local distribution under the FERC's Seven-Factor Test. These facilities are normally in close proximity to retail customers, typically provide radial service to customers, and are of reduced voltage. Power usually flows only one way into these local systems, is consumed in a relatively small geographical area and is not normally wheeled through the low voltage system to other markets. The application of the FERC Seven-Factor Test on these systems supports that they should be classified as local distribution

Q52. What was NIPSCO's approach with respect to substation assets?

A52. NIPSCO considered a number of criteria, including:

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

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

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

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

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

- The high side of the substation is any voltage greater than the distribution line voltage.

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

Q53. What was done with generator leads and generator step-up transformers?

A53. Both of these facilities were classified as generation, consistent with FERC precedence in NIPSCO's recent Open Access Transmission Tariff filing.

Q54. What is shown on Schedule 4.0 accompanying your testimony?

A54. At the conclusion of the Seven-Factor Test a set of rules was developed in the form of an algorithm to be used to reclassify existing transmission and distribution assets in accordance with the results of the Seven-Factor Test. This would be used, as well, as the guideline for booking future plant additions to FERC primary accounts. The procedures are set forth in Schedule 4.0 of my testimony.

Q55. Have transfers among primary accounts been quantified based upon the Company's findings?

A55. Yes. The net effect of plant and depreciation reserve transfers among FERC primary accounts at December 31, 2007 are detailed in an exhibit accompanying the testimony of NIPSCO Witness Mitchell E. Hershberger, and for convenience are also shown on Schedule 4.1 of Petitioner's Exhibit RDG-2.

Q56. How are the effects of these transfers reflected in this proceeding?

A56. Although the actual transfers were not made to NIPSCO's plant and reserve accounts until the beginning of 2008, they are incorporated in the cost of service study as a functional reclassification among primary accounts. At year end 2008 they will be reported in their respective primary account in FERC Form 1.

Q57. Does this conclude your prepared direct testimony?

A57. Yes, it does.

INDS01 1063033v9

VERIFICATION

I, Robert D. Greneman, Associate Director for 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 Greneman

Robert D. Greneman

Date: December 17, 2008

Petitioner's Exhibit RDG-S1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY

OF

ROBERT D. GRENEMAN

ASSOCIATE DIRECTOR

SPONSORING PETITIONER'S EXHIBITS RDG-2, REVISED SCHEDULE 2.0, RDG-3 (REVISED) AND RDG-4 (REVISED)

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY OF ROBERT D. GRENEMAN

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

A1. Robert D. Greneman, Associate Director, Stone & Webster Management Consultants, Inc., 1 Main Street, Cambridge, MA

Q2. Did you previously submit Prepared Direct Testimony as a part of the Case-In-Chief of Petitioner Northern Indiana Public Service Company ("NIPSCO") filed with the Commission in this Cause on August 29, 2008?

A2. Yes. My Prepared Direct Testimony has been marked as <u>Petitioner's Exhibit RDG-1</u>.

Q3. What is the purpose of your Supplemental Direct Testimony?

A3. The purpose of my Supplemental Direct Testimony is to describe the changes to my Prepared Direct Testimony, exhibits and accompanying workpapers in this proceeding as the result of the new in-service date of the Sugar Creek generating station and its impact on NIPSCO's revenue requirement.

Q5. Please describe the supplemental exhibits and workpapers that you are sponsoring.

A5. With regard to my exhibits:

- Exhibit RDG-2, Schedule 2.0, which shows earned rates of return under proposed service classifications, is being replaced with Schedule 2.0 (Revised).
- Exhibit RDG-2, Schedule 2.1 is eliminated in its entirety.

- Exhibit RDG-3, Schedule 1.0, which shows earned rates of return under present service classifications, Schedule 2.0, which shows earned rates of return under proposed service classifications, Schedule 2.1, which shows the revenue requirement at parity rate of return under the proposed service classifications, Schedule 2.2, which develops the unbundled revenue requirement at parity rate of return under the proposed service classifications and Schedule 2.3, which computes unit costs at parity rate of return under the proposed service classifications are being replaced with Exhibit RDG-3 (Revised).

- Exhibit RDG-3, Schedule 3.0, which shows Step 1 revenue requirement at moderated rates of return, Schedule 3.1, which shows the unbundled revenue requirement at the moderated rates of return and Schedule 3.2, which shows unit costs at moderated rates of return are being replaced with Exhibit RDG-3 (Revised), to show NIPSCO's revised filing at moderated rates of return for each customer class.

- Exhibit RDG-3, Schedules 4.0, 4.1 and 4.2 which pertain to the cost of service study with Sugar Creek in Step 2, are deleted in their entirety and is being replaced with Exhibit RDG-3 (Revised), Schedules 4.0, 4.1, 4.2 and 4.3, which details the steps used to moderate increases to customer classes under the Company's revised filing.

- Exhibit RDG-4, which contains the proof of revenues under Step 2 is replaced with Exhibit RDG-4 (Revised), including Schedule 1.0, which shows the proof of revenues under present rates and Schedule 2.0, which shows the proof of revenues under the revised proposed rates.

With regard to my workpapers that have been filed with the Commission,

- WP Nos. 1.0, 1.1, 2.0, 2.1 and 2.2 are being replaced with revised WP Nos. 1.0, 1.1, 2.0, 2.1 and 2.2, which pertain to the Company's revised revenue requirement.
- WP Nos. 3.0, 3.1 and 3.2, which deal with Sugar Creek in former Step 2 are deleted in their entirety.
- WP Nos. 4.0 through 10.0 remain intact.
- WP No. 11.0, which sets forth the proof of revenues under present rates, is being replaced with revised workpaper 11.0.
- WP No. 12.0, which contains typical bill comparisons for the former Step 1 increase, is being replaced with WP No. 12.0 to show typical bill comparisons under the revised revenue requirement.
- WP. No. 12.1 is deleted in its entirety.

Q6. Are there any salient changes to your Direct Prepared Testimony as a result of NIPSCO's revised revenue requirement?

A6. No. The only changes to my Direct Prepared Testimony are those that pertain to references to my exhibits and workpapers, as originally filed.

Q7. Have you made any changes in the cost of service methodology?

A7. The revised cost of service methodology is the same as before with two exceptions. One is to correct for a misallocation of uncollectible write-offs under the proposed service classifications. The effect on Residential Rate 511 was to increase the moderated revenue requirement by approximately $435,000. The other is to revise the allocation factor for line transformers. In the as-filed cost of service, line transformers were allocated based on class diversified demand. The revised allocation of line transformers is based on an average of class diversified demand and the sum of customer individual demands. This change was made because this composite factor is more closely related to a combination of diversified and undiversified demand on these facilities.

Q8. Where can the complete cost of service study be found?

Q8. The complete cost of service studies under present and proposed service classifications are voluminous and are being submitted to the Commission as supplemental workpapers. However, cost of service summary schedules are contained in the supplemental exhibits that accompany my supplemental direct testimony, as noted above.

Q9. Were any notable changes made to the rate design now being proposed as a result of this revised filing?

A9. No. The principles used to design the revised rates are the same as originally filed. Only the target revenues for the proposed service classifications changed. As was done in NIPSCO's original filing in this proceeding, revenues were moderated in order to reduce the impact of the proposed rate increase to customer classes.

Q10. Please explain the methodology that was used to moderate the increases to each customer class.

A10. Moderating the rate increase to customer classes involved a two-step process.

In the first step, movement was made to more closely align gross margin from NIPSCO's last approved rate design with its current pro forma cost of service at the Company's overall earned rate of return of 6.49 percent. The manner in which this was accomplished was as follows:

- For each customer class for which an increase was needed to bring that class to parity return, only 25 percent of that increase was applied.
- The shortfall in gross margin was made up by moderating the decrease to those customer classes for which a decrease was indicated. The shortfall was apportioned based on the full indicated decreases needed to bring these classes to parity with the overall earned rate of return.

In the second step, the Company's requested increase (the difference between 8.37 percent and 6.49 percent overall rate of return) was applied to each customer class based on full cost responsibility. The method used was to compute the difference in cost of service based revenue requirement at 8.37 percent parity return for each class and 6.49 percent earned return for each class and to apply this difference to the increase resulting from step 1, above.

Q11. Have you prepared a schedule that demonstrates these steps?

A11. Yes. Exhibit RDG-3 (Revised), Schedules 4.0, 4.1, 4.2 and 4.3 contain the details of the analytics.

Q12. What effect did each of the two steps in the moderation procedure have on the overall class increase?

A12. The class impact of each step as well as the overall impact is summarized on Schedule 4.0 of Exhibit RDG-3 (Revised).

Lines 6 and 7 of this schedule show the impact on customer classes based on the Company's revised revenue requirement and parity rate of return of 8.37 percent for each class. Based on this full cost of service increase to customer classes, the overall Company increase would be 9.88 percent and Residential would be impacted with a 31.42 percent increase.

Lines 2 and 3 show the impact on each customer class based on setting a parity rate of return for each class at the Company overall earned return of 6.49 percent. If this full realignment of 1985 rates were implemented, with no increase to the overall revenue requirement, it would result in a 19.58 percent increase to Residential Rate 511.

Lines 12 and 13, the result of the first step in the moderation process, shows the impact of moderating the full realignment of 1985 rates by implementing a 25 percent movement towards parity. The effect on Residential is to reduce the 19.58 percent increase to 4.89 percent.

Lines 10 and 11, the second step in the moderation process, shows the overlay of the Company's requested increase at full cost responsibility to each customer class. The impact is a 9.88 percent overall increase, with an 11.84 percent increase to Residential.

Lines 15 and 16, show the result of adding the step 1 moderated increase to the step 2 overlay. The effect on Residential is an overall increase of 16.73 percent. It should be noted that this is less than the 19.58 percent increase to Residential if full realignment of 1985 rates were implemented with no increase to the overall revenue requirement.

Lastly, lines 18-23 of Schedule 4.0 confirms that there is a significant improvement in rate of return index as compared with NIPSCO's existing rates.

Q13. Does this complete your direct supplemental testimony?

A13. Yes, it does.

VERIFICATION

I, Robert D. Greneman, Associate Director for 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 Greneman

Robert D. Greneman

Date: December 17, 2008

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	3.39%
Rate 521 - General Service Small	15.88%
Rate 523 - General Service Medium	9.95%
Rate 526 - Off-Peak Service	2.23%
Rate 527 - Limited Production Large	13.21%
Rate 533 - General Service Large	8.62%
Rate 534 - Industrial Service Large	7.57%
Rate 536 - Interruptible Industrial Service	1.90%
Rate 541 - Water Pumping	-1.65%
Rate 544 - Railroad Power Service	11.88%
Rate 550 - Street and Area Lighting	14.89%
Rate 555 - Traffic and Directive Lighting	15.68%
Rate 560 - Dusk-to-Dawn Lighting	-3.74%
Interdepartmental	-2.38%
Total Company	6.49%

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

Line No	Alloc. Factor	Acct		Total Company	Residential Rate 811	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comm Rate 820	GS Rate 821	Comm SH Rate 822	GS Rate 823	GS Large Rate 824
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			RATE OF RETURN SUMMARY									
1			OPERATING REVENUES	888,318,151	285,300,788	3,006,447	874,314	117,528	128,835,157	664,363	102,529,459	113,626,060
2												
3			OPERATING EXPENSES									
4			OPERATION & MAINTENANCE	353,377,324	130,851,647	1,206,968	415,524	269,429	38,369,567	382,527	34,995,361	35,402,378
5			DEPRECIATION	228,307,234	85,602,937	762,563	256,014	138,927	25,254,353	241,786	24,479,088	23,052,708
6			TAXES OTHER THAN INCOME	55,347,555	21,284,946	198,880	67,532	35,813	6,848,238	67,615	6,066,331	5,796,838
7												
8			TOTAL OPERATING EXPENSES	637,032,113	237,739,530	2,168,411	739,070	444,169	70,472,158	691,928	65,540,780	64,251,924
9												
10			INCOME TAXES	78,229,648	10,481,427	259,336	28,199	-148,719	21,010,216	-39,342	12,414,959	17,606,765
11												
12			NET OPERATING INCOME	173,056,390	37,079,832	578,699	107,045	-177,922	37,352,783	11,777	24,573,719	31,767,371
13												
14			RATE BASE	2,665,421,828	992,413,907	9,064,515	3,003,260	1,849,401	298,392,007	3,185,531	290,835,726	271,345,909
15												
16			RATE OF RETURN - %	6.49%	3.74%	6.38%	3.56%	-9.62%	12.52%	0.37%	8.45%	11.71%

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

Line No	Alloc. Factor	Acct		Comm GS Sm. Rate 817	Metel Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	Int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	WW Pumping Rate 842	Rate 844 Railroad
				(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			RATE OF RETURN SUMMARY									
1			OPERATING REVENUES	40,191	6,956,147	29,325,516	3,854,720	25,285,127	8,135,085	1,767,711	33,611	1,354,610
2												
3			OPERATING EXPENSES									
4			OPERATION & MAINTENANCE	116,911	3,420,481	11,038,343	1,207,841	11,304,876	8,013,666	1,066,537	1,640	329,775
5			DEPRECIATION	96,796	2,057,194	7,079,710	748,995	6,589,930	3,886,735	765,246	955	276,524
6			TAXES OTHER THAN INCOME	18,125	479,449	1,703,949	181,174	1,459,588	820,228	203,916	687	91,356
7												
8			TOTAL OPERATING EXPENSES	231,832	5,957,124	19,822,003	2,138,010	19,354,394	12,720,629	2,035,700	3,282	697,654
9												
10			INCOME TAXES	-87,661	192,711	3,114,185	618,819	1,721,901	-2,282,775	-194,879	12,192	228,628
11												
12			NET OPERATING INCOME	-103,980	806,311	6,389,328	1,097,891	4,208,832	-2,302,768	-73,110	18,137	428,329
13												
14			RATE BASE	1,129,009	23,965,024	83,263,373	8,683,341	76,980,361	47,979,084	9,753,896	11,171	4,254,824
15												
16			RATE OF RETURN - %	-9.21%	3.36%	7.67%	12.64%	5.47%	-4.80%	-0.75%	162.36%	10.07%

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

Line No	Alloc. Factor	Acct		Ind. Off-Peak Rate 845	Firm Contract Rate 847	ED GS Lrg. Rate 848	Backup & Maint 2100	Street Lighting	Traffic Lighting	Dusk-to-Dawn Lighting	Interdepart-mental
				(S)	(T)	()	(U)	(V)	(W)	(X)	(Y)
			RATE OF RETURN SUMMARY								
1			OPERATING REVENUES	274,484	163,290,828	0	1,243,311	7,491,655	847,447	1,941,766	1,521,827
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	12,064	69,946,755	0	149,728	2,094,201	511,559	1,239,048	1,030,498
5			DEPRECIATION	5,902	43,401,485	0	53,922	1,603,303	395,574	836,701	719,885
6			TAXES OTHER THAN INCOME	5,457	9,056,065	0	27,446	517,040	109,114	152,717	155,051
7											
8			TOTAL OPERATING EXPENSES	23,423	122,404,304	0	231,096	4,214,544	1,016,248	2,228,466	1,905,434
9											
10			INCOME TAXES	101,191	12,041,049	0	404,337	1,244,406	-108,745	-157,172	-231,380
11											
12			NET OPERATING INCOME	149,870	28,845,475	0	607,877	2,032,705	-60,056	-129,528	-152,227
13											
14			RATE BASE	62,490	511,548,554	0	663,031	9,288,607	4,550,777	4,621,964	8,576,066
15											
16			RATE OF RETURN - %	239.83%	5.64%	0.00%	91.68%	21.88%	-1.32%	-2.80%	-1.78%

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
Schedule 1.0

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

Line No	Alloc. Factor	Acct		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	288,984,884	44,359,220	148,458,024	7,320,390	10,902,740	185,407,037	157,736,051
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	353,377,324	134,799,522	12,336,141	47,313,424	3,905,777	3,535,228	65,891,565	61,468,408
5			DEPRECIATION	228,307,234	88,768,735	7,547,090	32,790,727	2,281,456	1,977,462	43,134,251	38,367,897
6			TAXES OTHER THAN INCOME	55,347,555	22,004,001	2,272,610	8,480,548	537,389	466,837	10,627,729	7,674,415
7											
8			TOTAL OPERATING EXPENSES	637,032,113	245,572,259	22,155,840	88,584,699	6,724,622	5,979,527	119,653,545	107,510,720
9											
10			INCOME TAXES	78,229,648	8,450,629	8,218,082	20,786,199	7,723	1,784,986	22,172,384	16,395,935
11											
12			NET OPERATING INCOME	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
13											
14			RATE BASE	2,665,421,828	1,031,984,823	88,053,958	392,829,890	26,402,623	23,752,033	505,427,064	447,010,157
15											
16			RATE OF RETURN - %	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%

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

Line No	Alloc. Factor	Acct		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)
			RATE OF RETURN SUMMARY							
1			OPERATING REVENUES	30,171,306	1,836,443	1,352,284	7,511,622	807,214	1,947,317	1,523,618
2										
3			OPERATING EXPENSES							
4			OPERATION & MAINTENANCE	17,656,615	1,202,408	306,473	2,334,427	230,657	1,305,068	1,091,611
5			DEPRECIATION	8,678,577	875,037	252,161	1,801,377	165,254	891,146	776,063
6			TAXES OTHER THAN INCOME	2,010,315	234,993	84,095	568,678	48,493	166,915	170,538
7										
8			TOTAL OPERATING EXPENSES	28,345,508	2,312,438	642,729	4,704,483	444,404	2,363,128	2,038,212
9										
10			INCOME TAXES	-205,290	-291,808	253,620	1,030,601	134,036	-215,914	-291,536
11										
12			NET OPERATING INCOME	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
13										
14			RATE BASE	106,831,331	11,180,429	3,838,573	11,928,214	1,459,342	5,347,652	9,375,741
15										
16			RATE OF RETURN - %	1.90%	-1.65%	11.88%	14.89%	15.68%	-3.74%	-2.38%

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
Schedule 2.0

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

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 Industral Lrg (H)
	REVENUE REQUIREMENT AT TARGET ROR								
A1	EARNED RATE OF RETURN	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%
A2									
A3	RATE BASE	2,665,421,829	1,031,984,823	88,053,958	392,829,890	26,402,623	23,752,033	505,427,064	447,010,157
A4									
A5	TARGET RATE OF RETURN	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%
A6									
A7	REQUIRED RETURN ON RATE BASE	223,095,807	86,377,130	7,370,116	32,879,862	2,209,900	1,988,045	42,304,245	37,414,750
A8	EARNED RETURN ON RATE BASE	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
A9									
A10	REQUIRED INCREASE IN RETURN	50,039,417	51,415,134	-6,615,182	-6,207,264	1,621,854	-1,150,182	-1,276,863	3,585,355
A11									
A12	ASSOC. INCR IN INCOME TAXES	34,207,310	35,147,759	-4,522,186	-4,243,331	1,108,711	-786,273	-872,873	2,450,974
A13									
A14	TOTAL INCREASE IN RETURN & INC TAXES	84,246,727	86,562,893	-11,137,368	-10,450,596	2,730,565	-1,936,454	-2,149,736	6,036,329
A15									
A16	INCREASE IN REVENUE-RELATED	1,497,954	1,539,137	-198,029	-185,817	48,551	-34,431	-38,224	107,329
A17									
A18	OPERATING EXPENSES PER COSS	637,032,113	245,572,259	22,155,840	88,584,699	6,724,622	5,979,527	119,653,545	107,510,720
A19	INCOME TAXES PER COSS	78,229,647	8,450,629	8,218,082	20,786,199	7,723	1,784,986	22,172,384	16,395,935
A20	RETURN PER COSS	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
A21									
A22	TOTAL REVENUE REQUIREMENT	974,062,831	377,086,913	33,023,824	137,821,611	10,099,506	8,931,855	183,219,077	163,879,709
A23	LESS OTHER REVENUES	20,405,463	8,552,852	836,754	2,322,025	183,105	124,775	3,163,543	3,645,455
A24	REVENUE REQUIREMENT FROM RATES	953,657,369	368,534,061	32,187,070	135,499,587	9,916,401	8,807,080	180,055,535	160,234,254
A25									
A26	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
A27									
A28	REVENUE INCREASE TO BASE RATES	85,744,681	88,102,030	-11,335,397	-10,636,413	2,779,116	-1,970,886	-2,187,960	6,143,658
A29	PERCENT REVENUE INCREASE	9.88%	31.42%	-26.04%	-7.28%	38.94%	-18.29%	-1.20%	3.99%
A30									
A31									
A32	TOTAL RETURN AND INCOME TAXES	335,532,764	129,975,518	11,066,012	49,422,730	3,326,334	2,986,759	63,603,756	56,261,660

