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INDIANA UTILITY
REGULATORY COMMISSION

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

NORTHERN INDIANA PUBLIC SERVICE COMPANY	))	CAUSE NO. 43526

DIRECT TESTIMONY

OF

DR. DALE E. SWAN

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

MAY 8, 2009

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
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TESTIMONY OF DR. DALE E. SWAN
CAUSE NO. 43526
NORTHERN INDIANA PUBLIC SERVICE COMPANY

1 **Q. Please state your name, occupation and address.**

2 A. My name is Dale E. Swan. I am a senior economist and principal with Exeter
3 Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland
4 21044.

5 **Q. Dr. Swan, please summarize your professional qualifications.**

6 A. I hold a B.S. degree in Business Administration from Ithaca College. I attended a
7 master's program in economics at Tufts University, and I hold a Ph.D. in economics
8 from the University of North Carolina at Chapel Hill. Prior to my consulting work,
9 I served as Assistant and Associate Professor on the economics faculties of several
10 colleges and universities. I also served as staff economist with the Federal Energy
11 Administration and with the Arabian American Oil Company. For the last 30 years,
12 I have consulted on matters primarily related to the electric utility industry, the last 26
13 years with Exeter. Much of my work over the last two decades has concentrated in
14 the areas of long-term electric power supply planning and contract negotiations for
15 large power users, and on electric utility cost allocation and rate design. For much of
16 this period, I have directed Exeter's utility support services projects with the United
17 States Department of Energy (DOE). As part of this work, I have been responsible
18 for technical supervision of Exeter's participation in DOE interventions in numerous
19 rate cases, and for the negotiation of technical aspects of power supply and facilities
20 contracts.

21 A complete copy of my resume is provided as an attachment to my testimony.

22 **Q. Have you testified in other regulatory proceedings?**

A. Yes. I have testified on a variety of topics relating to electric utilities in numerous proceedings before federal and state regulatory commissions, including the Indiana Utility Regulatory Commission ("IURC" or "Commission"). A complete list of the cases in which I have testified is provided as part of my resume.

I. Introduction

Q. Dr. Swan, what is the purpose of your testimony?

A. I have been asked by the Indiana Office of Utility Consumer Counselor (OUCC) to evaluate the reasonableness of the embedded, class cost-of-service study filed by Northern Indiana Public Service Company ("NIPSCO" or "Company") in this case, and to provide alternative cost studies if that is appropriate. I have also been asked to recommend to the Commission an appropriate allocation of the allowed jurisdictional revenue requirement among the customer classes based on cost of service and other general rate design considerations, such as rate moderation or continuity. Finally, I have been asked to assess the Company's proposed rate design and recommend changes as appropriate.

Q. Do you provide schedules in support of your testimony?

A. Yes. I have attached Schedules DES-1 through DES-10 to my testimony.

Q. Were these schedules prepared by you or under your direct supervision?

A. Yes.

Q. Dr. Swan, please briefly describe your conclusions and recommendations.

A. As a result of my evaluation of the Company's embedded class cost of service study, its proposed spread of its requested total jurisdictional revenue increase and its rate

design recommendations, I draw the following conclusions and make the following recommendations:

1. NIPSCO's allocation of its generation and transmission plant-related costs violates the principle of cost causality and produces incorrect indications of class rates of return and cross subsidies.
2. A significant portion of NIPSCO's generation and transmission plant-related costs are caused by planning decisions intended to reduce energy costs, and so should be allocated on the basis of energy use.
3. NIPSCO incorrectly allocates no portion of its generation and transmission plant-related costs on energy use.
4. The Company has correctly classified no portion of upstream distribution plant as customer related.
5. The Commission should use, as the cost basis for determining the spread of the allowed change in jurisdictional revenues in this case, the OUCC Peak and Average Cost (P&A) of Service Study, which allocates an appropriate portion of generation and transmission plant-related costs on energy use, and includes fuel costs and related base revenues and $55.1 million of additional revenues that result from the termination of the existing revenue credits.
6. If the Commission fails to adopt the OUCC's P&A study, then it should retain the use of the OUCC's alternative 12-CP study as the cost basis for spreading the allowed change in total jurisdictional revenue among the classes.

7. The adopted production plant allocator should be used to allocate costs in Riders 571, 572 and 573.
8. Increases in customer charges in Rates 511 and 521 should be limited to 20 percent on the basis of rate continuity concerns. If no jurisdictional increase or a reduction is ordered, no change should be made to these customer charges.
9. Reconnection charge increases should be limited to 20 percent if the Commission grants a total increase close to what the Company has requested. If no increase or a significant reduction in jurisdictional revenues is approved, the charges for reconnection at the meter should not change, but modest increases could be applied to reconnections at the pole.

II. Allocation of Costs in NIPSCO's Cost of Service Study

Q. Please describe the attributes of a class cost of service study and explain what such a study is supposed to accomplish.

A. Average, embedded, historic class cost of service studies of the type performed by NIPSCO witness Robert Greneman are performed in an attempt to determine the share of total costs that is incurred to provide service to each class of customers. Such studies are referred to as average, embedded, historic cost studies because they attempt to directly assign or allocate to each customer class, actual book plant and related costs, adjusted to test year levels as authorized by the Commission. They are also referred to as "fully allocated" costs because these studies require that 100 percent of the allowed total jurisdictional costs of service be allocated among the various classes. This is done by determining the average costs of the various

components of service (the total cost of the component divided by the units of service for that component), and then by allocating these component costs to each of the classes, based on each class' service units that have caused that cost. This is a fundamental aspect of an embedded cost of service study – that is, costs should be assigned or allocated to classes on the basis of the factors that caused each of those costs to be incurred.

The costs are first functionalized into broad categories, such as production costs, transmission costs and distribution costs. These costs may be further broken down by voltage delivery level and other sub-functions may be identified. Costs are then classified as to whether they are demand-related, energy related, customer related or related to some other factor, such as labor costs or revenue. Finally, the costs are allocated among the customer classes on the basis of the most appropriate measure of demand, energy or customers, in proportion to each class' share of the various allocation measures.

Q. What cost allocations in the Company's class cost of service study are of particular concern in this case?

A. Of particular concern is the way in which generation and transmission capital costs and generation and transmission plant-related O&M costs have been allocated in the Company's study. Specifically, these costs have largely been allocated on a peak demand basis, with no responsibility being assigned to energy.

Q. Please explain the basis upon which NIPSCO has allocated its generation plant and related O&M costs.

A. The Company has classified 100 percent of its production plant costs as demand related and has allocated these costs to customer classes based on each class' share of NIPSCO's control area peak demand in four summer months (June through

September). Mr. Greneman provides the following explanation of why all of these production (as well as transmission) plant costs are classified as demand related:

> 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. (Petitioner's Exhibit RDG-1, p. 11)

Q. How has the Company allocated transmission plant costs?

A. The Company has classified transmission plant costs as 100 percent demand related and has allocated those costs on the basis of class contributions to the average of the twelve monthly coincident peaks ("12 CP") of the Company's control area. The classification as 100 percent demand-related is based on the same logic as generation plant. Mr. Greneman's explanation for allocating these costs on the 12 CP is that this method is commonly used by FERC and is used by MISO. (Petitioner's Exhibit RDG-1, p. 17) It is also noted by the Company in response to OUCC Request 6-12(b) that, "Peak demands that drive transmission capacity are seen as being more diverse in nature than loads that drive generation." Of particular interest, it is also stated in that response that, "NIPSCO's transmission lines are constructed to make sure it reliably meets required loads under various conditions and meets the NERC criteria; which includes shoulder and off-peak as well as system peak periods."

Q. How has the Company allocated production plant-related and transmission plant-related O&M costs?

A. As is generally the case in most cost of service studies, the allocation of most of the production plant-related O&M costs follows the allocation of production plant, and the allocation of most of the transmission plant-related O&M costs follows the allocation of transmission plant. Thus, in the Company's study, these plant-related

O&M costs are also allocated essentially entirely on the basis of class contributions to the four summer coincident peak demands for production-related costs and on the 12 CP for transmission-related costs.

III. The Proper Allocation of Generation and Transmission Plant Costs

Q. Do you agree with the Company's classification and allocation of these production and transmission plant related costs as 100 percent peak demand related?

A. No. A cost study should classify and allocate costs among customer classes on the basis of the factors that caused those costs to be incurred, and NIPSCO's total production and transmission plant investment costs have not been caused solely by the peak demands of its customers. A significant portion of those investment costs have been directly caused by the need to meet the energy requirements of NIPSCO's customers, and so a commensurate portion of the investment costs and the associated plant-related O&M costs should be allocated on the basis of class energy usage.

Q. Please explain why a significant portion of generation investment costs should be properly classified as energy related and allocated on class energy usage.

A. Generation capacity planning by utilities, including NIPSCO, is conducted in order to meet reliability requirements as well as the sustained energy demands of its customers at the least possible cost. That means that sufficient generation capacity must be installed or purchased to meet the system peak demands plus the planning reserve requirement. Thus, the system peak demands are clearly responsible for the amount of generation capacity that NIPSCO has installed or purchased. However, the total cost of that capacity is not directly caused by the magnitude of the system peak demands. It would be inconsistent with rational economic planning to base generation

1 plant investment decisions solely on the basis of meeting peak demands. A simple
2 example will show how NIPSCO's current and planned mix of generation capacity
3 would differ considerably if its generation investment decisions were based only on
4 meeting peak demands. If NIPSCO had planned its generation mix only to meet the
5 four highest monthly peak demands over the course of the year at the lowest possible
6 cost, it would have done so by building only peaking plants. This is because peaking
7 generation facilities are more economical for meeting peak demands than for meeting
8 sustained demands for electricity. The capital cost of peaking facilities is relatively
9 low – generally the lowest of all possible generation alternatives. On the other hand,
10 the operating cost of peaking plants is generally the highest of all possible
11 alternatives, due to much higher heat rates and more expensive fuel as compared to
12 intermediate or baseload units. However, the high variable cost of peaking units is
13 inconsequential if the only objective is to meet the load during the four hours of the
14 Company's annual four coincident peaks, since those expensive operating costs
15 would only be experienced for four hours during the year.

16 **Q. Then why does a company such as NIPSCO build baseload generation plant?**

17 A. NIPSCO does not have to plan for generation plant only to meet the four highest
18 hourly loads during the year. It has sustained demands for all 8,760 hours during the
19 year, and NIPSCO, like all utilities, plans its generation mix to minimize the cost of
20 meeting, not just those four highest hourly demands, but the total cost of meeting
21 demands year round. To do that, NIPSCO has invested in significant baseload
22 generation capacity. Baseload plants have significantly higher capital costs, but
23 generally significantly lower operating costs than do peaking plants. The much lower

operating costs result from their ability to use less expensive fuels and to convert those fuels to electricity at lower heat rates. The question then is, what must occur to warrant the higher investment cost per kW of baseload plant as compared to peaking plant. The answer, of course, is that these higher capital cost baseload units must be operated sufficient hours during the year to result in operating cost savings sufficient to offset the higher capital costs. That means that these generating units are added to meet sustained demands of customers. Saying it slightly differently, it means that these higher capital costs are incurred to result in energy savings. Thus, the difference between the capital cost of a baseload unit and the capital cost of a peaker is incurred to meet energy requirements at a lower total cost.

Q. Can you provide a simple numerical example of this trade-off?

A. Yes. Let's consider a simplified world where there are only two types of generating plants for the Company to consider – baseload plants and peaking plants. Let us further assume that the operating cost per kWh is $0.025 for a baseload plant with an installed cost of $3,000 per kW, and $0.09/kWh for a peaking plant with an installed cost of $900 per kW. For sake of simplicity, let us assume that the annual carrying charge rate for both plants is 15 percent. Thus, the annual capital cost of the baseload unit is $450 per kW, and the annual capital cost of the peaker is $135 per kW. Building the baseload plant will result in a higher annual capital cost of $315 per kW. It will prove economic to build the baseload plant rather than the peaker as long as the baseload plant can be run for at least 4,846 hours a year, or at an annual capacity factor of 55 percent. This breakeven point is determined by dividing the additional capital costs of the baseload unit by the differential in operating costs of $0.065/kWh.

Savings are realized for every hour beyond 4,846 that the baseload plant is operated during the year. Clearly the difference between the $3,000 per kW and $900 per kW has been invested not to meet peak demand, but to reduce the cost of energy on the system in the process of minimizing total costs.

Q. Can you show graphically how this relationship works?

A. Yes. The breakeven point can also be shown with a simple diagram, as presented below in Figure 1. The two lines represent the total annual costs at varying levels of annual generation for a 1 kW peaking unit and a 1 kW baseload unit. Total annual cost is shown on the vertical axis and total hours of operation per year are shown on the horizontal axis, which is also the total kWh produced since we are concerned with two 1 kW units. The y-intercept of each line shows the annual capital cost of each unit, which is significantly higher for the baseload unit. The slope of each line shows the variable cost (primarily fuel) of producing an additional kWh, which is much higher (steeper) for the peaker than for the baseload unit. The intersection of the two lines is the break-even point, or the number of hours the baseload unit must be operated each year to warrant its higher capital cost. The difference between the two lines after the break-even point measures the annual total cost savings at each level of operation from building and operating the baseload unit as compared to the peaker. The cost savings are realized through the lower operating costs (i.e., energy savings) of the baseload unit compared to the peaker.

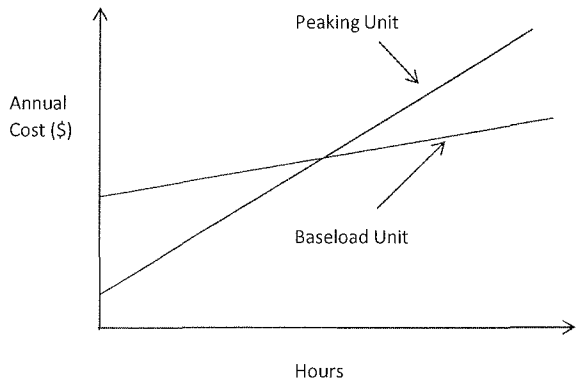

Figure 1

Q. Does NIPSCO experience sustained electric demands that would warrant investment in baseload units?

A. Yes. We obtained NIPSCO's hourly control area loads for 2007 in response to OUCC Request 23-007 and these load data were used to construct a Load Duration Curve (LDC) for that year, which is provided in Figure 2. That LDC shows that the minimum load was approximately 1,475 MW, or approximately 41 percent of the annual peak load of 3,625 MW. That is, loads were 41 percent of the annual peak for all 8,760 hours during the year. The average load was 2,282 MW, or approximately 63 percent of the annual peak load, which is referred to as the annual Load Factor. The annual Load Factor is a measure of the extent to which demand is sustained over the course of a year. The LDC shows NIPSCO's annual load shape and it makes it clear that NIPSCO has significant sustained demands over the course of the year. NIPSCO must plan its generation mix not only to meet its peak demands, but to meet those sustained loads at minimum total cost, and it has done that by installing an

appropriate mix of the several types of generation capacity – baseload, intermediate and peaking.

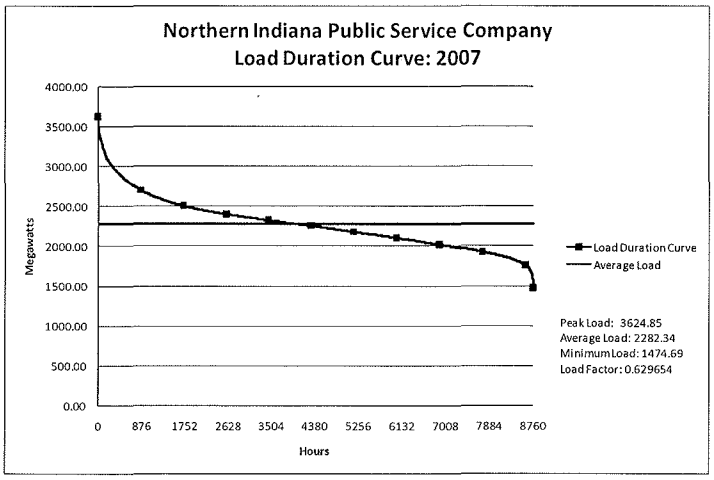

Figure 2

Q. How has NIPSCO planned its mix of generation capacity?

A. This is best explained by reference to NIPSCO's 2007 Integrated Resource Plan. In this document, NIPSCO develops its Short-Term Action Plan, which consists of adjustments to its resource plan over the next several years. Beginning at page 152, NIPSCO states that "The reason and rationale for the recommended plan is to identify the best combination of resources that will provide the highest value consistent with NIPSCO's objectives." Among those objectives are reliability, price stability, fuel transportation diversity and "Lowest Cost Reasonably Possible to Customers." In sum, NIPSCO has planned its resource mix "to minimize the net present value of revenue requirements over the time period 2007 through 2027," while meeting its reliability requirements, including having sufficient capacity to meet its peak

demands with adequate reserves, and also ensuring price stability and fuel transportation diversity.

Getting back to the issue of how NIPSCO should plan to meet its sustained energy demands throughout the year, it needs to plan its generation mix to meet, at least cost, not only the peak loads which occur for only a relatively few hours during the year, but also for the sustained loads that will last for between, say, 4,000 hours to 8,760 hours each year. That means that NIPSCO should have a mix of generation plant that includes a significant amount of baseload capacity that operates at high annual capacity factors to meet these sustained loads. In fact that is exactly the case.

