STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	**)**	**CAUSE NO. 45159**

Verified Cross-Answering Testimony and Attachments of

Nicholas Phillips, Jr.

On behalf of

The NIPSCO Industrial Group

March 15, 2019

BRUBAKER & ASSOCIATES, INC.

Project 10697

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	**CAUSE NO. 45159**

Verified Cross-Answering Testimony of Nicholas Phillips, Jr.

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME NICHOLAS PHILLIPS, JR. WHO PREVIOUSLY FILED TESTIMONY IN THIS CASE?

A Yes. On February 13, 2019, I filed direct testimony on behalf of the NIPSCO Industrial Group ("Industrial Group").

Q WHAT IS THE PURPOSE OF YOUR CROSS-ANSWERING TESTIMONY?

A I will respond to the Direct Testimony of Dr. Boerger and Glenn A. Watkins on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC") with respect to their recommendations on the allocation of production related investment cost in Northern Indiana Public Service Company's ("NIPSCO" or "Company") class cost of service study, rate issues and so-called transition charge.

I will also respond to the Direct Testimony of others including Mr. Wallach, Mr. Allison, Mr. Tillman and Ms. Medine regarding claims of subsidy, transition charge, cost of service and associated issues.

My silence on any aspect of the testimony of witnesses for other consumer parties should not be construed as an endorsement or agreement with their positions expressed in that testimony.

Q PLEASE COMMENT ON THE IMPORTANCE OF THIS PROCEEDING.

A The importance of establishing appropriate industrial rates in this proceeding cannot be underestimated. These are perilous times for NIPSCO and its customers. Energy-intensive industries are facing intense competition throughout this country and internationally. If industrial operations cannot remain competitive, the ripple effect on the Indiana economy should be a significant concern. NIPSCO has set forth a fair and intelligent proposal to provide cost based industrial rates, mitigate the residential increase, reduce risk and plan for the future.

Response to Assertions of <u>NIPSCO Legacy Generation Costs and Transition Charge</u>

Q HAVE YOU REVIEWED TESTIMONY REGARDING INDUSTRIAL RESPONSIBILITY TO PAY FOR LEGACY GENERATION COSTS?

A Yes. Mr. Watkins (and others including Dr. Boerger, Mr. Wallach, Mr. Allison and Mr. Tillman) attempt to justify a transition charge using the premise that:

> Under the Company's and Dr. Gaske's approach, these large industrial customers would be able to leave the system with no cost responsibility in paying for legacy generation costs that were largely planned and built to meet their energy needs.

(Watkins Direct, p. 37, lines 10-13)

The essential theory espoused by these witnesses is that "fairness" requires that Rate 831 customers remain responsible for the cost of NIPSCO's existing generation fleet and should be required to pay for those costs.

Q DO YOU AGREE WITH THE ARGUMENTS RAISED BY OTHERS REGARDING RATE 831 CUSTOMERS' RESPONSIBILITY FOR LEGACY GENERATION COSTS?

A No, I do not. This concept and premise is fraught with problems, constitutes unreasonable ratemaking and should be rejected.

The problems with the concept of legacy costs and a transition charge include:

1. The argument assumes industrial customers have not already paid a fair portion of the costs associated with the generation costs; and have not saved other customers the avoided costs associated with new generation through their own actions to self-supply power or accept the risk of interruptible load.

    a. NIPSCO's current coal fleet was constructed between 33 and 45 years ago. No customer is obligated to support costs for that duration.

    b. NIPSCO has already closed two generating stations (Mitchell and Bailly) for various reasons. NIPSCO plans on closing the remaining facilities in the near future making the concept of legacy costs problematic.

    c. Industrial customers have mitigated NIPSCO's need to add generation by taking interruptible service and investing in self-generation.

d. NIPSCO or its affiliates have been involved in constructing generating facilities for its industrial customers over the years making NIPSCO and the public aware of the plans of its industrial customers.

e. Customers of all classes are free to lower load, self-generate, or leave a service territory. Absent an actual contract commitment, it is not appropriate to claim legacy costs from previous decades for a transition charge associated with load reduction.

2. NIPSCO's industrial customers have provided hundreds of millions, if not billions of dollars of subsidies to other customer classes over the time frame of the so-called claimed "legacy costs."

3. A transition charge is not only unreasonable, but poor policy that could well result in additional losses of load.

Q PLEASE DISCUSS THE AGE AND STATUS OF NIPSCO'S COAL GENERATION.

A NIPSCO's last coal generator, Schaeffer 18, was constructed 33 years ago. Its Michigan City plant was constructed 45 years ago. When you consider that planning and construction would add an additional 10 years, NIPSCO's current coal fleet was planned and built between 43 and 55 years ago. It is inherently unreasonable to contend that any customer should be obligated to cover the costs of those plants for that duration. In addition, NIPSCO has already closed two of its generating stations. These facts alone make the concept of legacy costs unreasonable.

Q PLEASE DISCUSS NIPSCO'S CLOSED GENERATING STATIONS.

A NIPSCO closed its Mitchell Generating Station initially on a temporary basis in January 2002. Mitchell was a coal-fired base load facility rated at 502 MW and one of the four generating stations owned by NIPSCO. The stated reasons for the initial shutdown were a declining economy and environmental concerns.[1] In 2003, NIPSCO suspended

[1]Direct Testimony of Mark Maassel, page 4, Cause No. 42643.

its plans to start up Mitchell for a variety of reasons, which included the desire of the City of Gary to acquire the site and MISO's evolving energy marketplace dynamics.[2] Industrial customers served under real time pricing Rate 845 and Rider 846 were not necessarily in favor of the Mitchell shutdown due to potential increases in real time prices.

Q DID NIPSCO CLOSE ANOTHER MAJOR GENERATING STATION?

A Yes. On or about June 1, 2018, NIPSCO closed its coal-fired Bailly Generating Station rated at 480 MW. Later in 2018, NIPSCO announced plans to close its remaining coal units as part of its Integrated Resource Plan filed with the IURC; plans which it has discussed at length in this proceeding.

Q WHAT DOES NIPSCO'S ACTIVITY ASSOCIATED WITH ITS COAL-FIRED PLANTS INDICATE?

A NIPSCO has not planned and constructed a base load coal generating facility in approximately 50 years. It has already closed two major facilities and plans to close all remaining coal-fired facilities. NIPSCO's industrial customers do not plan, construct, operate or have decision making authority in the closure of these facilities. It is unreasonable to assert that they are responsible for so-called legacy costs associated with these or the remaining facilities. In addition, it should be noted that NIPSCO's proposed Rate 831 is making it possible to avoid excess new construction.

---

[2] *Id.*, page 13.

Q ARE THERE ANY RESPECTS IN WHICH LARGE INDUSTRIAL CUSTOMERS HAVE MITIGATED THE MAGNITUDE OF NIPSCO'S EXISTING LEVEL OF GENERATION COSTS?