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

Line No		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)
	REVENUE REQUIREMENT AT TARGET ROR							
A1	EARNED RATE OF RETURN	1.90%	-1.65%	11.88%	14.89%	15.68%	-3.74%	-2.38%
A2								
A3	RATE BASE	106,831,331	11,180,429	3,838,573	11,928,214	1,459,342	5,347,652	9,375,741
A4								
A5	TARGET RATE OF RETURN	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%
A6								
A7	REQUIRED RETURN ON RATE BASE	8,941,782	935,802	321,289	998,392	122,147	447,598	784,749
A8	EARNED RETURN ON RATE BASE	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
A9								
A10	REQUIRED INCREASE IN RETURN	6,910,694	1,119,988	-134,646	-778,147	-106,627	647,496	1,007,808
A11								
A12	ASSOC. INCR IN INCOME TAXES	4,724,201	765,632	-92,045	-531,947	-72,891	442,633	688,945
A13								
A14	TOTAL INCREASE IN RETURN & INC TAXES	11,634,894	1,885,620	-226,692	-1,310,093	-179,519	1,090,130	1,696,753
A15								
A16	INCREASE IN REVENUE-RELATED	206,875	33,527	-4,031	-23,294	-3,192	19,383	30,169
A17								
A18	OPERATING EXPENSES PER COSS	28,345,508	2,312,438	642,729	4,704,483	444,404	2,363,128	2,038,212
A19	INCOME TAXES PER COSS	-205,290	-291,808	253,620	1,030,601	134,036	-215,914	-291,536
A20	RETURN PER COSS	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
A21								
A22	TOTAL REVENUE REQUIREMENT	42,013,075	3,755,591	1,121,562	6,178,235	624,504	3,056,830	3,250,540
A23	LESS OTHER REVENUES	1,330,883	42,003	14,101	39,095	8,253	100,295	42,325
A24	REVENUE REQUIREMENT FROM RATES	40,682,193	3,713,588	1,107,461	6,139,139	616,250	2,956,535	3,208,216
A25								
A26	PRESENT RATE REVENUES	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
A27								
A28	REVENUE INCREASE TO BASE RATES	11,841,769	1,919,147	-230,722	-1,333,388	-182,710	1,109,513	1,726,923
A29	PERCENT REVENUE INCREASE	41.06%	106.95%	-17.24%	-17.84%	-22.87%	60.07%	116.58%
A30								
A31								
A32	TOTAL RETURN AND INCOME TAXES	13,460,693	1,409,626	482,863	1,497,046	183,291	674,318	1,182,159

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

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 Industral Lrg (H)
	TOTAL COST OF SERVICE *(Revenue-related distributed)*								
1	PRODUCTION								
2	FIXED	493,556,288	177,999,264	12,537,013	67,967,888	4,562,773	3,263,060	96,692,066	106,773,729
3	VARIABLE	74,980,645	16,497,323	1,883,317	9,521,586	991,785	1,266,035	15,586,340	19,695,264
4									
5	TRANSMISSION SUBSTAS.	85,308,184	23,232,547	2,108,477	11,549,304	994,243	595,460	17,137,051	21,231,084
6	TRANSMISSION LINES	33,767,016	9,211,722	835,693	4,574,545	393,621	235,215	6,785,273	8,395,952
7									
8	DISTRIB. SUBSTAS - GENERAL	36,709,020	16,670,178	1,259,004	6,580,136	634,783	985,347	8,855,058	745,160
9	DISTRIB. SUBSTAS - RAILROAD	665,464	0	0	0	0	0	0	0
10									
11	DIST. LINES PRIMARY - DEMAND	90,103,875	40,908,011	3,091,004	16,153,872	1,558,116	2,420,495	21,739,341	1,829,772
12	DIST. LINES PRIMARY - CUSTOMER	0	0	0	0	0	0	0	0
13									
14	DIST. LINES SEC. - DEMAND	38,930,905	21,205,654	3,373,165	9,640,723	25,230	0	3,886,655	0
15	DIST. LINES SEC. - CUSTOMER	0	0	0	0	0	0	0	0
16									
17	LINE TRANSFORMERS - DEMAND	22,719,629	13,020,364	981,139	4,987,827	22,177	0	2,984,008	0
18	LINE TRANSFORMERS - CUSTOMER	0	0	0	0	0	0	0	0
19									
20	SERVICES	9,918,930	8,467,115	809,577	546,338	179	0	63,472	0
21	METERS -GENERAL	19,716,627	12,395,771	2,167,305	2,663,440	54,708	6,816	1,883,163	259,925
22	STREET LIGHTING	4,783,558	0	0	0	0	0	0	0
23	DUSK-TO-DAWN LIGHTING	2,336,910	0	0	0	0	0	0	0
24	METER READING	10,176,648	5,662,878	582,963	494,176	39,143	3,560	3,316,673	45,866
25	BILLING & COLLECTING	24,509,591	19,624,976	2,026,180	575,618	598,622	31,084	682,597	801,215
26	CUSTOMER ACCOUNTS OTHER	217,208	186,625	19,203	5,417	5	0	436	6
27	CUSTOMER INFORMATION	1,540,182	258,431	184,328	145,857	40,927	0	435,923	456,177
28	SALES EXPENSE	3,716,687	3,193,203	328,702	92,858	88	8	7,478	103
29	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
30	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
31									
32	REVENUE TAXES	0	0	0	0	0	0	0	0
33									
34	TOTAL COST OF SERVICE FROM RATES	953,657,369	368,534,061	32,187,070	135,499,587	9,916,401	8,807,080	180,055,535	160,234,254

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

Line No		Rate 536 Interrupt. Ind. (I)	Rate 541 Water Pumpg (J)	Rate 544 Railroad (K)	Rate 550 Street Ltg (L)	Rate 555 Traffic Ltg (M)	Rate 560 Dusk-to-Dawn (N)	Interdept'l (O)
	TOTAL COST OF SERVICE *(Revenue-related distributed)*							
1	PRODUCTION							
2	FIXED	20,794,115	506,000	238,119	310,522	198,070	88,314	1,625,358
3	VARIABLE	8,757,019	119,904	81,924	235,500	43,658	66,917	234,075
4								
5	TRANSMISSION SUBSTAS.	7,890,751	109,464	84,483	98,595	37,360	26,774	212,591
6	TRANSMISSION LINES	3,109,419	43,411	33,443	39,100	14,803	10,625	84,195
7								
8	DISTRIB. SUBSTAS - GENERAL	0	517,083	0	172,503	16,091	46,186	227,491
9	DISTRIB. SUBSTAS - RAILROAD	0	0	665,464	0	0	0	0
10								
11	DIST. LINES PRIMARY - DEMAND	0	1,268,614	0	423,572	39,513	113,296	558,269
12	DIST. LINES PRIMARY - CUSTOMER	0	0	0	0	0	0	0
13								
14	DIST. LINES SEC. - DEMAND	0	519,344	0	142,630	13,305	38,163	86,035
15	DIST. LINES SEC. - CUSTOMER	0	0	0	0	0	0	0
16								
17	LINE TRANSFORMERS - DEMAND	0	363,123	0	134,730	12,563	36,090	177,607
18	LINE TRANSFORMERS - CUSTOMER	0	0	0	0	0	0	0
19								
20	SERVICES	0	32,250	0	0	0	0	0
21	METERS -GENERAL	112,784	170,935	0	0	0	0	1,781
22	STREET LIGHTING	0	0	0	4,545,668	237,891	0	0
23	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	2,336,910	0
24	METER READING	17,816	9,183	3,574	0	0	0	815
25	BILLING & COLLECTING	246	31,826	446	21,360	1,763	113,659	0
26	CUSTOMER ACCOUNTS OTHER	2	303	0	813	67	4,330	0
27	CUSTOMER INFORMATION	1	16,972	0	245	20	1,302	0
28	SALES EXPENSE	40	5,178	8	13,903	1,148	73,969	0
29	DIRECT TO RETAIL	0	0	0	0	0	0	0
30	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
31								
32	REVENUE TAXES	0	0	0	0	0	0	0
33								
34	TOTAL COST OF SERVICE FROM RATES	40,682,193	3,713,588	1,107,461	6,139,139	616,250	2,956,535	3,208,216

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
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, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

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 Industral 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***								
11			*$/KWH*		*$/KW/MO.*	*$/KW/MO.*	*$/KW/MO.*	*$/KW/MO.*	*$/KW/MO.*
12	*PRODUCTION FIXED*		*$ 0.05157*	*$ 0.03156*	*$ 9.74*	*$ 14.17*	*$ 6.33*	*$ 11.39*	*$ 10.37*
13									
14	*PRODUCTION VARIABLE*		*$ 0.00478*	*$ 0.00474*	*$ 0.00476*	*$ 0.00433*	*$ 0.00429*	*$ 0.00449*	*$ 0.00421*
15									
16	*TRANSMISSION*		*$ 0.00940*	*$ 0.00741*	*$ 2.31*	*$ 4.31*	*$ 1.61*	*$ 2.82*	*$ 2.88*
17									
18	*DISTRIBUTION*								
19	*PRIMARY*		*$ 0.01668*	*$ 0.01095*	*$ 3.26*	*$ 7.13*	*$ 6.61*	*$ 3.70*	*$ 3.64*
20	*SECONDARY*		*$ 0.00992*	*$ 0.01096*	*$ 2.17*	*$ 3.78*	*$ -*	*$ 1.85*	*$ -*
21									
22	*DISTRIBUTION TOTAL*		*$ 0.02660*	*$ 0.02191*	*$ 5.43*	*$ 10.91*	*$ 6.61*	*$ 5.55*	*$ 3.64*
23									
24	*TOTAL $/KWH*		***$ 0.09235***	***$ 0.06562***	***$ 0.00476***	*$ 0.00433*	*$ 0.00429*	*$ 0.00449*	*$ 0.00421*
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*		*$ -*	*$ -*		*$ 29.39*	*$ 14.55*	*$ 19.75*	*$ 16.89*
26									
27	*CUSTOMER ($/CUSTOMER/MONTH)*								
28	*SERVICES*		*$ 1.77*	*$ 1.63*	*$ 3.93*	*$ 1.36*	*$ -*	*$ 5.67*	*$ -*
29	*METERS*		*2.59*	*4.37*	*19.18*	*414.46*	*568.00*	*168.20*	*1,666.19*
30	*STREET LIGHTING*		*-*	*-*	*-*	*-*	*-*	*-*	*-*
31	*METER READING*		*1.18*	*1.17*	*3.56*	*296.54*	*296.69*	*296.24*	*294.01*
32	*BILLING & COLLECTING*		*4.10*	*4.08*	*4.15*	*4,535.02*	*2,590.30*	*60.97*	*5,136.00*
33	*CUSTOMER ACCOUNTS OTHER*		*0.04*	*0.04*	*0.04*	*0.04*	*0.04*	*0.04*	*0.04*
34	*CUSTOMER INFORMATION*		*0.05*	*0.37*	*1.05*	*310.06*	*0.01*	*38.94*	*2,924.21*
35	*SALES EXPENSE*		*0.67*	*0.66*	*0.67*	*0.67*	*0.67*	*0.67*	*0.66*
36									
37	*CUSTOMER TOTAL*		***$ 10.40***	***$ 12.33***	***$ 32.58***	***$ 5,558.14***	***$ 3,455.71***	***$ 570.72***	***$ 10,021.11***

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

Line No		Rate 536 Interrupt. Ind. (I)	Rate 541 Water Pumpg (J)	Rate 544 Railroad (K)	Rate 550 Street Ltg (L)	Rate 555 Traffic Ltg (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	4,538	0	0
5	*PRIMARY*	0	0	0	0	4,538	0	0
6	*SECONDARY*	0	0	0	0	4,538	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*	$ 6.93	$ 0.02005	$ -	$ 0.00635	$ 0.02170	$ 0.00620	
13								
14	*PRODUCTION VARIABLE*	$ 0.00420	$ 0.00475	$ 0.00433	$ 0.00482	$ 0.00478	$ 0.00469	
15								
16	*TRANSMISSION*	$ 3.67	$ 0.00606	$ -	$ 0.00282	$ 0.00571	$ 0.00262	
17								
18	*DISTRIBUTION*							
19	*PRIMARY*	$ -	$ 0.07077	$ -	$ 0.01219	$ 0.00609	$ 0.01119	
20	*SECONDARY*	$ -	$ 0.03498	$ -	$ 0.00567	$ 0.00283	$ 0.00521	
21								
22	*DISTRIBUTION TOTAL*	$ -	$ 0.10575	$ -	$ 0.01786	$ 0.00892	$ 0.01640	
23								
24	*TOTAL $/KWH*	$ 0.00420	$ 0.13661	$ 0.00433	$ 0.03185	$ 0.04112	$ 0.02991	
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*	$ 10.60	$ -	$ -	$ -	$ -	$ -	
26								
27	*CUSTOMER ($/CUSTOMER/MONTH)*							
28	*SERVICES*	$ -	$ 4.17	$ -	$ -	$ -	$ -	
29	*METERS*	1,879.73	22.12	-	-	-	-	
30	*STREET LIGHTING*	-	-	-	219.60	138.63	-	
31	*METER READING*	296.93	1.19	297.82	-	-	-	
32	*BILLING & COLLECTING*	4.11	4.12	37.14	1.03	1.03	1.00	
33	*CUSTOMER ACCOUNTS OTHER*	0.04	0.04	0.04	0.04	0.04	0.04	
34	*CUSTOMER INFORMATION*	0.01	2.20	0.01	0.01	0.01	0.01	
35	*SALES EXPENSE*	0.67	0.67	0.67	0.67	0.67	0.65	
36								
37	*CUSTOMER TOTAL*	**$ 2,181.49**	**$ 34.50**	**$ 335.68**	**$ 221.35**	**$ 140.38**	**$ 1.71**	

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

REVENUE REQUIREMENT, UNBUNDLED COSTS,
UNIT COSTS AT MODERATED RATE OF RETURN
(PROPOSED SERVICE CLASSIFICATIONS)

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 Industral Lrg (H)
	REVENUE REQUIREMENT AT TARGET ROR								
1	EARNED RATE OF RETURN	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%
2									
3	RATE BASE	2,665,421,829	1,031,984,823	88,053,958	392,829,890	26,402,623	23,752,033	505,427,064	447,010,157
4									
5	TARGET RATE OF RETURN	8.37%	6.04%	15.41%	10.96%	5.17%	13.41%	9.97%	9.18%
6									
7	REQUIRED RETURN ON RATE BASE	223,095,807	62,346,290	13,571,316	43,066,417	1,365,262	3,185,114	50,378,386	41,019,708
8	EARNED RETURN ON RATE BASE	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
9									
10	REQUIRED INCREASE IN RETURN	50,039,417	27,384,294	-413,982	3,979,291	777,217	46,887	6,797,278	7,190,313
11									
12	ASSOC. INCR IN INCOME TAXES	34,207,310	18,720,102	-283,001	2,720,272	531,311	32,052	4,646,668	4,915,350
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	84,246,727	46,104,396	-696,983	6,699,564	1,308,528	78,939	11,443,946	12,105,663
15									
16	INCREASE IN REVENUE-RELATED	1,497,954	819,762	-12,393	119,122	23,266	1,404	203,480	215,245
17									
18	OPERATING EXPENSES PER COSS	637,032,113	245,572,259	22,155,840	88,584,699	6,724,622	5,979,527	119,653,545	107,510,720
19	INCOME TAXES PER COSS	78,229,647	8,450,629	8,218,082	20,786,199	7,723	1,784,986	22,172,384	16,395,935
20	RETURN PER COSS	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
21									
22	TOTAL REVENUE REQUIREMENT	974,062,831	335,909,042	43,649,845	155,276,710	8,652,184	10,983,083	197,054,463	170,056,959
23	LESS OTHER REVENUES	20,405,463	8,552,852	836,754	2,322,025	183,105	124,775	3,163,543	3,645,455
24	REVENUE REQUIREMENT FROM RATES	953,657,369	327,356,190	42,813,091	152,954,685	8,469,079	10,858,308	193,890,920	166,411,504
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	85,744,681	46,924,158	-709,375	6,818,686	1,331,794	80,343	11,647,426	12,320,908
29	PERCENT REVENUE INCREASE	9.88%	16.73%	-1.63%	4.67%	18.66%	0.75%	6.39%	8.00%
30									
31									
32	TOTAL RETURN AND INCOME TAXES	335,532,764	89,517,021	21,506,397	66,572,889	1,904,296	5,002,152	77,197,438	62,330,994

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

REVENUE REQUIREMENT, UNBUNDLED COSTS,
UNIT COSTS AT MODERATED RATE OF RETURN
(PROPOSED SERVICE CLASSIFICATIONS)

Line No		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)
	REVENUE REQUIREMENT AT TARGET ROR							
1	EARNED RATE OF RETURN	1.90%	-1.65%	11.88%	14.89%	15.68%	-3.74%	-2.38%
2								
3	RATE BASE	106,831,331	11,180,429	3,838,573	11,928,214	1,459,342	5,347,652	9,375,741
4								
5	TARGET RATE OF RETURN	4.93%	2.26%	12.41%	10.73%	10.73%	10.73%	1.72%
6								
7	REQUIRED RETURN ON RATE BASE	5,262,964	253,233	476,321	1,279,644	156,556	573,689	160,905
8	EARNED RETURN ON RATE BASE	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
9								
10	REQUIRED INCREASE IN RETURN	3,231,876	437,419	20,386	-496,894	-72,218	773,587	383,964
11								
12	ASSOC. INCR IN INCOME TAXES	2,209,334	299,023	13,936	-339,681	-49,369	528,830	262,481
13								
14	TOTAL INCREASE IN RETURN & INC TAXES	5,441,209	736,442	34,322	-836,575	-121,587	1,302,417	646,445
15								
16	INCREASE IN REVENUE-RELATED	96,748	13,094	610	-14,875	-2,162	23,158	11,494
17								
18	OPERATING EXPENSES PER COSS	28,345,508	2,312,438	642,729	4,704,483	444,404	2,363,128	2,038,212
19	INCOME TAXES PER COSS	-205,290	-291,808	253,620	1,030,601	134,036	-215,914	-291,536
20	RETURN PER COSS	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
21								
22	TOTAL REVENUE REQUIREMENT	35,709,263	2,585,980	1,387,217	6,660,173	683,466	3,272,892	2,181,556
23	LESS OTHER REVENUES	1,330,883	42,003	14,101	39,095	8,253	100,295	42,325
24	REVENUE REQUIREMENT FROM RATES	34,378,380	2,543,977	1,373,116	6,621,078	675,212	3,172,597	2,139,232
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	5,537,957	749,536	34,932	-851,450	-123,748	1,325,575	657,939
29	PERCENT REVENUE INCREASE	19.20%	41.77%	2.61%	-11.39%	-15.49%	71.77%	44.42%
30								
31								
32	TOTAL RETURN AND INCOME TAXES	7,267,008	260,448	743,877	1,970,565	241,223	886,606	131,850

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
Schedule 3.0
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NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT MODERATED RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

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 Industral Lrg (H)
	TOTAL COST OF SERVICE *(Revenue-related distributed)*								
1	PRODUCTION								
2	FIXED	494,123,331	156,855,574	17,076,338	76,965,906	3,818,299	4,106,483	104,588,454	111,216,847
3	VARIABLE	75,132,746	15,969,642	2,066,353	9,858,597	947,837	1,354,677	15,928,994	19,922,576
4									
5	TRANSMISSION SUBSTAS.	85,680,375	20,255,466	2,932,074	13,198,504	819,376	761,263	18,646,115	22,182,542
6	TRANSMISSION LINES	33,933,981	7,885,070	1,202,743	5,309,668	315,719	309,086	7,457,763	8,819,469
7									
8	DISTRIB. SUBSTAS - GENERAL	36,769,446	13,997,434	1,874,678	7,757,253	495,033	1,329,395	9,831,689	786,932
9	DISTRIB. SUBSTAS - RAILROAD	850,144	0	0	0	0	0	0	0
10									
11	DIST. LINES PRIMARY - DEMAND	90,193,919	36,783,087	4,040,763	17,968,303	1,342,188	2,951,748	23,246,305	1,894,531
12	DIST. LINES PRIMARY - CUSTOMER	0	0	0	0	0	0	0	0
13									
14	DIST. LINES SEC. - DEMAND	39,058,108	18,648,666	4,613,037	10,936,541	21,051	0	4,208,918	0
15	DIST. LINES SEC. - CUSTOMER	0	0	0	0	0	0	0	0
16									
17	LINE TRANSFORMERS - DEMAND	22,052,537	10,674,402	1,520,504	5,991,271	16,688	0	3,354,107	0
18	LINE TRANSFORMERS - CUSTOMER	0	0	0	0	0	0	0	0
19									
20	SERVICES	9,130,139	7,236,937	1,168,309	634,920	144	0	69,819	0
21	METERS -GENERAL	19,495,763	11,106,555	2,854,058	2,971,774	46,899	8,354	2,017,649	269,388
22	STREET LIGHTING	5,105,353	0	0	0	0	0	0	0
23	DUSK-TO-DAWN LIGHTING	2,498,101	0	0	0	0	0	0	0
24	METER READING	10,140,077	5,483,708	638,956	511,422	37,436	3,804	3,388,486	46,386
25	BILLING & COLLECTING	24,053,025	18,924,028	2,245,997	598,330	569,159	33,488	699,292	811,428
26	CUSTOMER ACCOUNTS OTHER	215,830	184,447	19,879	5,485	5	0	439	6
27	CUSTOMER INFORMATION	1,565,994	250,340	201,845	150,893	39,160	0	445,263	461,294
28	SALES EXPENSE	3,658,502	3,100,834	357,558	95,819	85	9	7,626	104
29	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
30	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
31									
32	REVENUE TAXES	0	0	0	0	0	0	0	0
33									
34	TOTAL COST OF SERVICE FROM RATES	953,657,369	327,356,190	42,813,091	152,954,685	8,469,079	10,858,308	193,890,920	166,411,504

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

REVENUE REQUIREMENT, UNBUNDLED COSTS,
UNIT COSTS AT MODERATED RATE OF RETURN
(PROPOSED SERVICE CLASSIFICATIONS)

