ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	CAUSE NO. 44688 APPROVED: JUL 18 2016

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
James F. Huston, Commissioner
David E. Veleta, Administrative Law Judge

On October 1, 2015, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition for General Rate Increase and Associated Relief Under Indiana Code §§ 8-1-2-61 and 8-1-2-42.7, Notice of Provision of Information Required by the Commission's Minimum Standard Filing Requirements and Request for Administrative Notice with the Indiana Utility Regulatory Commission ("Commission"). NIPSCO provided testimony and exhibits from the following witnesses:

- Curt A. Westerhausen, Director of Rates and Contracts with NIPSCO
- David Joseph Mays, Manager of Rates and Contracts with NIPSCO
- J. Stephen Gaske, Senior Vice President of Concentric Energy Advisors, Inc. ("Concentric")
- Bickey Rimal, Senior Consultant with Concentric
- William Gresham, Manager of Demand Forecasting, NiSource Corporate Services Company ("NCSC")
- Christopher D. Smith, Vice President of Human Resources with NCSC
- Susanne M. Taylor, Director TSA Financials & Governance with NCSC

- Derric J. Isensee, Executive Director of Rates and Regulatory Finance with NIPSCO
- Daniel T. Williamson, Executive Director of Energy Supply and Trading with NIPSCO
- Kelly R. Carmichael, Vice President, Environmental with NCSC
- Michael Hooper, Senior Vice President, Electric Operations with NIPSCO
- Frank A Shambo, Vice President, Regulatory and Legislative Affairs with NIPSCO
- Violet Sistovaris, Executive Vice President with NIPSCO
- Ann E. Bulkley, Vice President with Concentric
- Paul R. Moul, Managing Consultant, P. Moul & Associates
- Vicent V. Rea, Director, Regulatory Finance and Economics with NCSC
- Michael D. McCuen, Director of Income Taxes with NCSC
- John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants, LLC
- Victor Ranalletta, Associate Engineer and Manager of the Energy Division in the Chicago Regional Office of Burns & McDonnell Engineering Co., Inc. ("BMD")
- Alan Felsenthal, Certified Public Accountant and a Managing Director at PricewaterhouseCoopers LLP

Petitions to intervene were granted to the following parties, without objection:

- NIPSCO Industrial Group.
- United States Steel Corporation ("U.S. Steel")
- Citizens Action Coalition of Indiana ("CAC")
- Indiana Municipal Utilities Group ("IMUG")
- NLMK, Indiana ("NLMK")
- Wal-Mart Stores East, LP and Sam's East, Inc. ("Walmart")
- LaPorte County Board of Commissioners ("LaPorte")
- Praxair
- Environmental Law & Policy Center ("ELPC")

On November 18, 2015, the Commission established a procedural schedule for this proceeding. Additionally, on November 18, 2015, the Commission conducted a Technical Conference in this proceeding. The Commission conducted a public field hearing in this proceeding on December 14, 2015. At the field hearing, members of the public offered comments to the Commission.

The Indiana Office of Utility Consumer Counselor ("OUCC") provided testimony and exhibits from the following witnesses:

- Lafayette Morgan, Jr., Public Utilities Consultant, Exeter Associates, Inc. ("Exeter")
- Dwight D. Etheridge, Principal and Vice President with Exeter
- Wes R. Blakley, Senior Utility Analyst
- Stacie R. Gruca, Senior Utility Analyst
- Michael D. Eckert, Senior Utility Analyst

- Margaret A. Stull, Senior Utility Analyst
- J. Randall Woolridge, Professor of Finance, Goldman Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of Pennsylvania State University
- Glenn A. Watkins, Principal and Senior Economist with Technical Associates, Inc.
- Eric M. Hand, Utility Analyst
- Edward T. Rutter, Utility Analyst
- Cynthia M. Armstrong, Senior Utility Analyst

LaPorte provided testimony and exhibits from the following witness:

- Reed W. Cearley

The CAC and ELPC provided testimony and exhibits from the following witnesses:

- Karl R. Rábago, Principal with Rábago Energy Limited Liability Company
- John Howat, Senior Policy Analyst with National Consumer Law Center ("NCLC")

IMUG provided testimony and exhibits from the following witnesses:

- Theodore Sommer, a Partner with London Witte Group, LLC
- Dr. Robert Kramer, Purdue University, Professor of Physics, NiSource Charitable Foundation Professor of Energy and the Environment, and Director of the Energy Efficiency and Reliability Center

NIPSCO Industrial Group provided testimony and exhibits from the following witnesses:

- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. ("Brubaker")
- Brian C. Andrews, Consultant with Brubaker
- James R. Dauphinais, Consultant and a Managing Principal with Brubaker
- Nicholas Phillips, Jr., Managing Principal with Brubaker
- Stephen M. Rackers, Consultant with Brubaker

U.S. Steel provided testimony and exhibits from the following witnesses:

- Matthew B. Perkins,[1] General Manager with U.S. Steel's Gary Works
- Joseph A. Mancinelli, General Manager and Energy Practice President of NewGen Strategies and Solutions, LLC

[1] On April 11, 2016, U.S. Steel filed *United States Steel Corporation's Motion for Leave to Adopt Testimony* ("Motion"). The Motion indicated that Matthew B. Perkins was no longer employed by U.S. Steel, and requested leave to allow Mark G. Tabler to adopt the prefiled testimony of Mr. Perkins. The Presiding Officers granted the Motion.

Walmart provided testimony and exhibits from the following witness:

- Steve W. Chriss, Senior Manager, Energy Regulatory Analysis with Walmart

NLMK submitted the cross-answering testimony of the following witness:

- Jeffry Pollock, President of J. Pollock, Incorporated.

IMUG submitted the cross answering testimony of the following witness:

- Kerry A. Heid, Independent Rate Consultant

On January 22, 2016, the OUCC and Intervenors filed their respective cases-in-chief. On February 16, 2016, NIPSCO filed its rebuttal testimony. On February 19, 2016, NIPSCO; IMUG; NIPSCO Industrial Group; U.S. Steel; NLMK; LaPorte; United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC ("USW");[2] and the OUCC (the "Settling Parties") submitted a Stipulation and Settlement Agreement ("Settlement Agreement"). On March 4, 2016, the Settling Parties submitted testimony in support of the Settlement Agreement. On March 18, 2016, CAC and Walmart (the "Non-Settling Parties") submitted testimony in opposition to the Settlement Agreement. On March 24, 2016, the Settling Parties submitted rebuttal testimony.

Pursuant to notice given and published as required by law, the Commission conducted an evidentiary hearing in Room 222 beginning at 9:30 a.m. on April 13, 2016. The parties presented their evidence and NIPSCO Witness Shambo and OUCC Witness Smith were cross-examined. Joint Intervenors' Cross Exhibits 1 through 7 and Petitioner's Redirect Exhibits 1 through 3 were also admitted into the record.