Schedule DES-1 is developed from information provided by the Company in response to OUCC Request 6-2 and Municipal Group Request 2-09. This Schedule provides for each of NIPSCO's generation units the net capacity in MW, the fuel type, whether the unit is operated as a baseload, intermediate or peaking unit, the average annual generation for the years 2005 through 2007, and the average number of hours per year each unit was connected to load for the period 2005 through 2007. In addition, the statistics for the new Sugar Creek combined cycle plant are also provided. Several aspects of this Schedule are striking. First, over half of the generating units are baseload units. Including Sugar Creek in the total, nearly 60 percent of the non-hydro units are baseload units and they account for nearly 78 percent of the total net generation capacity. The two hydro units are run-of-the-river units, which will be operated essentially as baseload units as well since they cannot be dispatched. There are only four peaking units, accounting for only 203 MW of net generating capacity, or approximately 6 percent of the total. Sugar Creek will be the

only intermediate unit in NIPSCO's resource mix, accounting for approximately 16 percent of total net generating capacity.

The other thing that is striking is that, over the period 2005 through 2007, all of the baseload plants were connected to load in excess of 6,000 hours a year, after taking into account the unusual outages that applied to Bailley Unit No. 7. On the other hand, during this same period, the Company's peaking units were connected to load an average of just over 100 hours, after accounting for the unusual outages affecting Bailley Unit No. 10 and Schahfer Unit No. 16A during 2007. The Company's baseload units accounted for 99.5 percent of total generation during this period, while its peaking units were responsible for only 0.2 percent of total generation. The remaining 0.3 percent was made up by the two run-of-the-river hydro units.

Q. What do you conclude from this information?

A. NIPSCO maintains a diverse mix of generating capacity, but the lion's share of that capacity is baseload generation that is connected to load for an average of nearly 80 percent of the hours in the year. This more expensive baseload capacity has clearly been installed in order to meet sustained demands over the year – that is, the energy requirements of NIPSCO. NIPSCO's peaking units make up a very small share of total capacity (6%), have been connected to load an average of only about 100 hours a year during typical operation, or only about 1 percent of the total annual hours, and have produced only 0.2 percent of total energy output. It is equally clear that these peaking facilities, with significantly lower capital costs, were installed primarily to meet peak demands on the system that occur for no more than a few hundred hours

each year. While the total amount of NIPSCO generation capacity has been planned to meet peak demands, the cost of that capacity is only partly caused by the system peak demands and significantly caused by the need to meet sustained energy demands throughout the year at lower operating costs.

Q. Given these observations, is it reasonable for the Company to allocate total generation plant and related costs only on the basis of four peak hour demands during the year?

A. No. NIPSCO's $3.0 billion invested in generation plant reflects the Company's baseload plant requirements as well as its intermediate and peaking plant requirements. Petitioner's Exhibit JPK-4 shows that baseload coal plants comprise 86 percent of the total original cost production plant investment after adding in the $363 million investment in Sugar Creek as reflected in Petitioner's Exhibit LEM-6, page 2 of 2. It would be incorrect to find that NIPSCO's total generation investment was caused only by its need to meet peak demands during the year. The more expensive baseload and intermediate steam plant, which comprise the bulk of NIPSCO's generation capacity, has been installed only because it can provide fuel and operating cost savings sufficient to overcome the higher capital costs of these units. Thus, only a portion of NIPSCO's generation plant and related costs relate to the need to meet peak demands. A significant portion of those generation plant costs relate to the sustained energy demands that caused baseload plant, not peaking plant, to be included in and to dominate the Company's generation plant mix.

Q. How do you respond to the argument that, if you have enough plant to meet peak loads, then you automatically have enough capacity to meet all lesser demands, and so it is only peak demands and the need to service them that cause all generation plant costs?

A. If peak demands were the only demands that had to be met, then only peaking plants would be required, and the total generation plant investment would be significantly lower. This again goes back to the observation that peak demands do determine the total amount (Megawatts) of generation plant that is required, but peak demands do not determine the total cost of that plant. The additional generation investment costs result from the decision to invest in much more expensive baseload plant in order to reduce the cost of meeting the sustained energy demands of customers through fuel and operating cost savings. Thus, peak loads do not cause all generation plant costs and it would be wrong to allocate NIPSCO's generation facilities on peak demands only.

Q. Can you provide an example of how costs are misallocated when all generation plant and related costs are allocated on a peak demand basis only?

A. Yes. The 4-CP method utilized in the Company's study allocates all generation plant cost, including the high-cost baseload plant, on the basis of each class' contribution to four monthly system coincident peak demands. Under this approach the Residential Class (511) is allocated 37.2 percent of total generation costs, including baseload plant. (See Company Revised Cost of Service Study with Fuel, April 24, 2009, Allocation Factor No. 1.) The major benefit of baseload plant operation is the ability to reduce energy costs by using lower cost fuels and converting that fuel to electric energy at lower heat rates. The energy cost savings are allocated to customer classes on the basis of their relative energy usage at source. Since residential customers are generally relatively low load factor customers, they use relatively less energy per kW of their contribution to the system coincident peak demands. Specifically, under the Company's revised study with fuel, the Residential class receives only 22.0 percent of

the energy savings that are realized by the installation of baseload units, rather than peaking units, to meet sustained energy demands. Thus, the residential class would be caused to pay for 35.9 percent of the cost of the plant that generates the energy savings but is only allocated 22.1 percent of the resulting savings. This amounts to a clear mis-match of the costs of and the benefits associated with the construction and operation of baseload generation plants.

Q. Is there an allocation method that recognizes the importance of both peak demands and sustained demands being responsible for NIPSCO's generation facilities costs?

A. Yes. I recommend a method that allocates a portion of plant and related expenses on the basis of class contributions to the relevant measure of system coincident peak demand, and the remainder on the basis of class energy use at source. This is sometimes referred to as a Peak and Average method, since annual energy divided by the number of hours in a year yields the average demand. The average demand portion of the P&A allocator recognizes sustained demands; the peak portion of the P&A allocator recognizes that peak demands are also responsible for a portion of a utility's generation plant related costs.

Q. How does one determine the share of these costs that should be allocated on peak demand and the share that should be allocated on average demand or energy?

A. There are several ways to make this split. One approach is to determine what the installed cost of total generation plant would have been had only peaking generation been installed. Expressing that cost as a percentage of total generation installed costs provides the share of production plant investment and associated O&M costs that should be allocated on some appropriate measure of system coincident peak demand. The remaining share is the portion of total production investment costs that have been

1 incurred to meet year-round energy requirements at minimum total costs. This
2 calculation can be made using actual installed costs. The problem with this approach
3 is that the on-line dates of generating units may vary widely. For example,
4 NIPSCO's 2007 FERC Form 1 Report shows that its two hydro units were brought on
5 line during the mid-1920's, its Bailley units were brought on line during the 1960's, its
6 Schahfer units during the 1970's and 1980's, while the new Sugar Creek unit will be
7 brought on for NIPSCO during 2009. This wide variation in on-line dates tends to
8 distort the calculation of the portion of these costs incurred solely to meet peak
9 demands unless the data are massaged to account for the inflation in capital costs over
10 this ninety-year period. Alternatively, one can take a more forward-looking approach
11 and value each type of plant by the investment cost per kW that NIPSCO has used
12 when evaluating its various capacity expansion options.

13 **Q. Have you developed this type of calculation for NIPSCO?**

14 A. I have made this calculation for NIPSCO based on forward-looking replacement costs
15 of each type of capacity. This calculation is presented in Schedule DES-2. I have not
16 undertaken the calculation at original costs because of the problem associated with
17 widely differing on-line dates that I just mentioned and, more importantly, because
18 NIPSCO was unable to provide the installed capacity cost by unit which was
19 requested in OUCC 6-002.

20 **Q. Please describe Schedule DES-2.**

21 A. Schedule DES-2 calculates the total installed capacity for each type of generation unit
22 that NIPSCO currently has in its fleet: peaking units, an intermediate unit, base load
23 units and two hydro units. The total amount of installed capacity for each unit type is
24 valued by the cost of a new unit of the same type. These replacement costs were

obtained in NIPSCO's 2007 Integrated Resource Plan, and were used in the evaluation of NIPSCO's alternative capacity expansion plans. The one exception is that the two hydro plants are valued at their actual plant installation costs when constructed, which were obtained from NIPSCO's 2007 FERC Form No.1. Actual costs were used for the two hydro plants because there really is no reliable replacement cost estimates for these two units, they represent a very small portion of NIPSCO's total capacity, and NIPSCO's Integrated Resource Plan did not consider run-of-the-river hydro plants as candidates in any of its expansion scenarios. I should note that, if replacement costs were used for these two hydro facilities, it would have increased substantially the total cost of all generation, and thereby increased the estimated share of generation plant that should be allocated on energy. In the last column of Schedule DES-2 I have calculated what the total cost of NIPSCO's generation fleet would be if all of its capacity had taken the form of peaking units, intended only to meet the peak demands on the system. That amount is $3.9 billion, which constitutes only 37.3 percent of the total cost of NIPSCO's generation fleet of $10.5 billion, valued at replacement costs. On the basis of this analysis, approximately 63 percent of production plant and associated O&M expenses should be allocated on energy and the remaining 37 percent should be allocated on the basis of class contributions to the relevant measure of system peak demand.

Q. Is there another method by which to determine the split between demand-related and energy-related allocations of production plant and associated O&M expenses?

A. Yes. Another common way to determine this split is to set the proportion of plant allocated on average demand on the basis of the system load factor. Thus, if the load

factor were 0.54, then 54 percent of the generation plant and plant related costs would be allocated on energy, while the remaining 46 percent of these costs would be allocated on peak demands. Similarly, if the load factor were 0.60, then 60 percent of the generation plant related costs would be allocated on energy and the remainder on peak demands. The load factor percentage reflects the relationship between average demand and peak demand, and using the load factor split explicitly recognizes the need to allocate a substantial portion of electric generating plant and related costs on average demands. As the load factor increases, and baseload plant becomes more and more the plant of choice, the amount of plant allocated on average demand increases.

Q. What is the appropriate load factor share for NIPSCO?

A. The 2007 load factor calculated in Figure 2 for NIPSCO is 63 percent. Using the load data provided in NIPSCO's 2007 FERC Form No. 1 (page 401b) yields an annual load factor of about 67 percent. The Company's 2007 Integrated Resource Plan shows a 2007 load factor of 64.2 percent and it hovers around 64 percent for the next several years (p. 41).

Q. Based on both your analysis in Schedule DES-2 and the evaluation of NIPSCO's load factor, what portion of production plant costs and related O&M expense do you propose to allocate on energy, and what portion on a measure of peak demand?

A. Based on both of these analyses, I recommend that 65 percent of production plant and related O&M costs be allocated on class energy use, and the remaining 35 percent be allocated on each class' contribution to the appropriate measure of peak demand.

Q. Dr. Swan, how do you propose that the portion of generation plant and related costs assigned to peak demands be allocated?

A. Once the proper classification of the energy portion of production costs is determined, the demand-related portion of these costs should be allocated on a fairly narrow

definition of peak demand. The Company has made a reasonable case for measuring peak demand by the class shares of the average of the four highest summer monthly system coincident peaks -- the 4-CP method. Thus, I propose to use that allocator to allocate the peak demand related portion of generation plant costs among the customer classes. But, it should be understood that my endorsement of the 4-CP method is limited to the allocation of only the demand-related portion of costs in the P&A method. In my view the 4-CP measure is too narrow a definition of peak demand to be used to allocate the total of production plant and related expenses.

Q. Dr. Swan, earlier you indicated you do not agree with the Company's decision to allocate 100 percent of transmission plant costs on peak demands, and that a significant portion of these costs should also be allocated on energy use. Please explain.

A. NIPSCO's $745 million investment in transmission plant has resulted in a transmission system that is essential to NIPSCO's reliance on large, fuel efficient, baseload generating plants that are sometimes remotely located from load centers. NIPSCO could not deliver its baseload generation of electricity, which is essential at all times during the year, without its transmission system. In short, NIPSCO's decision to minimize its total cost of service by relying heavily on baseload generation necessitates its significant investment in transmission facilities. Thus, NIPSCO's reliance on transmission facilities is "caused" in large part by its decision to rely heavily on large, lower fuel-cost baseload generation rather than to rely on smaller, higher fuel-cost peaking generation.

Q. Can you explain further how transmission investment is largely related to energy use?

1 A. Consider the utility's decision whether or not to invest in transmission facilities.
2 A utility could meet is generation capacity requirements by building more and smaller
3 peaking generating plants close to its load centers and tying these smaller plants into
4 the lower voltage delivery system in the localities that make up the load centers. This
5 approach would have significantly reduced the need to build transmission lines.
6 Alternatively, the utility could build large, baseload generation plants at sites remote
7 from some or all of its load centers, but nearer low-cost fuel supplies or transportation
8 terminals, and transmit this power to its load centers at high voltages to minimize
9 losses. It can also use those high voltage transmission lines to import less expensive
10 energy from neighboring systems. It would take the latter course only if the operating
11 (mostly fuel) savings of the large, remote, baseload units or purchases from
12 neighboring systems were sufficient to more than offset the additional capital costs of
13 the required transmission lines. Most utilities, including NIPSCO, have taken this
14 latter course, and consequently the investment in transmission lines has, in fact, been
15 made largely to lower energy costs and not to meet peak demands.

16 **Q. How do you propose that investment in transmission plant be allocated among**
17 **the classes?**

18 A. NIPSCO's transmission costs are incurred in part to provide for the delivery of
19 baseload electricity at all times when a baseload plant is generating electricity.
20 However, NIPSCO's transmission investment is larger than it would be if NIPSCO
21 only had to meet its customers' average demands. Therefore, a portion of NIPSCO's
22 transmission costs relate to meeting NIPSCO's customers' energy demands, and a
23 portion relates to meeting peak demands. The Peak and Average allocation method

fairly and reasonably allocates NIPSCO's transmission-classified costs on an energy basis and on a peak demand basis.

IV. The Treatment of Upstream Distribution Plant

Q. How has the Company classified and allocated distribution plant?

A. The Company has classified primary lines, secondary lines and line transformers as 100 percent demand-related. These plant costs were allocated on class non-coincident peak demand (NCPs) or the sum of individual customer maximum demands. Importantly, none of these costs were classified as customer related. Costs classified as customer-related were limited to meters, services, meter reading, billing and collecting, customer service and informational expense, and sales expenses, which were allocated among the customer classes based on the number of weighted customers.

Q. Is it sometimes argued that "upstream distribution plant" (distribution plant above service drops) should be partly classified as customer-related?

A. Yes. Mr. Greneman stated that was not done in this case "because the Company's records are not sufficiently detailed as to reliably support a zero-intercept or minimum system analysis." (Petitioner's Exhibit RDG-1, p. 12, lines 15-16.)

Q. Would you support the use of either a zero-intercept or minimum system analysis to classify some portion of upstream distribution plant as customer related if the Company's records were sufficiently detailed to support such analyses?

A. No. The general rationale for arguing that some portion of these upstream distribution plant costs are customer-related is that a portion of these costs are incurred simply to "connect" customers to the system without providing any actual electric capacity or energy. The zero-intercept method attempts to construct a

1 regression for each major type of equipment (say, poles) that relates installed cost to
2 the size or capacity of the equipment. This equation is then extended back to zero
3 capacity (where no load is served) and the value on the y-axis is determined to be the
4 customer-related component of this investment. Of course, if the extended equation
5 intercepts the y-axis at a negative value, it is never suggested that the customer
6 component is negative. The data are usually massaged until the analyst gets the result
7 he was seeking. The minimum system method, which is used more frequently,
8 hypothetically reconstructs the distribution system with the smallest size poles,
9 conductors and transformers possible that is not capable of delivering actual capacity
10 and energy. The cost of that hypothetical system is deemed to be customer-related
11 and the remaining actual cost of the distribution system is deemed to be related to
12 meeting customer loads.

13 **Q. What is wrong with the minimum system approach?**

14 A. There are two fundamental reasons why this approach is incorrect. First, these costs
15 are not, in any meaningful way, directly related to the number of customers. Second,
16 the minimum system methodology cannot segregate out the costs of a system that
17 does not have any load carrying capability.

18 **Q. Please explain why these costs are not related to the number of customers.**

19 A. The cost of upstream distribution plant is incurred in order to meet the coincident
20 loads of the customers that it serves and their sustained energy demands throughout
21 the year. The size and costs of the required plant are a function of the amount of
22 diversity of customers' loads that must be served from this plant, as well as the
23 expected future coincident loads that may have to be served from these facilities as
24 growth occurs on the system. There is no direct relationship between the number of

customers and the size or the cost of poles, conductors or transformers. That is clearly the case for poles and conductors, but it is also true in most cases for transformers. Many transformers serve more than one customer and there is not even a unique requirement to install a transformer for a given number of customers on many systems. The number, sizes (and therefore costs) of transformers will depend on the diversity of the loads of the customers in the locality, the mix of customers served from the system in the area, the density of the population in that area, and probably the general configuration of the distribution system in that locality. To hypothetically carve out some portion of that cost as customer-related is simply inappropriate.

Q. Please explain why the minimum system approach cannot segregate out the costs of a system that does not have any load carrying capability?