A Yes. Two factors are of particular significance. First, the interruptible service received by industrial customers has reduced the capacity that NIPSCO has needed to build and maintain to meet firm service demand on its system. Second, the cogeneration and self-supply facilities installed by large industrials have similarly offset the need for NIPSCO to construct or procure additional capacity.

Q HAS THE COMMISSION RECOGNIZED THE ROLE OF INTERRUPTIBLE SERVICE IN MITIGATING THE AMOUNT OF CAPACITY THAT NIPSCO HAS NEEDED TO MAINTAIN?

A Yes, repeatedly. In the July 15, 1987 order in Cause No. 38054, at page 76, the Commission noted both the UCC and staff witnesses agreed that interruptible customers "theoretically place no demands on the system for capacity." At page 77 of the same order, the Commission stated that "if some of NIPSCO's customers enter into long-term contracts for interruptible power, NIPSCO can delay the building of generating capacity to serve those customers." Similarly, at pages 67-69 of the December 21, 2011 order in Cause No. 43969, the Commission found that interruptible service provides "benefits to all customers in the form of avoided capital costs for additional generation and lower fuel costs flowing through the FAC" and that such service "protects all of NIPSCO's customers by potentially avoiding the costs to build new generation that would ultimately be recovered through base rates." The same point was reiterated in the July 18, 2016 order in Cause No. 44688, where the Commission stated at page 89 that interruptible service "will continue to be beneficial to all customers over time because NIPSCO will be able to avoid purchases of capacity in the market and/or delay building new generation capacity."

Q WHAT EFFECT HAVE THE SELF-GENERATION FACILITIES INSTALLED BY LARGE INDUSTRIAL CUSTOMERS HAD ON THE AMOUNT OF GENERATION CAPACITY THAT NIPSCO HAS HAD TO CONSTRUCT AND MAINTAIN?

A Much like the impact of the interruptible service that industrial customers have taken, the utilization of self-supply options by NIPSCO's largest customers has substantially reduced the amount of generation capacity required to meet system demand.

Q HOW SUBSTANTIAL IS THE SELF-GENERATION CAPACITY SUPPORTING INDUSTRIAL OPERATIONS BEHIND THE NIPSCO SYSTEM?

A The U.S. Department of Energy maintains a list of combined heat and power installations in Indiana, available at https://doe.icfwebservices.com/chpdb/state/IN. The list is included here as Attachment NP-CA-1. That list shows more than 1,300 MW of installed capacity at industrial plants in NIPSCO territory, including the Whiting Clean Energy facility that was recently designated as a qualifying facility supporting the BP refinery. In the absence of those self-generation facilities, NIPSCO would have had to build or procure a much higher level of capacity to meet system demand.

Q HAS NIPSCO OR ITS AFFILIATES BEEN INVOLVED IN THE CONSTRUCTION OF GENERATING FACILITIES TO SERVE ITS INDUSTRIAL CUSTOMERS?

A Yes. NIPSCO and its then affiliate Primary Energy were involved with planning and providing on-site energy facilities for its major industrial customers in the 1990s. This fact is another reason that the so-called legacy costs are unreasonable. NIPSCO has been aware of the generating capabilities, load additions and load reductions of its customers for decades and presumably has planned accordingly.

Q HOW DO INTERRUPTIBLE SERVICE AND SELF-GENERATION FACILITIES RELATE TO THE PROPOSED TRANSITION CHARGES FOR LEGACY GENERATION COSTS?

A They have both substantially offset and mitigated the amount of generation capacity that NIPSCO has had to construct and maintain. All customer classes have already benefited historically from the resulting reduction in system resources that must be supported in NIPSCO's retail rates. As NIPSCO proceeds with the retirement of its coal-fired generation assets, the unrecovered value remaining on NIPSCO's books is materially smaller than it would have been if NIPSCO in past decades had needed to maintain additional capacity to serve industrial interruptible and self-supply load. NIPSCO's large industrial customers accepted the risks of interruptible service and made the private investment in self-generation. It would be unbalanced and unreasonable to require those same customers to bear added legacy costs, without recognizing and accounting for the avoided costs attributable to interruptible service and self-generation facilities.

Q ARE ALL CUSTOMERS ON THE NIPSCO SYSTEM FREE TO SELF-GENERATE, OTHERWISE REDUCE LOADS, OR LEAVE THE SERVICE TERRITORY, WITHOUT BEING CHARGED DECADES OLD LEGACY COSTS OR A TRANSITION CHARGE?

A Yes. Load reductions should not, and to my knowledge are not, charged legacy costs or transition charges in Indiana absent a specific contractual agreement. The current industrial tariffs typically have a one-year or two-year contract. A forty or fifty year contract is obviously non-existent. If there were such a contractual commitment, the customers would presumably have protection against plant closures. Utility management is charged with the task of planning and operating its system in a cost efficient and reliable manner. Customers should not and do not have that responsibility. The rate structure proposed by NIPSCO reasonably and appropriately balances cost responsibility, load retention and service efficiency objectives. Imposing legacy costs on large industrial customers would negate that balance and frustrate the objectives.

Q THERE ARE CLAIMS THAT THE RATE 831 CUSTOMERS WILL BE SUBSIDIZED BY THE OTHER CUSTOMER CLASSES UNDER NIPSCO'S PROPOSAL. HOW DO YOU RESPOND TO THOSE CLAIMS?

A Several witnesses claim that the Rate 831 customers would be getting a subsidy. This is false. NIPSCO's cost of service study allocates production plant to the Rate 831 customers based on the amount of capacity NIPSCO has estimated they will use. Allocating production plant cost to customers based on the amount they use is cost based ratemaking. It is definitely not creating a subsidy. In fact, NIPSCO's industrial customers have been subsidizing other rate classes for years.

Q HOW LONG HAVE INDUSTRIAL CUSTOMERS PAID RATES SUBSIDIZING OTHER RATE CLASSES?

A For nearly forty years. The Commission implemented a standard calling for cost-based rates in the early 1980s and the subsidy was already in place by that time. In the September 16, 1981 order in Cause No. 36394, at page 24, the Commission found: "[T]he undisputed evidence in this proceeding establishes that the Petitioner's existing rates are producing class rates of return which vary substantially from one another. In other words, some customer classes are subsidizing others." At pages 24-25 of the same order, the Commission presented a table showing relative returns by class. The residential class was providing a 4.14% rate of return, or only 73% of system average, whereas the large industrial class was providing the highest rate of return at 7.46%, or 132% of system average.

Q DID SUBSEQUENT RATE CASE ORDERS CONFIRM THE CONTINUED PRESENCE OF THE INTER-CLASS SUBSIDIES?