Line No		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)
	TOTAL COST OF SERVICE *(Revenue-related distributed)*							
1	PRODUCTION							
2	FIXED	17,115,375	348,954	287,208	347,569	221,841	99,003	1,075,481
3	VARIABLE	8,318,300	109,868	86,433	242,795	45,045	69,106	212,524
4								
5	TRANSMISSION SUBSTAS.	6,390,127	72,814	103,265	111,299	42,199	30,271	135,060
6	TRANSMISSION LINES	2,441,996	27,080	41,816	44,768	16,960	12,183	49,658
7								
8	DISTRIB. SUBSTAS - GENERAL	0	300,532	0	200,383	18,703	53,726	123,687
9	DISTRIB. SUBSTAS - RAILROAD	0	0	850,144	0	0	0	0
10								
11	DIST. LINES PRIMARY - DEMAND	0	934,333	0	466,362	43,533	124,940	397,825
12	DIST. LINES PRIMARY - CUSTOMER	0	0	0	0	0	0	0
13								
14	DIST. LINES SEC. - DEMAND	0	355,726	0	159,906	14,926	42,852	56,485
15	DIST. LINES SEC. - CUSTOMER	0	0	0	0	0	0	0
16								
17	LINE TRANSFORMERS - DEMAND	0	192,254	0	159,228	14,857	42,708	86,518
18	LINE TRANSFORMERS - CUSTOMER	0	0	0	0	0	0	0
19								
20	SERVICES	0	20,010	0	0	0	0	0
21	METERS -GENERAL	95,359	124,473	0	0	0	0	1,253
22	STREET LIGHTING	0	0	0	4,851,299	254,054	0	0
23	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	2,498,101	0
24	METER READING	16,948	8,422	3,767	0	0	0	741
25	BILLING & COLLECTING	233	28,850	473	22,103	1,826	117,817	0
26	CUSTOMER ACCOUNTS OTHER	2	293	0	822	68	4,382	0
27	CUSTOMER INFORMATION	1	15,581	0	252	21	1,343	0
28	SALES EXPENSE	38	4,786	8	14,291	1,180	76,164	0
29	DIRECT TO RETAIL	0	0	0	0	0	0	0
30	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
31								
32	REVENUE TAXES	0	0	0	0	0	0	0
33								
34	TOTAL COST OF SERVICE FROM RATES	34,378,380	2,543,977	1,373,116	6,621,078	675,212	3,172,597	2,139,232

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
Schedule 3.2

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

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 Industral 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***								
11			$/KWH		$/KW/MO.	$/KW/MO.	$/KW/MO.	$/KW/MO.	$/KW/MO.
12	*PRODUCTION FIXED*		$ 0.05157	$ 0.03156	$ 9.74	$ 14.17	$ 6.33	$ 11.39	$ 10.37
13									
14	*PRODUCTION VARIABLE*		$ 0.00478	$ 0.00474	$ 0.00476	$ 0.00433	$ 0.00429	$ 0.00449	$ 0.00421
15									
16	*TRANSMISSION*		$ 0.00940	$ 0.00741	$ 2.31	$ 4.31	$ 1.61	$ 2.82	$ 2.88
17									
18	*DISTRIBUTION*								
19	*PRIMARY*		$ 0.01668	$ 0.01095	$ 3.26	$ 7.13	$ 6.61	$ 3.70	$ 3.64
20	*SECONDARY*		$ 0.00992	$ 0.01096	$ 2.17	$ 3.78	$ -	$ 1.85	$ -
21									
22	*DISTRIBUTION TOTAL*		$ 0.02660	$ 0.02191	$ 5.43	$ 10.91	$ 6.61	$ 5.55	$ 3.64
23									
24	*TOTAL $/KWH*		**$ 0.09235**	**$ 0.06562**	**$ 0.00476**	$ 0.00433	$ 0.00429	$ 0.00449	$ 0.00421
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*		$ -	$ -		$ 29.39	$ 14.55	$ 19.75	$ 16.89
26									
27	*CUSTOMER ($/CUSTOMER/MONTH)*								
28	*SERVICES*		$ 1.77	$ 1.63	$ 3.93	$ 1.36	$ -	$ 5.67	$ -
29	*METERS*		2.59	4.37	19.18	414.46	568.00	168.20	1,666.19
30	*STREET LIGHTING*		-	-	-	-	-	-	-
31	*METER READING*		1.18	1.17	3.56	296.54	296.69	296.24	294.01
32	*BILLING & COLLECTING*		4.10	4.08	4.15	4,535.02	2,590.30	60.97	5,136.00
33	*CUSTOMER ACCOUNTS OTHER*		0.04	0.04	0.04	0.04	0.04	0.04	0.04
34	*CUSTOMER INFORMATION*		0.05	0.37	1.05	310.06	0.01	38.94	2,924.21
35	*SALES EXPENSE*		0.67	0.66	0.67	0.67	0.67	0.67	0.66
36									
37	*CUSTOMER TOTAL*		**$ 10.40**	**$ 12.33**	**$ 32.58**	**$ 5,558.14**	**$ 3,455.71**	**$ 570.72**	**$ 10,021.11**

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

REVENUE REQUIREMENT, UNBUNDLED COSTS, UNIT COSTS AT PARITY RATE OF RETURN (PROPOSED SERVICE CLASSIFICATIONS)

Line No		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)
	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	4,538	0	0
5	*PRIMARY*	0	0	0	0	4,538	0	0
6	*SECONDARY*	0	0	0	0	4,538	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*	$ 6.93	$ 0.02005	$ -	$ 0.00635	$ 0.02170	$ 0.00620	
13								
14	*PRODUCTION VARIABLE*	$ 0.00420	$ 0.00475	$ 0.00433	$ 0.00482	$ 0.00478	$ 0.00469	
15								
16	*TRANSMISSION*	$ 3.67	$ 0.00606	$ -	$ 0.00282	$ 0.00571	$ 0.00262	
17								
18	*DISTRIBUTION*							
19	*PRIMARY*	$ -	$ 0.07077	$ -	$ 0.01219	$ 0.00609	$ 0.01119	
20	*SECONDARY*	$ -	$ 0.03498	$ -	$ 0.00567	$ 0.00283	$ 0.00521	
21								
22	*DISTRIBUTION TOTAL*	$ -	$ 0.10575	$ -	$ 0.01786	$ 0.00892	$ 0.01640	
23								
24	*TOTAL $/KWH*	$ 0.00420	$ 0.13661	$ 0.00433	$ 0.03185	$ 0.04112	$ 0.02991	
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*	$ 10.60	$ -	$ -	$ -	$ -	$ -	
26								
27	*CUSTOMER ($/CUSTOMER/MONTH)*							
28	*SERVICES*	$ -	$ 4.17	$ -	$ -	$ -	$ -	
29	*METERS*	1,879.73	22.12	-	-	-	-	
30	*STREET LIGHTING*	-	-	-	219.60	138.63	-	
31	*METER READING*	296.93	1.19	297.82	-	-	-	
32	*BILLING & COLLECTING*	4.11	4.12	37.14	1.03	1.03	1.00	
33	*CUSTOMER ACCOUNTS OTHER*	0.04	0.04	0.04	0.04	0.04	0.04	
34	*CUSTOMER INFORMATION*	0.01	2.20	0.01	0.01	0.01	0.01	
35	*SALES EXPENSE*	0.67	0.67	0.67	0.67	0.67	0.65	
36								
37	*CUSTOMER TOTAL*	**$ 2,181.49**	**$ 34.50**	**$ 335.68**	**$ 221.35**	**$ 140.38**	**$ 1.71**	

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
SUMMARY: EFFECT OF 25% MODERATION

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 Industral Lrg (H)
1	***1985 Rates, No Rate Increase, Classes at Parity***								
2	*Revenue Increase*	0	54,903,829	(14,168,028)	(23,273,465)	1,929,763	(2,734,971)	(18,447,180)	(8,236,333)
3	*Increase / <Decrease> over Present Revenues*	0.00%	19.58%	-32.55%	-15.93%	27.04%	-25.38%	-10.12%	-5.35%
4									
5	***Refiling, Classes at Parity***								
6	*Revenue Increase*	85,744,681	88,102,030	(11,335,397)	(10,636,413)	2,779,116	(1,970,886)	(2,187,960)	6,143,658
7	*Increase / <Decrease> over Present Revenues*	9.88%	31.42%	-26.04%	-7.28%	38.94%	-18.29%	-1.20%	3.99%
8									
9	***Refiling at Parity minus 1985 Rates at Parity (overlay to moderated increase)***	85,744,681	33,198,201	2,832,632	12,637,052	849,353	764,086	16,259,221	14,379,991
10	*Increase / <Decrease> over Present Revenues*	9.88%	11.84%	6.51%	8.65%	11.90%	7.09%	8.92%	9.33%
11									
12	***Moderation of 1985 Rates with No Rate Increase (using one-fourth rule)***	0	13,725,957	(3,542,007)	(5,818,366)	482,441	(683,743)	(4,611,795)	(2,059,083)
13	*Increase / <Decrease> over Present Revenues*	0.00%	4.89%	-8.14%	-3.98%	6.76%	-6.34%	-2.53%	-1.34%
14									
15	***Total Moderated Increase (line 9 + line 12)***	85,744,681	46,924,158	(709,375)	6,818,686	1,331,794	80,343	11,647,426	12,320,908
16	*Increase / <Decrease> over Present Revenues*	9.88%	16.73%	-1.63%	4.67%	18.66%	0.75%	6.39%	8.00%
17									
18	***Test Improvement in Rate of Return Index***								
19	*Present Rate of Return*	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%
20	*Index with respect to total*	1.00	0.52	2.45	1.53	0.34	2.03	1.33	1.17
21									
22	*Proposed Rate of Return*	8.37%	6.04%	15.41%	10.96%	5.17%	13.41%	9.97%	9.18%
23	*Index with respect to total*	1.00	0.72	1.84	1.31	0.62	1.60	1.19	1.10

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
SUMMARY: EFFECT OF 25% MODERATION

No.		Rate 536 Interrupt. Ind. (I)	Rate 541 Water Pumpg (J)	Rate 544 Railroad (K)	Rate 550 Street Ltg (L)	Rate 555 Traffic Ltg (M)	Rate 560 Dusk-to-Dawn (N)	Interdept'l (O)
1	***1985 Rates, No Rate Increase, Classes at Parity***							
2	*Revenue Increase*	*8,405,083*	*1,559,481*	*(354,207)*	*(1,717,110)*	*(229,656)*	*937,483*	*1,425,312*
3	*Increase / <Decrease> over Present Revenues*	*29.14%*	*86.91%*	*-26.47%*	*-22.98%*	*-28.74%*	*50.76%*	*96.22%*
4								
5	***Refiling, Classes at Parity***							
6	*Revenue Increase*	*11,841,769*	*1,919,147*	*(230,722)*	*(1,333,388)*	*(182,710)*	*1,109,513*	*1,726,923*
7	*Increase / <Decrease> over Present Revenues*	*41.06%*	*106.95%*	*-17.24%*	*-17.84%*	*-22.87%*	*60.07%*	*116.58%*
8								
9	***Refiling at Parity minus 1985 Rates at Parity (overlay to moderated increase)***	*3,436,686*	*359,666*	*123,484*	*383,722*	*46,946*	*172,030*	*301,611*
10	*Increase / <Decrease> over Present Revenues*	*11.92%*	*20.04%*	*9.23%*	*5.14%*	*5.88%*	*9.31%*	*20.36%*
11								
12	***Moderation of 1985 Rates with No Rate Increase (using one-fourth rule)***	*2,101,271*	*389,870*	*(88,552)*	*(1,235,171)*	*(170,694)*	*1,153,545*	*356,328*
13	*Increase / <Decrease> over Present Revenues*	*7.29%*	*21.73%*	*-6.62%*	*-16.53%*	*-21.36%*	*62.45%*	*24.06%*
14								
15	***Total Moderated Increase (line 9 + line 12)***	*5,537,957*	*749,536*	*34,932*	*(851,450)*	*(123,748)*	*1,325,575*	*657,939*
16	*Increase / <Decrease> over Present Revenues*	*19.20%*	*41.77%*	*2.61%*	*-11.39%*	*-15.49%*	*71.77%*	*44.42%*
17								
18	***Test Improvement in Rate of Return Index***							
19	*Present Rate of Return*	*1.90%*	*-1.65%*	*11.88%*	*14.89%*	*15.68%*	*-3.74%*	*-2.38%*
20	*Index with respect to total*	*0.29*	*(0.25)*	*1.83*	*2.29*	*2.41*	*(0.58)*	*(0.37)*
21								
22	*Proposed Rate of Return*	*4.93%*	*2.26%*	*12.41%*	*10.73%*	*10.73%*	*10.73%*	*1.72%*
23	*Index with respect to total*	*0.59*	*0.27*	*1.48*	*1.28*	*1.28*	*1.28*	*0.21*

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES AT MODERATED RATE OF RETURN

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 Industral Lrg (H)
1	EARNED RATE OF RETURN	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%
2									
3	RATE BASE	2,665,421,829	1,031,984,823	88,053,958	392,829,890	26,402,623	23,752,033	505,427,064	447,010,157
4									
5	TARGET RATE OF RETURN	6.49%	4.16%	13.54%	9.09%	3.29%	11.53%	8.09%	7.30%
6									
7	REQUIRED RETURN ON RATE BASE	173,056,390	42,972,276	11,918,231	35,691,608	869,591	2,739,204	40,889,728	32,627,743
8	EARNED RETURN ON RATE BASE	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
9		----------	----------	----------	----------	----------	----------	----------	----------
10	REQUIRED INCREASE IN RETURN	0	8,010,280	-2,067,067	-3,395,518	281,546	-399,023	-2,691,380	-1,201,653
11									
12	ASSOC. INCR IN INCOME TAXES	0	5,475,886	-1,413,062	-2,321,201	192,467	-272,775	-1,839,847	-821,459
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	0	13,486,166	-3,480,128	-5,716,720	474,013	-671,798	-4,531,227	-2,023,111
15									
16	INCREASE IN REVENUE-RELATED	0	239,792	-61,879	-101,646	8,428	-11,945	-80,568	-35,972
17									
18	OPERATING EXPENSES PER COSS	637,032,113	245,572,259	22,155,840	88,584,699	6,724,622	5,979,527	119,653,545	107,510,720
19	INCOME TAXES PER COSS	78,229,647	8,450,629	8,218,082	20,786,199	7,723	1,784,986	22,172,384	16,395,935
20	RETURN PER COSS	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
21									
22	TOTAL REVENUE REQUIREMENT	888,318,151	302,710,841	40,817,213	142,639,658	7,802,831	10,218,998	180,795,242	155,676,967
23	LESS OTHER REVENUES	20,405,463	8,552,852	836,754	2,322,025	183,105	124,775	3,163,543	3,645,455
24	REVENUE REQUIREMENT FROM RATES	867,912,688	294,157,989	39,980,459	140,317,633	7,619,726	10,094,223	177,631,699	152,031,513
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	0	13,725,957	-3,542,007	-5,818,366	482,441	-683,743	-4,611,795	-2,059,083
29	PERCENT REVENUE INCREASE	0.00%	4.89%	-8.14%	-3.98%	6.76%	-6.34%	-2.53%	-1.34%
30		----------	----------	----------	----------	----------	----------	----------	----------

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES AT MODERATED RATE OF RETURN

Line No		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	EARNED RATE OF RETURN	1.90%	-1.65%	11.88%	14.89%	15.68%	-3.74%	-2.38%
2								
3	RATE BASE	106,831,331	11,180,429	3,838,573	11,928,214	1,459,342	5,347,652	9,375,741
4								
5	TARGET RATE OF RETURN	3.05%	0.39%	10.53%	8.85%	8.85%	8.85%	-0.16%
6								
7	REQUIRED RETURN ON RATE BASE	3,257,361	43,337	404,257	1,055,709	129,159	473,295	-15,111
8	EARNED RETURN ON RATE BASE	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
9								
10	REQUIRED INCREASE IN RETURN	1,226,273	227,523	-51,678	-720,829	-99,615	673,193	207,948
11								
12	ASSOC. INCR IN INCOME TAXES	838,289	155,536	-35,327	-492,764	-68,097	460,200	142,155
13								
14	TOTAL INCREASE IN RETURN & INC TAXES	2,064,562	383,059	-87,005	-1,213,593	-167,712	1,133,393	350,103
15								
16	INCREASE IN REVENUE-RELATED	36,709	6,811	-1,547	-21,578	-2,982	20,152	6,225
17								
18	OPERATING EXPENSES PER COSS	28,345,508	2,312,438	642,729	4,704,483	444,404	2,363,128	2,038,212
19	INCOME TAXES PER COSS	-205,290	-291,808	253,620	1,030,601	134,036	-215,914	-291,536
20	RETURN PER COSS	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
21					10,013,832			
22	TOTAL REVENUE REQUIREMENT	32,272,577	2,226,314	1,263,733	6,276,451	636,520	3,100,862	1,879,946
23	LESS OTHER REVENUES	1,330,883	42,003	14,101	39,095	8,253	100,295	42,325
24	REVENUE REQUIREMENT FROM RATES	30,941,694	2,184,311	1,249,632	6,237,356	628,266	3,000,567	1,837,621
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	2,101,271	389,870	-88,552	-1,235,171	-170,694	1,153,545	356,328
29	PERCENT REVENUE INCREASE	7.29%	21.73%	-6.62%	-16.53%	-21.36%	62.45%	24.06%
30								

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43526
Schedule 4.1

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES AT MODERATED RATE OF RETURN

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 Industral Lrg (H)
	Mechanism to Moderate Increases								
	Step 1 Target Percent Increase to Rates for which								
1	*Increase is Indicated -->*	*25.000%*							
2									
3	*Moderated Increases ->*	*4,552,353*	*3,431,489*	*0*	*0*	*120,610*	*0*	*0*	*0*
4	*Full Indicated Decreases ->*	*(18,209,412)*	*0*	*-3,542,007*	*-5,818,366*	*0*	*-683,743*	*-4,611,795*	*-2,059,083*
5									
6	*Present Revenue*	*867,912,688*	*280,432,032*	*43,522,466*	*146,136,000*	*7,137,285*	*10,777,965*	*182,243,494*	*154,090,596*
7	*Increases*	*4,552,353*	*3,431,489*	*0*	*0*	*120,610*	*0*	*0*	*0*
8	*Sub-Total*	*872,465,041*	*283,863,521*	*43,522,466*	*146,136,000*	*7,257,895*	*10,777,965*	*182,243,494*	*154,090,596*
9	*Target Revenue*	*867,912,688*							
10	*Allocate Revenue Shortfall*	*-4,552,353*	*0*	*-885,502*	*-1,454,591*	*0*	*-170,936*	*-1,152,949*	*-514,771*
11	*Total Revenue*	*867,912,688*	*283,863,521*	*42,636,965*	*144,681,408*	*7,257,895*	*10,607,030*	*181,090,546*	*153,575,825*
12	*Overall Increase*	*0.00%*	*1.22%*	*-2.03%*	*-1.00%*	*1.69%*	*-1.59%*	*-0.63%*	*-0.33%*
13	*Revenue Increase / <Decrease>*	*0*	*3,431,489*	*(885,502)*	*(1,454,591)*	*120,610*	*(170,936)*	*(1,152,949)*	*(514,771)*
14	*Margin Increase / <Decrease>*	*0*	*2,002,570*	*(516,767)*	*(848,880)*	*70,386*	*(99,756)*	*(672,845)*	*(300,413)*
15									
16	*Target Rate of Return*	*6.49%*	*3.58%*	*15.30%*	*9.73%*	*2.49%*	*12.79%*	*8.49%*	*7.50%*
17	*Target Rate of Return with Equalized Lighting Rates*	*6.49%*	*3.58%*	*15.30%*	*9.73%*	*2.49%*	*12.79%*	*8.49%*	*7.50%*

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES AT MODERATED RATE OF RETURN

Line No		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)
	Mechanism to Moderate Increases							
	Step 1 Target Percent Increase to Rates for which							
1	*Increase is Indicated -->*							
2								
3	*Moderated Increases ->*	525,318	97,468	0	0	0	288,386	89,082
4	*Full Indicated Decreases ->*	0	0	-88,552	-1,235,171	-170,694	0	0
5								
6	*Present Revenue*	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
7	*Increases*	525,318	97,468	0	0	0	288,386	89,082
8	*Sub-Total*	29,365,741	1,891,908	1,338,183	7,472,527	798,961	2,135,408	1,570,375
9	*Target Revenue*							
10	*Allocate Revenue Shortfall*	0	0	-22,138	-308,793	-42,674	0	0
11	*Total Revenue*	29,365,741	1,891,908	1,316,045	7,163,734	756,287	2,135,408	1,570,375
12	*Overall Increase*	1.82%	5.43%	-1.65%	-4.13%	-5.34%	15.61%	6.01%
13	*Revenue Increase / <Decrease>*	525,318	97,468	(22,138)	(308,793)	(42,674)	288,386	89,082
14	*Margin Increase / <Decrease>*	306,568	56,881	(12,919)	(180,207)	(24,904)	168,298	51,987
15								
16	*Target Rate of Return*	2.19%	-1.14%	11.54%	13.38%	13.97%	-0.59%	-1.82%
17	*Target Rate of Return with Equalized Lighting Rates*	2.19%	-1.14%	11.54%	9.44%	9.44%	9.44%	-1.82%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQ'T, CLASSES AT PARITY

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 Industral Lrg (H)
1	EARNED RATE OF RETURN	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%
2									
3	RATE BASE	2,665,421,829	1,031,984,823	88,053,958	392,829,890	26,402,623	23,752,033	505,427,064	447,010,157
4									
5	TARGET RATE OF RETURN	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%
6									
7	REQUIRED RETURN ON RATE BASE	223,095,807	86,377,130	7,370,116	32,879,862	2,209,900	1,988,045	42,304,245	37,414,750
8	EARNED RETURN ON RATE BASE	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
9									
10	REQUIRED INCREASE IN RETURN	50,039,417	51,415,134	-6,615,182	-6,207,264	1,621,854	-1,150,182	-1,276,863	3,585,355
11									
12	ASSOC. INCR IN INCOME TAXES	34,207,310	35,147,759	-4,522,186	-4,243,331	1,108,711	-786,273	-872,873	2,450,974
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	84,246,727	86,562,893	-11,137,368	-10,450,596	2,730,565	-1,936,454	-2,149,736	6,036,329
15									
16	INCREASE IN REVENUE-RELATED	1,497,954	1,539,137	-198,029	-185,817	48,551	-34,431	-38,224	107,329
17									
18	OPERATING EXPENSES PER COSS	637,032,113	245,572,259	22,155,840	88,584,699	6,724,622	5,979,527	119,653,545	107,510,720
19	INCOME TAXES PER COSS	78,229,647	8,450,629	8,218,082	20,786,199	7,723	1,784,986	22,172,384	16,395,935
20	RETURN PER COSS	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
21									
22	TOTAL REVENUE REQUIREMENT	974,062,831	377,086,913	33,023,824	137,821,611	10,099,506	8,931,855	183,219,077	163,879,709
23	LESS OTHER REVENUES	20,405,463	8,552,852	836,754	2,322,025	183,105	124,775	3,163,543	3,645,455
24	REVENUE REQUIREMENT FROM RATES	953,657,369	368,534,061	32,187,070	135,499,587	9,916,401	8,807,080	180,055,535	160,234,254
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	85,744,681	88,102,030	-11,335,397	-10,636,413	2,779,116	-1,970,886	-2,187,960	6,143,658
29	PERCENT REVENUE INCREASE	9.88%	31.42%	-26.04%	-7.28%	38.94%	-18.29%	-1.20%	3.99%
30									