The Commission, based upon the applicable law and evidence presented, now finds:

1. <u>Notice and Jurisdiction</u>. Notice of the filing of the Petition in this Cause was given and published by NIPSCO as required by law. Notice was given by NIPSCO to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Notices of the public hearings in this Cause were given and published as required by law. NIPSCO is a public utility as defined in Indiana Code § 8-1-2-1(a). NIPSCO is also a utility within the meaning of Indiana Code § 8-1-2-42.7(c). Pursuant to Indiana Code §§ 8-1-2-42 and 42.7, the Commission has jurisdiction over NIPSCO's rates and charges for utility service. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

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[2] On October 19, 2015, USW filed a Petition to Intervene in this proceeding. The Presiding Administrative Law Judge notified USW that the Commission could not rule on the Petition to Intervene until USW retained an attorney that is admitted to practice before the Indiana Supreme Court. Thus, USW is not a Party to this proceeding.

2. **NIPSCO's Characteristics.** NIPSCO is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana, and provides gas ("NIPSCO Gas") and electric service ("NIPSCO Electric") in Indiana. NIPSCO is authorized by the Commission to provide electric utility service in the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White Counties in northern Indiana.

3. **Existing Rates.** NIPSCO's current basic rates and charges were approved by the Commission in its Order dated December 21, 2011 in Cause No. 43969 ("43969 Order"). Those basic rates and charges remain in effect today, as modified, including by various riders approved by the Commission from time to time. The petition initiating Cause No. 43969 was filed with the Commission on November 19, 2010. Therefore, in accordance with Indiana Code § 8-1-2-42(a), more than fifteen months have passed since the filing date of NIPSCO's most recent request for a general increase in its basic rates and charges.

4. **Relief Requested.** NIPSCO's Petition requests approval of the following:

A. Electric Service Tariff and Standard Contract. NIPSCO seeks approval of changes to its basic rates and charges for electric utility service that will provide NIPSCO with the opportunity to earn a fair return on the fair value of its property. NIPSCO seeks approval of changes to its Electric Service Tariff, including changing from Series 600 Rate Schedules to Series 700 Rate Schedules, revising its Standard Contract, instituting a new Automated Meter Reading ("AMR") opt-out charge, implementing a new low-income program, revising its Economic Development Rider, adding new street lighting rates for Light Emitting Diode ("LED") luminaires, and miscellaneous changes to its General Rules and Regulations and Standard Contract for improved clarity and administrative simplification.

B. Depreciation Rates. NIPSCO seeks approval to revise its depreciation accrual rates.

C. Previously approved Environmental Compliance Projects and Critical Infrastructure Protection ("CIP") Compliance Projects. NIPSCO has been recognizing for ratemaking purposes the cost of previously approved Environmental Compliance Projects and CIP Compliance Projects and associated operating expense through its Environmental Cost Recovery Mechanism ("ECRM Tracker"), Environmental Expense Recovery Mechanism ("EERM Tracker") and Federally Mandated Cost Adjustment ("FMCA"). NIPSCO proposes to reflect in its basic rates and charges the capital costs and operating expenses associated with Environmental Compliance Projects and CIP Compliance Projects that were completed and in service at the end of the rate base cutoff date and that are currently being recovered through the ECRM, EERM and FMCA. When new tariff sheets are filed based upon the final order in this proceeding, NIPSCO proposes to adjust, as applicable, its then current ECRM, EERM and FMCA adjustment factors to reflect the removal of the in-service plant and related expenses as of the same effective date, subject to any necessary variance reconciliations in the ongoing ECRM, EERM, and FMCA proceedings. The ECRM will continue to reflect approved Environmental Compliance Projects that were not in service as of June 30, 2015 as explained in NIPSCO's case-in-chief. All CIP Compliance Projects previously approved by the Commission were in service as of June 30, 2015.

D. Accounting Relief. NIPSCO seeks accounting authority to implement the relief sought in this proceeding, including: (1) authority to defer, as a regulatory asset, discounts offered to certain customers under the Economic Development Rider for recovery in a future rate case; (2) authority to defer, as a regulatory asset or liability, an amount equal to 50% of annual off-system sales margins above or below the level of off-system sales margins included in the test year for recovery through the Regional Transmission Organization ("RTO") tracker; and (3) authority to defer, as a regulatory liability, revenues collected to fund NIPSCO's proposed low-income program until such amounts are disbursed to participating customers. Furthermore, due to the substantial nature of the investments that NIPSCO is making in transmission and distribution assets, NIPSCO requests authority, to the extent necessary, to defer, as a regulatory asset, all costs, including depreciation expense, property tax expense, and financing costs, associated with certain transmission and distribution related projects commenced by NIPSCO in 2014 and 2015 for recovery in this proceeding or in a future general electric rate case.

E. Demand Side Management ("DSM"). NIPSCO proposes to exclude from its basic rates and charges all costs associated with its DSM program. In addition, NIPSCO proposes adjustments to test year usage in order to reflect the impact of all DSM projects. This includes a downward adjustment to annualize the impact of measures installed through December 31, 2014 and an upward adjustment for measures installed between January 1 and March 31, 2015. Upon entry of the final order in this proceeding, NIPSCO proposes to adjust, as applicable, its then current DSM adjustment factors to reflect the removal of lost revenues for those DSM projects placed in service as of December 31, 2014, as of the same effective date.

F. RTO Tracker and Off-System Sales Margin Sharing. NIPSCO proposes to update Rider 671 – Adjustments of Charges for RTO tracker to reflect updated base levels of Midcontinent Independent System Operator, Inc. ("MISO") costs and revenues and off-system sales margins based on test year amounts and to share 50% of off-system sales margins above and below the base level amount through the RTO tracker. As part of this proposal, NIPSCO requests authority to defer, as a regulatory asset or liability, an amount equal to 50% of annual off-system sales margins above or below the level of off-system sales margins included in the test year for recovery through the RTO tracker.

G. Environmental Cost Recovery Mechanism and Environmental Expense Recovery Mechanism. NIPSCO proposes to combine its Rider 672 – Adjustment of Charges for ECRM and Rider 673 – Adjustment of Charges for EERM Tracker into one consolidated semi-annual Rider.

H. Economic Development Rider. NIPSCO requests approval to change certain aspects of its Rider 677 – Economic Development Rider ("EDR"), including: (i) waiver of the current tariff provision that, upon effectiveness of new base rates, existing EDR contracts would terminate; (ii) authority to defer, as a regulatory asset, the discounted revenue associated with the EDR contracts in effect during the test year and surviving beyond the effectiveness of new base rates; (iii) a tariff change inside of the EDR that would, on a going-forward basis, provide that EDR contracts would not terminate upon new base rates; and (iv) a tariff change reducing the maximum term of new EDR contracts from 5 years to 3 years.

I. Residential Space Heating. NIPSCO proposes to discontinue Rate 611 Space Heating and Rates 612 and 613 in their entirety.

J. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with Commission Orders.