A. The minimum system method must hypothetically construct a new upstream system that has no load carrying capability, but rather is only constructed to "connect" the customer to the system. The problem is that even the smallest size poles, conductors and transformers that can actually be purchased in the real world have significant load carrying capability. As long as the so-called minimum system has load carrying capability, one cannot allocate the remaining costs (if classified as solely demand-related) on unadjusted measures of class demands. Those demands must first be adjusted by the amount of the demand that the so-called "minimum system" can actually meet.

Q. Do you have any other concerns regarding the minimum system approach?

A. Yes. A fundamental precept of cost of service studies is that costs should be allocated on the units of service that cause those costs to be incurred. The minimum system

method, as well as the zero intercept method, is premised on the notion that it would provide "connection" service to customers without providing any actual capacity or energy. NIPSCO offers no "connection" service. Its tariff does not include "connection" service absent the taking of actual electric energy and capacity. Indeed, NIPSCO's General Rules and Regulations contain language that protects the Company from incurring costs associated with a customer who would demand "connection" service but has no sustained requirements for electricity.(See Section 6 on Service Extensions and Modifications.)

Q. Do you agree with the Company's classification of services and meters as 100 percent customer-related?

A. Yes. Meters and services are generally required one per customer and must be sized to meet the individual customer's maximum demand, regardless when that maximum demand occurs. Thus, there is generally a one-to-one relationship between the number of meters and services and the number of customers. That one-to-one relationship does not exist upstream of service drops.

Q. Can an argument be made that some portion of the upstream distribution system costs should be classified as energy-related?

A. Yes. The Company would not make the investment in upstream distribution plant if the only loads that system would carry are the few hours a year during which the system, the classes or individual customers experience peak demands. That would be too few hours during the year to warrant the investment in the delivery system. A fundamental aspect of finance is that an investment must result in an expected revenue stream adequate to generate a competitive rate of return on that investment. Without expected sustained demands over the entire course of the year (i.e., energy usage) NIPSCO would never have made the investment in its delivery system. While

the carrying capacity of the local distribution network is certainly determined by the maximum coincident demands that system must carry, the need for an adequate revenue stream dictates that energy also is a factor causing the investment to be made by NIPSCO in the first place. Thus, there is logic in classifying some portion of those investment costs as energy-related.

Q. Do you recommend that some portion of these upstream distribution plant costs be classified as energy-related in this case?

A. No. While logic calls for some portion of those costs to be classified as energy-related, I am aware of no precedent for doing so. Thus, to limit the issues in an already complicated case, I recommend that the Commission accept the Company's approach of classifying those costs as 100 percent demand related.

V. Effect of the Peak and Average Allocation

Q. Have you prepared a modified version of the NIPSCO cost of service study that allocates generation and transmission plant investment on the peak and average allocator?

A. Yes. The OUCC requested the Company to rerun its cost of service study so that generation and transmission plant investment would be allocated among the classes on the basis of the Peak and Average allocator, with 65 percent of these costs allocated on average demand or energy, and 35 percent of these costs allocated on the Company's 4 coincident peak demands. We also asked for a second run using a 12 CP allocator for generation and transmission plant and related expenses. The Company reran its study according to OUCC request 24-002. The Company also provided its cost of service model in Excel format with all formulas intact, which allowed us to rerun the model with the changes I believe are appropriate. We first

1 reran the model to replicate the two reruns that the Company conducted for the
2 OUCC to ensure we understood how to operate the model properly. That test was
3 completed satisfactorily and so we reran the model to account for the changes I
4 believe are necessary.

5 **Q. Has the Company provided modified versions of its class cost of service study?**

6 A. Yes. Mr. Greneman, on behalf of the Company, has provided several variants of the
7 Company's class cost of service study. On January 26, 2009, Mr. Greneman provided
8 a revised version of the cost study to correct certain inconsistencies between his study
9 and other parts of the Company's filing. The summary pages of this study were filed
10 as RDG-3 (2nd Revised) Schedules 2.0, 2.1 and 2.2. Then, on April 10, 2009, Mr.
11 Greneman provided another version of the Company's study to correct for a number
12 of errors, including errors in the production cost allocators. This study was not filed
13 by the Company but was filed jointly by the Consumer Parties as Consumer Parties
14 Joint Exhibit 1. On April 24, the Company provided this April 10, 2009 study with
15 fuel and purchased power costs included. This study also was not filed in this cause
16 by the Company.

17 **Q. Which Company study will you modify to incorporate the P&A allocation**
18 **method?**

19 A. I shall modify the Company's April 24, 2009 Study which incorporates fuel and
20 purchased power costs.

21 **Q. Is there another fundamental change you propose to make to the Company's**
22 **study?**

23 A. Yes. I shall add $55.1 million to pro forma revenues at current rates.

24 **Q. Why do you add $55.1 million to the pro forma revenues?**

A. Most customer classes currently receive revenue credits as part of a stipulated settlement in Cause No. 41746 in 2002. These credits expire when the rates determined in this proceeding are implemented. Therefore, NIPSCO's revenues in the first year new rates will be in effect would be $55.1 million higher than the Company has indicated. This is exactly the same treatment that was afforded the $80.1 million of discounts currently being extended to the special contract customers as computed by NIPSCO and reflected as REV-3 in Petitioner's Revised Exhibit LEM-2.

Q. Why is it appropriate to add in the $55.1 million?

A. If these credits were not eliminated, it would be tantamount to making these credits permanent. Changes to class revenue requirements from either an increase or a decrease in jurisdictional revenues would then have been in addition to the implicit changes that result from making the $55.1 million credit a permanent reduction in rates. It is more appropriate to specifically address what changes should be made in class revenues compared to the revenues that would be in effect when those credits are eliminated. This approach treats the $55.1 million revenue credit in the same manner as the $80.1 million special contract customer discounts are treated.

Q. How did you allocate the $55.1 million of additional revenue among the several customer classes?

A. The actual credits received by each of the 800 series of customer classes during the test year were provided in Exhibit RDG-4 (Revised), Schedule 1.0. These credits summed to $57.8 million. A similar showing of the credits for each of the 500 series of customer classes was not provided by the Company. I was able to directly map the credits between the 800 and 500 series for a few of the classes (Residential, Water

Pumping and Railroad), and the Interruptible Industrial and Interdepartmental classes received no credits. Thus, I established the test year credits for these 500 series classes as equal to what was received by their comparable 800 series classes. The remainder of the $57.8 million was allocated among the remaining classes on the basis of total revenues including pro forma fuel revenues from the Company's April 24, 2009 revised cost study with fuel. This calculation is shown in column (2) of Schedule DES-3. The Company's February 2009 FAC filing showed clearly that the pro forma amount of these credits is $55.1 million as opposed to the $57.8 million that was actually extended during the test year. Therefore, I recalculated each class' share of the normalized $55.1 million in column (4) on the basis of the distribution of the actual $57.8 million shown in column (2).

Q. Is this spread among the classes perfectly accurate?

A. That is unlikely to be the case, but we did not receive the information required to conduct a more accurate distribution of these credits. It is unlikely, however, that the precise distribution of these additional revenues will have a serious impact on the results of the revenue shortfalls or over charges for the several customer classes.

Q. Why have you modified the Company's April 24, 2009 study that added fuel and purchased power costs?

A. The OUCC determined that it would be more appropriate to address fuel costs as part of this proceeding and further determined that it preferred to see some version of the existing FAC cost recovery process retained. Under that procedure, pro forma fuel costs must be included in base rates, with the FAC being used to recover or credit differences between the actual quarterly fuel costs and the amount of fuel revenue that is recovered in base rates.

Q. Have you rerun the Company's April 24, 2009 Study with fuel to include the $55.1 million in revenue credits and to show the effect of the Peak and Average and 12-CP allocation factors for production plant and related expenses?

A. Yes. In Schedule DES-4 is provided the summary of the Company's 4-CP study with fuel, including the $55.1 million adjustment to revenues. Schedule DES-5 provides the comparable results for the OUCC Peak and Average study, and Schedule DES-6 provides the results for the alternative OUCC 12-CP study. In each Schedule, the Rate of Return Summary at present rates for the proposed rate classes is provided in the first two pages. The summary for equal rates of return at the Company's proposed revenues is provided in pages 3 and 4 of each of the three Schedules.

Q. Do class cost responsibilities change significantly when energy is properly recognized as being largely responsible for the amount of investment in generation and transmission plant?

A. Yes. This can be seen from a comparison of estimated class rates of return and class relative return indexes under the Company's 4-CP allocation and the class rates of return and relative return indexes that result from the OUCC Peak and Average Study that allocates a significant portion of generation and transmission plant on energy use. The "relative return index" is a class' rate of return expressed as a percentage of the jurisdictional average rate of return. This comparison between the two studies, both including fuel costs and the $55.1 million of revenue credits, is provided in the first four columns of Schedule DES-7. The Residential rate of return rises from 3.86 percent under the Company's study to 6.39 percent under the OUCC P&A Cost Study. When proper account is taken of the energy responsibility for generation and transmission investments, the Residential class is shown to be contributing a rate of return that is nearly 85 percent of the system average rate of return, as compared to the Company's estimate of only 51 percent of the system average rate of return under

the Company's 4-CP allocation method. Classes whose relative return indexes fall significantly include the Off-Peak (526), which falls from 44 percent to 16 percent, Limited Production Large (527), which falls from 206 percent to 98 percent, Industrial Large (534), which falls from 171 percent to 120 percent, and Interruptible Industrial (536), which falls from 48 percent to -30 percent. This is a logical implication of the P&A method, since each of these classes is a relatively high load factor class, which means they will bear a larger responsibility for generation and transmission plant and related O&M costs when a significant portion of these costs are properly allocated on energy usage.

Q. Please describe the second OUCC cost of service study that is summarized in Schedule DES-6.

A. If the Commission is unwilling to accept the results of the OUCC P&A study presented in Schedule DES-4, then I strongly believe the next best alternative is to maintain the 12-CP allocation of generation and transmission plant that was used in NIPSCO's last rate case, rather than to move to the Company's proposed 4-CP methodology. The 12-CP results are provided in Schedule DES-6, and the rate of return comparisons for this study are provided in the 5th and 6th columns of Scheduled DES-7.

Q. Why do you believe the 12-CP method is superior to the 4-CP method?

A. The 12-CP is a much broader reflection of usage than is the 4-CP, and I strongly believe that a broader allocator that recognizes year-round demands more accurately reflects the loads for which base load generation and transmission plant costs were incurred. Consider a class whose load is zero during each of the four critical summer peak hours, but has loads during the times of the other monthly peaks and during

most of the other hours during the year. Under the relatively narrow 4-CP peak definition, that class would be allocated none of the costs of the generation plant that provides the customers in that class with energy and capacity during all the other times of the year. It is patently unfair for this class to be assigned none of the costs of the capacity that is used to meet its loads, while imposing all of those costs on those classes and customers who happened to be on the system during those four hours. The 4-CP method is neither equitable nor an accurate reflection of the loads that caused the generation and transmission plant costs to be incurred in the first place.

Q. Does the P&A allocation method lead to symmetrical allocation of base load generation plant cost and the resulting savings?

A. Yes. Some critics of the P&A method have argued that it is somehow unfair to allocate additional production plant related costs to high load factor customers without providing those same customers with additional energy savings that result from those base load plants. These critics argue that the treatment of production plant costs and energy savings somehow lacks symmetry. What is meant by "additional production plant related costs", of course, is cost responsibility that is greater than would be allocated to them if production plant were classified as 100 percent peak demand related. This argument is entirely fallacious.

Q. How is this argument generally formulated?

A. It is usually demonstrated that, under a P&A method, the generation plant cost <u>per kW</u> is higher for high load factor classes than for low load factor classes. Then it is pointed out that total fuel cost is allocated on energy at source and so all classes pay the same fuel cost per kWh. Critics then conclude from this evidence that high load factor classes are treated unfairly and asymmetrically. That is, these classes are

required to pay more per kW for generation plant but do not get the benefit of lower energy costs per kWh.

Q. What is wrong with this argument?

A. The problem with this comparison is that it assumes 100 percent of generation capital costs are demand related. That is the only basis for dividing total capital costs allocated to the various classes by their contributions to the appropriate measure of peak demand. If one accepts that some portion of generation capital costs are, in fact, energy related, then the comparison of unit capital costs needs to be separated into two portions – one on the basis of cost per kW, and the other on the basis of the cost per kWh. I have developed that very comparison in Schedule DES-8 for NIPSCO.

Q. Please describe Schedule DES-8.

A. Schedule DES-8 shows the unit production plant cost and the unit fuel expense imposed on each class under the Company's 4-CP method (columns 3-6) and under the OUCC proposed Peak and Average allocation (columns 7-10). In the table I have unbundled the production plant cost into two components. The first is the demand related component, established as 35 percent based on the analysis in Schedule DES-2 and the NIPSCO system load factor, which were used to separate these costs into the demand- and energy-related components. That portion is divided by each class' contribution to the 4-CP to determine the unit cost per kW. Note that, under the 4-CP method, the amount is the same for all classes – $383.54 per kW. The second component is the energy related portion, established as 65 percent, or 1.0 minus the peak demand component. That portion is divided by each class' energy at generator to determine the unit cost per kWh. Under the 4-CP method that results in widely varying units costs, with low load factor classes paying significantly more than high

load factor classes. For example, the Residential class pays 19.14 cents per kWh, or 169 percent of the jurisdictional average cost of 11.33 cents per kWh. On the other hand, the higher load factor classes pay considerably less than the jurisdictional average. Limited Production Large (527) pays only 4.66 cents, or about 41 percent of the average; Large Industrial (534) pays only 8.22 cents, or about 73 percent of the average; and Street Lighting (550) and Dusk to Dawn (560) pay only 2.39 cents per kWh, or about 21 percent of the average cost of generation plant per kWh.

Q. What are the results for the Peak and Average study that you propose?

A. The unit production demand related costs are equal for all classes – the same $383.54 per kW. But, unlike the straight 4-CP method, the energy related unit production costs are also equal – 11.33 cents per kWh. The last column shows that, for both methods, the unit fuel cost per kWh is also equal for all classes – 2.8325 cents per kWh.

Q. What do you conclude from the analysis shown in Schedule DES-8?

A. Contrary to the argument raised by certain critics of the P&A method, if one accepts the reality that some portion of generation capital costs has been incurred to meet energy requirements, the Peak and Average allocation method provides perfect symmetry in the allocation of production capital costs and energy costs. All classes, regardless of their load factors, receive the same unit cost allocation of the demand-related component and the same unit cost allocation of the energy-related component. Then, all classes receive identical allocations per kWh of fuel expense. The asymmetry actually exists in the 100 percent demand related 4-CP method because high load factor classes receive a lower cost per kWh of the energy related portion of production plant costs but receive the same unit fuel cost allocation as do low load

factor classes. And this outcome is obvious if one thinks about it from a very practical perspective. Under the 100 percent demand related 4-CP method, when the Company decides to build a baseload unit with very high capital costs in order to generate fuel savings and lower energy costs, low load factor classes, like the Residential class, are allocated a disproportionate share (37.2%) of those capital costs, but receive a much smaller share of the resulting energy savings (22.0%). High load factor classes, like the Industrial Large (534) class, on the other hand, would be allocated a much smaller share of the capital costs (19.0%), but would receive a larger share of the resulting energy savings (26.2%). The asymmetry is even more dramatic for the interruptible class, which receives only 4.4 percent of the costs of baseload generation plant but would get 11.7 percent of the energy savings.

If the Commission agrees that some portion of generation capital costs have been incurred to meet energy requirements, which I believe cannot be disputed, then the Commission cannot reject the P&A method on the grounds that it treats capital and energy cost allocations asymmetrically. The fundamental question that the Commission must answer is whether it agrees that some portion of generation capital costs have been incurred to meet energy requirements. If the Commission agrees with this proposition, then some method that recognizes energy in the classification of production capital costs, like my proposed P&A study, should be used to allocate these costs among the customer classes.

Q. The Commission has never accepted an electric cost of service study that classifies a portion of generation and transmission costs as energy related. Should that prevent the Commission from doing so in this case?

A. No. While the Commission should surely consider the precedents it set in its earlier orders, it certainly is not restricted by its previous opinions if there is clear and convincing evidence that previously adopted methods should be changed. That is evidenced by its recent October 16, 2006 Order in Citizens Gas & Coke Utility (Cause No. 42767). There the Commission adopted the OUCC's proposed cost of service study that allocated distribution main costs on a combination of peak day consumption (20 percent) and annual volumes (80 percent). In that Order, the Commission stated:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding. (p. 74)

The method used by the OUCC in that case is directly comparable to allocating some significant portion of electric generation capital costs on annual energy use as I propose to do in this proceeding, I urge the Commission to evaluate the worth of the OUCC's P&A method in this case on "whether it is most reflective of cost causation."

VI. Class Revenue Responsibilities

Q. Should the Commission strive to equalize class rates of return?

A. The class cost responsibilities that result from any class cost of service study are estimates. That includes the Company's studies as well as the OUCC P&A Study. There are too many judgments that the analyst must make about how to classify and allocate each of the line item cost elements that comprise the utility's total cost of

service to permit anyone to suggest the resulting class cost estimates are precise. While I firmly believe that these study results provide a useful tool for the Commission to use in setting cost-based rates, I also believe they should not be slavishly adhered to. In particular, the results are not precise enough to warrant the need to set rates so as to equalize class rates of return. I believe that a reasonable target would be for each class' ROR Index to be between 95 percent and 105 percent of the jurisdictional rate of return. However, the disparities in class rates of return in both the Company's study and the two OUCC studies are too great to permit that target to be realized in this proceeding without resulting rate shock for some classes of customers.