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQ'T, CLASSES AT PARITY

Line No		Rate 536 Interrupt. Ind. (I)	Rate 541 Water Pumpg (J)	Rate 544 Railroad (K)	Rate 550 Street Ltg (L)	Rate 555 Traffic Ltg (M)	Rate 560 Dusk-to-Dawn (N)	Interdept'l (O)
1	EARNED RATE OF RETURN	1.90%	-1.65%	11.88%	14.89%	15.68%	-3.74%	-2.38%
2								
3	RATE BASE	106,831,331	11,180,429	3,838,573	11,928,214	1,459,342	5,347,652	9,375,741
4								
5	TARGET RATE OF RETURN	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%	8.37%
6								
7	REQUIRED RETURN ON RATE BASE	8,941,782	935,802	321,289	998,392	122,147	447,598	784,749
8	EARNED RETURN ON RATE BASE	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
9								
10	REQUIRED INCREASE IN RETURN	6,910,694	1,119,988	-134,646	-778,147	-106,627	647,496	1,007,808
11								
12	ASSOC. INCR IN INCOME TAXES	4,724,201	765,632	-92,045	-531,947	-72,891	442,633	688,945
13								
14	TOTAL INCREASE IN RETURN & INC TAXES	11,634,894	1,885,620	-226,692	-1,310,093	-179,519	1,090,130	1,696,753
15								
16	INCREASE IN REVENUE-RELATED	206,875	33,527	-4,031	-23,294	-3,192	19,383	30,169
17								
18	OPERATING EXPENSES PER COSS	28,345,508	2,312,438	642,729	4,704,483	444,404	2,363,128	2,038,212
19	INCOME TAXES PER COSS	-205,290	-291,808	253,620	1,030,601	134,036	-215,914	-291,536
20	RETURN PER COSS	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
21								
22	TOTAL REVENUE REQUIREMENT	42,013,075	3,755,591	1,121,562	6,178,235	624,504	3,056,830	3,250,540
23	LESS OTHER REVENUES	1,330,883	42,003	14,101	39,095	8,253	100,295	42,325
24	REVENUE REQUIREMENT FROM RATES	40,682,193	3,713,588	1,107,461	6,139,139	616,250	2,956,535	3,208,216
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	11,841,769	1,919,147	-230,722	-1,333,388	-182,710	1,109,513	1,726,923
29	PERCENT REVENUE INCREASE	41.06%	106.95%	-17.24%	-17.84%	-22.87%	60.07%	116.58%
30								

Petitioner's Exhibit No. RDG-3 (Revised)
Northern Indiana Public Service Company
Cause No. 43526
Schedule 4.2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, NO RATE INCREASE, CLASSES AT PARITY

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 Industral Lrg (H)
1	EARNED RATE OF RETURN	6.49%	3.39%	15.88%	9.95%	2.23%	13.21%	8.62%	7.57%
2									
3	RATE BASE	2,665,421,829	1,031,984,823	88,053,958	392,829,890	26,402,623	23,752,033	505,427,064	447,010,157
4									
5	TARGET RATE OF RETURN	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%
6									
7	REQUIRED RETURN ON RATE BASE	173,056,390	67,003,116	5,717,031	25,505,052	1,714,229	1,542,135	32,815,587	29,022,785
8	EARNED RETURN ON RATE BASE	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
9		----------	----------	----------	----------	----------	----------	----------	----------
10	REQUIRED INCREASE IN RETURN	0	32,041,120	-8,268,267	-13,582,074	1,126,183	-1,596,092	-10,765,521	-4,806,611
11									
12	ASSOC. INCR IN INCOME TAXES	0	21,903,543	-5,652,247	-9,284,805	769,867	-1,091,100	-7,359,388	-3,285,834
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	0	53,944,663	-13,920,514	-22,866,879	1,896,050	-2,687,191	-18,124,909	-8,092,445
15									
16	INCREASE IN REVENUE-RELATED	0	959,166	-247,515	-406,586	33,713	-47,780	-322,271	-143,888
17									
18	OPERATING EXPENSES PER COSS	637,032,113	245,572,259	22,155,840	88,584,699	6,724,622	5,979,527	119,653,545	107,510,720
19	INCOME TAXES PER COSS	78,229,647	8,450,629	8,218,082	20,786,199	7,723	1,784,986	22,172,384	16,395,935
20	RETURN PER COSS	173,056,390	34,961,996	13,985,298	39,087,126	588,045	3,138,227	43,581,108	33,829,395
21									
22	TOTAL REVENUE REQUIREMENT	888,318,151	343,888,713	30,191,192	125,184,560	9,250,153	8,167,769	166,959,856	149,499,718
23	LESS OTHER REVENUES	20,405,463	8,552,852	836,754	2,322,025	183,105	124,775	3,163,543	3,645,455
24	REVENUE REQUIREMENT FROM RATES	867,912,688	335,335,860	29,354,438	122,862,535	9,067,048	8,042,994	163,796,314	145,854,263
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	0	54,903,829	-14,168,028	-23,273,465	1,929,763	-2,734,971	-18,447,180	-8,236,333
29	PERCENT REVENUE INCREASE	0.00%	19.58%	-32.55%	-15.93%	27.04%	-25.38%	-10.12%	-5.35%
30		----------	----------	----------	----------	----------	----------	----------	----------

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, NO RATE INCREASE, CLASSES AT PARITY

Line No		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	EARNED RATE OF RETURN	1.90%	-1.65%	11.88%	14.89%	15.68%	-3.74%	-2.38%
2								
3	RATE BASE	106,831,331	11,180,429	3,838,573	11,928,214	1,459,342	5,347,652	9,375,741
4								
5	TARGET RATE OF RETURN	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%
6								
7	REQUIRED RETURN ON RATE BASE	6,936,180	725,906	249,225	774,457	94,750	347,204	608,734
8	EARNED RETURN ON RATE BASE	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
9								
10	REQUIRED INCREASE IN RETURN	4,905,091	910,092	-206,710	-1,002,082	-134,024	547,102	831,792
11								
12	ASSOC. INCR IN INCOME TAXES	3,353,156	622,145	-141,308	-685,030	-91,620	374,003	568,619
13								
14	TOTAL INCREASE IN RETURN & INC TAXES	8,258,247	1,532,237	-348,019	-1,687,112	-225,644	921,105	1,400,412
15								
16	INCREASE IN REVENUE-RELATED	146,836	27,244	-6,188	-29,998	-4,012	16,378	24,900
17								
18	OPERATING EXPENSES PER COSS	28,345,508	2,312,438	642,729	4,704,483	444,404	2,363,128	2,038,212
19	INCOME TAXES PER COSS	-205,290	-291,808	253,620	1,030,601	134,036	-215,914	-291,536
20	RETURN PER COSS	2,031,089	-184,186	455,935	1,776,538	228,774	-199,898	-223,059
21								
22	TOTAL REVENUE REQUIREMENT	38,576,389	3,395,924	998,078	5,794,513	577,558	2,884,800	2,948,929
23	LESS OTHER REVENUES	1,330,883	42,003	14,101	39,095	8,253	100,295	42,325
24	REVENUE REQUIREMENT FROM RATES	37,245,506	3,353,921	983,977	5,755,417	569,304	2,784,505	2,906,605
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	8,405,083	1,559,481	-354,207	-1,717,110	-229,656	937,483	1,425,312
29	PERCENT REVENUE INCREASE	29.14%	86.91%	-26.47%	-22.98%	-28.74%	50.76%	96.22%
30								