K. Prepaid Pension Asset. NIPSCO's pension plan is currently in a net prepaid pension asset position, which is represented on the balance sheet as the net of the related pension obligation and regulatory asset in accordance with governing accounting standards. NIPSCO proposes that its rates reflect this asset as part of its rate base, which reduces the pension cost that would otherwise be reflected in the revenue requirement and preserves the integrity of the pension fund.

L. LED Street Lighting Rates. NIPSCO proposes to add LED lighting to Rate 650 – Street Lighting.

5. Test Year and Rate Base Cutoff. As provided in the Prehearing Conference Order, the test year for determining NIPSCO's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the 12 month period ended March 31, 2015, adjusted for changes that are fixed, known, and measurable for ratemaking purposes and that occur within 12 months following the end of the test year. The Prehearing Conference Order recognized that NIPSCO is utilizing June 30, 2015 as the general rate base cut-off date and does not seek to update rate base beyond this cut-off date during the course of this proceeding.

6. NIPSCO's Evidence.

A. Curt Westerhausen. Mr. Westerhausen explained that NIPSCO intended for its Tariff to meet the needs of its customers and that NIPSCO retained its existing service structure in part because it was developed collaboratively with its stakeholders during months of negotiations in Cause No. 43969. Mr. Westerhausen described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 13, including the Schedule of Rates, Riders and General Rules and Regulations ("Proposed Tariff") and explained how the Proposed Tariff differs from NIPSCO's currently effective IURC Electric Service Tariff, Original Volume No. 12 (the "Current Tariff"). He noted that the current rates have been updated to reflect NIPSCO's proposed revenue requirement allocated to the rate classes through the Allocated Cost of Service Study ("ACOSS") and mitigation model.

Mr. Westerhausen summarized NIPSCO's proposed rates. He described the material changes to the other proposed rates as follows.

Rate 711 is available to residential and farm customers. This rate consists of a customer charge, an energy charge and applicable riders. In this proceeding, NIPSCO is proposing to discontinue the space heating rate and one-time credit per permanently installed space heating unit. Along with updating the billing rates, NIPSCO is also proposing to include a $0.20 flat surcharge that will provide a fund of dollars that will provide a $50 credit available to all electric customers who receive bill assistance through the Low Income Home Energy Assistance Program ("LIHEAP").

Rate 722 is available to Commercial Customers as of December 21, 2011, the date of the 43969 Order, who have arranged the wiring for permanently installed space heating equipment and for both heating and cooling the same space. For customers converting from electric space heating to natural gas, upon suitable verification acceptable to the company, NIPSCO provides a one-time credit of $25.00 per permanently installed space heating unit. This rate consists of a customer charge, an energy charge and applicable riders. In this proceeding, NIPSCO is proposing to change the energy charge to a single block. The billing rates have also been updated.

Rate 724 is available to general service customers and is a demand and energy metered rate and is available to customers with demand less than 25,000 kW. This rate consists of a demand charge, an energy charge and applicable riders. The definition of monthly minimum charge has been clarified to include applicable riders and the applicable billing rates have been updated.

Rate 732 is available to Industrial Customers. A customer requesting service under this rate is required to contract for a definite amount of electrical capacity which shall be not less than 15,000 kilowatts. This rate consists of a demand charge, an energy charge and applicable riders, with a contract required for service. The surplus capacity definition was changed to specify a one hour notice instead of a four hour notice to be in alignment with Rider 775 Option C. The billing rates have also been updated.

Rate 733 is available to Non-Residential Customers. A customer requesting service under this rate is required to contract for a definite amount of electrical capacity which shall be not less than 10,000 kilowatts. This rate consists of a demand charge, an energy charge and applicable riders. The surplus capacity definition was changed to specify a one hour notice instead of a four hour notice to be in alignment with Rider 775 Option C. The billing rates have also been updated.

Rate 734 is available to Industrial Customers primarily in the air separation and hydrogen production process industry. A customer requesting service under this rate is required to contract for (1) a definite amount of electrical capacity which shall be not less than 105,000 kilowatts, which may include the aggregation of multiple delivery points to facilitate interruption of load and (2) at least 40% of its total electric load as interruptible in accordance with Option D under Rider 775 – Interruptible Industrial Service Rider. This rate consists of a demand charge, an energy charge and applicable riders, with a contract required for service. This tariff has been updated for various clarifications based upon operating experience. The billing rates have also been updated.

Rate 750 is available for street, highway, and billboard lighting service to customers for lighting systems located on electric supply lines of NIPSCO. Billing is based upon type, ownership and responsible maintaining party of the lighting fixture. This rate is comprised of a lamp charge, an energy charge and applicable riders. In this proceeding, NIPSCO is proposing, along with updating the billing rates for the currently-existing lights, the addition of rates for LED street lighting. This proposal is further addressed by Mr. Mays.

Rate 755 is available to any customer for electric Energy for non-metered traffic directive lights located on NIPSCO's electric supply lines. This rate is comprised of a service drop charge, an energy charge and applicable riders. Other than updated billing rates, Rate 755 continues substantially unchanged. There also is a revenue adjustment related to traffic lighting that I discuss later in my testimony.

Mr. Westerhausen testified NIPSCO is proposing to discontinue electric space heating rates for residential customers in Rate 611, the two residential space heating Rates 612 and 613, the thermal storage Rate Code 617 (to be handled under proposed Rates 723 and 724), and the special contracts Rate Code 647 (NIPSCO does not currently have any special contracts).

Mr. Westerhausen summarized NIPSCO's proposed riders. He testified that Riders 778, 779, 780, 783, 785, 786, 787, and 788 continue substantially unchanged. He described the changes to the other proposed riders as follows:

Rider 770 has been updated with the average cost of fuel in base rates in this proceeding. The test year fuel costs were included in the ACOSS model and allocated by service voltage.

Rider 771 is a semi-annual mechanism approved in the 43526 Order to recover all non-fuel MISO charges and credits above and below the amount in base rates. The current version of this rider also includes a 50% sharing with customers of off-system sales margins over the amount in base rates on an annual basis. In this proceeding, NIPSCO is proposing to change the sharing mechanism to be symmetrical, and provide for sharing of off-system sales margins above and below the amount in base rates. NIPSCO is also proposing to update the rider for the value of MISO charges and credits and off-system sales included in base rates. The production and energy allocators utilized for purposes of allocating the costs inside of this rider will be updated based upon Mr. Gaske's ACOSS.

Rider 772 is applicable to all rates and is filed semi-annually. This rider has been updated to remove all approved environmental projects placed into service as of June 30, 2015. NIPSCO is proposing to combine the current ECRM Rider with the current Rider 673 - Adjustment of EERM and continue to file Rider 772 on a semi-annual basis. The production and energy allocators utilized for purposes of allocating the costs inside of this rider will be updated based upon Mr. Gaske's ACOSS.

Rider 774 is a semi-annual mechanism that was approved in the 43526 Order to recover the net cost of capacity purchases and sales and the recovery of the costs of interruptible credits paid to customers utilizing the Interruptible Rider 775. The production and energy allocators utilized for purposes of allocating the costs inside of this Rider will be updated based upon Mr. Gaske's ACOSS. The allocators will also reflect an appropriate adjustment for interruptible load subscribed under Rider 775.