A Yes. At page 32 of the August 3, 1983 order in Cause No. 37023, the Commission ordered NIPSCO to assign the authorized rate increase to the different rate classes "in such a way as to reduce the deviation from unity on an index of return basis." In the next rate case, Cause No. 38045, the Commission's July 15, 1987 order noted, at page 79, that the approved increases "will narrow the difference in return on investment between many of the customer classes." NIPSCO did not file another rate case for some 20 years, and the magnitude of the subsidy by that time is shown in Attachments NP-CA-2 and NP-CA-3. The Commission's August 25, 2010 order in that case, at pages 86-87, included an entire section titled "Reduction in Subsidy/Excess Revenues." The next rate case order in Cause No. 43969, on December 21, 2011, limited the rate increases to all rate classes "other than large industrials" to no more than 12%, as stated at page 66. The increase to large industrials, however, was over 20%, as noted at page 71 of the July 18, 2016 order in Cause No. 44688. It was not until the 2016 order in Cause No. 44688 that a concerted effort was made to remove the substantial subsidy paid by the large industrial classes.

Q CAN YOU PROVIDE AN ESTIMATE OF THE HISTORICAL SUBSIDIES PAID BY INDUSTRIAL CUSTOMERS.

A I will start with NIPSCO's 1987 case, brought to increase rates to add Schahfer 18 to rate base. The increase in that case was not based on cost of service but basically implemented on an across-the-board or equal percentage increase by class basis. NIPSCO's next rate case was filed approximately 20 years later. In Cause No. 43526, I presented evidence included as Attachment NP-CA-2 showing that under existing rates, industrial customers were providing an approximate $125 million annual subsidy to other classes. I should note that most large industrial customers were taking service under what, at that time, were Rates 845 and 847, which subjected them to real time prices and to NIPSCO's highest incremental costs. In the same case, the subsidies were also calculated under new rate schedules included as Attachment NP-CA-3 and the subsidy paid by industrial customers was approximately $142 million. Based on a reasonable assumption that the level of subsidy existed for the 20 year duration between rate cases, the total amount of subsidy paid by industrial customers would be $2.85 billion. To be conservative, if it were assumed that the industrial subsidy varied and was only one-half the stated level, it would total $1.4 billion over the 20 year period. However, it is doubtful that the subsidy was lower because in that 20 year duration, a complaint was filed against NIPSCO for excess earnings and the subsidies could easily be higher. Excess earnings are caused by customers paying higher rates than necessary for a utility to earn the return authorized by the Commission. In addition, it is clear that industrials were subsidizing other classes as far back as the 1981 case. In NIPSCO's most recent rate case, Cause No. 44688, I calculated that the industrial subsidy being provided was approximately $31.5 million. Under the current rate structure as shown in Attachment NP-CA-5, the industrial subsidy being provided to other customers is shown as $42.5 million.

Q WHAT IS THE SIGNIFICANCE OF THIS HISTORY?

A It confirms that NIPSCO's large industrial customers consistently paid rates at returns substantially above system average for many decades, providing massive subsidies throughout that period for other customer classes that paid rates at returns significantly below system average. That subsidized rate structure has been recognized by the Commission as a deviation from cost of service principles since at least 1981. While those subsidies were in place, large industrial customers contributed revenue far in excess of their cost-based share for use of NIPSCO's system resources. The excess revenue provided by industrial customers over that period is much greater than the computed legacy costs that Mr. Watkins and other witnesses propose to impose through a transition charge to Rate 831 customers. NIPSCO's large industrial customers have already paid far more than their allocated share of the generation costs in question.

Q ARE YOU AWARE THAT SOME OF THE COMMISSION ORDERS YOU HAVE CITED TO WERE SETTLED PROCEEDINGS?

A Yes, however, I would point out that the portions of those orders on which I rely are factual findings made by the Commission, not separately negotiated agreements of the parties. The orders in both contested and settled cases set forth the history of inter-class subsidies and interruptible service on NIPSCO's system and are not being cited here as precedent.

Q WHAT IS YOUR CONCLUSION REGARDING THE PROPOSAL TO IMPOSE LEGACY COSTS THROUGH A TRANSITION CHARGE ON RATE 831 CUSTOMERS?

A As I discussed above, industrial customers have taken the risk of interruptible service and incurred the costs of self-generation, which has enabled NIPSCO to avoid the cost of serving that load to the benefit of all customers. Consequently, in my opinion, there are no legacy costs associated with the industrials moving to service under Rate 831. In addition, any asserted legacy cost has to be offset by the legacy subsidies paid by industrial customers, which clearly dwarf the claimed $40 - $80 million legacy costs other parties allege. I urge the Commission to reject the concept of legacy costs or a transition charge to customers based on plants constructed 33-45 years ago. No customer should be forced to pay a charge on that basis. I recommend no transition charges for Rate 831 customers.

CAC 5-1 Cost of Service Revision

Q HAVE YOU REVIEWED NIPSCO'S RESPONSE TO CAC 5-1, WHICH IS A COST OF SERVICE UNDER THE ASSUMPTION THE COMMISSION DOES NOT APPROVE THE COMPANY'S PROPOSED CHANGE IN SERVICE STRUCTURE, RATE 831?

A Yes. NIPSCO provided a cost of service study, which did not include the change in service structure to Rate 830 and Rate 831. CAC witness Wallach and Walmart witness Tillman rely on this data response to claim that the cost shift from the reduction in load by the Rate 831 customers is significantly larger than NIPSCO's $40 million calculation. Based on my review, this response is not a valid cost of service study to form conclusions regarding the current industrial class rates of return or conclusions with regard to cost shifting.

Q WHAT PROBLEMS DO YOU HAVE WITH THE COST OF SERVICE IN RESPONSE TO DISCOVERY REQUEST 5-1?

A Initially, the response to the request assumes that the word "charge" really intended to mean "change" (Attachment JFW-4). More importantly, neither the request nor the response specifies or explains the treatment of the significant level of interruptible load that exists on Rates 732, 733 and 734.

The level of interruptible load, which amounts to 528 MW, is the majority of the load that currently exists on these rate classes. How the interruptible load is treated dramatically changes the results of the cost of service study. It is inappropriate to allocate fixed generation investment to interruptible loads as done in the response to CAC 5-1.

Q PLEASE PROVIDE THE CURRENT LEVEL OF INTERRUPTIBLE LOAD ON RATES 732, 733 AND 734.

A Attachment NP-CA-4 is an exhibit from NIPSCO's most recent filing in Cause No. 44155-RA-15. This document shows the exact amount of interruptible load by rate.

Q HAVE YOU CORRECTED THE COST OF SERVICE TO REFLECT THE STATED INTERRUPTIBLE LOAD FOR THESE CLASSES?

A Yes. I used the highest summer coincident peak loads for Rates 732, 733 and 734 less the interruptible loads and information associated with firm contract demands of the largest customers to recalculate a normalized 4 CP allocator. The corrected results are shown in Attachment NP-CA-5 and also compared to the original CAC 5-1 response. The response to CAC-5-1 apparently included as <u>Attachment JFW-8</u> incorrectly allocates firm generation costs to interruptible load and should be given no weight.