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 811 - Residential									
1	Customer Charge		4,733,472	$ 5.95	$ 5.14	$ 28,164,158	$ 24,327,954		4,733,472	$ 24,327,954
2										
3	Energy Charge									
4	First 36 kWh (included in customer charge)	4.89%	170,074,661	$ 0.022556	$ -	$ -	$ -		170,074,661	
5	Next 14 kWh	1.88%	65,431,627	0.165220	0.142664	10,810,613	9,334,738		65,431,627	$ 9,334,738
6	Next 150 kWh	19.34%	672,408,386	0.120410	0.097854	80,964,694	65,797,850		672,408,386	65,797,850
7	Over 200 kWh	71.68%	2,492,833,171	0.096370	0.073814	240,234,333	184,005,988	(83,222,551)	2,409,610,620	177,862,998
8	Over 500 kWh (Space Heating)	2.21%	76,736,746	0.071490	0.048934	5,485,910	3,755,036		76,736,746	3,755,036
9	Primary metering adjustment (net)		(12,108)						(12,108)	
10										
11	Total Energy	100.00%	3,477,484,591			$ 337,495,550	$ 262,893,611	(83,222,551)	3,394,249,932	$ 256,750,622
12										
13	Sub-Total (calculated)					$ 365,659,708	$ 287,221,566			$ 281,078,576
14										
15	Adjustment Factor[5]					1.0011317	1.0011317			1.0011317
16										
17	Sub-Total (as adjusted)					$ 366,073,523	$ 287,546,612			$ 281,396,671
18										
19	FAC & Reconciling Fuel[6]					$ 24,924,478				
20	Utility Receipts Tax[6]					1,355,149				
21	EERM Tracker[1]					3,977,675	$ 3,977,675			$ 3,977,675.1
22	ECRM Tracker[1]					8,280,591	8,280,591			8,280,591
23	Revenue Credit[1]					(22,392,392)	(22,392,392)			(22,392,392)
24										
25	Total					$ 382,219,023	$ 277,412,486			$ 271,262,544
26										
27	Target Revenue[1]					$ 382,219,023	$ 277,412,486			
28	Over / Under Difference					-	-			
29										
30	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker811*	*$ 0.0035*				
31	Calculated Revenue Credit[1]				*Credit811*	*-5.53%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 812 - Good Cents Residential									
1	Customer Charge		33,168	$ 5.95	$ 5.14	$ 197,350	$ 170,417		33,168	$ 170,417
2										
3	Energy Charge									
4	First 36 kWh (included in customer charge)	2.64%	1,232,454	$ 0.022556	$ -	$ -	$ -		1,232,454	
5	Next 14 kWh	1.02%	478,533	0.165220	0.142664	79,063	68,269		478,533	$ 68,269
6	Next 150 kWh	10.88%	5,083,757	0.120410	0.097854	612,135	497,466		5,083,757	497,466
7	Over 200 kWh	54.22%	25,334,831	0.096370	0.073814	2,441,518	1,870,065	(789,582)	24,545,249	1,811,783
8	Over 700 kWh (Space Heating October to April)	31.24%	14,595,429	0.055000	0.032444	802,749	473,534		14,595,429	473,534
9	Primary metering adjustment (net)		(286)						(286)	
10										
11	Total Energy	100.00%	46,725,004			$ 3,935,465	$ 2,909,335	(789,582)	45,935,136	2,851,052
12										
13	Sub-Total (calculated)					$ 4,132,814	$ 3,079,751			3,021,469
14										
15	Adjustment Factor[5]					0.9879769	0.9879769			0.9879769
16										
17	Sub-Total (as adjusted)					$ 4,083,125	$ 3,042,723			$ 2,985,142
18										
19	FAC & Reconciling Fuel[6]					$ 363,106				
20	Utility Receipts Tax[6]					18,385				
21	EERM Tracker[1]					43,201	$ 43,201			$ 43,201
22	ECRM Tracker[1]					75,457	75,457			75,457
23	Revenue Credit[1]					(246,821)	(246,821)			(246,821)
24										
25	Total					$ 4,336,453	$ 2,914,560			$ 2,856,979
26										
27	Target Revenue[1]					$ 4,336,453	$ 2,914,560			
28	Over / Under Difference					-	-			
29										
30	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker812*	$ *0.0025*				
31	Calculated Revenue Credit[1]				*Credit812*	*-5.39%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Present Base Rates or "Margin" (Weather Normalized): Adjusted Billing Determinants	Present Base Rates or "Margin" (Weather Normalized): Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 813 - Good Cents Multifamily									
1	Customer Charge		19,274	$ 5.95	$ 5.14	$ 114,680	$ 99,030		19,274	$ 99,030
2										
3	Energy Charge									
4	First 36 kWh (included in customer charge)	6.20%	704,019	$ 0.022556	$ -	$ -	$ -		704,019	
5	Next 14 kWh	2.40%	272,319	0.165220	0.142664	44,993	38,850		272,319	$ 38,850
6	Next 150 kWh	24.76%	2,811,025	0.120410	0.097854	338,476	275,070		2,811,025	275,070
7	Over 200 kWh	45.21%	5,132,668	0.096370	0.073814	494,635	378,863	(194,625)	4,938,043	364,497
8	Over 500 kWh (Space Heating October to April)	21.43%	2,432,221	0.055000	0.032444	133,772	78,911		2,432,221	78,911
9	Primary metering adjustment (net)		(112)						(112)	
10										
11	Total Energy	100.00%	11,352,251			$ 1,011,875	$ 771,694	(194,625)	11,157,514	$ 757,328
12										
13	Sub-Total (calculated)					$ 1,126,556	$ 870,723			$ 856,357
14										
15	Adjustment Factor[5]					0.9984213	0.9984213			0.9984213
16										
17	Sub-Total (as adjusted)					$ 1,124,777	$ 869,349			$ 855,005
18										
19	FAC & Reconciling Fuel[6]					$ 80,546				
20	Utility Receipts Tax[6]					4,401				
21	EERM Tracker[1]					13,411	$ 13,411			$ 13,411
22	ECRM Tracker[1]					26,714	26,714			26,714
23	Revenue Credit[1]					(69,097)	(69,097)			(69,097)
24										
25	Total					$ 1,180,752	$ 840,377			$ 826,034
26										
27	Target Revenue[1]					$ 1,180,752	$ 840,377			
28	Over / Under Difference					-	-			
29										
30	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker813*	$ *0.0035*				
31	Calculated Revenue Credit[1]				*Credit813*	*-5.53%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 817 - Thermal Storage									
1	Energy Charge									
2	All kWh	100.00%	1,232,313	$ 0.04250	$ 0.01994	$ 52,373	$ 24,577			
3	Primary metering adjustment (net)		(184,649)							
4										
5	Total Energy	100.00%	1,232,313			$ 52,373	$ 24,577			
6										
7	Sub-Total (calculated)					$ 52,373	$ 24,577			
8										
9	Adjustment Factor[5]					1.1879418	1.1879418			
10										
11	Sub-Total (as adjusted)					$ 62,216	$ 29,196			
12										
13	FAC & Reconciling Fuel[6]					$ 5,595				
14	Utility Receipts Tax[6]					506				
15	EERM Tracker[1]					1,353	$ 1,353			
16	ECRM Tracker[1]					2,696	2,696			
17	Revenue Credit[1]					-	-			
18										
19	Total					$ 72,367	$ 33,246			
20										
21	Target Revenue[1]					$ 72,367	$ 33,246			
22	Over / Under Difference					-	-			
23										
24	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker817*	*$ 0.0033*				
25	Calculated Revenue Credit[1]				*Credit817*	*0.00%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 820 - Good Cents Commercial									
1	Customer Charge		2,472	$ 5.95	$ 5.95	$ 14,708	$ 14,708			
2										
3	Energy Charge									
4	All kWh	100.00%	20,510,895	$ 0.055000	$ 0.03244	$ 1,128,099	$ 665,455			
5	Primary metering adjustment (net)		(2,158)							
6										
7	Total Energy	100.00%	20,510,895			$ 1,128,099	$ 665,455			
8										
9	Sub-Total (calculated)					$ 1,142,808	$ 680,164			
10										
11	Adjustment Factor[5]					0.1508811	0.1508811			
12										
13	Sub-Total (as adjusted)					$ 172,428	$ 102,624			
14										
15	FAC & Reconciling Fuel[6]					$ 521,737				
16	Utility Receipts Tax[6]					7,749				
17	EERM Tracker[1]					3,210	$ 3,210			
18	ECRM Tracker[1]					2,852	2,852			
19	Revenue Credit[1]					(36,652)	(36,652)			
20										
21	Total					$ 671,324	$ 72,034			
22										
23	Target Revenue[1]					$ 671,324	$ 72,034			
24	Over / Under Difference					-	-			
25										
26	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker820*	$ *0.0003*				
27	Calculated Revenue Credit[1]				*Credit820*	*-5.18%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 821 - General Service Small									
1	Customer Charge		589,704	$ 5.95	$ 5.14	$ 3,508,739	$ 3,029,890		589,704	$ 3,029,890
2										
3	Energy Charge									
4	First 36 kWh (included in customer charge)	1.34%	19,242,214	$ 0.022556	$ -	$ -	$ -		19,242,214	
5	Next 64 kWh	2.16%	31,128,576	0.164970	0.142414	5,135,281	4,433,145		31,128,576	$ 4,433,145
6	Next 400 kWh	10.95%	157,773,911	0.133610	0.111054	21,080,172	17,521,424		157,773,911	17,521,424
7	Over 2,500 kWh	32.46%	467,626,985	0.119990	0.097434	56,110,562	45,562,768	(39,217,584)	428,409,400	41,741,642
8	Over 3,000 kWh	53.09%	764,686,619	0.099930	0.077374	76,415,134	59,166,862		764,686,619	59,166,862
9										
10	Total Energy	100.00%	1,440,458,305			$ 158,741,149	$ 126,684,199	(39,217,584)	1,401,240,721	$ 122,863,073
11										
12	Sub-Total (calculated)					$ 162,249,888	$ 129,714,089			$ 125,892,963
13										
14	Adjustment Factor[5]					1.0239942	1.0239942			1.0239942
15										
16	Sub-Total (as adjusted)					$ 166,142,943	$ 132,826,473			$ 128,913,663
17										
18	FAC & Reconciling Fuel[6]					$ 8,547,604				
19	Utility Receipts Tax[6]					548,393				
20	EERM Tracker[1]					1,630,940	$ 1,630,940			$ 1,630,940
21	ECRM Tracker[1]					3,508,553	3,508,553			3,508,553
22	Revenue Credit[1]					(10,314,974)	(10,314,974)			(10,314,974)
23										
24	Total					$ 170,063,460	$ 127,650,993			$ 123,738,182
25										
26	Target Revenue[1]					$ 170,063,460	$ 127,650,993			
27	Over / Under Difference					-	-			
28										
29	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker821*	*$ 0.0036*				
30	Calculated Revenue Credit[1]				*Credit821*	*-5.72%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Present Base Rates or "Margin" (Weather Normalized): Adjusted Billing Determinants	Present Base Rates or "Margin" (Weather Normalized): Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 822 - Commercial Space Heating									
1	Customer Charge		4,140	$ 5.95	$ 5.14	$ 24,633	$ 21,271			
2										
3	Energy Charge									
4	First 36 kWh (included in customer charge)	0.43%	83,159	$ 0.022556	$ -	$ -	$ -			
5	Next 1964 KWH	16.05%	3,097,108	0.075780	0.053224	234,699	164,840			
6	Over 2000 KWH	83.52%	16,115,194	0.070380	0.047824	1,134,187	770,693			
7	Primary metering adjustment (net)		(19,553)							
8										
9	Total Energy	100.00%	19,295,461			$ 1,368,886	$ 935,534			
10										
11	Sub-Total (calculated)					$ 1,393,519	$ 956,805			
12										
13	Adjustment Factor[5]					0.6991814	0.6991814			
14										
15	Sub-Total (as adjusted)					$ 974,323	$ 668,980			
16										
17	FAC & Reconciling Fuel[6]					$ 308,831				
18	Utility Receipts Tax[6]					8,045				
19	EERM Tracker[1]					6,144	$ 6,144			
20	ECRM Tracker[1]					5,915	5,915			
21	Revenue Credit[1]					(71,210)	(71,210)			
22										
23	Total					$ 1,232,048	$ 609,829			
24										
25	Target Revenue[1]					$ 1,232,048	$ 609,829			
26	Over / Under Difference					-	-			
27										
28	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker822*	*$ 0.0006*				
29	Calculated Revenue Credit[1]				*Credit822*	*-5.46%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
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4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 823 - General Service Medium									
1	Customer Charge (includes first 10 kW)		43,776	$ 206.15	$ 206.15	$ 9,024,422	$ 9,024,422		43,776	$ 9,024,422
2	Excess Demand (Demand above 10 kW)		4,385,393	7.59	7.59	33,285,135	33,285,135		4,385,393	33,285,135
3										
4	Energy Charge								-	
5	All kWh		1,558,295,932	$ 0.06206	$ 0.03950	$ 96,707,846	$ 61,558,922	(36,061,574)	1,522,234,357	$ 60,134,346
6										
7	Sub-Total (calculated)		1,558,295,932			$ 139,017,403	$ 103,868,480	(36,061,574)	1,522,234,357	$ 102,443,903
8										
9	Adjustment Factor[5]					1.0081380	1.0081380			1.0081380
10										
11	Sub-Total (as adjusted)					$ 140,148,722	$ 104,713,758			$ 103,277,589
12										
13	FAC & Reconciling Fuel[6]					$ 7,368,022				
14	Utility Receipts Tax[6]					560,692				
15	EERM Tracker[1]					1,700,074	$ 1,700,074			$ 1,700,074
16	ECRM Tracker[1]					3,417,399	3,417,399			3,417,399
17	Revenue Credit[1]					(9,411,597)	(9,411,597)			(9,411,597)
18										
19	Total					$ 143,783,314	$ 100,419,635			$ 98,983,466
20										
21	Target Revenue[1]					$ 143,783,314	$ 100,419,635			
22	Over / Under Difference					-	-			
23										
24	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker823*	*$ 0.0033*				
25	Calculated Revenue Credit[1]				*Credit823*	*-6.14%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
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6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 824 - General Service Large									
1	Customer Charge (includes first 50 kW)		4,562	$ 822.84	$ 822.84	$ 3,753,542	$ 3,753,542		4,562	$ 3,753,542
2										
3	Demand Charges									
4	Demand Included in Customer Charge	4.71%	228,085							
5	Excess demand (next 1950)	80.13%	3,883,231	9.87	9.87	38,327,494	38,327,494		3,883,231	38,327,494
6	Excess demand (over 2000)	15.16%	734,745	9.35	9.35	6,869,869	6,869,869		734,745	6,869,869
7										
8		100.00%	4,846,061			$ 45,197,363	$ 48,950,905		8,662,674	$ 48,950,905
9										
10	Energy Charges									
11	Energy Charge (1st 30,000)	6.31%	129,012,521	$ 0.06295	$ 0.04039	$ 8,121,338	$ 5,211,332		129,012,521	$ 5,211,332
12	Energy Charge (next 70,000)	13.73%	280,712,111	0.05528	0.03272	15,517,765	$ 9,186,023		280,712,111	9,186,023
13	Energy Charge (next 900,000)	64.83%	1,324,963,493	0.05173	0.02917	68,540,362	$ 38,654,485	(3,816,613)	1,321,146,880	38,543,139
14	Energy Charge (over 1,000,000)	15.12%	309,088,875	0.04811	0.02555	14,870,266	$ 7,898,457		309,088,875	7,898,457
15	Primary metering adjustment (net)		(64,740)						(64,740)	
16										
17	Total Energy	100.00%	2,043,777,000			$ 107,049,731	$ 60,950,297		2,039,895,647	$ 60,838,951
18										
19	Sub-Total (calculated)					$ 156,000,636	$ 109,901,202			$ 109,789,857
20										
21	Adjustment Factor[5]					0.9861305	0.9861305			0.9861305
22										
23	Sub-Total (as adjusted)					$ 153,836,989	$ 108,376,930			$ 108,267,129
24										
25	FAC & Reconciling Fuel[6]					$ 13,400,210				
26	Utility Receipts Tax[6]					771,033				
27	EERM Tracker[1]					2,039,050	$ 2,039,050			$ 2,039,050
28	ECRM Tracker[1]					4,143,030	4,143,030			4,143,030
29	Revenue Credit[1]					(9,711,561)	(9,711,561)			(9,711,561)
30										
31	Total					$ 164,478,751	$ 104,847,449			$ 104,737,647
32										
33	Target Revenue[1]					$ 164,478,751	$ 104,847,449			
34	Over / Under Difference					-	-			
35										
36	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker824*	*$ 0.0030*				
37	Calculated Revenue Credit[1]				*Credit824*	*-5.58%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
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[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 825 - Metal Melting Service									
1	Customer Charge (includes first 500 kW)		132	$ 9,571.77	$ 9,571.77	$ 1,263,474	$ 1,263,474			
	Demand Charges									
	Demand Included in Customer Charge	21.09%	65,991							
2	Excess demand (excess 500)	88.91%	278,200	18.14	18.14	5,046,553	5,046,553			
3										
4		1.1000	312,901			$ 5,046,553	$ 6,310,027			
5										
6										
7	Energy Charge (All kWh)	100.00%	244,976,131	$ 0.02975	$ 0.00719	$ 7,288,040	$ 1,762,358			
8										
9	Total Energy	100.00%	244,976,131			$ 7,288,040	$ 1,762,358			
10										
11	Sub-Total (calculated)					$ 13,598,067	$ 8,072,385			
12										
13	Adjustment Factor[5]					0.9274808	0.9274808			
14										
15	Sub-Total (as adjusted)					$ 12,611,945	$ 7,486,982			
16										
17	FAC & Reconciling Fuel[6]					$ 2,170,003				
18	Utility Receipts Tax[6]					95,559				
19	EERM Tracker[1]					113,623	$ 113,623			
20	ECRM Tracker[1]					166,888	$ 166,888			
21	Revenue Credit[1]					(804,972)	$ (804,972)			
22										
23	Total					$ 14,353,046	$ 6,962,520			
24										
25	Target Revenue[1]					$ 14,353,046	$ 6,962,520			
26	Over / Under Difference					-	-			
27										
28	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker825*	$ *0.0011*				
29	Calculated Revenue Credit[1]				*Credit825*	*-5.31%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 826 - Off-Peak Service									
1	Customer Charge (includes first 200 kW)		1,380	$ 4,533.99	$ 4,533.99	$ 6,256,906	$ 6,256,906			
2										
3	Demand Charges									
4	Demand Included in Customer Charge	20.28%	239,364							
5	Excess demand (next 500)	35.31%	416,707	21.66	21.66	9,025,880	9,025,880			
6	Excess demand (next 1300)	30.29%	357,534	20.65	20.65	7,383,079	7,383,079			
7	Excess demand (over 2000)	14.12%	166,700	20.16	20.16	3,360,664	3,360,664			
8										
9		100.00%	1,180,295			$ 26,026,529	$ 26,026,529			
10										
11	Energy Charges									
12	Energy Charge (All kWh)	100.00%	677,450,790	$ 0.02975	$ 0.00719	$ 20,154,161	$ 4,873,581			
13	Primary metering adjustment (net)		(9,683)							
14										
15	Total Energy	100.00%	677,460,473			$ 20,154,161	$ 4,873,581			
16										
17	Sub-Total (calculated)					$ 46,180,690	$ 30,900,110			
18										
19	Adjustment Factor[5]					0.9792837	0.9792837			
20										
21	Sub-Total (as adjusted)					$ 45,223,997	$ 30,259,974			
22										
23	FAC & Reconciling Fuel[6]					$ 4,775,168				
24	Utility Receipts Tax[6]					258,571				
25	EERM Tracker[1]					427,685	$ 427,685			
26	ECRM Tracker[1]					783,025	$ 783,025			
27	Revenue Credit[1]					(2,855,326)	$ (2,855,326)			
28										
29	Total					$ 48,613,120	$ 28,615,358			
30										
31	Target Revenue[1]					$ 48,613,120	$ 28,615,358			
32	Over / Under Difference					-	-			
33										
34	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker826*	*$ 0.0018*				
35	Calculated Revenue Credit[1]				*Credit826*	*-5.55%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 832 - Industrial Power Service									
1	First Demand Block (1st 50,000 kW)		153,889	$ 15.78	$ 15.78	$ 2,428,368	$ 2,428,368			
2	Excess Demand (over 50,000 kW)		-	14.11	14.11	-	-			
3										
4						$ 2,428,368	$ 2,428,368			
5	Energy Charges									
6	Energy Charge (1st 660 x billing kW)	99.87%	79,218,932	$ 0.03707	$ 0.01452	$ 2,936,883	$ 1,150,021			
7	Energy Charge (all other)	0.13%	99,845	0.03482	0.01227	3,477	1,225			
8	Primary metering adjustment (net)		225,545							
9										
10	Total Energy	100.00%	79,318,777			$ 2,940,360	$ 1,151,246			
11										
12	Sub-Total (calculated)					$ 5,368,729	$ 3,579,614			
13										
14	Adjustment Factor[5]					0.9250791	0.9250791			
15										
16	Sub-Total (as adjusted)					$ 4,966,499	$ 3,311,426			
17										
18	FAC & Reconciling Fuel[6]					$ 701,146				
19	Utility Receipts Tax[6]					30,865				
20	EERM Tracker[1]					88,416	$ 88,416			
21	ECRM Tracker[1]					164,321	164,321			
22	Revenue Credit[1]					(255,929)	(255,929)			
23										
24	Total					$ 5,695,317	$ 3,308,234			
25										
26	Target Revenue[1]					$ 5,695,317	$ 3,308,234			
27	Over / Under Difference					-	-			
28										
29	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker832*	*$ 0.0032*				
30	Calculated Revenue Credit[1]				*Credit832*	*-4.30%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 833 - Industrial Power Service									
1	All Demand		1,337,773	$ 17.70	$ 17.70	$ 23,680,976	$ 23,680,976			
2										
3						$ 23,680,976	$ 23,680,976			
4	Energy Charges									
5	Included in Billing Demand (kW x 600)	77.12%	794,634,000	$ 0.02256	$ -	$ 17,923,765	$ -			
6	Energy Charge Block 2 ((660 - 600) x kW)	6.76%	69,682,920	0.03707	0.01452	2,583,355	$ 1,011,587			
7	Energy Charge Block 3 (all other)	16.12%	166,025,412	0.03482	0.01227	5,781,171	$ 2,036,302			
8	Primary metering adjustment (net)		94,464							
9										
10	Total Energy	100.00%	1,030,436,796			$ 26,288,290	$ 3,047,889			
11										
12	PraxAir Generation Credit					$ (4,726,250)	$ (4,726,250)			
13										
14	Sub-Total (calculated)					$ 45,243,016	$ 22,002,614			
15										
16	Adjustment Factor[5]					0.9925597	0.9925597			
17										
18	Sub-Total (as adjusted)					$ 44,906,393	$ 21,838,908			
19										
20	FAC & Reconciling Fuel[6]					$ 7,672,814				
21	Utility Receipts Tax[6]					402,679				
22	EERM Tracker[1]					1,339,288	$ 1,339,288			
23	ECRM Tracker[1]					1,812,541	1,812,541			
24	Revenue Credit[1]					(349,255)	(349,255)			
25										
26	Total					$ 55,784,460	$ 24,641,482			
27										
28	Target Revenue[1]					$ 55,784,460	$ 24,641,482			
29	Over / Under Difference					-	-			
30										
31	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker833*	$ *0.0031*				
32	Calculated Revenue Credit[1]				*Credit833*	*-0.62%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 836 - Interruptible Industrial Service									
1	Demand Charge		1,316,848	$ 6.32	$ 6.32	$ 8,322,479	$ 8,322,479			
2										
3						$ 8,322,479	$ 8,322,479			
4										
5										
6	Energy Charges									
7	Energy Charge (all other)	100.00%	961,254,668	$ 0.027797	$ 0.00524	$ 26,719,996	$ 5,037,936			
8										
9	Total Energy	100.00%	961,254,668			$ 26,719,996	$ 5,037,936			
10										
11	Sub-Total (calculated)					$ 35,042,475	$ 13,360,415			
12										
13	Adjustment Factor[5]					0.5013166	0.5013166			
14										
15	Sub-Total (as adjusted)					$ 17,567,375	$ 6,697,798			
16										
17	FAC & Reconciling Fuel[6]					$ 17,745,054				
18	Utility Receipts Tax[6]					374,834				
19	EERM Tracker[1]					411,036	$ 411,036			
20	ECRM Tracker[1]					390,488	390,488			
21	Revenue Credit[1]					-	-			
22										
23	Total					36,488,785	7,499,321			
24										
25	Target Revenue[1]					36,488,785	7,499,321			
26	Over / Under Difference					-	-			
27										
28	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker836*	$ *0.0008*				
29	Calculated Revenue Credit[1]				*Credit836*	*0.00%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 841 - Municipal Power									
1	**Energy Charges**									
2	All kWh	100.00%	25,135,393	$ 0.091310	$ 0.06875	$ 2,295,113	$ 1,728,159			
3	Primary metering adjustment (net)		(146)							
4										
5	Total Energy	100.00%	25,135,393			$ 2,295,113	$ 1,728,159			
6										
7	Sub-Total (calculated)					$ 2,295,113	$ 1,728,159			
8										
9	Adjustment Factor[5]					1.0356436	1.0356436			
10										
11	Sub-Total (as adjusted)					$ 2,376,919	$ 1,789,757			
12										
13	FAC & Reconciling Fuel[6]					$ 140,750				
14	Utility Receipts Tax[6]					9,535				
15	EERM Tracker[1]					22,099	$ 22,099			
16	ECRM Tracker[1]					33,963	33,963			
17	Revenue Credit[1]					(155,729)	(155,729)			
18										
19	Total					$ 2,427,537	$ 1,690,090			
20										
21	Target Revenue[1]					$ 2,427,537	$ 1,690,090			
22	Over / Under Difference					-	-			
23										
24	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker841*	*$ 0.0022*				
25	Calculated Revenue Credit[1]				*Credit841*	*-6.03%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 844 - Railroad Power Service									
1	Demand Charge		79,171	$ 14.52	$ 14.52	$ 1,149,563	$ 1,149,563			
2										
3						$ 1,149,563	$ 1,149,563			
4										
5	Energy Charges									
6	Energy Charge (1st 660 x billing kW)	100.00%	18,905,250	$ 0.037073	$ 0.01452	$ 700,874	$ 274,448			
7	Energy Charge (all other)	0.00%	-	0.034821	0.012265	-	$ -			
8										
9	Total Energy	100.00%	18,905,250			$ 700,874	$ 274,448			
10										
11	Sub-Total (calculated)					$ 1,850,437	$ 1,424,010			
12										
13	Adjustment Factor[5]					1.0029770	1.0029770			
14										
15	Sub-Total (as adjusted)					1,855,946	1,428,250			
16										
17	FAC & Reconciling Fuel[6]					$ 135,384				
18	Utility Receipts Tax[6]					7,376				
19	EERM Tracker[1]					9,438	$ 9,438			
20	ECRM Tracker[1]					11,486	11,486			
21	Revenue Credit[1]					(111,659)	(111,659)			
22										
23	Total					$ 1,907,972	$ 1,337,515			
24										
25	Target Revenue[1]					$ 1,907,972	$ 1,337,515			
26	Over / Under Difference					-	-			
27										
28	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker844*	*$ 0.0011*				
29	Calculated Revenue Credit[1]				*Credit844*	*-5.53%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
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4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 847 - Industrial Off- Peak Service									
1	Energy Charges									
2	All kWh	100.0%	5,013,227,003	$ 0.039529	$ 0.01697	$ 198,167,850	$ 85,089,502			
3										
4	Total Energy	100%	5,013,227,003			$ 198,165,377	$ 73,575,844			
5										
6	Sub-Total (calculated)					$ 198,165,377	$ 73,575,844			
7										
8	Adjustment Factor[5]					1.0000000	1.0000000			
9										
10	Sub-Total (as adjusted)					$ 198,165,377	$ 73,575,844			
11										
12	FAC & Reconciling Fuel[6]					$ 24,896,918				
13	Utility Receipts Tax[6]					1,958,179				
14	EERM Tracker[1]					2,601,756	$ 2,601,756			
15	ECRM Tracker[1]					3,515,606	3,515,606			
16	Revenue Credit[1]			-		-	-			
17										
18	Total					231,137,836	79,693,206			
19										
20	Target Revenue[1]					231,137,836	79,693,206			
21	Over / Under Difference					-	-			
22										
23	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker847*	*$ 0.0012*				
24	Calculated Revenue Credit[1]				*Credit847*	*0.00%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 848 - General Service Large Economic Development									
1	All kWh Charges	100.0%	89,279,919	$ 0.037073	$ 0.01452	$ 3,309,874	$ 1,296,077			
2										
3	Total Energy	100%	89,279,919			$ 3,309,874	$ 1,296,077			
4										
5	Sub-Total (calculated)					$ 3,309,874	$ 1,296,077			
6										
7	Adjustment Factor[5]					2.8981476	2.8981476			
8										
9	Sub-Total (as adjusted)					$ 9,592,505	$ 3,756,221			
10										
11	FAC & Reconciling Fuel[6]					$ (3,184,068)				
12	Utility Receipts Tax[6]					34,742				
13	EERM Tracker[1]					-	$ -			
14	ECRM Tracker[1]					-	-			
15	Revenue Credit[1]					(348,103)	(348,103)			
16										
17	Total					$ 6,095,076	$ 3,408,118			
18										
19	Target Revenue[1]					$ 6,095,076	$ 3,408,118			
20	Over / Under Difference					-	-			
21										
22	Calculated Tracker (EERM & ECRM/kWh)[1]				*Tracker848*	*$ -*				
23	Calculated Revenue Credit[1]				*Credit848*	*-5.40%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 861 - Overhead Street Lighting Mercury Vapor									
1	Customer Charge									
2	175W		750	$ 12.05	$ 12.05	$ 9,038	$ 9,038			
3	400W		2,994	19.68	19.68	58,922	58,922			
4										
5						$ 67,959	$ 67,959			
6	Energy Charges									
7	Fuel Charges		589,944	$ -	$ (0.022556)	-	$ (13,307)			
8										
9	Sub-Total (calculated)					$ 67,959	$ 54,653			
10										
11	Adjustment Factor[5]					0.9949277	0.9949277			
12										
13	Sub-Total (as adjusted)					$ 67,615	$ 54,375			
14										
15	FAC & Reconciling Fuel[6]					$ 24				
16	Utility Receipts Tax[6]					172				
17	Revenue Credit[1]					(3,749)	$ (3,620)			
18										
19	Total					$ 64,062	$ 50,755			
20										
21	Target Revenue[1]					$ 64,062	$ 50,755			
22	Over / Under Difference					-	-			
23										
24	Calculated Revenue Credit[1]				*Credit861*	*-5.53%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 873 - Ornamental Street Lighting Mercury Vapor									
1	Customer Charge									
2	400W D to D		96	$ 15.85	$ 15.85	$ 1,522	$ 1,522			
3	400W D to 1		-	12.00	12.00	-	-			
4										
5						$ 1,522	$ 1,522			
6										
7	Energy Charges									
8	Fuel Charges		17,712	$ -	$ (0.022556)	-	$ (400)			
9										
10	Total Energy		17,712			-	$ (400)			
11										
12	Sub-Total (calculated)					$ 1,522	$ 1,122			
13										
14	Adjustment Factor[5]					0.9972093	0.9972093			
15										
16	Sub-Total (as adjusted)					$ 1,518	$ 1,119			
17										
18	FAC & Reconciling Fuel[6]					$ (4)				
19	Utility Receipts Tax[6]					5				
20	Revenue Credit[1]					(81)	$ (81)			
21										
22	Total					$ 1,438	$ 1,038			
23										
24	Target Revenue[1]					$ 1,438	$ 1,038			
25	Over / Under Difference					-	-			
26										
27	Calculated Revenue Credit[1]				*Credit873*	*-5.34%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 877 - Strret, Highway or Area Lighting Customer Owned									
1	Customer Charge									
2	1000 Watt HPS		12,336	$ 26.91	$ 26.91	$ 331,900	$ 331,900			
3	400 Watt HPS		41,336	13.48	13.48	557,140	557,140			
4	310 Watt HPS		1,561	10.67	10.67	16,658	16,658			
5	250 Watt HPS		42,118	9.13	9.13	384,327	384,327			
6	200 Watt HPS		744	7.41	7.41	5,509	5,509			
7	150 Watt HPS		67,649	4.88	4.88	330,296	330,296			
8	150 Watt HPS Dusk to Midnight		24	2.64	2.64	63	63			
9	100 Watt HPS		23,573	4.27	4.27	100,617	100,617			
10	70 Watt HPS		10,697	3.99	3.99	42,672	42,672			
11	135 Watt Incan		60	4.96	4.96	298	298			
12	55 Watt LPS		130	3.88	3.88	505	505			
13	90 Watt LPS		677	4.96	4.96	3,360	3,360			
14	135 Watt LPS		6,746	5.57	5.57	37,603	37,603			
15	180 Watt LPS		-	6.70	6.70	-	-			
16	175 Watt MV/MH		9,569	5.85	5.85	55,947	55,947			
17	250 Watt MV/MH		18,101	7.60	7.60	137,613	137,613			
18	400 Watt MV/MH		704	12.97	12.97	9,129	9,129			
19	1500 Watt MH		24	37.52	37.52	900	900			
20	100 Watt MV		535	0.18	0.18	96	96			
21	Whiteco Non/Prof 175 D/D		24	0.18	0.18	4	4			
22	Whiteco Non/Prof 250 D/D		24	0.18	0.18	4	4			
23	Whiteco Profile 400 D/D		2,136	0.18	0.18	382	382			
24	Various Watt Dusk-Dawn		64	0.18	0.18	11	11			
25	Whiteco Non/Prof 175 D/M		2,892	0.18	0.18	518	518			
26	Whiteco Non/Prof 250 D/M		6,666	0.18	0.18	1,193	1,193			
27	Whiteco Non/Prof 400 D/M		612	0.18	0.18	110	110			
28	Whiteco Profile 175 D/M		48	0.18	0.18	9	9			
29	Whiteco Profile 250 D/M		372	0.18	0.18	67	67			
30	Whiteco Profile 400 D/M		10,044	0.18	0.18	1,798	1,798			
31										
32						$ 2,018,731	$ 2,018,731			
33	Energy Charges									
34	Fuel Charges		25,845,060	$ -	$ (0.022556)	-	$ (582,961)			
35										
36	Total Energy		25,845,060			$ -	$ (582,961)			
37										
38	Sub-Total (calculated)					$ 2,018,731	$ 1,435,770			
39										
40	Adjustment Factor[5]					1.0559869	1.0559869			
41										
42	Sub-Total (as adjusted)					$ 2,131,753	$ 1,516,154			
43										
44	FAC & Reconciling Fuel[6]					$ (40,176)				
45	Utility Receipts Tax[6]					7,538				
46	Revenue Credit[1]					(112,363)	$ (112,363)			
47										
48	Total					$ 1,986,752	$ 1,403,791			
49										
50	Target Revenue[1]					$ 1,986,752	$ 1,403,791			