Rider 775 is available to customers taking service under either Rate 732, 733 or 734 who have the ability to interrupt and/or curtail electric demand. NIPSCO offers four levels of interruptible and curtailable service. Interruptions are done on an economic basis while curtailment is done in regard to electric system reliability. A customer may continue to receive service upon being interrupted, but is billed at the MISO Locational Marginal Price ("LMP") at the NIPSCO load node.

Rider 776 is available to customers taking service under either Rate 732 or 733 who desire to take a curtailable service on a temporary basis, including for back-up or maintenance purposes, which allows them to take service for up to 60 days per year on a temporary basis.

Rider 777 is available to non-residential customers for new or increased service requirements that result in increased employment opportunities, which are new to the State of Indiana upon demonstrating the fulfillment of certain new production, increased load, and other economic-related characteristics that would otherwise have not occurred absent the availability of the rider.

Rider 781 is available to customers taking service under Rates 723, 724, 725, 726, 732, 733 or 734 who have a sustainable ability to reduce energy requirements through indirect participation in MISO wholesale energy market by managing electric usage as described by MISO.

Rider 782 is available to customers taking service under Rates 723, 724, 725, 726, 732, 733 or 734 who have a sustainable ability to reduce energy requirements through indirect participation in MISO wholesale energy market by managing electric usage as described by MISO.

Finally, Mr. Westerhausen stated NIPSCO proposes to eliminate the residential air conditioning cycling program Rider 684, which was closed to new customers beginning in 2015.

Mr. Westerhausen testified NIPSCO is proposing to adjust the test year billing determinant energy by 25,028,861 kWh and demand by 1,609 kW to reflect in the test year the annual impact of the installation of the energy efficiency measures that were installed as of December 31, 2014 under NIPSCO's DSM programs. Additionally, Mr. Westerhausen described and supported the following proposed pro forma adjustments: REV-1, REV-4, REV-5, REV-6, REV-7, REV-8, FP-3, and FP-4.

B. David Joseph Mays. Mr. Mays explained that NIPSCO has two residential space heating rates (Rates 612 and 613) and two commercial space heating rates (Rates 620 and 622), as well as a provision in Rate 611 for customers who utilize permanently installed electric space heating equipment as the primary heating of the residence (the latter is referred to herein as

"Rate 611 Space Heating"). In its Order in Cause No. 44436, the Commission approved that customers served under the space heating options with qualifying equipment would ultimately move to standard service under Rate 611 at the end of five years. This would discontinue discounts to the energy rates for space heating customers at the end of that five-year period. During the five years, NIPSCO would evenly increase the impact to space heating customers' bills each year in order to smoothly transition them to full service tariff rates. Likewise, NIPSCO would make corresponding changes to the energy rates for non-space heating customers on Rate 611. These adjustments would be revenue neutral. NIPSCO collapsed the allocators for Rates 611, 612, and 613 into one allocation for all these customers in Year 1 of the transition. This was a straight-forward application of the trackers and provided a transparent approach.

Mr. Mays explained that although they are also closed to new customers, NIPSCO did not propose to transition commercial space heating rates at that time for two main reasons. First, the Settlement Agreement approved by the 43969 Order only prescribed a transition plan filing for residential customers. Second, the demand rate element present in the general or commercial class is a complicating factor that NIPSCO felt would be better addressed in a future base rate case.

Mr. Mays testified that in this proceeding, NIPSCO is proposing to discontinue Rate 611 Space Heating and Rates 612 and 613 in their entirety. He stated that NIPSCO originally proposed a 5-year transition plan in Cause No. 44436 because it achieved an appropriate balance between impact on space heating customers' bills while not extending the plan too far out in time to make it uncertain or ineffective. It was presumed at that time that NIPSCO would be filing a rate case near the end of the five years, however, NIPSCO entered into a Stipulation and Settlement Agreement in Consolidated Cause Nos. 44370 and 44371 wherein NIPSCO agreed to file an electric general rate case proceeding by December 31, 2015. Since NIPSCO is filing this base rate case now, and the base rates will in effect reflect an increased cost of service along with a new allocation and new determinants, it is appropriate to propose to consolidate the rate schedules in this proceeding.

Mr. Mays testified that NIPSCO was not proposing a transition plan for its commercial space heating rates in this proceeding because the block energy structures create a significant level of complexity. Also, the energy-only space heating customers that would be migrating to a demand rate do not currently have demand meters. Before NIPSCO requests to transition these customers to rates with a demand charge, NIPSCO will need to install demand meters to better understand their usage characteristics. Approximately 100 demand meters will be needed for customers under Rates 620 and 622 moving to Rates 623 and 624. However, NIPSCO has plans to install the requisite demand meters on these customers so that it may propose a transition at a later time or later base rate case filing.

Mr. Mays also testified regarding street lighting rates. He noted that in the 43969 Order, the Commission approved NIPSCO's request to replace its 20 separate street lighting rates with three new lighting-related rates: Rate 650 – Street Lighting, Rate 655 – Traffic and Directive Lighting and Rate 660 – Dusk to Dawn Area Lighting. In this proceeding, NIPSCO is proposing to add LED lighting to Rate 650 – Street Lighting. NIPSCO has been working with municipalities in its service territory regarding interest in upgrading existing streetlights owned and maintained by NIPSCO to LED streetlights, also to be owned and maintained by NIPSCO. Mr. Mays explained the development of the new LED standard. He explained NIPSCO conducted research with various vendors, including visits to vendor facilities and pilots in Dyer, Schererville and Plymouth, Indiana, to solicit feedback from residents and public safety workers. In addition, NIPSCO collaborated with IMUG and Dr. Robert A. Kramer of Purdue University to study LED lighting. Mr. Mays noted NIPSCO then synthesized this information into the LED Streetlight standard. Mr. Mays provided the proposed monthly LED lamp rates and energy charges.

C. J. Stephen Gaske. Dr. Gaske testified that NIPSCO requested that Concentric conduct a fully-allocated cost of service study to determine the embedded costs of serving its various electric retail customers, and design rates that would be reasonable and appropriate for recovering the test year revenue requirements from the various customers. Dr. Gaske sponsored the class cost of service study and rate design filed in this proceeding.

Dr. Gaske discussed the purpose of an ACOSS and described the Concentric Cost of Service Model ("Concentric Model") used in conducting NIPSCO's electric cost of service study. Dr. Gaske testified that the purpose of the ACOSS is to allocate NIPSCO's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Dr. Gaske further discussed various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in NIPSCO's electric cost of service studies. He noted that customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, line transformers, services, meters, and customer billing and accounting expenses.

Dr. Gaske and Mr. Rimal also described the relative cost studies and other analyses employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes. Dr. Gaske further explained that demand costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, larger transformers, and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. He also explained that energy costs are those costs that vary with the amount of kWhs sold to customers. For example, included in the instant study are base fuel rates as well as some production operating costs that tend to vary with the amount of energy produced. However, with the exception of fuel the vast majority of

NIPSCO's costs are fixed with respect to energy usage and very little of its remaining delivery service cost structure is energy related.