Q. The OUCC has recommended a large reduction in revenues. What class revenue spread recommendation do you have for the Commission if it were to order a large revenue reduction?

A. I have rerun the Company's class cost of service study at the Company's proposed revenue increase to facilitate comparison between the OUCC study and the Company's study, as it relates particularly to the allocation of production plant and related expenses. If the Commission were to order a large revenue reduction in line with the recommendation of the OUCC revenue requirements witnesses, then the class cost of service study must be adjusted to reflect the much lower cost of service. In Schedule DES-9, I have provided a rough estimate of what those class cost responsibilities would be based on a proportional adjustment of the cost of service allocated to each class in the P&A version of the Company's study with fuel and the $55.1 million of revenue credits included. I use these reduced full cost rate revenues as the basis for determining a reasonable spread of a large reduction in revenues.

Q. What guidelines do you use in spreading a large reduction?

A. I believe it is inappropriate to impose large increases on any class when the jurisdiction as a whole would be realizing a large revenue reduction. Thus, I would place a ceiling on the increases. On the other side of the coin, I would place a floor under the percentage reductions that any class could receive.

Q. Please explain Schedule DES-9.

A. On page 1 of Schedule DES-9, I develop an illustrative spread of the revenue reduction assuming the Commission ordered a $140 million reduction from pro forma current revenues, which include fuel revenues and the revenues associated with the $55.1 million revenue credit. The first column provides the present rate revenues from Schedule DES-5, which is the summary results of the P&A allocation study including fuel and the $55.1 million of additional revenues. The second column presents the Full Cost Revenues from that same Schedule. The term "Full Cost Revenues" represents the revenues that would be assigned to each class to generate an equal rate of return at the Company's requested total revenues. The $140 million reduction would result in Adjusted Full Cost Revenues of $1,281.4 million, which amounts to 87.8 percent of the Full Cost Revenues at the Company proposed total revenues. Thus, in column (3), each class' Full Cost Revenue responsibility is reduced to 87.8 percent of its value in column (2). The resulting adjusted full cost changes from current revenues are shown in columns (4) and (5). I then placed a floor on the potential reductions at -13.0 percent, which is approximately 133 percent of the jurisdictional average percentage reduction of 9.85 percent, as well as a ceiling of zero percent. The resulting changes are shown in columns (6) and (7). Employment of the cap and floor results in recovering $1.131 million more than

required. This further reduction is then allocated back in column (8) to all the classes that should have received reductions but remain above the -13% floor, in proportion to their Adjusted Full Cost Change in column (4). Column (9) shows the final revenue distribution and columns (10) and (11) show the final revenue changes.

Q. Does this spread of the total jurisdictional reduction result in significant movement toward cost of service?

A. Yes. I was unable to calculate class rates of return that would result from the proposed spread of the $140 million revenue reduction presented on page 1 of Schedule DES-9 because I do not have a specific allocation of rate base and operating costs by classes. However, we can gain an understanding of how each class is moved toward its full cost responsibility by comparing its current and proposed revenues relative to the full cost of service revenue requirement assigned to each class. This is done for the $140 million proposed rate spread on page 2 of Schedule DES-9. Column (1) shows each class' percentage of Adjusted Full Cost Revenues at present rates. For example, the Residential class is currently paying 105.9 percent of its assigned Adjusted Full Cost Revenues. The jurisdiction as a whole is paying 110.9 percent of Adjusted Full Cost Revenues at current rates. In column (2) these class percentages are stated as a percent of the jurisdictional percentage. Thus, the Residential class is currently paying 95.9 percent of the jurisdictional average share of full cost revenues. In column (3) are shown the class percentages of Adjusted Full Cost Revenues under the proposed rate spread. A comparison of columns (2) and (3) shows that each class is moved significantly toward 100 percent of its Adjusted Full Cost Revenue responsibility in absolute terms and compared to the jurisdiction as a whole.

Q. Do you provide another illustrative rate spread at a somewhat lower total reduction in jurisdictional revenues?

A. Yes. On page 3 of Schedule DES-9 I present an illustrative revenue reduction spread assuming the Commission were to order a total jurisdictional reduction of $70 million. The process is the same, except that I imposed a ceiling increase of 5 percent, and a floor of -7.5 percent, which is approximately 150 percent of the average reduction of -4.92 percent. These constraints resulted in recovering approximately $7.2 million more than required, which again was allocated to all of the classes that should have received reductions but were above the floor, in proportion to their adjusted full cost changes in column (4). That resulted in moving Ltd. Prod. Large (527) below the floor of -7.5 percent. When that class was limited to the -7.5 percent reduction, the remainder was allocated to the Residential class, which was the only remaining class that should receive a reduction but was above the floor. The final changes are shown in columns (10) and (11) and it shows that all the classes would either receive the cap increase of +5.0 percent or the floored reduction of -7.5 percent, except for the Residential class which would receive a reduction of -2.01 percent.

Q. Does this spread of the $70 million reduction provide considerable progress toward cost of service?

A. Yes. Page 4 of Schedule DES-9 presents the same information as was provided in page 2 for the $140 million reduction case. The resulting ratios are very similar to those that were obtained in the $140 million reduction case, and inspection of this

table shows that significant but somewhat more moderate progress is made toward full cost of service for every customer class.

Q. What increase does the Company request?

A. In its April 24, 2009 study with fuel included, the Company has requested an increase of $93.0 million. After adding in the $55.1 million of revenues from the elimination of the current revenue credit, the requested increase falls to $37.6 million.

Q. Has the Company proposed a class revenue spread that is entirely based on its estimated class costs?

A. No. Mr. Greneman also proposes to moderate the class rate adjustments "in order to reduce the impact of the proposed rate increase to customer classes." (Exhibit RDG-S1, p. 6, lines 3-4) In particular, Mr. Greneman uses a 2-step process to spread the proposed revenue increase among the customer classes, which is referred to as a 25 percent moderation plan. In his first step he proposes to moderate the amount of the reallocation of the current revenue so as to move each subsidized class 25 percent of the way toward full cost of service. That means that each class that would receive a positive increase would get an increase equal to 25 percent of the amount that would move it to full cost of service, and each class that would receive a reduction would receive a decrease equal to 25 percent of the amount that would move it to full cost of service. In the second step, Mr. Greneman spreads the proposed total increase requested in this case among the classes based on full cost of service. The results are presented in lines 15 and 16 of the first page of the Company's April 24 study with fuel. The Residential class would wind up with an increase of 13.89 percent or about 204 percent of the jurisdictional increase of 6.81 percent including fuel costs. Other classes that would receive large increases are the Off-Peak (Rate 526) at 10.03

1 percent, Water Pumping (Rate 541) at 32.45 percent, Dusk to Dawn (Rate 560) at
2 61.44 percent, and Interdepartmental at 25.34 percent. Percentage decreases range
3 from -0.43 percent for GS Small (Rate 521) to -8.17 percent for Street Lighting (Rate
4 550).

5 **Q. Under Mr. Greneman's proposal, are the class increases limited to 25 percent of**
6 **the movement to full cost of service?**

7 A. No. Since the total $93.0 million increase, including fuel, requested in this case is
8 allocated among the classes on full cost of service, the movement toward full cost
9 based rates turns out to be a lot higher than 25 percent for classes that would receive
10 increases. The Residential class, for example, would be moved 51.8 percent of the
11 way toward full cost-based rates. The Interruptible Industrial (Rate 536) would be
12 moved approximately 57 percent of the way toward full cost based rates.

13 **Q. How would you propose that the Company requested revenue increase be spread**
14 **among the customer classes in this proceeding, should the Commission award**
15 **the Company with its full request?**

16 A. In that event, I recommend that the Commission spread the allowed total
17 jurisdictional increase among the classes by first establishing a ceiling for each class
18 percentage increase above current revenues, including fuel revenues and the $55.1
19 million from the revenue credit. I also recommend that a floor of zero percent be
20 established since I think it is inappropriate to permit some classes to receive absolute
21 rate reductions when others are receiving significant rate increases. I would
22 recommend that the ceiling be set between 133 percent of the jurisdictional
23 percentage increase of 2.65 percent, or 3.52 percent, and 150 percent of the
24 jurisdictional average increase, or 3.97 percent. I propose that the revenue spread be
25 based on the OUCC Peak and Average cost of service study, as provided in Schedule

1 DES-5. In Schedule DES-10 are shown two rate spreads based on the OUCC P&A
2 study and the Company's requested increase of $37.6 million. On page 1 is presented
3 the 133 percent cap case, and page 2 presents the 150 percent cap case.

4 **Q. Please explain how you developed these rate spreads.**

5 A. I first put the increase at the cap for all classes whose percentage increase would
6 exceed the cap and placed each class that would receive a rate reduction at a zero
7 increase. Next, I calculated the resulting revenue shortfall and then spread that
8 shortfall among the non-capped classes. If the resulting percentage increase for any
9 class then exceeded the cap, I placed that class at the cap and proceeded to allocate
10 the additional revenue shortfall among the remaining non-capped classes.

11 **Q. How would you summarize these rate spreads?**

12 A. Under each of these rate spreads, classes requiring positive increases would receive
13 reasonable increases that will make progress toward moving them to full cost-based
14 rates. Those classes that would receive rate reductions under full cost based rates
15 would receive modest positive increases. The higher the cap, the more modest those
16 increases would be for classes that are currently paying in excess of their allocated
17 costs. But, no class would receive a reduction while other classes would be receiving
18 significant increases.

19 **Q. Do these two revenue allocations make progress toward fully cost-based rates?**

20 A. Yes. On page 3 of Schedule DES-10 are provided the class rates of return under
21 current rates and rates that would result from my proposed 133 percent cap and 150
22 percent cap revenue spreads. Inspection of this table shows that each class' relative
23 ROR recovery index moves toward 100 percent under either capped revenue spread

1 proposal. At the same time the movement toward cost of service is moderated and
2 does not result in a rate shock increase for any class.

3 **Q. Which of the caps do you favor?**

4 A. That will depend on the size of the total jurisdictional increase that is allowed by the
5 Commission. More specifically, I think greater relative progress toward full cost base
6 rates can be made at lower overall jurisdictional revenue increases. Specifically, if
7 the Commission were to approve an increase close to that requested by the Company,
8 then I would favor the lower cap of 133 percent of the jurisdictional average. If, on
9 the other hand, the Commission were to authorize a positive jurisdictional increase,
10 but much smaller than that requested by NIPSCO, then I believe the classes could
11 tolerate a cap equal to a full 150 percent of the jurisdictional average.

12

13 **VII. Rate Design Issues**

14 **Q. Do you have any specific recommendations regarding the Company's design of**
15 **rates?**

16 A. Yes. I recommend three specific changes to the Company's proposed design of rates.
17 The first relates to the allocation of costs under Riders 571, 572 and 573. The second
18 relates to the proposed increase in customer charges for residential and small general
19 service customers. The final recommendation relates to the proposed increases in
20 reconnection charges.

21 **Q. If the Commission accepts either your proposed Peak and Average or 12-CP**
22 **production allocator, should the accepted allocation method be included in**
23 **Riders 571, 572 and 573?**

24 A. Yes. Rider 571 (Reliability Adjustment), Rider 572 (Environmental Cost Recovery
25 Mechanism), and Rider 573 (Environmental Expense Recovery Mechanism) each

utilize the "Production Demand Allocation percentage" for each rate schedule in computing the rider charge for each rate schedule. During his cross examination (page S-108), Mr. Westerhausen confirmed that "We use production allocators out of the cost of service study..." in allocating costs among the classes in these riders. The rate schedule percentages used in each of these three riders should be based on the production allocator that the Commission ultimately accepts. If the Commission adopts either the Peak and Average or the 12-CP production allocator, then the rate schedule percentages should be based on one of those production allocators, not the 4-CP allocator.

Q. What changes does the Company recommend in the customer charges for residential and small commercial customers?

A. The current customer charge for residential customers on Rates 811, 812 and 813 is $5.95 a month, including the first 36 kWh per month. In its unfiled proposed rate schedules (Revised 4-10-09), the Company proposes to set the customer charge for Residential Service (Rate 511) at $10.55 per month, with no associated energy. Adding the first 36 kWh at the Company's proposed rate of $0.08021/kWh raises the comparable charge to $13.44 per month. That amounts to an increase of 126 percent. The Company's estimated unit cost for the residential customer function is $10.57. Thus, the proposed Residential customer charge is essentially set at the full estimated cost of service. The General Service Small (Rate 521) customer charge is proposed at $12.40 per month. Many of the customers that will be served under this rate schedule are currently served under Rates 820, 821 and 822. Current Rates 821 and 822 also have a customer charge of $5.95 per month, including 36 kWh. With the first 36 kWh under Rate 521 proposed to be charged $0.09097/kWh, the total comparable

1 charge will be $15.67 per month, an increase of 163 percent. Rate 820 does not
2 include any energy in the $5.95 customer charge, so the effective increase for
3 customers that are currently served under that rate is $6.45 per month or 108 percent.
4 Some customers who will take service under Rate 521 apparently will have been
5 moved from current Rates 823, 824 and Rider 848 under the Company's proposal.
6 None of those rate schedules currently contains a customer charge. As with the case
7 of the Residential customer charge, the proposed $12.40 reflects 100 percent of the
8 Company's estimated unit cost of the customer function for the General Service Small
9 rate class.

10 **Q. Are the Company's proposed increases in the customer charges for residential**
11 **and small general service customers reasonable?**

12 A. No. Increases ranging from 108 percent to 163 percent are excessive and are
13 inconsistent with one of the usual objectives of good rate design, which is rate
14 stability or continuity in rates.[1] As important, increases of the magnitude proposed by
15 the Company in these customer charges will have particularly adverse effects on the
16 smallest and poorest customers who can least afford it. To suggest an increase in
17 customer charges of this magnitude is especially troubling during this period of
18 economic crisis when rates of unemployment are rapidly rising and people are
19 struggling to afford the bare necessities of life. I find it perplexing that the Company
20 would propose customer charge increases of this magnitude when, at the same time, it
21 has taken pains to mitigate the move to cost based rates by moving only part way
22 toward what it believes to be class cost responsibilities.

[1]See the venerable James C. Bonbright, Principles of Public Utility Rates (Columbia University Press, New York: 1961), p.291. Specifically, Bonbright stated the following objective: "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."

1 **Q. What do you recommend?**

2 A. If the Commission were to grant an increase in revenues comparable to what the
3 Company has requested, I recommend that the Commission limit the magnitude of
4 the increase in customer charges for these two classes to no more that approximately
5 20 percent, or around $7.00 per month. With the elimination of the associated energy
6 in this charge, that would actually result in an increase of approximately $2.89, or
7 about 49 percent, for residential customers, and $3.27, or about 55 percent for small
8 general service customers. If the Commission were to find that the total jurisdictional
9 revenue requirement were more in line with that proposed by the OUCC, then I
10 would recommend no increase in the current customer charge, except I would not
11 object to the elimination of the associated 36 kWh as part of that charge.

12 **Q. What changes has the Company proposed for its Reconnection Charges?**

13 A. Currently, the Company has two reconnection charges – a $45 charge if the
14 reconnection is made during normal working hours, and a $60 charge if the
15 reconnection is made after normal working hours. The Company proposes to replace
16 these two charges with nine different charges that vary depending on whether the
17 reconnection is made during working hours, after working hours on Monday through
18 Saturday, or on Sundays or holidays; and whether the reconnection is made at the
19 meter, at the pole or at the pole with an easement. The charges vary from $69.85 (at
20 the meter during normal working hours) to $290.74 if the reconnection is made at the
21 pole with an easement on a Sunday or a holiday. The percentage increases proposed
22 by the Company vary from 55 percent to 385 percent.

23 **Q. Do you believe these increases are reasonable?**

A. No. The Company has provided detailed backup showing the costs of reconnecting service under each of these sets of conditions and the charges it proposes are set exactly equal to those estimated costs. I have no basis upon which to challenge the reasonableness of those cost estimates. However, I believe that increases of this magnitude are not appropriate on the basis of the same rate stability or rate continuity criterion. One of the reasons for disconnecting a customer listed in the Company's General Rules and Regulations (Sect. 12.3) is for the non-payment of bills. I suspect that failure to pay is one of the primary reasons for disconnecting customers and, with the current severe recession in full force, I would anticipate that failure to pay will become increasingly the reason for disconnections. It is difficult enough for a customer to have to go through the disconnection process, but to increase the cost to reconnect by from 55 percent to 385 percent would place an unacceptable burden on those in the most dire circumstances.

Q. What do you recommend?

A. I strongly urge the Commission to require the Company to greatly modify the movement to cost based reconnection charges. If the Commission were to grant a jurisdictional increase close to what the Company has requested, then I would recommend that the increase in those charges not average more than about 20 percent. If the Commission decides that the total jurisdictional revenue requirement is closer to what the OUCC has recommended, then I would recommend that the charges for reconnection at the meter remain where they are currently, and that modest increases (say, between $10 and $20) be applied to reconnections made at the pole with and without an easement to differentiate between reconnections made at the meter.