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)** **(C*D)**	**(G)** **(C*E)**	**(H)**	**(I)** **(C+H)**	**(J)** **(E*I)**
51	Over / Under Difference					-	-			
52										
53	Calculated Revenue Credit[1]				*Credit877*	*-5.35%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 878 - Dusk to Dawn Outdoor Lighting									
	Customer Charge									
1	175 Watt Lamps MV		36,021	$ 12.59	$ 12.59	$ 453,504	$ 453,504			
2	400 Watt Lamps MV		8,224	21.32	21.32	175,336	175,336			
3	100 Watt HPS DD		84,680	7.87	7.87	666,432	666,432			
4	250 Watt HPS DD		15,375	15.33	15.33	235,699	235,699			
5	400 Watt HPS DD		6,230	21.04	21.04	131,079	131,079			
6	150 Watt HPS FLOODLIGHT		5,694	15.04	15.04	85,638	85,638			
7	250 Watt HPS FLOODLIGHT		9,771	17.91	17.91	174,999	174,999			
8	400 Watt HPS FLOODLIGHT		17,756	22.17	22.17	393,651	393,651			
9	30 FT WOOD POLE		13,612	2.49	2.49	33,894	33,894			
10	35 FT WOOD POLE		4,900	3.10	3.10	15,190	15,190			
11	40 FT WOOD POLE		204	3.76	3.76	767	767			
12	GUY & ANCHOR SET		60	1.23	1.23	74	74			
13	EXTRA SPAN		940	0.49	0.49	461	461			
14	30 FT WOOD POLE		16,281	7.74	7.74	126,015	126,015			
15	35 FT WOOD POLE		4,896	9.38	9.38	45,924	45,924			
16	40 FT WOOD POLE		642	11.63	11.63	7,466	7,466			
17	GUY & ANCHOR SET		27	5.51	5.51	149	149			
18	EXTRA SPAN		2,043	2.98	2.98	6,088	6,088			
19										
20						$ 2,552,365	$ 2,552,365			
21										
22	Energy Charges									
23	Fuel Charges		14,252,921	$ -	$ (0.022556)	-	$ (321,489)			
24										
25	Total Energy		14,252,921			$ -	$ (321,489)			
26										
27	Sub-Total (calculated)					$ 2,552,365	$ 2,230,876			
28										
29	Adjustment Factor[5]					0.8887867	0.8887867			
30										
31	Sub-Total (as adjusted)					$ 2,268,508	$ 1,982,773			
32										
33	FAC & Reconciling Fuel[6]					$ 31,597				
34	Utility Receipts Tax[6]					4,157				
35	Revenue Credit[1]					(135,947)	$ (135,947)			
36										
37	Total					$ 2,168,315	$ 1,846,826			
38										
39	Target Revenue[1]					$ 2,168,315	$ 1,846,826			
40	Over / Under Difference					-	-			
41										
42	Calculated Revenue Credit[1]				*Credit878*	*-5.90%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

			Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
	Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					(C*D)	(C*E)		(C+H)	(E*I)

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 879 - Overhead Street Lighting Underground									
	Customer Charge									
1	400 Watt DD OVER DIST		60	$ 24.66	$ 24.66	$ 1,480	$ 1,480			
2	400 Watt DD UND DIST		12	23.33	23.33	280	280			
3										
4						$ 1,760	$ 1,760			
5										
6	Energy Charges									
7	Fuel Charges		13,284	$ -	$ (0.022556)	-	$ (300)			
8										
9	Total Energy		13,284			$ -	$ (300)			
10										
11	Sub-Total (calculated)					$ 1,760	$ 1,460			
12										
13	Adjustment Factor[5]					0.9975613	0.9975613			
14										
15	Sub-Total (as adjusted)					$ 1,755	$ 1,457			
16										
17	FAC & Reconciling Fuel[6]					$ (3)				
18	Utility Receipts Tax[6]					4				
19	Revenue Credit[1]					(94)	$ (94)			
20										
21	Total					$ 1,662	$ 1,363			
22										
23	Target Revenue[1]					$ 1,662	$ 1,363			
24	Over / Under Difference					-	-			
25										
26	Calculated Revenue Credit[1]				*Credit879*	*-5.34%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 880 - Street or Highway Lighting Customer Owned									
1	Customer Charge									
2	400 Watt HPS		444	$ 17.86	$ 17.86	$ 7,928	$ 7,928			
3	250 Watt HPS		461	12.68	12.68	5,847	5,847			
4	250 Watt MV		96	10.62	10.62	1,020	1,020			
5										
6						$ 14,795	$ 14,795			
7										
8	Energy Charges									
9	Fuel Charges		129,220	$ -	$ (0.022556)	-	$ (2,915)			
10										
11	Total Energy		129,220			$ -	$ (2,915)			
12										
13	Sub-Total (calculated)					$ 14,795	$ 11,880			
14										
15	Adjustment Factor[5]					0.9633138	0.9633138			
16										
17	Sub-Total (as adjusted)					$ 14,252	$ 11,444			
18										
19	FAC & Reconciling Fuel[6]					$ 69				
20	Utility Receipts Tax[6]					38				
21	Revenue Credit[1]					(788)	$ (788)			
22										
23	Total					$ 13,571	$ 10,656			
24										
25	Target Revenue[1]					$ 13,571	$ 10,656			
26	Over / Under Difference					-	-			
27										
28	Calculated Revenue Credit[1]				*Credit880*	*-5.49%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 881 - Overhead Street Lighting HPS									
1	Customer Charge									
2	100 Watt		26,063	$ 19.62	$ 19.62	$ 511,465	$ 511,465			
3	150 Watt		17,074	$ 20.73	$ 20.73	$ 353,859	$ 353,859			
4	250 Watt		7,855	$ 27.91	$ 27.91	$ 219,259	$ 219,259			
5	400 Watt		4,139	$ 31.50	$ 31.50	$ 130,375	$ 130,375			
6										
7						$ 1,214,958	$ 1,214,958			
8										
9	Energy Charges									
10	Fuel Charges		4,038,256	$ -	$ (0.022556)	-	$ (91,087)			
11										
12	Total Energy		4,038,256			$ -	$ (91,087)			
13										
14	Sub-Total (calculated)					$ 1,214,958	$ 1,123,871			
15										
16	Adjustment Factor[5]					0.9971959	0.9971959			
17										
18	Sub-Total (as adjusted)					$ 1,211,551	$ 1,120,719			
19										
20	FAC & Reconciling Fuel[6]					$ (922)				
21	Utility Receipts Tax[6]					1,178				
22	Revenue Credit[1]					(64,712)	$ (64,712)			
23										
24	Total					$ 1,147,094	$ 1,056,007			
25										
26	Target Revenue[1]					$ 1,147,094	$ 1,056,007			
27	Over / Under Difference					-	-			
28										
29	Calculated Revenue Credit[1]				*Credit881*	*-5.34%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 882 - Ornamental Street Lighting HPS									
1	Customer Charge									
2	100 Watt		1,936	$ 19.62	$ 19.62	$ 37,992	$ 37,992			
3	150 Watt		2,178	2.04	2.04	4,440	4,440			
4	250 Watt		1,461	27.91	27.91	40,781	40,781			
5	400 Watt		1,020	31.50	31.50	32,129	32,129			
6										
7						$ 115,343	$ 115,343			
8										
9	Energy Charges									
10	Fuel Charges		565,468	$ -	$ (0.022556)	-	$ (12,755)			
11										
12	Total Energy		565,468			$ -	$ (12,755)			
13										
14	Sub-Total (calculated)					$ 115,343	$ 102,588			
15										
16	Adjustment Factor[5]					1.3654088	1.3654088			
17										
18	Sub-Total (as adjusted)					$ 157,490	$ 140,075			
19										
20	FAC & Reconciling Fuel[6]					$ (4,826)				
21	Utility Receipts Tax[6]					165				
22	Revenue Credit[1]					(8,311)	$ (8,311)			
23										
24	Total					$ 144,518	$ 131,763			
25										
26	Target Revenue[1]					$ 144,518	$ 131,763			
27	Over / Under Difference					-	-			
28										
29	Calculated Revenue Credit[1]				*Credit882*	*-5.44%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 883 - Overhead Street Lighting HPS									
1	Customer Charge									
2	100 Watt		279,051	$ 10.10	$ 10.10	$ 2,818,415	$ 2,818,415			
3	150 Watt		119,881	12.18	12.18	1,459,551	1,459,551			
4	400 Watt		8,052	31.50	31.50	253,631	253,631			
5										
6						$ 4,531,598	$ 4,531,598			
7										
8	Energy Charges									
9	Fuel Charges		15,233,078	$ -	$ (0.022556)	-	$ (343,597)			
10										
11	Total Energy		15,233,078			$ -	$ (343,597)			
12										
13	Sub-Total (calculated)					$ 4,531,598	$ 4,188,000			
14										
15	Adjustment Factor[5]					0.9903711	0.9903711			
16										
17	Sub-Total (as adjusted)					$ 4,487,963	$ 4,147,675			
18										
19	FAC & Reconciling Fuel[6]					$ (1,134)				
20	Utility Receipts Tax[6]					4,443				
21	Revenue Credit[1]					(241,367)	$ (241,367)			
22										
23	Total					$ 4,249,905	$ 3,906,308			
24										
25	Target Revenue[1]					$ 4,249,905	$ 3,906,308			
26	Over / Under Difference					-	-			
27										
28	Calculated Revenue Credit[1]				*Credit883*	*-5.37%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line	(A)	Percent Distribution[1] (B)	Billing Determinants (kW, kWh, Bills)[1] (C)	Present Rates from Tariffs: Including Base Fuel[2] (D)	Present Rates from Tariffs: Excluding Base Fuel[3] (E)	Present Revenue (Actual): Including Total Fuel[2] (F) (C*D)	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3] (G) (C*E)	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4] (H)	Adjusted Billing Determinants (I) (C+H)	Revenue Excluding Fuel ("Margin" or Base Rate Revenues) (J) (E*I)
	Rate 884 - Ornamental Street Lighting HPS									
1	Customer Charge									
2	100 Watt		1,821	$ 10.10	$ 10.10	$ 18,392	$ 18,392			
3	150 Watt		1,361	12.18	12.18	16,570	16,570			
4	400 Watt		120	31.50	31.50	3,780	3,780			
5										
6						$ 38,742	$ 38,742			
7										
8	Energy Charges									
9	Fuel Charges		202,802	$ -	$ (0.022556)	-	$ (4,574)			
10										
11	Total Energy		202,802			$ -	$ (4,574)			
12										
13	Sub-Total (calculated)					$ 38,742	$ 34,168			
14										
15	Adjustment Factor[5]					0.9926197	0.9926197			
16										
17	Sub-Total (as adjusted)					$ 38,456	$ 33,916			
18										
19	FAC & Reconciling Fuel[6]					$ (25)				
20	Utility Receipts Tax[6]					59				
21	Revenue Credit[1]					(2,064)	$ (2,064)			
22										
23	Total					$ 36,426	$ 31,852			
24										
25	Target Revenue[1]					$ 36,426	$ 31,852			
26	Over / Under Difference					-	-			
27										
28	Calculated Revenue Credit[1]				*Credit884*	*-5.36%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 886 - Ornamental Street Lighting HPS									
1	Customer Charge									
2	100 Watt		216	$ 18.29	$ 18.29	$ 3,952	$ 3,952			
3	150 Watt		1,048	19.55	19.55	20,488	20,488			
4										
5						$ 24,439	$ 24,439			
6										
7	Energy Charges									
8	Fuel Charges		80,524	$ -	$ (0.022556)	-	$ (1,816)			
9										
10	Total Energy		80,524			$ -	$ (1,816)			
11										
12	Sub-Total (calculated)					$ 24,439	$ 22,623			
13										
14	Adjustment Factor[5]					0.9856836	0.9856836			
15										
16	Sub-Total (as adjusted)					$ 24,089	$ 22,299			
17										
18	FAC & Reconciling Fuel[6]					$ 3				
19	Utility Receipts Tax[6]					23				
20	Revenue Credit[1]					(1,302)	$ (1,302)			
21										
22	Total					$ 22,813	$ 20,997			
23										
24	Target Revenue[1]					$ 22,813	$ 20,997			
25	Over / Under Difference					-	-			
26										
27	Calculated Revenue Credit[1]				*Credit886*	*-5.40%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 887 - Ornamental Street Lighting HPS									
1	Customer Charge									
2	150 Watt		1,371	$ 28.52	$ 28.52	$ 39,104	$ 39,104			
3										
4						$ 39,104	$ 39,104			
5										
6	Energy Charges									
7	Fuel Charges		92,457	$ -	$ (0.022556)	-	$ (2,085)			
8										
9	Total Energy		92,457			$ -	$ (2,085)			
10										
11	Sub-Total (calculated)					$ 39,104	$ 37,019			
12										
13	Adjustment Factor[5]					0.9899741	0.9899741			
14										
15	Sub-Total (as adjusted)					$ 38,712	$ 36,648			
16										
17	FAC & Reconciling Fuel[6]					$ (6)				
18	Utility Receipts Tax[6]					27				
19	Revenue Credit[1]					(2,083)	$ (2,083)			
20										
21	Total					$ 36,650	$ 34,565			
22										
23	Target Revenue[1]					$ 36,650	$ 34,565			
24	Over / Under Difference					-	-			
25										
26	Calculated Revenue Credit[1]				*Credit887*	*-5.38%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 888 - Ornamental Street Lighting HPS									
1	Customer Charge									
2	100 Watt		901	$ 12.13	$ 12.13	$ 10,930	$ 10,930			
3										
4						$ 10,930	$ 10,930			
5										
6	Energy Charges									
7	Fuel Charges		35,014	$ -	$ (0.022556)	-	$ (790)			
8										
9	Total Energy		35,014			$ -	$ (790)			
10										
11	Sub-Total (calculated)					$ 10,930	$ 10,140			
12										
13	Adjustment Factor[5]					0.9368023	0.9368023			
14										
15	Sub-Total (as adjusted)					$ 10,239	$ 9,499			
16										
17	FAC & Reconciling Fuel[6]					$ 40				
18	Utility Receipts Tax[6]					10				
19	Revenue Credit[1]					(582)	$ (582)			
20										
21	Total					$ 9,707	$ 8,917			
22										
23	Target Revenue[1]					$ 9,707	$ 8,917			
24	Over / Under Difference					-	-			
25										
26	Calculated Revenue Credit[1]				*Credit888*	*-5.66%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 890 - Overhead & Ornamental Street Lighting Ind									
1	Customer Charge									
2	250 Candle Pwr		192	$ 8.61	$ 8.61	$ 1,653	$ 1,653			
3	400 Candle Pwr		-	12.86	12.86	-	-			
4										
5						$ 1,653	$ 1,653			
6										
7	Energy Charges									
8	Fuel Charges		12,944	$ -	$ (0.022556)	-	$ (292)			
9										
10	Total Energy		12,944			$ -	$ (292)			
11										
12	Sub-Total (calculated)					$ 1,653	$ 1,361			
13										
14	Adjustment Factor[5]					0.9974973	0.9974973			
15										
16	Sub-Total (as adjusted)					$ 1,649	$ 1,357			
17										
18	FAC & Reconciling Fuel[6]					$ (3)				
19	Utility Receipts Tax[6]					4				
20	Revenue Credit[1]					(88)	$ (88)			
21										
22	Total					$ 1,561	$ 1,269			
23										
24	Target Revenue[1]					$ 1,561	$ 1,269			
25	Over / Under Difference					-	-			
26										
27	Calculated Revenue Credit[1]				*Credit890*	*-5.34%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 891 - Overhead Street Lighting Underground HPS									
1	Customer Charge									
2	100 Watt DD OVER DIST		300	$ 15.54	$ 15.54	$ 4,662	$ 4,662			
3	150 Watt DD OVER DIST		132	17.15	17.15	2,264	2,264			
4	100 Watt DD UND DIST		8,133	13.50	13.50	109,823	109,823			
5	150 Watt DD UND DIST		824	15.82	15.82	13,036	13,036			
6										
7						$ 129,785	$ 129,785			
8										
9	Energy Charges									
10	Fuel Charges		493,592	$ -	$ (0.022556)	-	$ (11,133)			
11										
12	Total Energy		493,592			$ -	$ (11,133)			
13										
14	Sub-Total (calculated)					$ 129,785	$ 118,651			
15										
16	Adjustment Factor[5]					0.9981123	0.9981123			
17										
18	Sub-Total (as adjusted)					$ 129,540	$ 118,427			
19										
20	FAC & Reconciling Fuel[6]					$ (123)				
21	Utility Receipts Tax[6]					144				
22	Revenue Credit[1]					(6,913)	$ (6,913)			
23										
24	Total					$ 122,648	$ 111,515			
25										
26	Target Revenue[1]					$ 122,648	$ 111,515			
27	Over / Under Difference					-	-			
28										
29	Calculated Revenue Credit[1]				*Credit891*	*-5.34%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 892 - Overhead Street Lighting Underground HPS									
1	Customer Charge									
2	100 Watt DD OVER DIST		636	$ 42.52	$ 42.52	$ 27,045	$ 27,045			
3	150 Watt DD OVER DIST		420	43.62	43.62	18,322	18,322			
4	250 Watt DD OVER DIST		36	50.81	50.81	1,829	1,829			
5	400 Watt DD OVER DIST		-	54.40	54.40	-	-			
6	100 Watt DD UND DIST		16,886	30.85	30.85	520,905	520,905			
7	150 Watt DD UND DIST		5,553	31.95	31.95	177,414	177,414			
8	250 Watt DD UND DIST		192	39.14	39.14	7,514	7,514			
9	400 Watt DD UND DIST		48	42.72	42.72	2,051	2,051			
10										
11						$ 755,080	$ 755,080			
12										
13	Energy Charges									
14	Fuel Charges		1,333,818	$ -	$ (0.022556)	-	$ (30,086)			
15										
16	Total Energy		1,333,818			$ -	$ (30,086)			
17										
18	Sub-Total (calculated)					$ 755,080	$ 724,994			
19										
20	Adjustment Factor[5]					1.0009973	1.0009973			
21										
22	Sub-Total (as adjusted)					$ 755,833	$ 725,718			
23										
24	FAC & Reconciling Fuel[6]					$ (419)				
25	Utility Receipts Tax[6]					389				
26	Revenue Credit[1]					(40,218)	$ (40,218)			
27										
28	Total					$ 715,585	$ 685,500			
29										
30	Target Revenue[1]					$ 715,585	$ 685,500			
31	Over / Under Difference					-	-			
32										
33	Calculated Revenue Credit[1]				*Credit892*	*-5.32%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 893 - Ornamental Street Lighting HPS									
1	Customer Charge									
2	150 Watt		68	$ 15.36	$ 15.36	$ 1,044	$ 1,044			
3										
4						$ 1,044	$ 1,044			
5										
6	Energy Charges									
7	Fuel Charges		3,924	$ -	$ (0.022556)	-	$ (89)			
8										
9	Total Energy		3,924			$ -	$ (89)			
10										
11	Sub-Total (calculated)					$ 1,044	$ 956			
12										
13	Adjustment Factor[5]					0.8762885	0.8762885			
14										
15	Sub-Total (as adjusted)					$ 915	$ 838			
16										
17	FAC & Reconciling Fuel[6]					$ 10				
18	Utility Receipts Tax[6]					1				
19	Revenue Credit[1]					(56)	$ (56)			
20										
21	Total					$ 870	$ 782			
22										
23	Target Revenue[1]					$ 870	$ 782			
24	Over / Under Difference					-	-			
25										
26	Calculated Revenue Credit[1]				*Credit893*	*-6.01%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

Line		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 895 - Traffic Directive Lighting									
1	Customer Charge									
2	150 Watt		12,517,094	$ 0.08560	$ 0.08560	$ 1,071,463	$ 1,071,463			
3										
4						$ 1,071,463	$ 1,071,463			
5										
6	Energy Charges									
7	Fuel Charges		9,129,140	$ -	$ (0.022556)	-	$ (205,917)			
8										
9	Total Energy		9,129,140			$ -	$ (205,917)			
10										
11	Sub-Total (calculated)					$ 1,071,463	$ 865,546			
12										
13	Adjustment Factor[5]					98.83%	98.83%			
14										
15	Sub-Total (as adjusted)					$ 1,058,977	$ 855,460			
16										
17	FAC & Reconciling Fuel[6]					$ (263)				
18	Utility Receipts Tax[6]					2,663				
19	Revenue Credit[1]					(57,069)	$ (57,069)			
20										
21	Total					$ 1,004,307	$ 798,390			
22										
23	Target Revenue[1]					$ 1,004,307	$ 798,390			
24	Over / Under Difference					-	-			
25										
26	Calculated Revenue Credit[1]				*Credit895*	*-5.38%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 898 - Street Lighting Customer Owned									
1	Customer Charge									
2	250 Watt		1,137	$ 11.70	$ 11.70	$ 13,298	$ 13,298			
3										
4						$ 13,298	$ 13,298			
5										
6	Energy Charges									
7	Fuel Charges		126,168	$ -	$ (0.022556)	-	$ (2,846)			
8										
9	Total Energy		126,168			$ -	$ (2,846)			
10										
11	Sub-Total (calculated)					$ 13,298	$ 10,452			
12										
13	Adjustment Factor[5]					1.0215176	1.0215176			
14										
15	Sub-Total (as adjusted)					$ 13,584	$ 10,677			
16										
17	FAC & Reconciling Fuel[6]					$ (98)				
18	Utility Receipts Tax[6]					37				
19	Revenue Credit[1]					(708)	$ (708)			
20										
21	Total					$ 12,815	$ 9,969			
22										
23	Target Revenue[1]					$ 12,815	$ 9,969			
24	Over / Under Difference					-	-			
25										
26	Calculated Revenue Credit[1]				*Credit898*	*-5.24%*				