Another issue is that the 2017 load data associated with interruptions is not normal or indicative of the 2019 test year. NIPSCO apparently did not find it necessary to interrupt load on 2 of the 4 summer peaks. The loads should be normalized, they were not, which is another reason not to rely on the results of the CAC 5-1 response.

Q WHAT DO YOU CONCLUDE?

A To my knowledge, reliance on the CAC 5-1 cost of service is only used to inflate the claimed so called "cost shift" from $40 million to $80 million. The study is not accurate and should not be relied upon for this assertion.

<u>Response to Mr. Watkins</u>

Q WHAT WAS YOUR DIRECT TESTIMONY RECOMMENDATION WITH RESPECT TO THE ALLOCATION OF PRODUCTION INVESTMENT IN THE COMPANY'S CLASS COST OF SERVICE STUDY?

A In my direct testimony, I agreed with NIPSCO that a four coincident peak ("4 CP") demand method is appropriate for the allocation of production investment. As I further explained in my direct testimony, the summer peak period is the driver on the NIPSCO electric system for system planning, reliability and reserve margin considerations. As a result, I recommended an allocation method (4 CP) which utilizes the four summer peaks of June through September.

Q AFTER REVIEWING MR. WATKINS' DIRECT TESTIMONY, DO YOU CONTINUE TO RECOMMEND A COINCIDENT DEMAND ALLOCATION OF PRODUCTION INVESTMENT COSTS IN THE COMPANY'S CLASS COST OF SERVICE STUDY?

A Yes.

Q MR. WATKINS AT PAGE 26 COMPARES 4-CP ALLOCATION PERCENTAGES FROM NIPSCO'S LAST CASE TO THOSE USED IN THIS CASE AND STATES THAT THE RESTRUCTURING PLAN GREATLY REDUCES THE LARGE INDUSTRIALS' ALLOCATION OF GENERATION-RELATED COSTS. IS THE COMPARISON PROBLEMATIC?

A Yes. The allocation percentages are derived from the coincident loads placed on the NIPSCO electric system by the various customer classes. The four summer coincident peak loads are used because of cost causation associated with NIPSCO's fixed generation related cost. The comparison is problematic for two significant reasons.

First, the loads in the current case are reduced because of the loss of a large amount of firm BP load as explained by NIPSCO. Second, the loads used in Cause No. 44688 inappropriately contain interruptible loads. Fixed generation related costs should not be allocated on the basis of interruptible load. The allocation percentages in the current case are based on only firm loads. A valid comparison should adjust for the loss of BP firm load and also remove interruptible load. Mr. Watkins comparison does not.

Q WHAT DID MR. WATKINS CONCLUDE WITH RESPECT TO AN APPROPRIATE METHOD FOR ALLOCATING THE COMPANY'S PRODUCTION INVESTMENT?

A Mr. Watkins rejects the Company's allocation of production investment based on the 4 CP method. Beginning at page 10 of his direct testimony, Mr. Watkins opines as to the strengths and weaknesses of several cost allocation methods that are used to allocate the costs of production investment to rate classes.

At page 35 of his direct testimony, Mr. Watkins opines that the Base, Intermediate and Peak ("BIP") and the Peak & Average ("P&A") cost allocation methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. Mr. Watkins states that he has also given consideration to the 12 CP method to allocate generation plant.

Q DOES MR. WATKINS MAKE A SPECIFIC RECOMMENDATION WITH RESPECT TO THE ALLOCATION OF PRODUCTION INVESTMENT COSTS IN THE COMPANY'S CLASS COST OF SERVICE STUDY?

A Mr. Watkins conducted several alternative class cost of service studies using the BIP, P&A and 12 CP allocation methods. He concludes that in the interest of moderation, the use of the 12 CP method in conjunction with an appropriate transition charge for Rate 831 customers would result in reasonable rates.

Q DO YOU AGREE WITH MR. WATKINS CONCLUSIONS AND FINDINGS WITH RESPECT TO THE ALLOCATION OF PRODUCTION INVESTMENT COSTS?

A No, I do not. Due to their heavy reliance on class energy use for allocating production-related investment, the BIP and P&A methods do not best reflect cost causation on the Company's system. The 12 CP method also does not properly reflect cost causation on NIPSCO's system. I will address each of these methods below.

Q TO YOUR KNOWLEDGE, HAS THE COMMISSION PREVIOUSLY CLASSIFIED AND ALLOCATED PRODUCTION INVESTMENT COSTS ON AN ENERGY BASIS?

A No. I am not familiar with any orders issued by the IURC that would support the classification and allocation of production investment costs on an energy basis. Although over the years the OUCC has presented different witnesses with different approaches to inappropriately classify demand-related production investment on the basis of energy, that approach has been consistently rejected in the past and it should continue to be rejected in this proceeding.

Mr. Watkins attempts to justify his emphasis on energy allocations by discussing the high capital costs of coal and nuclear plants presumably to produce lower energy costs. This analysis suffers from a "time-warp." In the current time frame, no nuclear or coal plants are considered as viable options. Combined cycle gas-fired units have both lower capital and energy costs than coal or nuclear plants and, as such, Mr. Watkins' justification is meaningless.

Q WHAT IS THE BIP METHOD?

A The BIP method classifies and assigns individual generating assets based on their specific role in a utility's generation portfolio. Under the BIP method, typically "Base" load units are classified and allocated on energy, "Intermediate" units are classified and allocated based on their capacity factor, and "Peak" units are classified and allocated on peak demand.

Q IS THE BIP METHOD A REASONABLE COST ALLOCATION METHOD TO USE?

A No, it is not. Mr. Watkins has not demonstrated that there is a clear cost-causation relationship between the BIP methodology, customers' loads, and NIPSCO's resource planning. Utilities identify a need for new generation resources when generating capacity is needed to meet peak day demands and capacity reserves.

The reserve margin requirements are tied to contribution to the Company's highest peak demands in the year. The generation resource ultimately selected would be the lowest cost resource available to meet that need for additional peak day capacity.

The BIP methodology fails to reflect cost causation because factors like fuel cost, technological obsolescence and environmental requirements can change significantly, distorting the dispatch order of the generating resources over time. Changes in these factors can change the designation of units as Base or Intermediate, affect the economic utilization of the plant or be distorted by the addition of new plants that produce a different generation mix.

The BIP methodology ignores all these significant events that distort the dispatch arrangement and the designation of Base, Intermediate or Peak nature of NIPSCO's resources over time. The BIP methodology simply does not reflect the reality of NIPSCO's planning, the reality of how resources dispatch or change over time, and does not accurately assign the resource costs between classes in proportion to class demands for service.

Q ARE THERE ANY OTHER PROBLEMS WITH THE BIP METHODOLOGY?

A Yes. The BIP method allocates production plant associated with Base, Intermediate and Peak production costs using the BIP designations. However, the BIP method allocates all fuel costs on the basis of average energy cost and total energy usage. As such, the BIP method is internally inconsistent in allocating production plant investment on the basis of BIP units but allocating the fuel costs associated with the BIP units without regard to the Base, Intermediate and Peak designations.