1 **Q. Does this conclude your direct testimony?**

2 A. Yes.

3

VERIFICATION

STATE OF MARYLAND)
) ss:
COUNTY OF HOWARD)

The undersigned, Dale E. Swan, under penalties of perjury and being first duly sworn on his oath, says that he is a Vice President and Principal of Exeter Associates, Inc., a Consultant for the Indiana Office of Utility Consumer Counselor; and in the matter of Cause No. 43526 that he caused to be prepared and read the foregoing that the representations set forth therein are true and correct to the best of his knowledge, information and belief.

Dated: May 6, 2009

Dale E Swan

By:

Subscribed and sworn to before me, a Notary Public, this 6 day of May 2009.

Deborah M Adams

Signature

Deborah M Adams

Printed Name

My Commission Expires: 2/2011

My County of Residence: Prince Georges Co

RESUME

DR. DALE E. SWAN

DALE E. SWAN

Dr. Swan is a senior economist and principal at Exeter Associates, Inc. His areas of expertise include energy supply planning, electric industry restructuring, utility cost allocation and rate structure design, utility contract negotiation, antitrust policy, and public utility regulation.

Dr. Swan has presented expert testimony in utility rate cases before the Federal Energy Regulatory Commission and before numerous state regulatory commissions. He has testified on marginal and embedded costing, rate structure design, long-term demand forecasting, short-term sales forecasts, the treatment of off-system sales, electric industry restructuring, and antitrust considerations. He has directed major projects for the U.S. Department of Energy, the U.S. Air Force, and the Rhode Island Public Utilities Commission on such issues as alternative power supply options and innovative rate structure experiments and implementation, and he has prepared and presented seminars and workshops on such issues as marginal costing, rate design, and interruptible rates for, among others, the National Regulatory Research Institute, the U.S. Department of Energy, and for state commission staffs in Maryland, Minnesota, and New Hampshire.

Dr. Swan has assisted federal agencies in the negotiation of electric power supply contracts and in the financial and locational assessment of transmission and generation projects. He has also prepared reports to several federal and state agencies on costing methods, rate design, the demand for electric power, PURPA requirements, bulk power supply planning, stranded cost recovery, standby rates, value-of-service pricing, the use of special contracts, and other issues. He has also acted as an Advisor to the Maine Public Utilities Commission in the restructuring proceedings for the three investor-owned Maine electric companies.

Education:

B.S. (Business Administration) - Ithaca College, 1962.

M.A. Program in Economics - Tufts University, 1962-63.

Ph.D. (Economics) - University of North Carolina at Chapel Hill, 1972.

Previous Employment:

1976-1980	-	Senior Economist, J.W. Wilson & Associates, Inc.
1974-1976	-	Associate Professor of Economics, Jacksonville State University
1974	-	Economist, Office of Energy Systems, Federal Energy Administration
1973	-	Staff Economist, Economics Department, Arabian-American Oil Company

1968-1973	-	Assistant and Associate Professor of Economics, Hampden-Sydney College
1969-1973	-	Visiting Assistant Professor of Economics, Randolph-Macon Womans College
1967-1968	-	Assistant Professor of Economics, Southern Methodist University
1966-1967	-	Visiting Assistant Professor of Economics, North Carolina Central University
1963-1964	-	Market Research Analyst, The Carter's Ink Company

Previous Professional Work:

At J.W. Wilson & Associates, Inc., Dr. Swan had primary responsibility for the development and direction of several of the firm's largest projects relating to the electric utility industry and costing and rate design issues in particular. Dr. Swan also had major responsibilities in the areas of cogeneration, antitrust, PURPA requirements, and technical assistance to state regulatory authorities under DOE grant programs.

At the Federal Energy Administration, Dr. Swan participated in the development of a National Energy Accounting System, similar to and compatible with the National Income and Product Accounts and the U.S. Input/Output Accounts. During his tenure at Jacksonville State University, Dr. Swan continued with this work as a consultant to the FEA.

While with ARAMCO, Dr. Swan prepared financial analyses of capital investment alternatives, developed cost trend estimates for price negotiations, and initiated the preparation of revised price trend factors to be used for budgeting purposes.

At Carter's Ink Company, Dr. Swan was responsible for conducting new product and new market research for the Director of Marketing, including consumer attitudinal studies on new product and packaging designs.

Dr. Swan has taught both graduate and undergraduate courses during his academic career. Among the courses he has taught are Microeconomic Theory, Industrial Organization, Economic History, International Trade, Economic Development, and Principles of Economics.

Selected Publications, Papers, and Reports:

"Electric Power Options Study Follow-up Report for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2008.)

"Updated Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, April 2007.)

"Fermi National Accelerator Laboratory Phase 1 Electric Supply Options Study," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, December 2004.)

"Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2004).

"Phase 1 Electric Supply Options Study for Fermi National Accelerator Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, December 2004).

"Electric Power and Natural Gas Supply Options Study for the DOE Oak Ridge Reservation," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, March 2004).

"A Comparative Evaluation of Two Proposals to Meet the Long-Term Steam Requirements of the Savannah River Site." (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, November 2001.)

"Electric Power Supply Options to Meet the Cold Standby and Possible Restart Requirements of the Portsmouth Gaseous Diffusion Plant." (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, October 2001.)

"Strategic Options in Planning for the Long-Term Power Requirements of the DOE/OAK Laboratories." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, September 1998.)

"Utility Options Study: Rocky Flats Environmental Technology Site." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, March 1997.)

"Competitive Acquisition of Power by Federal Agencies: Current Possibilities and Future Prospects." (Presented before the Competitive Power Congress, Philadelphia, Pennsylvania, July 21, 1995.)

"Standby Rate Rulemaking: A Discussion of Issues and Proposed Positions." (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 10, 1995.)

"Stranded Cost Rulemaking: A Discussion of Issues and Proposed Positions." (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 3, 1995.)

"Superconducting Super Collider Permanent Power Supply: A Preliminary Consideration of Supply Alternatives." (Exeter Associates, Inc., revised draft report prepared for the U.S. Department of Energy, Office of Organization, Resources and Facilities Management, March 1992.)

"The Potential Savings Associated with Exporting EBR-II Energy from the Idaho National Engineering Laboratory to Another Federal Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, March 1991.)

"Planning and Preparing a Utilities Options Study," in Utilities Planning and Management for Department of Energy Facilities. (U.S. Department of Energy, February 1990.)

"An Evaluation of the Financial Benefits to the United States Government from Using $175 Million of the TRNLC Fund to Purchase Generating Capacity to Reduce Power Costs of the Superconducting Super Collider." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, January 1990.)

"Power Supply Arrangements at Brookhaven National Laboratory." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, October 1989.)

"Electric Power Supply Options for the Continuous Electron Beam Accelerator Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, July 1989.)

"The Potential Future Value of Byproduct Steam from a New Production Reactor Based on Four Alternative Technologies and Three Alternative Sites," with Steven Estomin and Richard Galligan. (Exeter Associates, Inc. for the U.S. Department of Energy, August 1988.)

"An Analysis of the Optimal Allocation of Available Western Area Power Administrative Preference Power Among Three Northern California Laboratories," with Charles E. Johnson. (Exeter Associates Inc. for DOE San Francisco Operations Office, March 1986.)

"Report on the Role of Special Contracts in Electric and Gas Utility Ratemaking." (Exeter Associates, Inc. for the U.S. Postal Service, February 1984.)

"The Electric Utility Industry," in Study of Pricing Precedents in the Public Utility Industry. (Exeter Associates, Inc., for the U.S. Postal Service, February 1984.)

"State Regulatory Attitudes Toward Fuel Expense Issues," with Matthew I. Kahal, Report to the Electric Power Research Institute, June 1983.

"A Summary and Analysis of Federal Legislation Affecting Electric and Gas Utility Diversification." (Exeter Associates, Inc. for Argonne National Laboratory, August 1981.)

"Average Embedded Cost Studies as the Basis for Rate Designs Consistent with the Goals of the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 6, 1981.

"Analysis of the Major Comments Made on the ERA Proposed Voluntary Guideline for the Cost-of-Service Standard Under the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 1981.

"The Rhode Island - DOE Electric Utilities Demonstration Project." Final Report - November 1980, and three Interim Reports in July 1978, November 1979, and July 1980. (J.W. Wilson & Associates, Inc. for the Rhode Island Division of Public Utilities and Carriers.)

"An Evaluation of Power Supply Planning by the Six Investor-Owned Electric Utilities in South Dakota," with Ralph E. Miller. (J.W. Wilson & Associates, Inc. for the South Dakota Public Utilities Commission, 1977.)

The Structure and Profitability of the Antebellum Rice Industry: 1859. (New York: Arno Press, 1975.)

"The Structure and Profitability of the Antebellum Rice Industry: 1859." Journal of Economic History, (December 1972.)

"The Productivity and Profitability of Antebellum Slave Labor: A Micro Approach," with James D. Foust. Agricultural History, (January 1970). Later published in William N. Parker (ed.), The Structure of the Cotton Economy of the Antebellum South. (New York: Agriculture History Society, 1970.)

Participation in Conferences, Seminars and Workshops:

Competitive Power Congress, 1995.

Department of Energy Utility Conferences, 1985, 1986, 1990, 1992, 1995, 1996, 1997.

DOD/DOE Combined Utility Planning Conference, March 1987.

American Historical Association Meetings, 1981.

National Regulatory Research Institute Workshop on Time-of-Use Rates, September 1979.

National Regulatory Research Institute State Needs Assessment Conference, August 1979.

Southern Economic Association Meetings, 1969, 1972, 1975.

Economic History Association Meetings, 1972.

Expert Testimony

Presented by Dale E. Swan

1. Before the Public Utilities Commission of the State of Ohio, Case No. 78-676-EL-AIR, on marginal costs and electric rate structure design.

2. Before the Public Utilities Commission of the State of South Dakota, Docket No. 3362, on marginal costs and electric rate structure design.

3. Before the Public Utilities Commission of the State of South Dakota, Docket Nos. F-3240 and F-3241, on electric rate structure design.

4. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1311, on the design of a proposed inverted rate structure experiment.

5. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1262, on the operation and the results of a time-of-day rate experiment.

6. Before the Public Utilities Commission of the State of South Dakota, Docket No. F-3116, on test year sales forecasts.

7. Before the Public Utilities Commission of the State of Montana, Docket No. 6441, on test year sales forecasts.

8. Before the Public Service Commission of the State of Maryland, Case No. 6807, on long-term demand forecasting methodology.

9. Before the Public Service Commission of the State of New York, Docket No. 27136, on test year sales forecasts and economic impact.

10. Before the Federal Energy Regulatory Commission, Docket No. ER77-530, on retail competition in the Ohio electric power market.

11. Before the Public Service Commission of the State of Maryland, Case No. 7441 (Phase III), on electric rate structure design and PURPA ratemaking standards.

12. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1591, on class revenue requirements and electric rate structure design.

13. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1606, on PURPA Section 111 standards, class cost-of-service, and rate structure design.

14. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1605, on class revenue requirements and electric rate structure design.

15. Before the Public Utilities Commission of the State of Idaho, Case No. U-1006-185, on class revenue requirements and rate design.

16. Before the Illinois Commerce Commission, Docket No. 82-0026, on marginal-cost-based class revenue responsibilities and rate design.

17. Before the Public Utilities Commission of the State of Idaho, Case No.. U-1009-120, on contractual arrangements, embedded-cost-based class revenue requirements, and rate design.

18. Before the Public Utilities Commission of the State of Maryland, Case No. 7695, on proper electric class cost-of-service methodologies.

19. Before the Public Service Commission of Nevada, Docket No. 83-707, on marginal-cost-based class revenue responsibilities and rate design.

20. Before the Illinois Commerce Commission, Docket No. 83-0537, on marginal-cost-based class revenue responsibilities, rate design, and rate schedule qualification standards.

21. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-137, on jurisdictional separations, embedded class cost-of-service studies, interruptible service credits, and class revenue requirements.

22. Before the South Carolina Public Service Commission, Docket No. 84-122-E, on embedded class cost-of-service methodologies, class revenue requirements, and rate design.

23. Before the Public Utilities Commission of the State of Idaho, Case No. U-1500-157 (May 1985), on the public interest aspects of declaring one utility as the sole supplier of the Idaho National Engineering Laboratory.

24. Before the Illinois Commerce Commission, Docket Nos. 83-0537 (Step 2) and 84-0555 (Consolidated), June 1985, on marginal-cost-based class revenue responsibilities and rate design.

25. Before the Public Utilities Commission of the State of Idaho. Case No. U-1006-265A (May 1987), on embedded class cost-of-service studies, class revenue requirements, and rate design.

26. Before the Public Utilities Commission of the State of Maine, Docket No. 86-242 (August 1987), on by-pass and incentive rate discounts for large industrial customers.

27. Before the Illinois Commerce Commission, Docket No. 87-0427, (February and April 1988), on marginal-cost-based class revenues, Ramsey pricing considerations, and industrial rate design.

28. Before the Illinois Commerce Commission, Docket No. 87-0695, (April 1988), on marginal-cost-based class revenues, Ramsey pricing issues, and industrial rate design.

29. Before the Indiana Utility Regulatory Commission, Cause No. 37414-S2 (October 1989), on ratemaking treatment of off-system sales, embedded cost-of-service study, and rate design.

30. Before the Public Utilities Commission of the State of Maine, Docket 89-68 (January 1990), on measurement and use of marginal costs for determining class revenues.

31. Before the Federal Energy Regulatory Commission, Docket No. EC90-10-000, et. al. (May 1990), with Matthew I. Kahal, on the potential effects of the Northeast Utilities acquisition of Public Service New Hampshire on market concentration and competition in the New England bulk power market.

32. Before the Illinois Commerce Commission, Docket No. 90-0169 (August and October 1990), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

33. Before the Public Service Commission of Nevada, Docket Nos. 91-5032 and 91-5055 (September 1991), on the estimation of marginal costs, class revenue responsibilities and rate design for large power users.

34. Before the Public Service Commission of Nevada, Docket No. 92-1067 (May 1992), on the estimation of marginal costs, the cost of providing interruptible power, class revenue responsibilities, and rate design for large power users.

35. Before the Public Utilities Commission of the State of Maine, Docket No. 92-095 (February 1993), Affidavit regarding the efficacy of rate discounts in attracting new business.

36. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (June 1993), on revamping of the rate structure to meet competition for sales.

37. Before the Public Utilities Commission of the State of Maine, Docket No. 92-345 (August 1993), with Marvin H. Kahn, on price cap mechanisms as an alternative form of regulation.

38. Before the Public Service Commission of Nevada, Docket No. 92-9055 (October 1993), on franchise rights to serve a large DOE customer.

39. Before the Illinois Commerce Commission, Docket No. 94-0065 (June 1994), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

40. Before the Public Service Commission of Nevada, Docket No. 93-11045 (June 1994) on the estimation of marginal costs, environmental externality adders, competition for loads, and class revenue responsibilities.

41. Before the Idaho Public Utilities Commission, Case No. IPC-E-94-5 (November 1994), on embedded class cost allocation and class revenue responsibilities.

42. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (II) (March 1995), on the estimation of marginal distribution demand and customer costs.

43. Before the Public Utilities Commission of the State of Maine, Docket No. 95-052 (RD) (October 1995 and January 1996), with Daphne Pscharopoulos, on the estimation of marginal costs as the basis for class revenues and rate design.

44. Before the Public Service Commission of Nevada, Docket No. 96-7020 (November 1996), on the estimation of marginal costs, class revenue responsibilities, and the reasonableness of fixed, up-front facilities charges.

45. Before the Public Service Commission of Montana, Docket No. 97.7.90 (November 1997 and March 1998), on aspects of Montana Power Company's proposed restructuring plan.

46. Before the Illinois Commerce Commission, Docket No. 99-0117 (April 1999), on the design of distribution delivery rates for Commonwealth Edison Company.

47. Before the Public Utilities Commission of Nevada, Docket Nos. 99-4005 and 99-4006, (November 1999), on the design of an electric distribution service tariff for Nevada Power Company.

48. Before the Public Utilities Commission of Nevada, Docket No. 99-7035 (January and February 2000), on Nevada Power proposed revision to its base rates and deferred energy adjustment rates, including the recovery and allocation of deferred capacity costs and the appropriate calculation of annualized fuel and purchased power costs.

49. Before the Illinois Commerce Commission, Docket No. 01-0423 (August, October 2001), on the proper design of distribution delivery rates for Commonwealth Edison Company.

50. Before the Public Utilities Commission of the State of Maine, Docket No. 2001-239 (November 2001), on appropriate procedures governing the provision of rate discounts to retain or attract customers.

51. Before the Public Utilities Commission of Nevada, Docket Nos. 01-10001, 01-10002 and 01-11029 (February 2002), on Nevada Power Company's proposed class cost allocations and revisions to its base rates.

52. Before the Illinois Commerce Commission, Docket No. 02-0479 (August 2002), on the appropriateness of the Company's petition to have bundled Rate 6L service to customers with loads of 3 MW or more declared a competitive service, thereby eliminating Rate 6L as a service of last resort for these customers.

53. Before the Illinois Commerce Commission, Docket Nos. 02-0656, 02-0671, and 02-0672 (CONS.) (December 2002), on proposed changes to Commonwealth Edison Company's retail access options.

54. Before the Public Utilities Commission of Nevada, Docket Nos. 03-10001 and 03-10002 (January 2004), on Nevada Power Company's proposed class revenue allocation and the imposition of new Customer Specific Facilities Charges on certain large customers.