1 - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
2 - Current applicable rates recalculated using 2007 data including all associated fuel costs
3 - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
4 - 2007 usage (kWh) normalized for weather
5 - Factor to adjust recalculated revenues to equal FERC Form 1
6 - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVISED REVENUE PROOF - PRESENT RATES

				Present Rates from Tariffs		Present Revenue (Actual)		Present Base Rates or "Margin" (Weather Normalized)		
		Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Including Base Fuel[2]	Excluding Base Fuel[3]	Including Total Fuel[2]	Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
	(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
	Rate 899 - Street or Highway Lighting Customer Owned									
1	Customer Charge									
2	400 Watt HPS		228	$ 13.26	$ 13.26	$ 3,024	$ 3,024			
3	100 Watt HPS		777	5.35	5.35	4,155	4,155			
4										
5						$ 7,179	$ 7,179			
6										
7	Energy Charges									
8	Fuel Charges		78,590	$ -	$ (0.022556)	-	$ (1,773)			
9										
10	Total Energy		78,590			$ -	$ (1,773)			
11										
12	Sub-Total (calculated)					$ 7,179	$ 5,406			
13										
14	Adjustment Factor[5]					0.9688518	0.9688518			
15										
16	Sub-Total (as adjusted)					$ 6,955	$ 5,238			
17										
18	FAC & Reconciling Fuel[6]					$ 32				
19	Utility Receipts Tax[6]					23				
20	Revenue Credit[1]					(382)	$ (382)			
21										
22	Total					$ 6,628	$ 4,856			
23										
24	Target Revenue[1]					$ 6,628	$ 4,856			
25	Over / Under Difference					-	-			
26										
27	Calculated Revenue Credit[1]				*Credit899*	*-5.45%*				

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007 REVISED REVENUE PROOF - PRESENT RATES	Percent Distribution[1]	Billing Determinants (kW, kWh, Bills)[1]	Present Rates from Tariffs: Including Base Fuel[2]	Present Rates from Tariffs: Excluding Base Fuel[3]	Present Revenue (Actual): Including Total Fuel[2]	Present Revenue (Actual): Excluding Fuel ("Margin" or Base Rate Revenues)[3]	Present Base Rates or "Margin" (Weather Normalized): Weather Normalization Adjustment[4]	Adjusted Billing Determinants	Revenue Excluding Fuel ("Margin" or Base Rate Revenues)
(A)	(B)	(C)	(D)	(E)	(F) (C*D)	(G) (C*E)	(H)	(I) (C+H)	(J) (E*I)
842 - Intermittent Wastewater Pumping									
1 Target Revenue					$ 33,355	$ 33,355			
2 Sub-Total (adjusted)					33,355	33,355			
3 Sub-Total (calculated)					33,355	33,355			
845 - Industrial Service									
1 Target Revenue					$ 274,474	$ 274,474			
2 Sub-Total (adjusted)					274,474	274,474			
3 Sub-Total (calculated)					274,474	274,474			
2100									
1 Target Revenue					$ 2,274,107	$ 1,237,913			
2 Sub-Total (adjusted)					2,274,107	1,237,913			
3 Sub-Total (calculated)					2,274,107	1,237,913			
Interdepartmental									
1 Target Revenue					$ 2,887,915	$ 1,406,379			
2 Sub-Total (adjusted)					2,887,915	1,406,379			
3 Sub-Total (calculated)					2,887,915	1,406,379			

[1] - Usage data, distributions, trackers and total revenue from FERC Form 1 and Customer Information System (CIS)
[2] - Current applicable rates recalculated using 2007 data including all associated fuel costs
[3] - Current applicable rates recalculated using 2007 data excluding all associated fuel costs
[4] - 2007 usage (kWh) normalized for weather
[5] - Factor to adjust recalculated revenues to equal FERC Form 1
[6] - FAC collected, Utility Receipts Tax and fuel reconciliation

NORTHERN INDIANA PUBLIC SERVICE COMPANY

SUMMARY: REVENUE PROOF - PRESENT RATES

Line	Rate	Gross Margin Before Adjustment Factor	Adjustment Factor	Gross Margin After Adjustment Factor
	(A)	(B)	(C)	(D)
1	811	$ 287,221,566	1.001132	$ 287,546,612
2	812	3,079,751	0.987977	3,042,723
3	813	870,723	0.998421	869,349
4	817	24,577	1.187942	29,196
5	820	680,164	0.150881	102,624
6	821	129,714,089	1.023994	132,826,473
7	822	956,805	0.699181	668,980
8	823	103,868,480	1.008138	104,713,758
9	824	109,901,202	0.986131	108,376,930
10	825	8,072,385	0.927481	7,486,982
11	826	30,900,110	0.979284	30,259,974
12	832	3,579,614	0.925079	3,311,426
13	833	22,002,614	0.992560	21,838,908
14	836	13,360,415	0.501317	6,697,798
15	841	1,728,159	1.035644	1,789,757
16	842	33,355	1.000000	33,355
17	844	1,424,010	1.002977	1,428,250
18	845	274,474	1.000000	274,474
19	847	73,575,844	1.000000	73,575,844
20	848	1,296,077	2.898148	3,756,221
21	861	54,653	0.994928	54,375
22	873	1,122	0.997209	1,119
23	877	1,435,770	1.055987	1,516,154
24	878	2,230,876	0.888787	1,982,773
25	879	1,460	0.997561	1,457
26	880	11,880	0.963314	11,444
27	881	1,123,871	0.997196	1,120,719
28	882	102,588	1.365409	140,075
29	883	4,188,000	0.990371	4,147,675
30	884	34,168	0.992620	33,916
31	886	22,623	0.985684	22,299
32	887	37,019	0.989974	36,648
33	888	10,140	0.936802	9,499
34	890	1,361	0.997497	1,357
35	891	118,651	0.998112	118,427
36	892	724,994	1.000997	725,718
37	893	956	0.876289	838
38	895	865,546	0.988347	855,460
39	898	10,452	1.021518	10,677
40	899	5,406	0.968852	5,238
41	Interdepartmental	1,406,379	1.000000	1,406,379
42	2100	1,237,913	1.000000	1,237,913
43		---------------	---------------	---------------
44	Total	$ 806,190,244	0.994889	$ 802,069,794

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

	Proposed Rate 511 - Residential Service					
	At Earned Margin 1,2/				At 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)
Customer Charge		4,813,076	$ 5.95	$ 28,637,802	$ 10.40	$ 50,055,990
Energy Charge						
All kWh (Excl. Space Heating)		3,378,833,787	$ 0.073972	$ 249,937,692	$ 0.081340	$ 274,834,340
Space Heating 811 (Over 700 kWh)		57,265,740	0.048934	2,802,242	0.057160	3,273,310
Space Heating 812 & 813 (Over 700 kWh)		15,255,561	0.032444	494,951	0.057160	872,008
Total Energy		3,451,355,088		$ 253,234,885		$ 278,979,658
Total Calculated Margin				$ 281,872,687		$ 329,035,648
Adjustment Factor				0.994889		0.994889
Total Adjusted Margin				$ 280,432,032		$ 327,353,942
Target Margin				$ 280,432,032		$ 327,356,190
Over / <Under>						$ (2,247)
Percent Incr./<Decr.> vs. Existing						16.73%

1/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
2/ Existing margin for Customers on rates 811, 812 and 813.

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

Line		**Proposed Rate 521 - General Service Small**					
		At Earned Margin 3,4/				At 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	$ 6.09	$ 3,022,406	$ 12.40	$ 6,152,727
2							
3	Energy Charge						
4	kWh		397,251,629	$ 0.102513	$ 40,723,647	$ 0.092840	$ 36,880,841
5			----------------		----------------		----------------
6	Total Energy		397,251,629		$ 40,723,647		$ 36,880,841
7							
8	Total Calculated Margin				$ 43,746,053		$ 43,033,568
9							
10	Adjustment Factor				0.994889		0.994889
11							
12	Total Adjusted Margin				$ 43,522,466		$ 42,813,623
13	Target Margin				$ 43,522,466		$ 42,813,091
14	Over / <Under>						$ 532
15	Percent Incr./<Decr.> vs. Existing						-1.63%
16							
17	--------------------------						
18	3/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
19	4/ Existing margin for Customers on rates 820, 821, 822, 823, 824 & 848						

Petitioner's Exhibit No. RDG-4 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
Schedule 2.0

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

		Proposed Rate 523 - General Service Medium					
		At Earned Margin 5,6/				At Proposed Margin 5/	
		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		138,859	$ 78.85	$ 10,948,759	$ 32.55	$ 4,519,850
2							------------------
3	Demand Metered Customers						$ 4,519,850
4	Energy Charge						
5	kWh		1,106,789,505	$ 0.016810	$ 18,604,621	$ 0.004960	$ 5,489,676
6			----------------		----------------		------------------
7	Sub-Total Energy		1,106,789,505		$ 18,604,621		$ 5,489,676
8							
9	Demand Charge (sum of applicable voltage levels)						
10	Transmission		3,102,088	$ 12.13	$ 37,628,323	$ 13.78	$ 42,746,767
11	Primary		3,102,088	2.97	9,213,200	3.71	11,508,745
12	Secondary		2,989,264	2.76	8,250,368	2.51	7,503,052
13	Thermal Storage kW		93,044	17.86	1,661,773	20.00	1,860,888
14			----------------		----------------		------------------
15	Total Demand		3,195,132		$ 56,753,663		$ 63,619,452
16							
17	Non-Demand Metered Customers						
18	Energy Charge (all kWh)		892,661,429	$ 0.067960	$ 60,665,271	$ 0.089850	$ 80,205,629
19			----------------		----------------		------------------
20	Total Energy		1,999,450,934		$ 60,665,271		$ 80,205,629
21							
22					----------------		------------------
23	Total Calculated Margin				$ 146,972,314		$ 153,834,607
24							
25	Thermal Storage Discount		2,957,137		$ (85,574)		$ (93,778)
26					----------------		------------------
27	Total Revenue less Thermal Storage				$ 146,886,740		$ 153,740,829
28							
29	Adjustment Factor				0.994889		0.994889
30							
31	Total Adjusted Margin				$ 146,136,000		$ 152,955,058
32	Target Margin				$ 146,136,000		$ 152,954,685
33	Over / <Under>						$ 372
34	Percent Incr./<Decr.> vs. Existing						4.67%
35							
36	--------------------------						
37	5/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
38	6/ Existing margin for Customers on rates 820, 821, 822, 823, 824 & 848						

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

		Proposed Rate 526 - Off-Peak Service					
		At Earned Margin 7,8/				At 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	$ 1,000.00	$ 132,000	$ 5,500.00	$ 726,000
2							
3	Energy Charge						
4	All kWh		229,025,082	$ 0.005213	$ 1,194,003	$ 0.004190	$ 959,615
5			---------------		---------------		---------------
6	Total Energy		229,025,082		$ 1,194,003		$ 959,615
7							
8	Demand Charge (sum of applicable voltage levels)						
9	Transmission		322,085	$ 12.87	$ 4,145,228	$ 15.34	$ 4,940,776
10	Primary		307,510	5.45	1,675,930	5.97	1,835,836
11	Secondary		12,542	1.55	19,441	3.01	37,753
12							
13	Power Factor Correction Charge ($/kVAr)						
14	Transmission Customers			1.60		1.14	
15	Primary & Secondary Customers		18,373	0.40	7,349	0.60	11,024
16	Transmission Metering Credit						
17	Primary Metering Credit						
18			---------------		---------------		---------------
19	Total Demand		322,085		$ 5,847,948		$ 6,825,388
20							
21	Total Calculated Margin				$ 7,173,951		$ 8,511,004
22							
23	Adjustment Factor				0.994889		0.994889
24							
25	Total Adjusted Margin				$ 7,137,285		$ 8,467,504
26	Target Margin				$ 7,137,285		$ 8,469,079
27	Over / <Under>						$ (1,575)
28	Percent Incr./<Decr.> vs. Existing						18.66%
29							
30	------------------------						

31 7/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
32 8/ Existing margin for Customers on rate 825

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

		Proposed Rate 527 - Limited Production Large					
		At Earned Margin 9,10/				At 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			$ 3,450.00	$ 41,400
2							
3	Energy Charge						
4	kWh		295,360,506	$ 0.008431	$ 2,490,082	$ 0.00489	$ 1,444,313
5			---------------		---------------		---------------
6	Total Energy		295,360,506		$ 2,490,082		$ 1,444,313
7							
8	Demand Charge (sum of applicable voltage levels)						
9	Transmission		515,592	$ 9.14	$ 4,712,511	$ 9.35	$ 4,820,785
10	Primary		515,592	6.38	3,289,477	8.28	4,269,102
11	Secondary						
12							
13	Power Factor Correction Charge ($/kVAr)						
14	Transmission Customers					1.14	-
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		$ 8,343,252		$ 9,431,151
20							
21	Total Calculated Margin				$ 10,833,335		$ 10,916,864
22							
23	Adjustment Factor				0.994889		0.994889
24							
25	Total Adjusted Margin				$ 10,777,965		$ 10,861,068
26	Target Margin				$ 10,777,965		$ 10,858,308
27	Over / <Under>						$ 2,760
28	Percent Incr./<Decr.> vs. Existing						0.75%
29							

30 ------------------------
31 9/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
32 10/ Existing margin for Customers on rates 824, 833, 847 & 848

Petitioner's Exhibit No. RDG-4 (Revised)
Northern Indiana Public Service Company
Cause No. 43528
Schedule 2.0

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

		Proposed Rate 533 - General Service Large					
		At Earned Margin 11,12/				At Proposed Margin 11/	
		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		11,327	$ 845.96	$ 9,582,546	$ 560.00	$ 6,343,388
2							
3	Energy Charge						
4	kWh		3,471,330,760	$ 0.009762	$ 33,887,502	$ 0.004600	$ 15,968,121
5			----------------		----------------		----------------
6	Total Energy		3,471,330,760		$ 33,887,502		$ 15,968,121
7							
8	Demand Charge (sum of applicable voltage levels)						
9	Transmission		8,491,593	$ 12.33	$ 104,701,344	$ 15.40	$ 130,770,535
10	Primary		8,274,198	3.27	27,056,628	4.00	33,096,792
11	Secondary		3,709,696	1.88	6,974,228	2.04	7,567,779
12	Thermal Storage kW		43,646	17.48	762,939	21.44	935,778
13							
14	Power Factor Correction Charge ($/kVAr)						
15	Transmission Customers		24,952	1.14	28,445	1.14	28,445
16	Primary & Secondary Customers		383,711	0.60	230,227	0.60	230,227
17	Transmission Metering Credit						
18	Primary Metering Credit						
19			----------------		----------------		----------------
20	Total Demand		8,491,593		$ 139,753,809		$ 172,629,556
21							
22	Total Calculated Margin				$ 183,223,857		$ 194,941,065
23							
24	Thermal Storage Discount		12,255,201		$ (44,129)		$ (49,608)
25					----------------		----------------
26	Total Revenue less Thermal Storage				$ 183,179,728		$ 194,891,458
27							
28	Adjustment Factor				0.994889		0.994889
29							
30	Total Adjusted Margin				$ 182,243,494		$ 193,895,365
31	Target Margin				$ 182,243,494		$ 193,890,920
32	Over / <Under>						$ 4,444
33	Percent Incr./<Decr.> vs. Existing						6.39%
34							
35	------------------------						

36 11/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
37 12/ Existing margin for Customers on rates 823, 824, 832 & 848

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

Proposed Rate 534 - Industrial Large Service

		At Earned Margin 13,14/				At 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	$ 195.08	$ 29,684	$ 10,000.00	$ 1,521,654
2							
3	Energy Charge						
4	kWh		4,672,758,395	$ 0.003510	$ 16,401,262	$ 0.004250	$ 19,859,223
5			---------------		---------------		---------------
6	Total Energy		4,672,758,395		$ 16,401,262		$ 19,859,223
7							
8	Demand Charge (sum of applicable voltage levels)						
9	Transmission		10,297,716	$ 12.88	$ 132,634,582	$ 13.67	$ 140,769,778
10	Primary		707,472	3.55	2,511,526	3.79	2,681,319
11	Secondary						
12							
13	Power Factor Correction Charge ($/kVAr)						
14	Transmission Customers		2,004,572	1.60	3,207,316	1.14	2,285,212
15	Primary & Secondary Customers		244,580	0.40	97,832	0.60	146,748
16	Transmission Metering Credit						
17	Primary Metering Credit						
18			---------------		---------------		---------------
19	Total Demand		10,297,716		$ 138,451,255		$ 145,883,057
20							
21	Total Calculated Margin				$ 154,882,201		$ 167,263,934
22							
23	Adjustment Factor				0.994889		0.994889
24							
25	Total Adjusted Margin				$ 154,090,596		$ 166,409,046
26	Target Margin				$ 154,090,596		$ 166,411,504
27	Over / <Under>						$ (2,458)
28	Percent Incr./<Decr.> vs. Existing						8.00%
29							

30 --------------------------
31 13/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
32 14/ Existing margin for Customers on rates 824, 833, 847 & 848

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

Proposed Rate 536 - Interruptible Industrial Service

		At Earned Margin 15,16/				At 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	$ 500.00	$ 30,000	$ 2,200.00	$ 132,000
2							
3	Energy Charge						
4	kWh		2,084,025,091	$ 0.001247	$ 2,599,132	$ 0.004070	$ 8,481,982
5			----------------		----------------		----------------
6	Total Energy		2,084,025,091		$ 2,599,132		$ 8,481,982
7							
8	Demand Charge (sum of applicable voltage levels)						
9	Transmission		2,998,800	$ 8.79	26,359,452	$ 8.65	$ 25,939,620
10			----------------		----------------		----------------
11	Total Demand		2,998,800		$ 26,359,452		$ 25,939,620
12							
13	Total Calculated Margin				$ 28,988,584		$ 34,553,602
14							
15	Adjustment Factor				0.994889		0.994889
16							
17	Total Adjusted Margin				$ 28,840,423		$ 34,376,998
18	Target Margin				$ 28,840,423		$ 34,378,380
19	Over / <Under>						$ (1,382)
20	Percent Incr./<Decr.> vs. Existing						19.20%
21							

22 ------------------------
23 15/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.
24 16/ Existing margin for Customers on rate 836

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

		Proposed Rate 541 - Water Pumping Service					
		At Earned Margin 17,18/				At 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		7,680	$ 15.00	$ 115,200	$ 35.00	$ 268,800
2	Customer Charge (non metered)		60	$ 50.00	$ 3,000	$ 45.00	$ 2,700
3							
4	Energy Charge						
5	Residential Pumps (Unmetered Service)		953	$ 2.75	$ 2,621	$ 3.90	$ 3,715
6	Commercial Pumps (Unmetered Service)		38	3.20	122	4.54	172
7							
8	kWh		25,135,539	0.066946	1,682,717	0.090780	2,281,804
9							
10	Total Energy		25,135,539		$ 1,685,459		$ 2,285,692
11							
12	Total Calculated Margin				$ 1,803,659		$ 2,557,192
13							
14	Adjustment Factor				0.994889		0.994889
15							
16	Total Adjusted Margin				$ 1,794,440		$ 2,544,122
17	Target Margin				$ 1,794,440		$ 2,543,977
18	Over / <Under>						$ 145
19	Percent Incr./<Decr.> vs. Existing						41.77%
20							
21	------------------------						
22	17/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
23	18/ Existing margin for Customers on rates 841 & 842						

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REV, REQ'T

		Proposed Rate 544 - Railroad Power Service					
		At Earned Margin 19,20/				At 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	$ 200.00	$ 2,400	$ 335.00	$ 4,020
2							
3	Energy Charge						
4	kWh		18,905,250	$ 0.019511	$ 368,855	$ 0.007290	$ 137,819
5			---------------		---------------		---------------
6	Total Energy		18,905,250		$ 368,855		$ 137,819
7							
8	Demand Charge (sum of applicable voltage levels)						
9	Transmission		79,171	$ 9.55	$ 756,083	$ 5.55	$ 439,399
10	Primary		79,171	2.75	217,720	10.09	798,835
11	Secondary			2.22		3.20	
12			---------------		---------------		---------------
13	Total Demand		79,171		$ 973,803		$ 1,238,234
14							
15	Total Calculated Margin				$ 1,345,058		$ 1,380,074
16							
17	Adjustment Factor				0.994889		0.994889
18							
19	Total Adjusted Margin				$ 1,338,183		$ 1,373,020
20	Target Margin				$ 1,338,183		$ 1,373,116
21	Over / <Under>						$ (96)
22	Percent Incr./<Decr.> vs. Existing						2.61%
23							
24	----------------------						
25	19/ Margin and Base Revenues (revenues excluding all fuel collection) have the same meaning in this analysis.						
26	20/ Existing margin for Customers on rate 844						

REVENUE PROOF - REVISED REVENUE REQUIREMENT - PROPOSED SERVICE CLASSIFICATIONS

NORTHERN INDIANA PUBLIC SERVICE COMPANY
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE PROOF - REVISED REVENUE REQUIREMENT

Summary		Total
Proposed Rate 511 - Residential Service	$	327,353,942
Proposed Rate 521 - General Service Small		42,813,623
Proposed Rate 523 - General Service Medium		152,955,058
Proposed Rate 526 - Off-Peak Service		8,467,504
Proposed Rate 527 - Limited Production Large		10,861,068
Proposed Rate 533 - General Service Large		193,895,365
Proposed Rate 534 - Industrial Large Service		166,409,046
Proposed Rate 536 - Interruptible Industrial Service		34,376,998
Proposed Rate 541 - Water Pumping Service		2,544,122
Proposed Rate 544 - Railroad Power Service		1,373,020
Proposed Rate 550 - Traffic Lighting		6,621,556
Proposed Rate 555 - Street Lighting		675,085
Proposed Rate 560 - Dusk to Dawn Lighting		3,170,745
Interdepartmental		2,139,232
Total Calculated Revenue	$	953,656,363
Target Revenue	$	953,657,369
Over/(Under)	$	(1,006)

Petitioner's Exhibit CAW-S1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY

OF

CURT A. WESTERHAUSEN
MANAGER OF RATES AND CONTRACTS

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY OF CURT A. WESTERHAUSEN

Q1. Please state your name, occupation 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. Did you previously submit Prepared Direct Testimony as a part of the Case-In-Chief of Petitioner Northern Indiana Public Service Company ("NIPSCO") filed with the Commission in this Cause on August 29, 2008 and corrected on September 29, 2008?