Dr. Gaske sponsored attachments and workpapers that showed how NIPSCO's costs were functionalized, classified and then allocated to the various rate classes. Dr. Gaske discussed the coincident peaks during the four summer months of the test period ("4-CP"), June through September, were used to allocate the demand-related costs associated with the production functions. The coincident peak demands during each of the twelve months of the test period ("12-CP") were utilized to allocate demand-related costs associated with the transmission functions. Dr. Gaske explained that after he reviewed the system peaks for all months during the 2010 – 2015 period and applied the Federal Energy Regulatory Commission ("FERC") cost allocation tests to NIPSCO's load characteristics. Those tests indicated that either a 4-CP or a 12-CP methodology would be appropriate for the production function. Dr. Gaske noted that after reviewing several years of data, there were ambiguous results for the FERC tests for using a 12-CP allocator. Dr. Gaske further noted that during the past six years, the months of June – September were almost always within 90% of the annual peak, but none of the other eight months were ever within 90% of the annual peak. Thus, it is appropriate to use a 4-CP allocator for NIPSCO's demand-related production costs in this proceeding. Dr. Gaske noted that other adjustments to the test period demand and energy determinants we made. During the test year two of NIPSCO's large industrial customers shut down facilities. Therefore, it was necessary to adjust the test period demand and energy determinants to account for these changes.

Dr. Gaske provided a class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for: (i) the 600 series rate classes that were in effect during the test year, and (ii) the 700 series rate classes that are being proposed in this rate filing, which included the resulting unit costs by class for customer, demand and energy-related costs within the ACOSS. Dr. Gaske also described the method used to apportion NIPSCO's revenue deficiency to the various rate schedules. Specifically, he described the principles and methods used to mitigate the impacts on those classes that would receive larger rate increases if the unmitigated results of the ACOSS were to be used to set rates in this proceeding.

Dr. Gaske described the process and showed the calculations used to design the rates that are being proposed in this proceeding. He also described the method used to calculate the rate design for new LED street lights being proposed by NIPSCO. The proposed rate design for new LED street lights reasonably assumes that LED's will reduce NIPSCO's demand-related production costs.

Dr. Gaske concluded by discussing the customer impacts of the proposed rates. Dr. Gaske determined that the proposed rate levels and structure establish rates that are just, reasonable, and not unreasonably preferential or discriminatory. Dr. Gaske opined that the proposed rate structure and rates should provide NIPSCO a reasonable opportunity to earn a reasonable return on its invested capital and recover its necessary and reasonable operating expenses.

D. Bickey Rimal. Mr. Rimal testified in support of the ACOSS used in conducting NIPSCO's electric cost of service study. Mr. Rimal supported the various special studies that were utilized within the ACOSS to apportion the various categories of plant and O&M expenses to the respective customer classes. Some of these special studies include the functional split study, which consists of analyses that provide the functional split for costs relating to the sub-transmission, railroad, primary and secondary functions. He also provided the basis for several studies including the asset allocation study which allows for the appropriate assignment of assets to different rate classes, and the methodology of the transformer asset allocation analysis. Mr. Rimal described the general need for, and methodology of, the special studies, including how these studies were conducted for NIPSCO's ACOSS. He stated that there were two main sources of the data and inputs utilized within the studies: (a) the historical books and records of NIPSCO including the general ledger and engineering systems; and (b) interviews with relevant NIPSCO personnel.

Mr. Rimal also noted the data used to calculate the total replacement cost of transformers for each rate class. Mr. Rimal testified that he used data provided by NIPSCO regarding the total count of transformers by type at each pole/pad number; mapping of rate classes to each pole/pad number; and a replacement cost for each type of transformer. These class replacement costs were then utilized to develop a weighted customer allocator which represents the relative expense of transformers for each rate class and customer category. Lastly, Mr. Rimal noted that the ratio of fixed and variable production O&M expenses resulting from his study reasonably reflects the cost structure of NIPSCO's production operations and is in line with the experience of other utilities in the region.

E. William Gresham. Mr. Gresham testified regarding weather normalization. He noted that NIPSCO's test year kWh consumption was adjusted to reflect the kWh consumption that would have occurred had weather been normal and why this is the appropriate level to use for ratemaking. He noted that NIPSCO used the same procedure used in its most recent electric rate case in Cause No. 43969. In response to suggestions and comments from the Commission in the 43526 Order, NIPSCO used May as the base load month and normalized the months June through September in Cause No. 43969. NIPSCO used the base load/temperature-sensitive load normalization procedure approved by the Commission in its 43526 Order. This procedure identifies a level of energy units per customer that is not dependent on weather and subtracts that from total energy units per customer to derive temperature-sensitive energy units per customer.

Mr. Gresham explained in detail the base load temperature-sensitive load normalization procedure. He testified that the Commission provided comments concerning balance point temperature in the 43526 Order, noting that it was skeptical that the use of 65 degrees as a threshold for measuring cooling degree days reflects actual consumer behavior. Mr. Gresham noted that the Commission stated in the 43526 Order that it would anticipate that in future cases, NIPSCO would present testimony in support of an appropriate threshold; testimony that would reconcile air conditioning use assumptions with energy efficiency program assumptions. Mr. Gresham addressed those concerns raised by the Commission. He explained that NIPSCO used the month of April in the 43526 Order as the base month in its normalization and did not recognize an air conditioning load in that month. There was no assumption about customers turning on air conditioners on any day in April, regardless of temperature. Mr. Gresham explained that in NIPSCO's experience, there is not a direct correlation between thermostat settings for heating units and the operation of air conditioners. Finally, the weather normalization adjustment was based on observed consumption, not theoretical consumption in relation to energy efficiency program assumptions. So, there is no basis for reconciling air conditioning use assumptions with energy efficiency program assumptions. NIPSCO chose to use 65 degree fahrenheit as the balance point temperature. Mr. Gresham explained that with actual cooling degree days lower than normal by 17%, the test year was cooler than normal, and usage for the adjusted rates was adjusted up by 2.0% to reflect normal weather.

F. Christopher D. Smith. Mr. Smith described and supported the reasonableness and competitiveness of NIPSCO's wages and salaries, incentive compensation, and employee benefits. He also supported NIPSCO's pro forma adjustment to test year operating expenses relating to incentive compensation and profit sharing expenses.

Mr. Smith testified that NIPSCO's compensation philosophy is to compensate employees competitively in comparison to the utility industry and general industry, on a "total rewards" basis, in order to attract, retain, and motivate employees who are qualified to perform the needed functions of the particular position. According to Mr. Smith, this compensation philosophy enables NIPSCO to meet its obligation to provide safe, reliable, and cost-effective electric service to its customers. The components of NIPSCO's total compensation and benefits consist of market-driven base pay, employee benefits programs (retirement savings, health and welfare plan coverage), job scope incentive level, and merit increases to base pay. NIPSCO utilizes benefits consultants to set competitive salary ranges and to evaluate and recommend changes to its health and welfare benefit plans.