Q WHY IS THIS UNREASONABLE?

A The BIP method essentially averages energy costs and allocates those across customer classes based on only energy usage. However, to be consistent with the BIP method for allocating fixed costs, customer classes should receive an allocation of the energy costs from the BIP resources that are allocated to them. For example, customers that are allocated a larger percentage of Base generating resource fixed costs should benefit from receiving a higher allocated share of the lower energy cost produced through the Base units. Customers that are allocated a higher percentage of peak costs should pay the higher energy costs derived from peaking units because they pay a lower allocated share of base capacity costs.

This more balanced methodology would ensure that customers that pay higher capital costs for base units benefit by receiving the lower energy costs produced by those units. Conversely, customers assigned the fixed costs for a cheaper combination of Base, Intermediate and Peak units should be assigned higher energy costs associated with the fuel cost produced by the higher cost mix of resources.

However, the BIP method fails to be consistent in allocating costs. Mr. Watkins' proposal to use the BIP method to allocate energy on an average basis across all customers creates an economic detriment to customers that largely contribute to the cost of Base generation resources. His proposal also provides a subsidy to customers that require less Base generation but more Intermediate and Peak facilities and, more fundamentally, as discussed previously, the BIP method does not accurately reflect cost causation on NIPSCO's system.

Q WHAT IS THE P&A METHOD?

A The P&A method assigns production investment costs partially on the basis of contributions to peak demand and partially on the basis of energy consumption through the year.

Q IS THE P&A METHOD A REASONABLE COST ALLOCATION METHOD TO USE?

A No, it is not. Because the system load factor is used to weight the peak and average components of the P&A allocator, this allocation method gives essentially equal weighting to annual energy consumption and the contribution to system peaks used in the allocation of the investment in production facilities. Because generation facilities must be designed to carry peak loads, the roughly equal weighting to energy consumption in the allocation factor is not related to cost of service at all.

Q IS IT EVER REASONABLE TO ALLOCATE A PORTION OF BASE LOAD FIXED PLANT INVESTMENT ON THE BASIS OF ENERGY USAGE?

A No. Base load generation facilities must be designed to carry the peak loads imposed on them. Weighting roughly half of the allocation factor on an energy basis is thus not related to cost of service at all and will force high load factor classes to subsidize low load factor classes. This not only is unfair, but it also provides poor price signals to customers.

Q WHAT IS THE TYPICAL ARGUMENT GIVEN FOR THE USE OF THE P&A METHOD?

A Generally, those who endorse the use of an energy allocator argue that it reflects resource planning because it accounts for both the system coincident peak and the average demand. Typically, the argument for using an allocation method that includes energy is because this method assumes the electric utility will invest in more expensive types of generating capacity solely because of lower fuel costs associated with that capacity. As a result, this argument assumes a substitution of capital investment for fuel cost. This assumption can be referred to as a capital substitution method.

Q GENERALLY, WHAT ARE THE FLAWS WITH THE USE OF A PRODUCTION PLANT ALLOCATION METHOD BASED ON BOTH ENERGY AND DEMAND?

A The basic flaws of utilizing such a method are:

1. Such an allocation method is an over-simplification of the utility planning process.
2. An allocation method for a production plant that includes a component for energy, if viewed as a capital substitution method, fails to appropriately recognize the trade-offs between capital and operating costs. This is sometimes referred to as a fuel symmetry problem.

Q DO UTILITY PLANNERS CONSTRUCT MORE CAPITAL-INTENSIVE CAPACITY FOR THE SOLE PURPOSE OF REDUCING FUEL COSTS?

A No. The belief that they do is based on an oversimplification of the planning process. In reality, planners are faced with balancing the provision of reliable service and minimizing total costs.

Utilities are required to minimize total costs, i.e., provide service at the lowest reasonable overall cost. The utility strives to install a mix of generating capacity that, along with its existing generation, yields the lowest total cost. In other words, the economic choice between a base load plant and a peaking plant must account for both capital costs and operating costs.

The utility's investment decisions can also be affected by existing generation mix, the availability of a suitable site for the plant, environmental restrictions and fuel diversification.

Q HOW DOES AN ALLOCATION METHOD THAT UTILIZES ENERGY FOR ALLOCATING PRODUCTION PLANT, AS A CAPITAL SUBSTITUTION METHOD, FAIL TO PROVIDE A SYMMETRICAL ALLOCATION OF BOTH CAPITAL AND OPERATING COSTS?

A Such an allocation method focuses on the allocation of fixed production costs. For example, the P&A allocation method allocates more production plant to high load factor classes than the coincident peak allocation method. This result is claimed to be fair by proponents of allocation methods for production plants that include energy, because high load factor customers require more base load capacity and because the capital cost of base load units tends to be higher than peaking plants. However, an energy allocation method, as applied, makes no attempt to recognize the other side of the capital cost/operating cost trade-off. Base load plants may have higher capital costs, but they also have below average fuel costs relative to peaking units. To ignore the fuel cost differential creates a mismatch between the theory and application. If the P&A system planning principles are to be applied in determining the allocation of production plant, it is also logical and consistent to apply the same principles to the allocation of fuel expense.

Q DO YOU HAVE ANY DISAGREEMENT WITH THE ALLOCATION OF FUEL AND VARIABLE PURCHASED POWER COSTS ON THE BASIS OF ENERGY?

A In the context of traditional studies like coincident peak, I do not. However, in the context of the P&A method, which heavily weights energy on the allocation of fixed or demand-related generation costs, it is not appropriate.

Q PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO ALLOCATE VARIABLE ENERGY COSTS IN THIS FASHION WHEN USING A P&A APPROACH.

A The P&A method allocates significantly more generation fixed costs to high load factor customers than do the traditional coincident peak studies. In other words, the higher the load factor of a class, the larger the share of the generation fixed costs that gets allocated to the class. If the costs allocated to classes under these methods were divided by the contribution of these classes to the system peak demand, the result is a higher capital cost per kW for the higher load factor classes, and a lower capital cost per kW for the low load factor classes. Effectively, this means that the high load factor classes have been allocated an above-average share of capital cost for generation, and the low load factor customer classes have been allocated a below average share of capital costs.

Given these allocations of capital cost, it would not be appropriate to use the same fuel cost for all classes. Rather, the fuel cost allocation should recognize that the higher load factor customer classes should receive below average fuel cost to correspond to the above-average capital cost (similar to base load units) allocated to them, and the lower load factor classes should get an allocation of fuel cost that is above the average, corresponding to the lower than average capital cost allocated to them.

Q WHY WOULD IT BE APPROPRIATE TO RECOGNIZE A LOWER FUEL COST ALLOCATION TO THOSE CLASSES THAT ARE ALLOCATED A HIGHER CAPITAL COST?