A3. Yes. My Prepared Direct Testimony has been marked as <u>Petitioner's Exhibit CAW-1</u>.

Q4. What is the purpose of your Supplemental Direct Testimony?

A4. The purpose of my supplemental direct testimony is to describe the changes to NIPSCO's proposed Tariff, including the Schedules of Rates ("Rates"), Riders and General Rules and Regulations ("Rules") resulting from the inclusion of the Sugar Creek generating facility in one step, thereby eliminating the second step originally proposed and the adjustment to test year medical expense as explained in the revised testimony of NIPSCO Witness Linda E. Miller. I am also supporting corrections to the Tariffs.

Q5. Are you sponsoring any exhibits?

A5. Yes, I am sponsoring revisions to Petitioner's Exhibits CAW-2, Northern Indiana Public Service Company, IURC Electric Service Tariff, Original Volume No. 11 ("Tariff").

Q6. What changes in the Tariff (Petitioner's Exhibit CAW-2) resulted from the revised revenue requirements as proposed in this supplemental filing?

A6. The revisions to the revenue requirement resulted in various changes to our proposed rates, including the customer charge, the energy charge, the demand charge, and pump charge, as applicable. These changes are included in the attached revised pages to Petitioner's Exhibit CAW-2.

Q7. Please explain the other corrections being made to the Tariff.

A7. I am sponsoring a correction to the Usage Tables applicable to Rates 550 and 560. In the past, NIPSCO had lighting rates for both "All Night" and "Dusk to Dawn" operation. In order to simplify the lighting rates, the reference to "All Night" has been removed and the Hours of Operation table has been corrected. However, when the Usage tables containing the monthly kWh values were prepared, the values were incorrect and inadvertently shifted by one month. The corrected tables are shown in the attached revised pages in Petitioner's Exhibit CAW-2.

VERIFICATION

I, Curt A. Westerhausen, Manager of Rates and Contracts 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.

Curt A. Westerhausen

Date: December 19, 2008

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

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Also effective in rural territories furnished electric service by Company.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

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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.
6. Any other instance when the financial institution refuses to honor the tendered payment.

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 greater than 600 volts and less than 69,000 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
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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.

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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.

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

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

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

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)

14.2 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

$10.40 per month

Energy Charge

$0.08134 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

$12.40 per month

Energy Charge

$0.09284 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

$32.55 per month

Demand Charge

$20.00 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

$0.00496 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:

$0.08985 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 $2.51 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

$24.32 per kilowatt per month

Energy Charge

$000419 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

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 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 $3.01 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 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 $8.98 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

$3,450.00 per month

Demand Charge

$17.63 per kilowatt

Energy Charge

$0.00489 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 $8.28 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.

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

$560.00 per month

Demand Charge

$21.44 per kilowatt of Billing Demand per month

Energy Charge

$0.00460 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 the Company installs an 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 $2.04 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 $6.04 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

$10,000.00 per month

Demand Charge

$17.46 per kilowatt per month

Energy Charge

$0.00425 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 $3.79 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

$8.65 per kilowatt per month.

Energy Charge

$0.00407 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 for electric power service to be used for water pumping 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

$0.09078 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 $3.90 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 $3.90 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 $4.54 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 $4.54 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

$335.00 per month

Demand Charge

$15.64 per kilowatt of Maximum Demand per month

Energy Charge

$0.00729 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 and Demand 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.

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	$3.30 per month
400 Watt Mercury Vapor*	$10.50 per month	n/a
100 Watt High Pressure Sodium	$8.10 per month	$2.85 per month
150 Watt High Pressure Sodium	$8.50per month	n/a
250 Watt High Pressure Sodium	$8.80 per month	$2.95 per month
400 Watt High Pressure Sodium	$9.10 per month	$3.00 per month

*Available to existing Customers only

For Customer-Owned – Customer Maintained Lamps, the Lamp Charge shall be $1.30 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

$0.03495 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	Tc
Lamp Type													
100 Watt Mercury Vapor	52.9	44.7	44.3	37.9	34.8	31.5	33.5	37.3	40.7	47.1	49.9	54.0	
150 Watt Mercury Vapor	78.7	66.5	65.9	56.3	51.8	46.9	49.9	55.4	60.6	70.1	74.3	80.4	
175 Watt Mercury Vapor	87.0	73.6	72.9	62.3	57.3	51.8	55.2	61.3	67.0	77.6	82.2	88.9	
250 Watt Mercury Vapor	126.9	107.4	106.3	90.9	83.5	75.6	80.5	89.4	97.7	113.2	119.9	129.7	1,
400 Watt Mercury Vapor	230.2	194.8	192.7	164.9	151.5	137.1	145.9	162.2	177.2	205.2	217.4	235.3	2,
175 Watt Metal Halide	89.7	75.9	75.1	64.3	59.0	53.4	56.9	63.2	69.1	80.0	84.7	91.7	
250 Watt Metal Halide	123.7	104.7	103.6	88.6	81.4	73.7	78.4	87.1	95.3	110.3	116.8	126.4	1,
400 Watt Metal Halide	189.7	160.5	158.8	135.9	124.8	113.0	120.2	133.6	146.0	169.1	179.1	193.8	1,
1500 Watt Metal Halide	692.9	586.2	580.0	496.3	456.0	412.7	439.2	488.0	533.5	617.6	654.2	708.1	6,
55 Watt Low Pressure Sodium	35.0	29.6	29.3	25.1	23.0	20.8	22.2	24.6	26.9	31.2	33.0	35.8	
90 Watt Low Pressure Sodium	57.5	48.6	48.1	41.2	37.8	34.2	36.4	40.5	44.3	51.3	54.3	58.8	
135 Watt Low Pressure Sodium	70.2	59.4	58.8	50.3	46.2	41.8	44.5	49.5	54.1	62.6	66.3	71.8	
70 Watt High Pressure Sodium	43.2	36.5	36.1	30.9	28.4	25.7	27.4	30.4	33.2	38.5	40.8	44.1	
100 Watt High Pressure Sodium	63.3	53.6	53.0	45.4	41.7	37.7	40.1	44.6	48.7	56.4	59.8	64.7	
150 Watt High Pressure Sodium	85.2	72.1	71.4	61.1	56.1	50.8	54.0	60.0	65.6	76.0	80.5	87.1	
200 Watt High Pressure Sodium	101.4	85.8	84.9	72.7	66.8	60.4	64.3	71.4	78.1	90.4	95.8	103.7	
250 Watt High Pressure Sodium	135.6	114.7	113.5	97.1	89.2	80.7	85.9	95.5	104.4	120.9	128.0	138.5	1,
310 Watt High Pressure Sodium	163.6	138.4	136.9	117.2	107.7	97.4	103.7	115.2	125.9	145.8	154.5	167.2	1,
400 Watt High Pressure Sodium	221.6	187.5	185.5	158.7	145.9	132.0	140.5	156.1	170.6	197.6	209.3	226.5	2,
1000 Watt High Pressure Sodium	494.4	418.3	413.9	354.2	325.4	294.5	313.4	348.3	380.7	440.7	466.9	505.3	4,

A NiSource Company

Dusk to Midnight Usage:

(kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lamp Type													
175 Watt Mercury Vapor	42.8	35.8	31.9	25.8	23.6	20.6	21.6	24.8	28.6	34.6	42.2	45.1	377.3
250 Watt Mercury Vapor	62.5	52.3	46.6	37.7	34.4	30.1	31.5	36.3	41.8	50.5	61.6	65.8	551.1
400 Watt Mercury Vapor	112.9	94.4	84.1	68.1	62.1	54.4	56.9	65.5	75.4	91.1	111.2	118.8	994.9
150 Watt High Pressure Sodium	42.0	35.1	31.3	25.4	23.1	20.2	21.2	24.4	28.1	33.9	41.4	44.2	370.4

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:

Hours of Operation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Dusk to Dawn	**447**	**379**	**375**	**321**	**295**	**267**	**284**	**315**	**345**	**399**	**423**	**457**	**4,304**
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

$16.56 per month

Energy Charge

$0.04605 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*	$12.75 per month
400 Watt Mercury Vapor*	$17.10 per month
100 Watt High Pressure Sodium Dusk to Dawn Fixture	$12.90 per month
250 Watt High Pressure Sodium Dusk to Dawn Fixture	$13.95 per month
400 Watt High Pressure Sodium Dusk to Dawn Fixture	$14.25 per month
150 Watt High Pressure Sodium Floodlight	$14.20 per month
250 Watt High Pressure Sodium Floodlight	$14.60 per month
400 Watt High Pressure Sodium Floodlight	$14.85 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	$6.10 per month
Guy and anchor set	$1.55 per month
Extra span of secondary	$1.55 per month

***Available to existing Customers only**

Energy Charge –

$0.03495 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	87.0	73.6	72.9	62.3	57.3	51.8	55.2	61.3	67.0	77.6	82.2	88.9	837.1
400 Watt Mercury Vapor	230.2	194.8	192.7	164.9	151.5	137.1	145.9	162.2	177.2	205.2	217.4	235.3	2,214.4
100 Watt High Pressure Sodium Dusk to Dawn Fixture	63.3	53.6	53.0	45.4	41.7	37.7	40.1	44.6	48.7	56.4	59.8	64.7	609.0
250 Watt High Pressure Sodium Dusk to Dawn Fixture	135.6	114.7	113.5	97.1	89.2	80.7	85.9	95.5	104.4	120.9	128.0	138.5	1,304.1
400 Watt High Pressure Sodium Dusk to Dawn Fixture	221.6	187.5	185.5	158.7	145.9	132.0	140.5	156.1	170.6	197.6	209.3	226.5	2,131.8
150 Watt High Pressure Sodium Floodlight	85.2	72.1	71.4	61.1	56.1	50.8	54.0	60.0	65.6	76.0	80.5	87.1	819.9
250 Watt High Pressure Sodium Floodlight	135.6	114.7	113.5	97.1	89.2	80.7	85.9	95.5	104.4	120.9	128.0	138.5	1,304.1
400 Watt High Pressure Sodium Floodlight	221.6	187.5	185.5	158.7	145.9	132.0	140.5	156.1	170.6	197.6	209.3	226.5	2,131.8

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 3-month KWH sales forecast for each Rate Schedule.

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:

Reliability Factor ("RF") = ((D x P) + (E x 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 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 ("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.

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.

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 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:

$0.05716 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 one 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. Any back-up and maintenance power taken by the Qualified Facility will be billed under an appropriate Rate Schedule.

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.

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 as 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): ______________

Attach documentation confirming that a nationally recognized testing and certification laboratory has listed the equipment.

Attach a single line diagram or sketch one below that includes all electrical equipment from the point where service is taken from Northern Indiana Public Service Company to the inverter which includes the main panel, sub-panels, breaker sizes, fuse sizes, transformers, and disconnect switches (which may need to be located outside and accessible by utility personnel).

Mail to: NIPSCO, Attn: Business Link, 801 E. 86th Avenue, Merrillville, IN 46410

* 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**

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).

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 Company 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.

______________________________	CUSTOMER
By: ____________________________	By: ______________________________
Printed Name: ___________________	Printed Name: _____________________
Title: __________________________	Title: _____________________________

Mail To:
NIPSCO
Attn: Business Link
801 E. 86th Avenue
Merrillville, IN 46410

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) Company Rules 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 such excess facilities be detailed in Exhibit B of this Agreement including the facilities to be added by the Company to facilitate the interconnection of the Customer's Generation Facilities and the costs of such excess facilities shall be paid by the Customer to the Company.

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	
Property Damage	and size of the Generation Facilities.)

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

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 578 – 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.

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	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
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, 527, 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 [ ] per kilowatt hour

APPENDIX C
RELIABILITY ADJUSTMENT FACTOR

The Reliability Adjustment Factor in Rates 511, 521, 523, 526, 527, 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 527	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, 526, 527, 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 527	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, 527, 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 527	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

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Q17. Please generally describe NIPSCO's generation fleet at the end of the test year.

A17. The NIPSCO generating facilities have a total capacity of 2,787 megawatts ("MW") and consist of six (6) separate generation sites, including Schahfer, Michigan City Generating Station, Bailly Generating Station, Mitchell, and Norway and Oakdale hydroelectric facilities, which are described in more detail by NIPSCO Witness Philip W. Pack. The total MWs exclude the Sugar Creek Facility, which is discussed later.

Q18. Is NIPSCO planning to retire any of its generation facilities in the near future?

A18. Yes. NIPSCO plans to retire Units 4, 5, 6, 9A, and 11 at Mitchell and Units 2 and 3 at Michigan City.

Q19. Why is NIPSCO retiring Mitchell Units 4, 5, 6 and 11?

A19. Those Units were indefinitely shutdown about January 2002. NIPSCO has continued to evaluate the Mitchell Units as recently as its 2007 IRP. NIPSCO has concluded that restarting the Mitchell Units, compared to the alternatives in the 2007 IRP, is not the most effective balance between economics and risk mitigation.

Q20. Why is NIPSCO retiring Unit 9A at Mitchell?

A20. Unit 9A at Mitchell will be retired near the end of the demolition of the other Mitchell Units. The 2007 IRP projected Unit 9A's retirement to be the end of 2016. The retirement as proposed herein would occur a number of years prior to 2016. This retirement is appropriate when the costs of security, monthly testing, and on-going maintenance are considered.

A26. Yes. The Commission granted NIPSCO a CPCN to acquire the Sugar Creek Facility in its May 28, 2008 Order in Cause No. 43396 (the "CPCN Order"). The CPCN Order found that the purchase price for the Sugar Creek Facility was reasonable and that the acquisition was in the public interest.

Q27. What was the purchase price of the Sugar Creek Facility?

A27. The total purchase price paid by NIPSCO for the Sugar Creek Facility was $329,672,739 as of June 30, 2008, but expects to adjust this purchase price to reflect a post-closing working capital adjustment.

Q28. How did NIPSCO assume ownership of the Sugar Creek Facility?

A28. NIPSCO acquired the equity interests in Sugar Creek Power Company, LLC, (the then owner of the plant) on May 30, 2008. On July 7, 2008, Sugar Creek Power Company, LLC was merged into NIPSCO. Accordingly, the Sugar Creek Facility is now an asset owned directly by NIPSCO.

Q29. Is NIPSCO seeking to include the Sugar Creek Facility as part of its rate base in this proceeding?

A29. Yes. ~~NIPSCO is proposing to do so as part of a second step rate change that would become effective when the Sugar Creek Facility is dispatched into the Midwest ISO.~~

Q30. Why is NIPSCO proposing to include ~~a second step rate change to reflect~~ the Sugar Creek Facility as part of its rate base?

A30. Although NIPSCO has already acquired the Sugar Creek Facility, the CPCN Order found that the Sugar Creek Facility could not be deemed to be "in service" under Indiana law until it can be dispatched into the Midwest ISO. The prior owner of the Sugar Creek Facility originally committed its output to the PJM capacity market through May 31, 2010. ~~NIPSCO will dedicate~~ However, NIPSCO arranged for ~~As of December 1, 2008,~~ the Sugar Creek Facility to become ~~is~~ an Internal Designated Network Resource in ~~to~~ the Midwest ISO as of December 1, 2008. ~~after the unit's commitment to PJM expires~~. As a result of this change, NIPSCO is seeking approval to include ~~adjust its rates and charges at such time to reflect thise in-service status of~~ the Sugar Creek Facility in its rate base immediately (rather than in 2010).

Q31. Is NIPSCO also seeking to include additional O&M expenses associated with the Sugar Creek Facility ~~in its second phase rate increase~~?

A31. Yes. Mr. Pack discusses NIPSCO's costs.

V. TRANSMISSION PLANNING

Q32. Have there been any changes in NIPSCO's transmission planning processes?

A32. Yes. NIPSCO's transmission processes have been modified as a result of the impacts of the Energy Policy Act of 2005 ("EPAct 2005"), which made important changes to improve reliability, promote investment in electric facilities, enhance the nation's electric infrastructure, improve wholesale competition, and promote greater efficiency in electric generation and delivery. FERC is taking action on multiple fronts to enhance the reliability of the electric transmission system. FERC certified NERC as the nation's ERO, which began operation on June 18, 2007.

FERC has issued various orders making NERC reliability standards mandatory and sanctionable. The ERO and the Regional Reliability Organizations must monitor compliance with these reliability standards and may direct violators to comply with the standards and impose penalties for violations, subject to review by and appeal to FERC. FERC has asserted that the transmission system needs to be expanded and improved to promote wholesale competition and to produce the greatest benefit for all stakeholders from RTO participation.

Q33. Does this conclude your prepared direct testimony?

A33. Yes, it does.

Q17. Please generally describe NIPSCO's generation fleet at the end of the test year.

A17. The NIPSCO generating facilities have a total capacity of 2,787 megawatts ("MW") and consist of six (6) separate generation sites, including Schahfer, Michigan City Generating Station, Bailly Generating Station, Mitchell, and Norway and Oakdale hydroelectric facilities, which are described in more detail by NIPSCO Witness Philip W. Pack. The total MWs exclude the Sugar Creek Facility, which is discussed later.

Q18. Is NIPSCO planning to retire any of its generation facilities in the near future?

A18. Yes. NIPSCO plans to retire Units 4, 5, 6, 9A, and 11 at Mitchell and Units 2 and 3 at Michigan City.

Q19. Why is NIPSCO retiring Mitchell Units 4, 5, 6 and 11?

A19. Those Units were indefinitely shutdown about January 2002. NIPSCO has continued to evaluate the Mitchell Units as recently as its 2007 IRP. NIPSCO has concluded that restarting the Mitchell Units, compared to the alternatives in the 2007 IRP, is not the most effective balance between economics and risk mitigation.

Q20. Why is NIPSCO retiring Unit 9A at Mitchell?

A20. Unit 9A at Mitchell will be retired near the end of the demolition of the other Mitchell Units. The 2007 IRP projected Unit 9A's retirement to be the end of 2016. The retirement as proposed herein would occur a number of years prior to 2016. This retirement is appropriate when the costs of security, monthly testing, and on-going maintenance are considered.

A26. Yes. The Commission granted NIPSCO a CPCN to acquire the Sugar Creek Facility in its May 28, 2008 Order in Cause No. 43396 (the "CPCN Order"). The CPCN Order found that the purchase price for the Sugar Creek Facility was reasonable and that the acquisition was in the public interest.

Q27. What was the purchase price of the Sugar Creek Facility?

A27. The total purchase price paid by NIPSCO for the Sugar Creek Facility was $329,672,739 as of June 30, 2008, but expects to adjust this purchase price to reflect a post-closing working capital adjustment.

Q28. How did NIPSCO assume ownership of the Sugar Creek Facility?

A28. NIPSCO acquired the equity interests in Sugar Creek Power Company, LLC, (the then owner of the plant) on May 30, 2008. On July 7, 2008, Sugar Creek Power Company, LLC was merged into NIPSCO. Accordingly, the Sugar Creek Facility is now an asset owned directly by NIPSCO.

Q29. Is NIPSCO seeking to include the Sugar Creek Facility as part of its rate base in this proceeding?

A29. Yes.

Q30. Why is NIPSCO proposing to include the Sugar Creek Facility as part of its rate base?

A30. Although NIPSCO has already acquired the Sugar Creek Facility, the CPCN Order found that the Sugar Creek Facility could not be deemed to be "in service" under Indiana law until it can be dispatched into the Midwest ISO. The prior owner of the Sugar Creek Facility originally committed its output to the PJM capacity market through May 31, 2010. However, NIPSCO arranged for the Sugar Creek Facility to become an Internal Designated Network Resource in the Midwest ISO as of December 1, 2008,. As a result of this change, NIPSCO is seeking approval to include the Sugar Creek Facility in its rate base immediately (rather than in 2010).

Q31. Is NIPSCO also seeking to include additional O&M expenses associated with the Sugar Creek Facility?

A31. Yes. Mr. Pack discusses NIPSCO's costs.

V. <u>TRANSMISSION PLANNING</u>

Q32. Have there been any changes in NIPSCO's transmission planning processes?

A32. Yes. NIPSCO's transmission processes have been modified as a result of the impacts of the Energy Policy Act of 2005 ("EPAct 2005"), which made important changes to improve reliability, promote investment in electric facilities, enhance the nation's electric infrastructure, improve wholesale competition, and promote greater efficiency in electric generation and delivery. FERC is taking action on multiple fronts to enhance the reliability of the electric transmission system. FERC certified NERC as the nation's ERO, which began operation on June 18, 2007.

FERC has issued various orders making NERC reliability standards mandatory and sanctionable. The ERO and the Regional Reliability Organizations must monitor compliance with these reliability standards and may direct violators to comply with the standards and impose penalties for violations, subject to review by and appeal to FERC. FERC has asserted that the transmission system needs to be expanded and improved to promote wholesale competition and to produce the greatest benefit for all stakeholders from RTO participation.

Q33. Does this conclude your prepared direct testimony?

A34. Yes, it does.

VERIFICATION

I, Bradley K. Sweet, Vice President, Strategic Planning and Operations Support for the NiSource Inc. Northern Indiana Energy group, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Bradley K Sweet

Bradley K. Sweet

Date: December 19, 2008