Mr. Smith opined that NIPSCO provides reasonable and competitive compensation and benefits to its employees – through annual base pay increases pursuant to collective bargaining agreements and merit increases; incentive pay; retirement plans and health and welfare benefit plans. Mr. Smith testified that NIPSCO is effective in recruiting, retaining, and motivating its employees through these means, including through incentive compensation, which is an important component in maintaining a competitive compensation package.

Mr. Smith further testified that NIPSCO's compensation and benefits package is competitive with the market. As support for this conclusion, Mr. Smith pointed to a competitive analysis NIPSCO prepared in conjunction with an outside benefits consultant that compares total cash compensation provided by NIPSCO to other utilities and to general industry companies. This analysis demonstrates that NIPSCO's base salary and total cash compensation are slightly below the market comparison data in both base pay and total cash compensation, regionally and nationally. As further support for his conclusion, Mr. Smith pointed to another outside benefits consultant study prepared for NIPSCO, which demonstrated that NIPSCO's benefit plan value is slightly below both the energy industry and general industry.

With regard to incentive compensation in particular, Mr. Smith testified that NIPSCO's incentive compensation is based first upon meeting certain corporate incentive plan goals, and if those goals are met, an incentive pool is created for distribution to NIPSCO employees. Incentive payouts for bargaining unit and non-exempt employees are determined arithmetically. Incentive payouts for all other employees are determined in large part by assessing how well the employee met individual performance objectives that are focused on factors such as customer service improvement, operating performance, reliability, and safety.

Finally, Mr. Smith described and supported a decrease of $2,798,207 to remove all long-term incentive compensation and profit-sharing expenses recorded during the test year. He explained that while NIPSCO believes these are necessary and proper business expenses, NIPSCO removed this amount from test year expenses in order to achieve consistency with previous Commission orders on the subject of incentive compensation.

G. Susanne M. Taylor. Ms. Taylor testified about NCSC – its accounting policies and procedures, the role it serves within NiSource, and the Service Agreement in place between NCSC and NIPSCO which designates the types of services to be performed by NCSC for NIPSCO and the method of calculating charges for those services. Ms. Taylor also supported the annualized level of NCSC charges billed to NIPSCO during the test year, and the amounts billed to NIPSCO Electric. She also supported several pro forma ratemaking adjustments.

Ms. Taylor testified that NCSC's accounting and financial reporting policies and practices confirm to Generally Accepted Accounting Principles ("GAAP"), and that NCSC's accounting records are kept in accordance with the Uniform System of Accounts for service companies or for major electric utilities, as applicable, as prescribed by FERC. She described various controls in place to ensure that an affiliate is consistently and appropriately billed. She explained that the accounting books and records and financial statements of NCSC are also subject to scrutiny from other entities, such as outside auditors, the OUCC, the Commission and FERC. She noted that NCSC and NIPSCO Electric both underwent a FERC audit covering the period January 1, 2009 through December 31, 2010. Among other things, the audit staff reviewed and tested the supporting details for NCSC's cost allocation method including those costs billed to NIPSCO Electric; and sampled and selected supporting documents to ensure that NCSC's billings and NCSC and NIPSCO Electric accounting complied with the uniform system of accounts. She stated that FERC did not issue any adverse comments to NCSC related to its allocation methods.

Ms. Taylor testified that NCSC is a subsidiary of NiSource and an affiliate of NIPSCO, and that NCSC provides a range of services to NiSource's operating companies, including NIPSCO. These services include the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC and third party vendors. She explained there are two types of billings made to affiliates, including NIPSCO: (1) contract billing, and (2) convenience billing. Contract billings represent NCSC labor and costs billed to the respective affiliates, and are identified by job orders. Contract billed charges may be direct billed or allocated, depending upon the nature of the expense. Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed on a monthly basis for its proportional share of the payments made in that month. In the case of convenience billing, NCSC makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate.

Ms. Taylor testified that, during the test year, NCSC billed NIPSCO a total of $110,886,357, on an unadjusted basis, net of capital and balance sheet transfers. This amount includes billings for both NIPSCO Electric and Gas operations. The portion of these charges allocated to NIPSCO Electric is $81,669,805. The types of services for which these billings were made include information technology, legal, corporate, accounting and statistical, operations support and planning, employee, purchasing, storage and disposition, budget, transportation, and auditing services.

Ms. Taylor described in detail the cost assignment processes NCSC uses to determine charges applicable to NIPSCO, as well as the controls in place to ensure consistent and appropriate billings. She also described the various bases of allocation used, and that such bases were previously approved by the U.S. Securities and Exchange Commission and filed annually with the FERC. She noted that in accordance with the 2015 Service Agreement filed with this Commission, all services are provided at cost, including compensation for capital, which includes interest on short-term and long-term debt.

Ms. Taylor testified that two types of adjustments were made to test year NCSC billings to NIPSCO Electric. The first type of adjustments are ratemaking adjustments to eliminate expenses that NIPSCO Electric is not seeking to recover in rates. More specifically, Ms. Taylor explained that a rate making adjustment of $6,145,034 was made to eliminate expenses that NIPSCO Electric is not seeking to recover in rates, consisting of the following items that were removed from the test year: promotional advertising related expenses, social membership dues, charitable contributions, political lobbying costs, miscellaneous severance costs, long term incentive compensation and profit sharing expenses, and other miscellaneous items that NIPSCO is not seeking to recover in rates (e.g., sporting events, non-recurring costs, etc.).

Ms. Taylor testified that after making these adjustments, the level of NCSC costs billed to NIPSCO Electric for the test year, net of capital, is $75,544,920. She explained that the increased NCSC costs during the test period, compared to the last rate case level, is primarily made up of the following drivers: merit adjustments and related increases to benefits and payroll taxes for merit increases; inflation for outside services; movement of a function, security services, from the books of NIPSCO to NCSC; increase of personnel costs and associated expenses due to headcount additions; increases attributable to the ongoing application, data center infrastructure and network support services required to support IT investments; increases for IT software maintenance and depreciation; increases in lease costs; and increases due to changes in the common allocation factor percentages since the last rate case.

The second type of adjustment was made to reflect ongoing NCSC ongoing levels of expense through March 31, 2016. One such adjustment of $1,468,666 adjusts test year labor expense to reflect normal, ongoing labor expense levels, and accounts for payroll merit increases and associated payroll tax and benefit increases made for NCSC employees effective June 2015.

A second adjustment reflects an increase to test year pension expense based on an adjustment amount derived from the most recent Controller Letter issued in July 2015 compared to the test year expense. A third adjustment reflects a decrease to the historic test year for the 2015 projected level of OPEB expense, based on the July 2015 Controller Letter. A fourth adjustment reflects a net adjustment for increased rent, related to NCSC employees moving to a new leased facility in Columbus, Ohio. Ms. Taylor testified that each of these adjustments is fixed in time, measurable in amount, and known to occur within 12 months following the close of the test year. She testified that as a result of these adjustments, the amount of pro forma test year expense level represented by NIPSCO Electric to be used in this rate proceeding is $77,163,456, net of capital. This reflects a net adjustment of ($4,506,349) compared to test year NCSC contract billings to NIPSCO Electric.