A It is not only appropriate, but it is essential if the heavily energy-weighted P&A method allocation of generation costs is employed. Failure to make this kind of distinction would give high load factor customers the worst of both worlds – above-average capital costs and average fuel costs; and the low load factor customers the best of both worlds – below average capital costs and average fuel costs. This Commission has rejected the peak and average method before and it should continue to reject it here. Mr. Watkins presents nothing new to this issue.

Q WHAT IS THE 12 CP METHOD?

A A 12 CP method uses the average of each monthly peak for production cost allocation. A method that uses the average of the 12 monthly peaks is only appropriate for a utility system with a flat load pattern in which each of the monthly coincident peaks is relatively equal.

The average of the 12 CP method is not reflective of NIPSCO's current or projected loads. Since the summer peak period is critical on the NIPSCO electric system, an allocation method which utilizes the four summer peaks of June through September best reflects production cost causation on the NIPSCO system. Also, it is important to recognize that many of the 12 monthly peaks contained buy-through loads by customers taking interruptible service under Rider 775. Those buy through loads should not be used to allocate production investment to classes because NIPSCO has not planned or built its generation for those interruptible loads and the customers utilizing buy through are obtaining the power from the market.

Q WHAT BEST REFLECTS COST CAUSATION ON THE COMPANY'S SYSTEM WITH RESPECT TO PRODUCTION INVESTMENT?

A Because peak production facilities must be designed to carry the peak loads imposed on them, an allocation that uses peak demands best reflects cost causation. I continue to recommend that the 4 CP method be used to allocate the Company's production investment costs.

Q PLEASE COMMENT ON MR. WATKINS' CONCERN REGARDING THE STREET LIGHTING LOADS.

A Mr. Watkins' uses street lighting loads as an example of the flaws with a 1 CP methodology, noting that street lights may not be on during a peak period and not be allocated production plant.. Mr. Watkins' concern is not valid. NIPSCO is not proposing a 1 CP methodology. However, if a class is off-peak, it should not be allocated cost. A method should not be selected to achieve an end result, but because it reflects the loads and planning of the system. The 4 CP method reflects the actual planning and operation of the NIPSCO electric system and should be adopted.

Q DOES MR. WATKINS AGREE WITH THE COMPANY'S PROPOSED CLASS REVENUE ALLOCATION?

A Yes, with an additional increase to Rate 831. Ironically, it appears that the residential class is being subsidized under all of the cost of service studies presented by Mr. Watkins. Mr. Watkins does not follow the results of his cost studies regarding the residential rate increase.

Q HOW DOES MR. WATKINS PROPOSE TO ALLOCATE REVENUES TO THE COMPANY'S CLASSES?

A In developing his proposed class revenue distribution, Mr. Watkins has basically considered Mr. Gaske's approach with some additional costs to Rate 831. The various studies presented by Mr. Watkins are not used for the overall revenue allocation to classes. However, Mr. Watkins recommends that either the BIP, P&A or 12 CP methodology should be used for Rate 831 customers plus a transition charge. Watkins Direct at 37. To support his 12 CP recommendation, Mr. Watkins relies on the Commission's order in Cause No. 43526. However, he fails to mention that in approving a 12 CP allocation the Commission also found that all subsidies should be removed. Cause No. 43526, page 87. The residential subsidy is not addressed by Mr. Watkins and would continue under his approach. I recommend the Commission reject the use of a 12 CP allocation methodology.

Q DOES THIS CONCLUDE YOUR CROSS-ANSWERING TESTIMONY?

A Yes, it does.

\\consultbai.local\documents\ProlawDocs\MED\10697\Testimony-BAI\362080.docx

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	**CAUSE NO. 45159**

Verification

I, Nicholas Phillips, Jr., a Consultant and Managing Principal of Brubaker & Associates, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Nicholas Phillips, Jr.

Nicholas Phillips, Jr.
3/15/2019

U.S. DOE Combined Heat and Power Installations in Indiana

Search:

City	Organization Name	Facility Name	Application	SIC4	NAICS	Op Year	Latest Install Year	Capacity (KW)	Prime Mover	Fuel Class-Primary Fuel	Last Verified
Burns Harbor	ArcelorMittal	Burns Harbor Plant	Primary Metals	3312	331111	1969	1969	177,720	B/ST	WASTE - Blast Furnace Gas	2018
Crown Point	Franciscan Health	St. Anthony's Medical Center CI	Hospitals	8062	62211	1990	1990	2,748	CC	NG - Natural Gas	1989
Culver	Culver Educational Foundation	Culver Educational Foundation Facility / Culver Military Academy CI	Schools	8299	611699	1996	1996	1,050	ERENG	NG - Natural Gas	1998
Decatur	Central Soya Company, Inc.	Central Soya Decatur Plant	Food Processing	2075	311222	1950	1950	2,000	B/ST	COAL - Coal	2014
East Chicago	ArcelorMittal / Primary Energy	Indiana Harbor Works / Ironside Energy	Primary Metals	3312	331111	2002	2002	50,000	B/ST	WASTE - Blast Furnace Gas	2018
East Chicago	ArcelorMittal / SunCoke Energy / Primary Energy	Indiana Harbor Works / Cokenergy	Primary Metals	3312	331111	1998	1998	95,000	Other WHP*	WASTE - Waste Heat	2018
East Chicago	ArcelorMittal / Primary Energy	Indiana Harbor Works / North Lake Energy	Primary Metals	3312	331111	1996	2015	90,000		WASTE - Steam	2018
East Chicago	ArcelorMittal	Indiana Harbor Works	Primary Metals	3312	331111	1939	2002	135,000	B/ST	WASTE - Blast Furnace Gas	2015
Fair Oaks	Fair Oaks Dairy	Fair Oaks Dairy	Agriculture	241	11212	2008	2008	1,050	ERENG	BIOMASS - Digester Gas	2017
Fair Oaks	Hidden View Dairy	Hidden View Dairy	Agriculture	241	11212	2007	2007	950	ERENG	BIOMASS - Digester Gas	2017
Fair Oaks	Boss #4 Dairy	Fair Oaks Dairy - 2	Agriculture	241	11212	2005	2005	700	ERENG	BIOMASS - Digester Gas	2016
Fair Oaks	Herrema Dairy	Herrema Dairy	Agriculture	241	11212	2004	2004	800	ERENG	BIOMASS - Digester Gas	2017
Fishers	Loftus Robinson	The Flats at Switch	Multi-Family	6513	53111	2016	2016	135	ERENG	NG - Natural	2017