55. Before the Illinois Commerce Commission, Docket No. 05-0159 (June 2005), on the need for Commonwealth Edison Company to offer a fixed-price POLR service to large customers.

56. Before the Illinois Commerce Commission, Docket No. 05-0597 (February 2006), on the allocation of costs and the design of rates for retail delivery service.

57. Before the Illinois Commerce Commission, Docket No. 07-0566 (February 2008), on embedded class cost of service and the design of rates for retail delivery service.

58. Before the Indiana Utility Regulatory Commission, Cause No. 43306 (September 2008), on embedded class cost of service and the design of rates for retail customers.

PUBLIC'S EXHIBIT NO. 9

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

NORTHERN INDIANA PUBLIC SERVICE COMPANY	))	CAUSE NO. 43526

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

DR. DALE E. SWAN

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

MAY 8, 2009

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Generating Plant Information
2005-2007

	Unit ID	Net Capacity (MW)	Fuel Type	Plant Type	Average Generation (mWh)	Average Hours Connected To Load
Michigan City	12	469	Coal	Base Load	2,655,507	7,113
D.H. Mitchell	9	17	Gas	Peaking	247	17
Bailley	7[1]	160	Coal	Base Load	844,729	6,403
	8	320	Coal	Base Load	1,660,374	6,236
	10[2]	31	Gas	Peaking	1,190	55
R.M. Schahfer	14	431	Coal	Base Load	2,503,090	7,049
	15	472	Coal	Base Load	2,645,437	7,181
	17	361	Coal	Base Load	2,424,474	6,911
	18	361	Coal	Base Load	2,452,364	7,837
	16A[1]	78	Gas	Peaking	10,720	147
	16B	77	Gas	Peaking	14,012	187
Norway Hydro	-	4	Water	R-of-R	19,664	N/A
Oakdale Hydro	-	6	Water	R-of-R	31,902	N/A
System Total		2,787			15,263,710	
Sugar Creek	-	535	Gas	Intermediate	n/a	n/a
Total Peaking		203 (6.1%)			26,169 (0.2%)	
Total Intermediate		535 (16.1%)			n/a	
Total Baseload		2,574 (77.5%)			15,185,975 (99.5%)	
Total R-of-R		10 (0.3%)			1,566 (0.3%)	
Total		3,322 (100.0%)			15,263,710 (100.0%)	

[1]Based on 2005 and 2006 experience only since these units experienced unusual outages during 2007. Exhibit PWP-1, page 5.
N/A: Not available.
n/a: Not applicable.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Analysis of Demand and Energy Responsibility
for Cost of Existing Generation Plant
(Based on Replacement Cost of Plant)

	Installed Capacity[1] (MW)	Replacement Cost Per kW	Total Replacement Cost	Cost if 100% Peaking Capacity
Peaking Units				
Mitchell 9	17.4			
Bailley 10	37.5			
Schahfer 16A	129.0			
Schahfer 16B	129.0			
Total	312.9	$976[2]	$305,390,400	
Intermediate Units				
Sugar Creek	581.3	$1,257[2]	730,694,100	
Base Load				
Michigan City 12	540.0			
Bailley 7	194.0			
Bailley 8	421.6			
Schahfer 14	540.0			
Schahfer 15	556.4			
Schahfer 17	423.5			
Schahfer 18	423.5			
Total	3,099.0	$3,047[2]	$9,442,653,000	
Hydro				
Norway	7.2		9,048,0000[3]	
Oakdale	9.2		6,098,0000[3]	
Total	16.4	$923.54	15,146,000	
Total All Types	4,009.6		$10,493,883,500	$3,913,369,600

Demand-Related Share (3,913,369.6 ÷ 10,493,883.5) x 100 = 37.3%

Energy-Related Share 100 - 37.3 = 62.7%

[1] OUCC 6-002
[2] NIPSCO 2007 Integrated Resource Plan, p. 19, Table 2-2.
[3] Actual costs from NIPSCO 2007 FERC Form 1, p. 410.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Allocation of Additional $55.1 Million of Revenues
Among the Classes Due to Elimination of Revenue Credit

	Class	Total Revenues w/Fuel[1] ($1,000s) (1)	Spread of Credit[2] ($) (2)	Spread of Credit[2] (%) (3)	Normalized Credit[3] $ (4)
511	Residential	385,086	22,708,310	39.27	21,638,575
521	GS Small	56,322	2,224,303	3.85	2,121,429
523	GS Medium	202,705	8,005,350	13.85	7,631,634
526	Off-Peak	14,103	556,964	0.96	528,980
527	Ltd. Prod Large	19,716	778,636	1.35	743,878
533	GS Large	283,586	11,199,551	19.37	10,673,267
534	Industrial Large	293,966	11,609,485	20.08	11,064,493
536	Int. Ind.	91,806	-0-	-0-	-0-
541	Water Pump	2,492	155,729	0.27	148,776
544	Railroad	1,909	111,659	0.19	104,694
550	St. Light	8,576	338,689	0.59	325,102
555	Traffic Light	1,005	39,690	0.07	38,571
560	D-to-D	2,169	85,659	0.15	82,653
	Interdept'l	2,893	-0	-0-	-0-
		$1,366,334	**$57,814,025**	**100.00%**	**$55,102,050**

1 NIPSCO April 24, 2009 Revised Cost Study with Fuel, "Present Rate Revenues."

2 The total Revenue Credit was taken from Exh. RDG-4 (Revised), Schedule 1. Actual credit amounts were used for Residential, Interruptible Industrial, Water Pumping, Railroad and Interdepartmental, where there was a direct mapping between the 800 and 500 series of customers classes. The remaining credit amount was allocated on the basis of Total Revenues, including fuel, pursuant to the Order in Cause 41746, p. 5.

3 From Exhibit D, page 1, Cause No. 38706-FAC82; allocated on column (2).

NORTHERN INDIANA PUBLIC SERVICE COMPANY
NIPSCO COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION (PRESENT RATES, PROPOSED SERVICE CLASSIFICATIONS)
BASE CASE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No	Alloc. Factor	Acct	PROPRIETARY AND CONFIDENTIAL	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	1,456,109,087	418,521,441	59,642,390	214,467,549	15,027,120	20,830,220	300,502,344	312,099,230
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	866,023,926	250,756,323	25,891,132	113,509,642	11,010,979	12,151,978	173,649,062	189,451,515
5			DEPRECIATION	228,307,234	91,004,913	7,731,991	33,658,262	2,282,958	2,020,181	44,325,997	33,454,387
6			TAXES OTHER THAN INCOME	63,296,036	23,895,955	2,407,334	9,364,661	630,637	677,381	12,214,055	9,889,522
7											
8			TOTAL OPERATING EXPENSES	1,157,627,196	365,657,191	36,030,457	156,532,566	13,924,574	14,849,540	230,189,113	232,795,423
9											
10			INCOME TAXES	97,355,767	12,063,022	8,771,649	19,914,090	209,319	2,209,418	23,898,295	28,669,775
11											
12			NET OPERATING INCOME	201,126,124	40,801,229	14,840,285	38,020,893	893,228	3,771,262	46,414,936	50,634,032
13											
14			RATE BASE	2,665,421,828	1,056,573,625	90,001,431	402,604,571	26,830,906	24,215,594	519,189,861	391,725,965
15											
16			RATE OF RETURN - %	7.55%	3.86%	16.49%	9.44%	3.33%	15.57%	8.94%	12.93%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
NIPSCO COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
ALLOCATION (PRESENT RATES, PROPOSED SERVICE CLASSIFICATIONS)
BASE CASE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No	Alloc. Factor	Acct	PROPRIETARY AND CONFIDENTIAL	Total Company	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
				(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
			RATE OF RETURN SUMMARY								
1			OPERATING REVENUES	1,456,109,087	94,888,801	2,705,158	2,043,566	8,980,109	1,059,609	2,363,266	2,978,283
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	866,023,926	77,842,631	2,028,639	858,252	3,904,252	525,630	1,768,597	2,675,294
5			DEPRECIATION	228,307,234	9,028,003	882,216	255,667	1,805,983	167,760	893,763	795,156
6			TAXES OTHER THAN INCOME	63,296,036	2,884,008	247,152	92,722	578,466	51,244	171,514	191,384
7											
8			TOTAL OPERATING EXPENSES	1,157,627,196	89,754,642	3,158,007	1,206,641	6,288,701	744,634	2,833,874	3,661,834
9											
10			INCOME TAXES	97,355,767	1,101,087	-283,193	304,872	983,246	114,399	-238,307	-361,904
11											
12			NET OPERATING INCOME	201,126,124	4,033,072	-169,656	532,054	1,708,163	200,576	-232,301	-321,648
13											
14			RATE BASE	2,665,421,828	110,707,338	11,266,718	3,879,805	11,979,603	1,487,715	5,368,721	9,589,976
15											
16			RATE OF RETURN - %	7.55%	3.64%	-1.51%	13.71%	14.26%	13.48%	-4.33%	-3.35%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
NIPSCO COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQT., CLASSES AT PARITY
BASE CASE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	EARNED RATE OF RETURN	7.55%	3.86%	16.49%	9.44%	3.33%	15.57%	8.94%	12.93%
2									
3	RATE BASE	2,665,421,828	1,056,573,625	90,001,431	402,604,571	26,830,906	24,215,594	519,189,861	391,725,965
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	88,435,212	7,533,120	33,698,003	2,245,747	2,026,845	43,456,191	32,787,463
8	EARNED RETURN ON RATE BASE	201,126,124	40,801,229	14,840,285	38,020,893	893,228	3,771,262	46,414,936	50,634,032
9		---	---	---	---	---	---	---	---
10	REQUIRED INCREASE IN RETURN	21,969,683	47,633,984	-7,307,165	-4,322,890	1,352,519	-1,744,417	-2,958,745	-17,846,569
11									
12	ASSOC. INCR IN INCOME TAXES	15,018,635	32,562,938	-4,995,231	-2,955,159	924,592	-1,192,496	-2,022,620	-12,200,044
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	36,988,318	80,196,922	-12,302,396	-7,278,049	2,277,111	-2,936,914	-4,981,364	-30,046,613
15									
16	INCREASE IN REVENUE-RELATED	657,673	1,425,946	-218,743	-129,408	40,488	-52,220	-88,571	-534,246
17									
18	OPERATING EXPENSES PER COSS	1,157,627,196	365,657,191	36,030,457	156,532,566	13,924,574	14,849,540	230,189,113	232,795,423
19	INCOME TAXES PER COSS	97,355,767	12,063,022	8,771,649	19,914,090	209,319	2,209,418	23,898,295	28,669,775
20	RETURN PER COSS	201,126,124	40,801,229	14,840,285	38,020,893	893,228	3,771,262	46,414,936	50,634,032
21									
22	TOTAL REVENUE REQUIREMENT	1,493,755,078	500,144,309	47,121,251	207,060,092	17,344,720	17,841,087	295,432,408	281,518,372
23	LESS OTHER REVENUES	34,674,484	11,796,873	1,199,321	4,131,334	395,345	369,968	6,242,931	7,068,491
24	REVENUE REQUIREMENT FROM RATES	1,459,080,594	488,347,435	45,921,930	202,928,757	16,949,375	17,471,119	289,189,477	274,449,881
25									
26	PRESENT RATE REVENUES	1,421,434,603	406,724,568	58,443,069	210,336,214	14,631,775	20,460,253	294,259,413	305,030,739
27									
28	REVENUE INCREASE TO TOTAL RATES	37,645,991	81,622,868	-12,521,139	-7,407,457	2,317,600	-2,989,134	-5,069,936	-30,580,858
29	PERCENT TOTAL REVENUE INCREASE	2.65%	20.07%	-21.42%	-3.52%	15.84%	-14.61%	-1.72%	-10.03%
30		---	---	---	---	---	---	---	---

NORTHERN INDIANA PUBLIC SERVICE COMPANY
NIPSCO COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQT., CLASSES AT PARITY
BASE CASE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No		Total Company	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
		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	EARNED RATE OF RETURN	7.55%	3.64%	-1.51%	13.71%	14.26%	13.48%	-4.33%	-3.35%
2									
3	RATE BASE	2,665,421,828	110,707,338	11,266,718	3,879,805	11,979,603	1,487,715	5,368,721	9,589,976
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	9,266,204	943,024	324,740	1,002,693	124,522	449,362	802,681
8	EARNED RETURN ON RATE BASE	201,126,124	4,033,072	-169,656	532,054	1,708,163	200,576	-232,301	-321,648
9		---	---	---	---	---	---	---	---
10	REQUIRED INCREASE IN RETURN	21,969,683	5,233,132	1,112,680	-207,314	-705,470	-76,054	681,663	1,124,329
11									
12	ASSOC. INCR IN INCOME TAXES	15,018,635	3,577,407	760,636	-141,721	-482,264	-51,991	465,990	768,599
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	36,988,318	8,810,539	1,873,317	-349,035	-1,187,734	-128,046	1,147,653	1,892,928
15									
16	INCREASE IN REVENUE-RELATED	657,673	156,656	33,309	-6,206	-21,119	-2,277	20,406	33,657
17									
18	OPERATING EXPENSES PER COSS	1,157,627,196	89,754,642	3,158,007	1,206,641	6,288,701	744,634	2,833,874	3,661,834
19	INCOME TAXES PER COSS	97,355,767	1,101,087	-283,193	304,872	983,246	114,399	-238,307	-361,904
20	RETURN PER COSS	201,126,124	4,033,072	-169,656	532,054	1,708,163	200,576	-232,301	-321,648
21									
22	TOTAL REVENUE REQUIREMENT	1,493,755,078	103,855,996	4,611,783	1,688,325	7,771,256	929,287	3,531,325	4,904,868
23	LESS OTHER REVENUES	34,674,484	3,083,225	64,158	30,149	79,324	16,105	112,014	85,247
24	REVENUE REQUIREMENT FROM RATES	1,459,080,594	100,772,771	4,547,626	1,658,175	7,691,932	913,182	3,419,312	4,819,621
25									
26	PRESENT RATE REVENUES	1,421,434,603	91,805,576	2,641,000	2,013,417	8,900,785	1,043,505	2,251,252	2,893,036
27									
28	REVENUE INCREASE TO TOTAL RATES	37,645,991	8,967,195	1,906,625	-355,242	-1,208,853	-130,323	1,168,059	1,926,585
29	PERCENT TOTAL REVENUE INCREASE	2.65%	9.77%	72.19%	-17.64%	-13.58%	-12.49%	51.88%	66.59%
30		---	---	---	---	---	---	---	---

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

ALLOCATION (PRESENT RATES, PROPOSED SERVICE CLASSIFICATIONS)
PEAK AND AVERAGE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No	Alloc. Factor	Acct	PROPRIETARY AND CONFIDENTIAL	Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industrial Lrg
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			RATE OF RETURN SUMMARY								
1			OPERATING REVENUES	1,456,109,087	418,079,651	59,638,612	214,303,781	15,039,054	20,897,540	300,436,467	312,422,045
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	866,023,926	235,367,586	25,815,076	111,688,674	11,469,315	13,241,039	173,959,000	196,999,581
5			DEPRECIATION	228,307,234	77,096,693	7,663,511	32,030,607	2,697,398	2,998,606	44,618,271	40,259,021
6			TAXES OTHER THAN INCOME	63,296,036	21,844,743	2,396,757	9,091,211	691,393	832,482	12,234,759	10,924,875
7											
8			TOTAL OPERATING EXPENSES	1,157,627,196	334,309,022	35,875,343	152,810,492	14,858,106	17,072,127	230,812,030	248,183,477
9											
10			INCOME TAXES	97,355,767	25,927,011	8,839,672	21,519,875	-203,986	1,239,503	23,595,753	21,902,670
11											
12			NET OPERATING INCOME	201,126,124	57,843,617	14,923,597	39,973,414	384,935	2,585,909	46,028,683	42,335,898
13											
14			RATE BASE	2,665,421,828	905,480,112	89,246,001	384,118,840	31,324,395	35,104,663	521,826,106	466,413,695
15											
16			RATE OF RETURN - %	7.55%	6.39%	16.72%	10.41%	1.23%	7.37%	8.82%	9.08%