H. Derric J. Isensee. Mr. Isensee presented the results of NIPSCO's electric operations during the test year, on both an actual test period basis and as adjusted for fixed, known and measurable changes (*i.e.*, on a pro forma basis) expected to occur within 12 months after the end of the test period, and as adjusted for the normalization and annualization of certain amounts included in the test period. He also testified that retail electric revenues at NIPSCO's current rates do not produce a level of net operating income sufficient to provide a fair return on the fair value of property, plant and equipment owned and operated on behalf of jurisdictional electric customers. Mr. Isensee quantified the amount by which retail electric revenues should be increased so that the NIPSCO may have the opportunity to earn a fair and reasonable return. Additionally, Mr. Isensee provided an overview of NIPSCO's accounting practices, including its audits and controls, and sponsored NIPSCO's financial statements, balance sheets and cash flow statements. He testified how NIPSCO and NCSC common costs are allocated between NIPSCO's gas and electric businesses. He also described NIPSCO's request for approval of proposed depreciation rates on an account-by-account basis. Finally, Mr. Isensee described NIPSCO's proposed changes to certain riders.

Mr. Isensee stated that NIPSCO's accounting and financial reporting policies and procedures conform to GAAP, rules of the SEC, and the FERC Uniform System of Accounts. In addition, he explained that NIPSCO's (and NiSource's) financial books and records are formally audited by its outside auditors, and these outside audits are supplemented by internal audits. He also discussed the various controls NIPSCO utilizes to ensure the accuracy of its accounting books and records and financial statements. He testified that the financial information provided in this proceeding was compiled from NIPSCO's accounting records kept and maintained by NIPSCO in the ordinary course of business.

Regarding the allocation of common costs between NIPSCO Electric and NIPSCO Gas, Mr. Isensee testified that these costs are allocated using common allocation ratios that measure the cost causation relationship between the electric and gas functions for such costs. He explained that such ratios are updated twice each year to reflect current information. He testified that NCSC costs are allocated between NIPSCO Electric and Gas based upon allocators developed specifically for the allocation of NCSC charges between electric and gas operations.

Mr. Isensee testified that NIPSCO utilized a historical test period consisting of the 12 months ended March 31, 2015 and updated rate base and capital structure based on values as of June 30, 2015. Further, NIPSCO proposed certain pro forma adjustments to reflect updates to costs or revenues that will be fixed, known, and measurable within 12 months following the end of the test period, and to normalize or annualize certain amounts included in the test period. Mr. Isensee testified that NIPSCO believes these cutoff dates and pro forma adjustments will be indicative of ongoing operations.

Mr. Isensee testified that NIPSCO proposes retail electric rates designed to recover through base rates the gross retail electric revenue in the amount of $1,735,834,315, an increase of $126,587,616 over the test year pro forma results based on current rates. He also noted that rates based upon this level of annual revenue requirements would provide NIPSCO with an opportunity to earn annual jurisdictional net operating income of $234,457,717. Mr. Isensee noted that the original cost rate base does not include MISO Multi-Value Projects ("MVPs") because the Commission previously determined that MVPs should be treated as non-jurisdictional assets.

Mr. Isensee testified that NIPSCO's rate base included a prepaid pension asset – the difference between the cumulative amount of cash contributions to NIPSCO's pension trust fund and the cumulative amount of pension expense that has been recorded on NIPSCO's books and records in accordance with GAAP. He explained that the pension fund contributions in excess of historical amounts charged to operating expense, which were included in the determination of revenue requirements in past rate cases and therefore recovered from NIPSCO's retail electric customers, represent investor-contributed capital. He further testified that NIPSCO's retail electric customers benefit from these investor capital contributions because earnings on excess pension trust fund contributions (a "prepaid pension asset") serve to reduce pension expense, and therefore reduce revenue requirements and rates. He estimated that the prepaid pension asset reduces annualized electric pension cost by approximately $18 million; without the savings from the additional pension contributions, current annualized pension costs would be approximately $28.9 million instead of the $10.9 million reflected in NIPSCO's revenue requirements in this case. Accordingly, in order not to understate the cost of providing service to NIPSCO retail electric customers, NIPSCO's prepaid pension asset should be included in the determination of revenue requirements and rates.

Mr. Isensee also testified that NIPSCO's rate base included several regulatory assets, relating to Federally Mandated Costs, Utility Mercury and Air Toxics Standards ("MATS") expenses, and Transmission & Distribution ("T&D") Costs. The amounts included in rate base reflect amounts deferred as of June 30, 2015. He noted that the deferral of Federally Mandated Costs, with carrying costs (representing 20% of all Federally Mandated Costs) was approved by the Commission in Cause No. 44340; the deferral of the MATS expenses, with carrying costs, was authorized by the Commission in Cause Nos. 44311 and 42150-ECR-23; and the deferral of 2014 and 2015 T&D Costs related to substantial transmission and distribution related projects.

Using the original cost rate base, as adjusted, at June 30, 2015, Mr. Isensee testified that the required net operating income for purposes of designing rates is calculated by multiplying the original cost rate base of $3,437,796,443 by NIPSCO's proposed rate of return of 6.82% (as supported by Witnesses Rea and Moul). This calculation results in a required net operating income of $234,457,717 for purposes of designing rates.

Mr. Isensee testified that NIPSCO's rate base also included the balance of electric materials and supplies as of June 30, 2015; and the balance of production fuel at June 30, 2015.

Mr. Isensee testified NIPSCO is proposing to update Rider 671 ("RTO Rider") to reflect updated base levels of MISO non-fuel costs and revenues and off-system sales margins, based on test year amounts. Specifically, NIPSCO is proposing to recover in base rates the test year net amount of MISO non-fuel transmission revenues and expenses in the amount of $16,585,108 and update Rider 671 to reflect the recovery or pass back of net non-fuel MISO costs and revenues above or below $16,585,108. NIPSCO is also proposing to reset the off-system sales margin credit to base rates to reflect the level of off-system sales margins included in the test year ($4,741,390) and to share 50% of margins above and below this amount through Rider 671. As part of this proposal, NIPSCO requests authority to defer, as a regulatory asset or liability, an amount equal to 50% of annual off-system sales margins above and below the level of margins included in the year for recovery through the RTO Rider.

Mr. Isensee testified NIPSCO is proposing to combine Rider 672 and Rider 673 into one semi-annual rider. Currently, Rider 672 is administered semi-annually and Rider 673 is administered on an annual basis. Mr. Isensee explained that the proposal to combine the two riders is reasonable because both riders recover costs associated with the same environmental compliance projects, and with this change, all costs associated with such projects will be shown on the same timeframe in the same filing, thus simplifying the review process.