City	Organization Name	Facility Name	Application	SIC4	NAICS	Op Year	Latest Install Year	Capacity (KW)	Prime Mover	Fuel Class-Primary Fuel	Last Verified
Fishers	Loftus Robinson	The Flats at Switch	Multi-Family Buildings	6513	53111	2016	2016	135	ERENG	NG - Natural Gas	2017
Fort Wayne	City of Fort Wayne	Fort Wayne Wastewater Treatment Plant CI	Wastewater Treatment	4952	22132	2015	2015	800	ERENG	BIOMASS - Digester Gas	2018
Fort Wayne	General Motors	Fort Wayne Assembly Plant	Transportation Equip.	3711	336111	2014	2014	14,000	ERENG	BIOMASS - Landfill Gas	2015
Gary	Lakeside Energy	US Steel - Gary Works	Primary Metals	3312	331111	1996	1996	161,000	B/ST	WASTE - Blast Furnace Gas	2014
Greensburg	Kroger	K.B. Specialty Foods	Food Sales	5149	42449	2018	2018	600	ERENG	BIOMASS - Digester Gas	2019
Hammond	Cargill, Inc.	Cargill - Cerestar	Food Processing	2046	311221	2000	2000	16,000	B/ST	NG - Natural Gas	1990
Indianapolis	Citizens Thermal Energy	Perry K Steam Plant	District Energy	4961	22133	2009	2009	3,400	B/ST	NG - Natural Gas	2017
Indianapolis	Energy Group Inc	Covanta Indianapolis Inc	Solid Waste Facilities	4953	562212	1988	1988	6,500	B/ST	WASTE - Municipal Solid Waste	2017
Indiannapolis	Rolls Royce Corp	Rolls Royce Corp	Transportation Equip.	3724	336111	1999	2000	13,000	CT	NG - Natural Gas	2015
Lafayette	Tate & Lyle Ingredients Americas	Sagamore Cogeneration Plant	Food Processing	2046	311221	1985	1985	7,400	B/ST	COAL - Coal	2014
Lafayette	Caterpillar Tractor Company	Caterpillar Tractor Company	Machinery	3519	333618	1980	1980	3,500	ERENG	OIL - Oil	1990
Marion	Marion Municipal Utilities	Marion Wastewater Treatment Plant CI	Wastewater Treatment	4952	22132	2016	2016	225	ERENG	BIOMASS - Digester Gas	2017
Middlebury	2G Energy	Culver Duck Farm	Food Processing	2015	311615	2013	2013	1,200	ERENG	BIOMASS - Digester Gas	2019

Search:

City	Organization Name	Facility Name	Application	SIC4	NAICS	Op Year	Latest Install Year	Capacity (KW)	Prime Mover	Fuel Class-Primary Fuel	Last Verified
Mishawaka	Stripco Inc / NiSource Inc.	Stripco Inc	Primary Metals	3312	331111	2003	2009	120	MT	NG - Natural Gas	2003
Monticello	Waste No Energy	Waste No Energy Digester	Agriculture	241	11212	2013	2013	1,059	ERENG	BIOMASS - Digester Gas	2017
Mount Vernon	SABIC Innovative Plastics	SABIC Mount Vernon	Rubber & Plastics	3081	326113	2014	2017	86,500	B/ST	NG - Natural Gas	2017
Munster	Munster Landfill	Munster Landfill	Solid Waste Facilities	4953	562212	2009	2009	130	MT	BIOMASS - Landfill Gas	2009
Munster	Town of Munster	Centenial Park	Amusement / Recreation	7990	71399	2008	2008	130	MT	BIOMASS - Biomass	2008
Newburgh	Alcoa Generating Corporation	Alcoa Smelting & Fabrication	Primary Metals	3341	331314	1960	1970	800,200	B/ST	COAL - Coal	2015
Notre Dame	University of Notre Dame	University of Notre Dame Power Plant CI	Colleges / Universities	8221	61131	1952	2000	23,100	B/ST	COAL - Coal	2016
Portage	US Steel / Primary Energy	US Steel Midwest Plant / Portside Energy	Primary Metals	3312	331111	1997	1997	63,000	CC	NG - Natural Gas	2018
Reynolds	Bio Town Ag, Inc.	Bio Town Ag, Inc.	Agriculture	241	11212	2011	2016	6,477	ERENG	BIOMASS - Digester Gas	2017
South Bend	University of Notre Dame	Energy Center in Stinson-Remick Hall CI	Colleges / Universities	8221	61131	2009	2009	30	MT	NG - Natural Gas	2009
Terra Haute	Indiana State University	Indiana State University CI	Colleges / Universities	8221	61131	2001	2001	14,000	CT	NG - Natural Gas	2016
Walton	Lewis Cass High School	Lewis Cass High School CI	Schools	8211	61111	1968	1968	1,750	ERENG	NG - Natural Gas	1990
West Lafayette	West Lafayette Wastewater Treatment Facility	West Lafayette Wastewater Treatment Facility CI	Wastewater Treatment	4952	22132	2009	2009	130	MT	BIOMASS - Digester Gas	2009

City	Organization Name	Facility Name	Application	SIC4	NAICS	Op Year	Latest Install Year	Capacity (KW)	Prime Mover	Fuel Class-Primary Fuel	Last Verified
Mount Vernon	SABIC Innovative Plastics	SABIC Mount Vernon	Rubber & Plastics	3081	326113	2014	2017	86,500	B/ST	NG - Natural Gas	2017
Munster	Munster Landfill	Munster Landfill	Solid Waste Facilities	4953	562212	2009	2009	130	MT	BIOMASS - Landfill Gas	2009
Munster	Town of Munster	Centenial Park	Amusement / Recreation	7990	71399	2008	2008	130	MT	BIOMASS - Biomass	2008
Newburgh	Alcoa Gererating Corporation	Alcoa Smelting & Fabrication	Primary Metals	3341	331314	1960	1970	800,200	B/ST	COAL - Coal	2015
Notre Dame	University of Notre Dame	University of Notre Dame Power Plant CI	Colleges / Universities	8221	61131	1952	2000	23,100	B/ST	COAL - Coal	2016
Portage	US Steel / Primary Energy	US Steel Midwest Plant / Portside Energy	Primary Metals	3312	331111	1997	1997	63,000	CC	NG - Natural Gas	2018
Reynolds	Bio Town Ag, Inc.	Bio Town Ag, Inc.	Agriculture	241	11212	2011	2016	6,477	ERENG	BIOMASS - Digester Gas	2017
South Bend	University of Notre Dame	Energy Center in Stinson-Remick Hall CI	Colleges / Universities	8221	61131	2009	2009	30	MT	NG - Natural Gas	2009
Terra Haute	Indiana State University	Indiana State University CI	Colleges / Universities	8221	61131	2001	2001	14,000	CT	NG - Natural Gas	2016
Walton	Lewis Cass High School	Lewis Cass High School CI	Schools	8211	61111	1968	1968	1,750	ERENG	NG - Natural Gas	1990
West Lafayette	West Lafayette Wastewater Treatment Facility	West Lafayette Wastewater Treatment Facility CI	Wastewater Treatment	4952	22132	2009	2009	130	MT	BIOMASS - Digester Gas	2009
West Lafayette	Purdue University	Wade Power Plant CI	Colleges / Universities	8221	61131	1969	2000	43,200	B/ST	COAL - Coal	2014
Whiting	BP Amoco Chemicals Company	Whiting Refinery / Whiting Clean Energy	Petroleum Refining	2911	32411	1948	2002	660,600	CC	NG - Natural Gas	2017