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

ALLOCATION (PRESENT RATES, PROPOSED SERVICE CLASSIFICATIONS)
PEAK AND AVERAGE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No	Alloc. Factor	Acct	PROPRIETARY AND CONFIDENTIAL	Total Company	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
				(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
			RATE OF RETURN SUMMARY								
1			OPERATING REVENUES	1,456,109,087	95,133,085	2,706,950	2,042,253	8,995,407	1,060,679	2,367,947	2,985,617
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	866,023,926	85,272,585	2,083,402	909,342	4,168,132	542,949	1,846,045	2,661,200
5			DEPRECIATION	228,307,234	15,738,101	931,674	302,293	2,043,219	183,320	963,360	781,159
6			TAXES OTHER THAN INCOME	63,296,036	3,882,907	254,512	98,766	615,767	53,710	182,515	191,638
7											
8			TOTAL OPERATING EXPENSES	1,157,627,196	104,893,593	3,269,589	1,310,401	6,827,118	779,979	2,991,920	3,633,998
9											
10			INCOME TAXES	97,355,767	-5,583,033	-332,462	257,977	747,920	98,974	-307,315	-346,793
11											
12			NET OPERATING INCOME	201,126,124	-4,177,475	-230,177	473,875	1,420,369	181,725	-316,658	-301,587
13											
14			RATE BASE	2,665,421,828	183,826,516	11,805,605	4,366,304	14,612,503	1,660,876	6,142,515	9,493,696
15											
16			RATE OF RETURN - %	7.55%	-2.27%	-1.95%	10.85%	9.72%	10.94%	-5.16%	-3.18%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
OUCC P&A COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQT., CLASSES AT PARITY
PEAK AND AVERAGE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	EARNED RATE OF RETURN	7.55%	6.39%	16.72%	10.41%	1.23%	7.37%	8.82%	9.08%
2									
3	RATE BASE	2,665,421,828	905,480,112	89,246,001	384,118,840	31,324,395	35,104,663	521,826,106	466,413,695
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	75,788,685	7,469,890	32,150,747	2,621,852	2,938,260	43,676,845	39,038,826
8	EARNED RETURN ON RATE BASE	201,126,124	57,843,617	14,923,597	39,973,414	384,935	2,585,909	46,028,683	42,335,898
9		---	---	---	---	---	---	---	---
10	REQUIRED INCREASE IN RETURN	21,969,683	17,945,068	-7,453,706	-7,822,667	2,236,917	352,351	-2,351,838	-3,297,072
11									
12	ASSOC. INCR IN INCOME TAXES	15,018,635	12,267,379	-5,095,408	-5,347,632	1,529,173	240,870	-1,607,734	-2,253,902
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	36,988,318	30,212,447	-12,549,114	-13,170,299	3,766,090	593,221	-3,959,572	-5,550,974
15									
16	INCREASE IN REVENUE-RELATED	657,673	537,194	-223,130	-234,175	66,963	10,548	-70,403	-98,699
17									
18	OPERATING EXPENSES PER COSS	1,157,627,196	334,309,022	35,875,343	152,810,492	14,858,106	17,072,127	230,812,030	248,183,477
19	INCOME TAXES PER COSS	97,355,767	25,927,011	8,839,672	21,519,875	-203,986	1,239,503	23,595,753	21,902,670
20	RETURN PER COSS	201,126,124	57,843,617	14,923,597	39,973,414	384,935	2,585,909	46,028,683	42,335,898
21									
22	TOTAL REVENUE REQUIREMENT	1,493,755,078	448,829,292	46,866,368	200,899,306	18,872,107	21,501,308	296,406,491	306,772,372
23	LESS OTHER REVENUES	34,674,484	11,504,373	1,196,242	3,982,504	402,802	427,604	6,172,217	7,320,677
24	REVENUE REQUIREMENT FROM RATES	1,459,080,594	437,324,919	45,670,126	196,916,802	18,469,305	21,073,705	290,234,274	299,451,695
25									
26	PRESENT RATE REVENUES	1,421,434,603	406,575,278	58,442,370	210,321,276	14,636,252	20,469,936	294,264,249	305,101,368
27									
28	REVENUE INCREASE TO TOTAL RATES	37,645,991	30,749,641	-12,772,245	-13,404,474	3,833,053	603,769	-4,029,975	-5,649,673
29	PERCENT TOTAL REVENUE INCREASE	2.65%	7.56%	-21.85%	-6.37%	26.19%	2.95%	-1.37%	-1.85%
30		---	---	---	---	---	---	---	---

NORTHERN INDIANA PUBLIC SERVICE COMPANY
OUCC P&A COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQT., CLASSES AT PARITY
PEAK AND AVERAGE WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No		Total Company	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
		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	EARNED RATE OF RETURN	7.55%	-2.27%	-1.95%	10.85%	9.72%	10.94%	-5.16%	-3.18%
2									
3	RATE BASE	2,665,421,828	183,826,516	11,805,605	4,366,304	14,612,503	1,660,876	6,142,515	9,493,696
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	15,386,279	988,129	365,460	1,223,067	139,015	514,129	794,622
8	EARNED RETURN ON RATE BASE	201,126,124	-4,177,475	-230,177	473,875	1,420,369	181,725	-316,658	-301,587
9									
10	REQUIRED INCREASE IN RETURN	21,969,683	19,563,754	1,218,307	-108,415	-197,303	-42,710	830,787	1,096,210
11									
12	ASSOC. INCR IN INCOME TAXES	15,018,635	13,373,925	832,843	-74,113	-134,877	-29,197	567,932	749,377
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	36,988,318	32,937,679	2,051,150	-182,528	-332,180	-71,906	1,398,718	1,845,587
15									
16	INCREASE IN REVENUE-RELATED	657,673	585,650	36,471	-3,245	-5,906	-1,279	24,870	32,816
17									
18	OPERATING EXPENSES PER COSS	1,157,627,196	104,893,593	3,269,589	1,310,401	6,827,118	779,979	2,991,920	3,633,998
19	INCOME TAXES PER COSS	97,355,767	-5,583,033	-332,462	257,977	747,920	98,974	-307,315	-346,793
20	RETURN PER COSS	201,126,124	-4,177,475	-230,177	473,875	1,420,369	181,725	-316,658	-301,587
21									
22	TOTAL REVENUE REQUIREMENT	1,493,755,078	128,656,414	4,794,571	1,856,479	8,657,321	987,494	3,791,536	4,864,019
23	LESS OTHER REVENUES	34,674,484	3,256,187	65,424	28,272	92,251	17,020	116,004	92,907
24	REVENUE REQUIREMENT FROM RATES	1,459,080,594	125,400,227	4,729,147	1,828,207	8,565,070	970,474	3,675,532	4,771,112
25									
26	PRESENT RATE REVENUES	1,421,434,603	91,876,898	2,641,526	2,013,981	8,903,156	1,043,659	2,251,944	2,892,710
27									
28	REVENUE INCREASE TO TOTAL RATES	37,645,991	33,523,329	2,087,620	-185,774	-338,086	-73,185	1,423,588	1,878,402
29	PERCENT TOTAL REVENUE INCREASE	2.65%	36.49%	79.03%	-9.22%	-3.80%	-7.01%	63.22%	64.94%
30									

(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007

ALLOCATION (PRESENT RATES, PROPOSED SERVICE CLASSIFICATIONS)
12CP ALLOCATION WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No	Alloc. Factor	Acct	PROPRIETARY AND CONFIDENTIAL	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	1,456,109,087	418,320,966	59,643,599	214,477,781	15,034,910	20,852,132	300,539,824	312,199,664
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	866,023,926	238,916,207	25,962,557	114,113,945	11,471,055	13,446,075	175,862,641	195,383,185
5			DEPRECIATION	228,307,234	80,281,245	7,796,681	34,205,584	2,699,653	3,192,254	46,330,849	38,826,738
6			TAXES OTHER THAN INCOME	63,296,036	22,356,180	2,416,623	9,443,249	690,469	845,675	12,501,925	10,660,920
7											
8			TOTAL OPERATING EXPENSES	1,157,627,196	341,553,632	36,175,861	157,762,778	14,861,177	17,484,004	234,695,415	244,870,842
9											
10			INCOME TAXES	97,355,767	22,773,466	8,707,038	19,367,444	-206,862	1,038,791	21,895,914	23,304,048
11											
12			NET OPERATING INCOME	201,126,124	53,993,867	14,760,700	37,347,559	380,595	2,329,337	43,948,495	44,024,774
13											
14			RATE BASE	2,665,421,828	941,080,787	90,698,140	408,499,164	31,318,665	36,838,698	540,781,925	449,585,654
15											
16			RATE OF RETURN - %	7.55%	5.74%	16.27%	9.14%	1.22%	6.32%	8.13%	9.79%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
OUCC 12CP COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007

ALLOCATION (PRESENT RATES, PROPOSED SERVICE CLASSIFICATIONS)
12CP ALLOCATION WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No	Alloc. Factor	Acct	PROPRIETARY AND CONFIDENTIAL	Total Company	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
				(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
			RATE OF RETURN SUMMARY								
1			OPERATING REVENUES	1,456,109,087	94,905,217	2,705,995	2,045,026	8,983,523	1,059,760	2,364,219	2,976,471
2											
3			OPERATING EXPENSES								
4			OPERATION & MAINTENANCE	866,023,926	78,812,177	2,078,060	944,448	4,105,892	534,499	1,824,908	2,568,276
5			DEPRECIATION	228,307,234	9,906,126	926,976	333,735	1,988,609	175,793	944,763	698,228
6			TAXES OTHER THAN INCOME	63,296,036	3,010,094	253,579	103,932	604,689	52,397	178,837	177,467
7											
8			TOTAL OPERATING EXPENSES	1,157,627,196	91,728,398	3,258,615	1,382,116	6,699,190	762,689	2,948,508	3,443,971
9											
10			INCOME TAXES	97,355,767	224,046	-327,898	226,899	800,844	106,377	-289,245	-265,096
11											
12			NET OPERATING INCOME	201,126,124	2,952,774	-224,722	436,011	1,483,489	190,694	-295,044	-202,404
13											
14			RATE BASE	2,665,421,828	120,164,642	11,748,783	4,720,599	13,946,472	1,574,226	5,917,995	8,546,079
15											
16			RATE OF RETURN - %	7.55%	2.46%	-1.91%	9.24%	10.64%	12.11%	-4.99%	-2.37%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
OUCC 12CP COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQT., CLASSES AT PARITY
12CP ALLOCATION WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industrial Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	EARNED RATE OF RETURN	7.55%	5.74%	16.27%	9.14%	1.22%	6.32%	8.13%	9.79%
2									
3	RATE BASE	2,665,421,828	941,080,787	90,698,140	408,499,164	31,318,665	36,838,698	540,781,925	449,585,654
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	78,768,462	7,591,434	34,191,380	2,621,372	3,083,399	45,263,447	37,630,319
8	EARNED RETURN ON RATE BASE	201,126,124	53,993,867	14,760,700	37,347,559	380,595	2,329,337	43,948,495	44,024,774
9		---	---	---	---	---	---	---	---
10	REQUIRED INCREASE IN RETURN	21,969,683	24,774,595	-7,169,266	-3,156,179	2,240,777	754,062	1,314,952	-6,394,455
11									
12	ASSOC. INCR IN INCOME TAXES	15,018,635	16,936,093	-4,900,962	-2,157,587	1,531,812	515,482	898,911	-4,371,296
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	36,988,318	41,710,688	-12,070,228	-5,313,765	3,772,589	1,269,544	2,213,863	-10,765,751
15									
16	INCREASE IN REVENUE-RELATED	657,673	741,639	-214,615	-94,482	67,079	22,573	39,364	-191,421
17									
18	OPERATING EXPENSES PER COSS	1,157,627,196	341,553,632	36,175,861	157,762,778	14,861,177	17,484,004	234,695,415	244,870,842
19	INCOME TAXES PER COSS	97,355,767	22,773,466	8,707,038	19,367,444	-206,862	1,038,791	21,895,914	23,304,048
20	RETURN PER COSS	201,126,124	53,993,867	14,760,700	37,347,559	380,595	2,329,337	43,948,495	44,024,774
21									
22	TOTAL REVENUE REQUIREMENT	1,493,755,078	460,773,293	47,358,756	209,069,534	18,874,578	22,144,249	302,793,051	301,242,492
23	LESS OTHER REVENUES	34,674,484	11,714,674	1,199,817	4,135,530	398,539	378,952	6,258,299	7,109,671
24	REVENUE REQUIREMENT FROM RATES	1,459,080,594	449,058,620	46,158,939	204,934,004	18,476,039	21,765,297	296,534,752	294,132,821
25									
26	PRESENT RATE REVENUES	1,421,434,603	406,606,292	58,443,783	210,342,251	14,636,371	20,473,180	294,281,525	305,089,993
27									
28	REVENUE INCREASE TO TOTAL RATES	37,645,991	42,452,328	-12,284,843	-5,408,247	3,839,667	1,292,117	2,253,226	-10,957,172
29	PERCENT TOTAL REVENUE INCREASE	2.65%	10.44%	-21.02%	-2.57%	26.23%	6.31%	0.77%	-3.59%
30		---	---	---	---	---	---	---	---

NORTHERN INDIANA PUBLIC SERVICE COMPANY
OUCC 12CP COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
1985 RATES, REVISED REV. REQT., CLASSES AT PARITY
12CP ALLOCATION WITH INTEGRATION OF FUEL AND PURCHASED POWER
NIPSCO APRIL 24, 2009 STUDY WITH $55.1 MILLION CREDIT

Line No		Total Company	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
		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	EARNED RATE OF RETURN	7.55%	2.46%	-1.91%	9.24%	10.64%	12.11%	-4.99%	-2.37%
2									
3	RATE BASE	2,665,421,828	120,164,642	11,748,783	4,720,599	13,946,472	1,574,226	5,917,995	8,546,079
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	10,057,781	983,373	395,114	1,167,320	131,763	495,336	715,307
8	EARNED RETURN ON RATE BASE	201,126,124	2,952,774	-224,722	436,011	1,483,489	190,694	-295,044	-202,404
9									
10	REQUIRED INCREASE IN RETURN	21,969,683	7,105,007	1,208,095	-40,897	-316,169	-58,931	790,381	917,711
11									
12	ASSOC. INCR IN INCOME TAXES	15,018,635	4,857,034	825,863	-27,957	-216,136	-40,286	540,310	627,354
13									
14	TOTAL INCREASE IN RETURN & INC TAXES	36,988,318	11,962,041	2,033,958	-68,854	-532,305	-99,217	1,330,691	1,545,065
15									
16	INCREASE IN REVENUE-RELATED	657,673	212,692	36,165	-1,224	-9,465	-1,764	23,660	27,472
17									
18	OPERATING EXPENSES PER COSS	1,157,627,196	91,728,398	3,258,615	1,382,116	6,699,190	762,689	2,948,508	3,443,971
19	INCOME TAXES PER COSS	97,355,767	224,046	-327,898	226,899	800,844	106,377	-289,245	-265,096
20	RETURN PER COSS	201,126,124	2,952,774	-224,722	436,011	1,483,489	190,694	-295,044	-202,404
21									
22	TOTAL REVENUE REQUIREMENT	1,493,755,078	107,079,951	4,776,117	1,974,948	8,441,754	958,778	3,718,570	4,549,008
23	LESS OTHER REVENUES	34,674,484	3,089,956	64,501	30,748	80,724	16,166	112,405	84,504
24	REVENUE REQUIREMENT FROM RATES	1,459,080,594	103,989,994	4,711,617	1,944,200	8,361,030	942,612	3,606,166	4,464,504
25									
26	PRESENT RATE REVENUES	1,421,434,603	91,815,261	2,641,494	2,014,278	8,902,800	1,043,593	2,251,815	2,891,967
27									
28	REVENUE INCREASE TO TOTAL RATES	37,645,991	12,174,733	2,070,123	-70,078	-541,770	-100,981	1,354,351	1,572,537
29	PERCENT TOTAL REVENUE INCREASE	2.65%	13.26%	78.37%	-3.48%	-6.09%	-9.68%	60.14%	54.38%
30									

Comparison of Rates of Return at Current Revenues
Under Three C-O-S Studies, Including Fuel Costs
and $55.1 Million of Additional Revenues

		NIPSCO		OUCC P&A		UCC 12 CP	
		%[1]	Index	%[2]	Index	%[3]	Index
		(1)	(2)	(3)	(4)	(5)	(6)
511	Residential	3.86%	51.1	6.39%	84.6	5.74	76.0
521	GS Small	16.47	218.1	16.72	221.5	16.27	215.5
523	GS Med	9.44	125.0	10.41	137.9	9.14	121.1
526	Off-Peak	3.33	44.1	1.23	16.3	1.21	16.0
527	Ltd. Prod. Large	15.57	206.2	7.37	97.6	6.32	83.7
533	GS Large	8.94	118.4	8.82	116.8	8.13	107.7
534	Indust. Lrg.	12.93	171.3	9.08	120.3	9.79	129.7
536	Int. Ind.	3.64	48.2	-2.27	-30.1	2.46	32.6
541	Water Pump.	-1.51	-20.0	-1.95	-25.8	-1.91	-25.3
544	Railroad	13.71	181.6	10.85	143.7	9.24	122.4
550	Street Ltg.	14.26	188.9	9.72	128.7	10.64	140.9
555	Traffic Ltg.	13.48	178.5	10.94	144.9	12.11	160.4
560	Dusk-to-Dawn	-4.33	-57.4	-5.16	-68.3	-4.99	-66.1
	Interdept'l	-3.35	-44.4	-3.18	-42.1	-2.37	-31.4
	Total Company	7.55%	100.0	7.55%	100.0	7.55%	100.0

[1] Schedule DES-4, pp. 1 and 2.
[2] Schedule DES-5, pp. 1 and 2.
[3] Schedule DES-6, pp. 1 and 2.

Comparison of Class Allocation of Production Plant and Fuel Costs
Between NIPSCO's 4-CP Cost of Service Method and
the OUCC Peak and Average Method

			4CP Method				OUCC P&A Method					
Rate Class	Energy at Generation[1]	4CP Peak[2]	Demand Related[3]		Energy Related[4]		Demand Related[3]		Energy Related[5]		Fuel Cost[6]	
	MWh	kW	$	$/kW	$	$/kWh	$	$/kW	$	$/kWh	$	¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
511 Residential	3,993,882	1,073,228	411,621,064	383.54	764,439,120	0.1914	411,621,064	383.54	452,632,339	0.1133	113,127,448	2.8325
521 GS Small	466,189	76,225	29,234,995	383.54	54,293,563	0.1165	29,234,995	383.54	52,833,864	0.1133	13,204,890	2.8325
523 GS Medium	2,300,514	409,838	157,187,432	383.54	291,919,518	0.1269	157,187,432	383.54	260,720,530	0.1133	65,162,486	2.8325
526 Off-Peak	255,602	27,543	10,563,719	383.54	19,618,335	0.0768	10,563,719	383.54	28,967,739	0.1133	7,239,974	2.8325
527 Ltd. Prod Large	302,893	19,800	7,594,003	383.54	14,103,149	0.0466	7,594,003	383.54	34,327,295	0.1133	8,579,500	2.8325
533 GS Large	3,760,962	584,228	224,072,193	383.54	416,134,072	0.1106	224,072,193	383.54	426,235,183	0.1133	106,529,946	2.8325
534 Industrial Large	4,739,103	546,938	209,770,153	383.54	389,573,141	0.0822	209,770,153	383.54	537,089,296	0.1133	134,235,971	2.8325
536 Int. Ind	2,111,140	126,770	48,620,799	383.54	90,295,769	0.0428	48,620,799	383.54	239,258,505	0.1133	59,798,432	2.8325
541 Water Pump	28,852	3,049	1,169,400	383.54	2,171,743	0.0753	1,169,400	383.54	3,269,838	0.1133	817,238	2.8325
544 Railroad	19,387	1,432	549,223	383.54	1,019,985	0.0526	549,223	383.54	2,197,156	0.1133	549,140	2.8325
550 Street Lighting	55,388	1,860	713,376	383.54	1,324,841	0.0239	713,376	383.54	6,277,201	0.1133	1,568,875	2.8325
555 Traffic Lighting	10,342	1,194	457,941	383.54	850,463	0.0822	457,941	383.54	1,172,074	0.1133	292,939	2.8325
560 Dusk-to-Dawn	16,147	542	207,876	383.54	386,056	0.0239	207,876	383.54	1,829,963	0.1133	457,367	2.8325
Interdepartmental	55,330	9,760	3,743,307	383.54	6,951,855	0.1256	3,743,307	383.54	6,270,628	0.1133	1,567,233	2.8325
Total Company	18,115,731	2,882,407	1,105,505,482	383.54	2,053,081,610	0.1133	1,105,505,482	383.54	2,053,081,610	0.1133	513,131,439	2.8325

[1] Allocation Factor No. 10, "Energy at Source," from the Company's 4/24/09 revised study with fuel.
[2] Allocation Factor No. 1, "Avg Control Area KW," from the Company's 4/24/09 revised study with fuel.
[3] 35% of Fixed Production Plant in Service from the Company's 4/24/09 revised study with fuel.
[4] 65% of Fixed Production Plant in Service from the Company's 4/24/09 revised study with fuel.
[5] 65% of Fixed Production Plant in Service allocated on energy use at source from OUCC P&A study.
[6] The Sum of Accounts 340 (Fuel), 547 (Fuel) and 555 (Purchased Power) functionalized as Production Variable Costs in the Company's 4/24/09 revised study with fuel.

Northern Indiana Public Service Company
Cause 43526
Proposed Rate Class Spread of $140 Million Revenue Reduction
Based on OUCC Peak and Average Cost Study
($1,000s)

Rate Class	Present Rate Revenue[1] ($) (1)	Full Cost Rate Revenue[2] ($) (2)	Adjusted Full Cost Revenues[3] ($) (3)	Adjusted Full Cost Change ($) (4)	Adjusted Full Cost Change (%) (5)	Change With 0% Ceiling and -13% Floor ($) (6)	Change With 0% Ceiling and -13% Floor (%) (7)	Excess Allocation[4] ($) (8)	Final Rate Revenues ($) (9)	Final Revenue Change ($) (10)	Final Revenue Change (%) (11)
511 Residential	406,575	437,325	384,080	-22,495	-5.53%	-22,495	-5.53%	-1041	383,039	-23,536	-5.79%
521 GS Small	58,442	45,670	40,110	-18,332	-31.37%	-7,597	-13.00%	0	50,845	-7,597	-13.00%
523 GS Medium	210,321	196,917	172,942	-37,379	-17.77%	-27,342	-13.00%	0	182,979	-27,342	-13.00%
526 Off-Peak	14,636	18,469	16,220	1,584	10.83%	0	0.00%	0	14,636	0	0.00%
527 Ltd. Prod Large	20,470	21,074	18,508	-1,962	-9.58%	-1,962	-9.58%	-91	18,417	-2,053	-10.03%
533 GS Large	294,264	290,234	254,897	-39,367	-13.38%	-38,254	-13.00%	0	256,010	-38,254	-13.00%
534 Industrial Large	305,101	299,452	262,993	-42,108	-13.80%	-39,663	-13.00%	0	265,438	-39,663	-13.00%
536 Int. Ind	91,877	125,400	110,132	18,255	19.87%	0	0.00%	0	91,877	0	0.00%
541 Water Pump	2,642	4,729	4,153	1,511	57.20%	0	0.00%	0	2,642	0	0.00%
544 Railroad	2,014	1,828	1,605	-409	-20.29%	-262	-13.00%	0	1,752	-262	-13.00%
550 Street Lighting	8,903	8,565	7,522	-1,381	-15.51%	-1,157	-13.00%	0	7,746	-1,157	-13.00%
555 Traffic Lighting	1,044	970	852	-192	-18.40%	-136	-13.00%	0	908	-136	-13.00%
560 Dusk-to-Dawn	2,252	3,676	3,228	976	43.36%	0	0.00%	0	2,252	0	0.00%
Interdepartmental	2,893	4,771	4,190	1,297	44.84%	0	0.00%	0	2,893	0	0.00%
Total Company	1,421,434	1,459,080	1,281,434	-140,000	-9.85%	-138,869	-9.77%	-1,131	1,281,434	-140,000	-9.85%

1 Schedule DES-5, pp 3-4, line 26.
2 Schedule DES-5, pp 3-4, line 24.
3 87.8 % of column (2).
4 Allocated among classes with negative changes in column (4)

Northern Indiana Public Service Company
Cause 43526
Movement Toward Cost-Based Rates
Under Proposed Spread of $140 Million Revenue Reduction

		Present Revenues as % of Adjusted Full Cost Revenues (%)	Class Relative Share of Adjusted Full Cost Revenues (%)	Proposed Revenues as % of Adjusted Full Cost Revenues (%)
		(1)	(2)	(3)
511	Residential	105.9%	95.9%	99.7%
521	GS Small	145.7	131.4	126.8
523	GS Medium	121.6	109.6	105.8
526	Off-Peak	90.2	81.3	90.2
527	Ltd. Prod. Large	110.6	99.7	99.5
533	GS Large	115.4	104.1	100.4
534	Indust. Lrg.	116.0	104.6	100.9
536	Int. Ind.	83.4	75.2	83.4
541	Water Pump.	63.6	57.4	63.6
544	Railroad	125.5	113.2	109.1
550	Street Ltg.	118.4	106.7	103.0
555	Traffic Ltg.	122.5	110.5	106.6
560	Dusk-to-Dawn	69.8	62.9	69.8
	Interdept'l	69.0	62.3	69.0
	Total Company	110.9%	100.0%	100.05

Northern Indiana Public Service Company
Cause 43526
Proposed Rate Class Spread of $70 Million Revenue Reduction
Based on OUCC Peak and Average Cost Study
($1,000s)

Rate Class	Present Rate Revenue[1] ($) (1)	Full Cost Rate Revenue[2] ($) (2)	Adjusted Full Cost Revenues[3] ($) (3)	Adjusted Full Cost Change ($) (4)	Adjusted Full Cost Change (%) (5)	Change With +5% Ceiling and -7.5% Floor ($) (6)	Change With +5% Ceiling and -7.5% Floor (%) (7)	Excess Allocation[4] ($) (8)	Final Rate Revenues ($) (9)	Final Revenue Change ($) (10)	Final Revenue Change (%) (11)
511 Residential	406,575	437,325	405,061	-1,514	-0.37%	-1,514	-0.37%	-6659	398,402	-8,173	-2.01%
521 GS Small	58,442	45,670	42,301	-16,141	-27.62%	-4,383	-7.50%	0	54,059	-4,383	-7.50%
523 GS Medium	210,321	196,917	182,389	-27,932	-13.28%	-15,774	-7.50%	0	194,547	-15,774	-7.50%
526 Off-Peak	14,636	18,469	17,106	2,470	16.88%	732	5.00%	0	15,368	732	5.00%
527 Ltd. Prod Large	20,470	21,074	19,519	-951	-4.64%	-951	-4.64%	-584	18,935	-1,535	-7.50%
533 GS Large	294,264	290,234	268,822	-25,442	-8.65%	-22,070	-7.50%	0	272,194	-22,070	-7.50%
534 Industrial Large	305,101	299,452	277,359	-27,742	-9.09%	-22,883	-7.50%	0	282,218	-22,883	-7.50%
536 Int. Ind	91,877	125,400	116,148	24,271	26.42%	4,594	5.00%	0	96,471	4,594	5.00%
541 Water Pump	2,642	4,729	4,380	1,738	65.79%	132	5.00%	0	2,774	132	5.00%
544 Railroad	2,014	1,828	1,693	-321	-15.93%	-151	-7.50%	0	1,863	-151	-7.50%
550 Street Lighting	8,903	8,565	7,933	-970	-10.89%	-668	-7.50%	0	8,235	-668	-7.50%
555 Traffic Lighting	1,044	970	898	-146	-13.94%	-78	-7.50%	0	966	-78	-7.50%
560 Dusk-to-Dawn	2,252	3,676	3,405	1,153	51.19%	113	5.00%	0	2,365	113	5.00%
Interdepartmental	2,893	4,771	4,419	1,526	52.75%	145	5.00%	0	3,038	145	5.00%
Total Company	1,421,434	1,459,080	1,351,434	-70,000	-4.92%	-62,757	-4.42%	-7,243	1,351,434	-70,000	-4.92%

1 Schedule DES-5, pp 3-4, line 26.
2 Schedule DES-5, pp 3-4, line 24.
3 92.6 % of column (2).
4 Allocated among classes with negative changes in column (4)

Northern Indiana Public Service Company
Cause 43526
Movement Toward Cost Based Rates
Under Proposed Spread of $70 Million Revenue Reduction

		Present Revenues as % of Adjusted Full Cost Revenues (%)	Class Relative Share of Adjusted Full Cost Revenues (%)	Proposed Revenues as % of Adjusted Full Cost Revenues (%)
		(1)	(2)	(3)
511	Residential	100.4%	95.4%	98.4%
521	GS Small	138.2	131.4	127.8
523	GS Medium	115.3	109.6	106.7
526	Off-Peak	85.6	81.3	89.8
527	Ltd. Prod. Large	104.9	99.7	97.0
533	GS Large	109.5	104.1	101.3
534	Indust. Lrg.	110.0	104.6	101.8
536	Int. Ind.	79.1	75.2	83.1
541	Water Pump.	60.3	57.3	63.3
544	Railroad	119.0	113.1	110.0
550	Street Ltg.	112.2	106.7	103.8
555	Traffic Ltg.	116.3	110.5	107.5
560	Dusk-to-Dawn	66.1	62.9	69.5
	Interdept'l	65.5	62.2	68.7
	Total Company	105.2	100.0%	100.05

Northern Indiana Public Service Company
Cause 43526
Proposed Rate Spread at 133% Cap
Based on Company Proposed Revenues and
OUCC Peak and Average Study Including Fuel Costs
and the $55.1 Million Revenue Credit

Rate Class	Present Rate Revenue ($)	Full Cost Revenue Requirement ($)	Full cost increase ($)	Full cost increase (%)	Total Revenue ($)	Revenue Increase ($)	Revenue Increase (%)
511 Residential	406,575,278	437,324,919	30,749,641	7.56%	420,896,645	14,321,367	3.52%
521 GS Small	58,442,370	45,670,126	-12,772,244	-21.85%	59,448,058	1,005,688	1.72%
523 GS Medium	210,321,276	196,916,802	-13,404,474	-6.37%	214,657,520	4,336,244	2.06%
526 Off-Peak	14,636,252	18,469,305	3,833,053	26.19%	15,151,805	515,553	3.52%
527 Ltd. Prod Large	20,469,936	21,073,705	603,769	2.95%	21,190,977	721,041	3.52%
533 GS Large	294,264,249	290,234,274	-4,029,975	-1.37%	300,655,407	6,391,158	2.17%
534 Industrial Large	305,101,368	299,451,695	-5,649,673	-1.85%	311,695,500	6,594,132	2.16%
536 Int. Ind	91,876,898	125,400,227	33,523,329	36.49%	95,113,206	3,236,308	3.52%
541 Water Pump	2,641,526	4,729,147	2,087,621	79.03%	2,734,572	93,046	3.52%
544 Railroad	2,013,981	1,828,207	-185,774	-9.22%	2,054,239	40,258	2.00%
550 Street Lighting	8,903,156	8,565,070	-338,086	-3.80%	9,091,765	188,609	2.12%
555 Traffic Lighting	1,043,659	970,474	-73,185	-7.01%	1,065,030	21,371	2.05%
560 Dusk-to-Dawn	2,251,944	3,675,532	1,423,588	63.22%	2,331,267	79,323	3.52%
Interdepartmental	2,892,710	4,771,112	1,878,402	64.94%	2,994,604	101,894	3.52%
Total Company	1,421,434,603	1,459,080,595	37,645,992	2.65%	1,459,080,595	37,645,992	2.65%

Northern Indiana Public Service Company
Cause 43526
Proposed Rate Spread at 150% Cap
Based on Company Proposed Revenues and
OUCC Peak and Average Study Including Fuel Costs
and the $55.1 Million Revenue Credit

Rate Class	Present Rate Revenue ($)	Full Cost Revenue Requirement ($)	Full Cost Increase ($)	Full Cost Increase (%)	Total Revenue ($)	Revenue Increase ($)	Revenue Increase (%)
511 Residential	406,575,278	437,324,919	30,749,641	7.56%	422,727,196	16,151,918	3.97%
521 GS Small	58,442,370	45,670,126	-12,772,244	-21.85%	59,316,113	873,743	1.50%
523 GS Medium	210,321,276	196,916,802	-13,404,474	-6.37%	214,088,612	3,767,336	1.79%
526 Off-Peak	14,636,252	18,469,305	3,833,053	26.19%	15,217,703	581,451	3.97%
527 Ltd. Prod Large	20,469,936	21,073,705	603,769	2.95%	21,283,140	813,204	3.97%
533 GS Large	294,264,249	290,234,274	-4,029,975	-1.37%	299,816,898	5,552,649	1.89%
534 Industrial Large	305,101,368	299,451,695	-5,649,673	-1.85%	310,830,361	5,728,993	1.88%
536 Int. Ind	91,876,898	125,400,227	33,523,329	36.49%	95,526,869	3,649,971	3.97%
541 Water Pump	2,641,526	4,729,147	2,087,621	79.03%	2,746,465	104,939	3.97%
544 Railroad	2,013,981	1,828,207	-185,774	-9.22%	2,048,958	34,977	1.74%
550 Street Lighting	8,903,156	8,565,070	-338,086	-3.80%	9,067,020	163,864	1.84%
555 Traffic Lighting	1,043,659	970,474	-73,185	-7.01%	1,062,226	18,567	1.78%
560 Dusk-to-Dawn	2,251,944	3,675,532	1,423,588	63.22%	2,341,406	89,462	3.97%
Interdepartmental	2,892,710	4,771,112	1,878,402	64.94%	3,007,628	114,918	3.97%
Total Company	1,421,434,603	1,459,080,595	37,645,992	2.65%	1,459,080,595	37,645,992	2.65%

Northern Indiana Public Service Company
Class Rates of Return Under OUCC Proposed
Spread of NIPSCO Total Revenue Request
and OUCC P&A COS Study

		Current Rate		133% Cap		150% Cap	
		ROR	ROR Index	ROR	ROR Index	ROR	ROR Index
		(1)	(2)	(3)	(4)	(5)	(6)
511	Residential	6.39%	84.6%	7.31%	87.3%	7.43%	88.8%
521	GS Small	16.72	221.5	17.37	207.5	17.29	206.6
523	GS Medium	10.41	137.9	11.08	132.4	10.99	131.3
526	Off-Peak	1.23	16.3	2.19	26.2	2.31	27.6
527	Ltd. Prod. Large	7.37	97.6	8.55	102.2	8.70	103.9
533	GS Large	8.82	116.8	9.55	114.1	9.45	112.9
534	Indust. Lrg.	9.08	120.3	9.90	118.3	9.79	117.0
536	Interrupt. Ind.	-2.27	-30.1	-1.24	-14.8	-1.11	-13.3
541	Water Pump.	-1.95	-25.8	-1.49	-17.8	-1.43	-17.1
544	Railroad	10.85	143.7	11.42	136.4	11.35	135.6
550	Street Ltg.	9.72	128.7	10.50	125.4	10.41	124.4
555	Traffic Ltg.	10.94	144.9	11.74	140.3	11.65	139.2
560	Dusk-to-Dawn	-5.16	-68.3	-4.38	-52.3	-4.29	-51.3
	Interdept'l	-3.18	-42.1	-2.55	-30.5	-2.47	-29.5
	Total Company	7.55%	100.0%	8.37%	100.0%	8.37%	100.0%