Exhibit NP-1
Schedule 1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Rate of Return, Index and Subsidies for 800 Series Rate Classes

Line	Rate Class	Rate Base (000)	Net Operating Income (000)	Rate of Return	Index	Subsidy[1] (000)
		(1)	(2)	(3)	(4)	(5)
1	811	$ 1,060,555	$ 21,509	2.03%	23	$ (121,914)
2	812	9,313	487	5.22%	60	(561)
3	813	3,125	68	2.18%	25	(351)
4	820	1,754	(198)	-11.31%	(129)	(602)
5	821	311,619	34,047	10.93%	125	11,690
6	822	2,960	35	1.19%	14	(383)
7	823	305,492	18,973	6.21%	71	(13,223)
8	824	281,174	24,957	8.88%	102	671
9	817	1,274	(129)	-10.11%	(116)	(411)
10	825	24,914	1,136	4.56%	52	(1,782)
11	826	86,014	6,203	7.21%	83	(2,248)
12	832	8,662	1,160	13.39%	153	691
13	833	76,565	6,045	7.89%	90	(1,104)
14	836	32,013	1,783	5.57%	64	(1,738)
15	841	10,746	(212)	-1.98%	(23)	(1,973)
16	842	11	16	143.36%	1,641	26
17	844	3,645	506	13.88%	159	321
18	845	62	150	240.47%	2,752	248
19	847	417,613	110,556	26.47%	303	126,924
20	848	-	3,579	0.00%	--	6,133
21	2100	503	962	191.14%	2,188	1,573
22	550	9,301	1,847	19.86%	227	1,772
23	555	4,032	(87)	-2.15%	(25)	(752)
24	560	4,655	(208)	-4.46%	(51)	(1,053)
25	Interdept'l	9,419	(318)	-3.37%	(39)	(1,954)
26	Total	$ 2,665,422	$ 232,868	8.74%	100	$ (0)

[1] A negative number indicates the amount of subsidy a class is receiving.
A positive number indicates the amount of subsidy a class is providing.

Exhibit NP-2
Schedule 1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Rate of Return, Index and Subsidies for 500 Series Rate Classes at NIPSCO Present Revenue Requirement Level

Line	Rate Class	Rate Base (000)	Net Operating Income (000)	Rate of Return	Index	Subsidy[1] (000)
		(1)	(2)	(3)	(4)	(5)
1	511	$ 1,102,013	$ 19,018	1.73%	20	$ (132,388)
2	521	90,822	13,522	14.89%	170	9,574
3	523	406,262	32,787	8.07%	92	(4,638)
4	526	25,868	886	3.43%	39	(2,354)
5	527 & 534	403,369	114,022	28.27%	324	134,996
6	533	520,259	40,434	7.77%	89	(8,601)
7	536	73,446	10,794	14.70%	168	7,500
8	541	11,345	(249)	-2.20%	(25)	(2,126)
9	544	3,672	502	13.68%	157	311
10	550	11,587	1,611	13.90%	159	1,026
11	555	1,480	182	12.32%	141	91
12	560	5,283	(273)	-5.16%	(59)	(1,258)
13	Interdept'l	10,014	(369)	-3.69%	(42)	(2,132)
14	Total	$ 2,665,422	$ 232,868	8.74%	100	$ 0

[1] A negative number indicates the amount of subsidy a class is receiving.
A positive number indicates the amount of subsidy a class is providing.

Northern Indiana Public Service Company
Adjusted Demand Allocators

Cause No. 44155-RA-15
Attachment B

	Demand Allocators - Production Rate Base	% of Total	**12 CP**	Rider 775 Interruptible Contract Demand	Customer Migration	12 CP adjusted for Interruptible Contract Demand and Customer Migration	Demand Allocators - Production Rate Base adjusted for Interruptible Contract Demand	% of Total
Rate 711	$ 888,424,094	27.47%	623,160		-	623,159.54	$ 1,156,578,846	35.76%
Rate 720	2,460,930	0.08%	1,726		-	1,726.15	3,203,717	0.10%
Rate 721	321,313,655	9.93%	225,376		6,225	231,600.94	429,849,391	13.29%
Rate 722	3,167,196	0.10%	2,222		-	2,221.54	4,123,157	0.13%
Rate 723	353,286,107	10.92%	247,802		422	248,224.71	460,702,974	14.24%
Rate 724	381,527,692	11.80%	267,612		(46,900)	220,711.91	409,639,433	12.66%
Rate 725	10,357,175	0.32%	7,265		7,940	15,205.19	28,220,711	0.87%
Rate 726	149,042,043	4.61%	104,541		17,098	121,639.27	225,761,455	6.98%
Rate 732	486,895,971	15.05%	341,519	(235,884)	3,953	109,587.90	203,394,212	6.29%
Rate 733	359,680,007	11.12%	252,287	(108,898)	11,262	154,650.70	287,030,401	8.87%
Rate 734	258,398,965	7.99%	181,247	(182,994)	-	-	-	0.00%
Rate 741	4,083,935	0.13%	2,865		-	2,864.56	5,316,597	0.16%
Rate 742	40,353	0.00%	28		-	28.30	52,533	0.00%
Rate 744	3,382,779	0.10%	2,373		-	2,372.75	4,403,810	0.14%
Rate 750	3,183,659	0.10%	2,233		-	2,233.09	4,144,589	0.13%
Rate 755	1,792,941	0.06%	1,258		-	1,257.61	2,334,107	0.07%
Rate 760	873,080	0.03%	612		-	612.40	1,136,604	0.04%
Interdepartmental	6,685,997	0.21%	4,690		-	4,689.70	8,704,044	0.27%
	$ 3,234,596,580	100.00%	2,268,815		-	1,742,786.26	$ 3,234,596,580	100.00%

NIPSCO Class Cost of Service Study

Comparison of Cost-of-Service Results under
NIPSCO's CAC 5.1 Study and IG Revised CAC 5-1*
for Rates 732, 733 and 734

		PRESENT RATES			
		NIPSCO CAC 5.1		IG Revised CAC 5.1	
Line	Rate Class	Rate of Return (1)	Subsidy (000) (2)	Rate of Return (3)	Subsidy (000) (4)
1	Rate 732	1.85%	$ (24,841)	6.53%	$ 8,072
2	Rate 733	5.37%	$ 1,638	10.76%	$ 17,599
3	Rate 734	2.78%	$ (12,425)	10.16%	$ 16,854
4	Total	3.00%	$ (35,628)	8.67%	$ 42,525
5	System Total	5.00%	$ -	5.00%	$ -

*IG COS study revised to use "firm only" loads for the Rate classes 732, 733 & 734.