Mr. Isensee testified that upon the receipt of the Commission's order, NIPSCO anticipates submitting a compliance filing to reflect the impact of new basic rates and charges on the individually impacted Riders.

Finally, Mr. Isensee summarized the deferral accounting treatment NIPSCO is requesting in this case. First, he testified that NIPSCO is seeking accounting authority to defer, as a regulatory asset, discounts offered to certain customers under the Economic Development Rider for recovery in a future rate case. Second, he reiterated that NIPSCO is seeking authority to defer 50% of annual off-system sales margins above or below the level included in the test year through the RTO rider. NIPSCO is also requesting authority, to the extent necessary, to defer all costs associated with its transmission and distribution program commenced by NIPSCO in 2014 and 2015, for recovery in this proceeding or in a future rate case. In connection with these requests for deferred accounting treatment, Mr. Isensee testified that such treatment is consistent with GAAP, specifically Accounting Standards Codification 980, if future recovery of an expense is probable as a result of regulatory action providing reasonable assurance.

I. Daniel T. Williamson. Mr. Williamson explained the MISO and associated markets, and their impact on NIPSCO. He explained the purpose of MISO, and provided an overview of the MISO Resource Adequacy Process. He explained that NIPSCO, as a Load Serving Entity ("LSE") in MISO, is obligated to have sufficient Capacity Resources to cover its forecasted peak demand plus its Planning Reserve Margin Requirements. If NIPSCO does not have sufficient Capacity Resources to cover its forecasted peak demand and Planning Reserve Margin, NIPSCO may acquire additional capacity through bilateral transactions with other Market Participants or by bidding on capacity in MISO's annual Planning Resource Auction ("PRA"). If NIPSCO has additional capacity, it may sell the additional capacity in MISO's PRA, or a bilateral transaction. Mr. Williamson explained that NIPSCO participates in the MISO Energy and Operating Reserve Market (the "MISO Market"), and offers electricity produced and purchases electricity from the MISO Market on a day-ahead and real-time basis. He explained that participating in the MISO Market provides several benefits, including increased reliability. Mr. Williamson also testified about the MISO-related costs incurred by NIPSCO.

Mr. Williamson explained that NIPSCO has two Wholesale Purchase and Sale Agreements for Wind Energy. NIPSCO is crediting any off-system sales created by its wind purchased power agreements ("wind PPAs") with Barton Windpower LLC and Buffalo Ridge I LLC. He explained NIPSCO's ability to recover costs of up to 46 megawatts ("MWs") of installed capacity and energy purchases made through the Electric Renewable Feed-In Tariff. NIPSCO recovers purchases of energy from eligible renewable resources through its Section 42(a) tracking mechanism, which is filed with its quarterly Fuel Adjustment Clause ("FAC") proceedings in a manner consistent with NIPSCO's treatment of its wind PPA purchases approved by the Commission in Cause No. 43393, and defers the costs of purchases of capacity under the Electric Renewable Feed-In Tariff for recovery through NIPSCO's Resource Adequacy tracker ("RA Tracker").

Mr. Williamson explained NIPSCO's Capacity, including MISO Requirements, Resources, and Cost. He testified that MISO's Resource Adequacy construct ensures adequate capacity. Any proceeds from the sale of excess capacity sold bi-laterally or through MISO's Planning Resource Auction are credited within NIPSCO's RA Tracker. Any excess capacity that is sold, or additional capacity that is purchased by NIPSCO to meet its Resource Adequacy, is recovered or credited in the NIPSCO RA Tracker. Mr. Williamson explained NIPSCO's three existing Demand Response programs (1) an Interruptible offering under Rider 675 whereby large industrial customers can sign up to offer interruptible service used for both economic and reliability reasons and qualifies as a Load Modifying Resource under MISO's Tariff, and allows NIPSCO to receive Zonal Resource Credits; (2) a Demand Response Resource offering under Rider 681 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy; and (3) an Emergency Demand Response offering under Rider 682 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy for use only during emergency operations.

Mr. Williamson explained NIPSCO's RA Tracker is a semi-annual mechanism coordinated with the FAC audit process. He noted that NIPSCO is proposing that the credit of $506,640 realized through the purchase of capacity and the sale of excess capacity be removed from the test year and included in future RA Tracker filings.

Mr. Williamson testified regarding NIPSCO's RTO Tracker, including Off-System Sales ("OSS"). He noted that the August 25, 2010 Order in NIPSCO's 2008 electric rate case in Cause

No. 43526 (the "43526 Order") found that NIPSCO's MISO non-fuel costs and revenues and off system sales sharing should be included in one mechanism designated as the RTO Adjustment. He explained that the MISO charges and credits are included in the RTO Tracker and the basis on which (energy or demand) each is allocated to customers. Mr. Williamson noted that NIPSCO is proposing a change to the RTO Tracker in this proceeding. Namely NIPSCO is proposing to include $16.5 million of MISO non-fuel costs (net of revenues) in base rates and reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO rider. NIPSCO is also proposing to reset the off-system sales margin credit to base rates to reflect the level of OSS margins included in the test year, which was $4,741,390.

Mr. Williamson described and supported NIPSCO's proposal for a new volume of natural gas liquefaction at NIPSCO's Liquefied Natural Gas ("LNG") facility occurring during the adjustment period, specifically a decrease of $1,258,232 and an associated decrease to fuel costs of $445,669. He noted that NIPSCO liquefied more gas in the test year as compared to the volumes NIPSCO expects going forward. NIPSCO proposed to use the 5-year average of LNG liquefaction.

J. Kelly R. Carmichael. Mr. Carmichael testified regarding environmental challenges facing NIPSCO and the electric utility industry. He explained that there are many environmental mandates that have and will continue to have an impact on costs to NIPSCO's customers. The most significant mandates include: (1) the Environmental Protection Agency's ("EPA") Clean Air Interstate Rule ("CAIR"), regarding required reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions. CAIR was replaced by the Cross State Air Pollution Rule ("CSAPR") as of January 1, 2015, an emission allowance trading program that establishes SO_2 and NO_x emission allowance allocations. (2) MATS, establishing new limits aimed at reducing the emissions of mercury and other air toxics. (3) A Settlement Agreement with the EPA and the State of Indiana to resolve alleged New Source Review Clean Air Act violations, requiring NIPSCO to upgrade and install additional environmental controls. (4) NIPSCO has filed several filings at the Commission regarding Flue Gas Desulfurization ("FGD") units and other environmental compliance projects.

Mr. Carmichael testified regarding federal, state and local environmental laws and regulations, involving air, land, and water, applicable to NIPSCO and its operations. Currently, the most significant economic impact on NIPSCO's operations involves the Clean Air Act and its amendments, the Clean Water Act, and the Resource Conservation and Recovery Act. Mr. Carmichael testified regarding how each of these laws and regulations could impact NIPSCO, and how NIPSCO is in compliance with all applicable environmental regulations. One of the biggest potential future impacts stems from the EPA's Clean Power Plan, specifically, Rule 111(d) regarding CO_2 emissions from existing power plants. Mr. Carmichael noted that NIPSCO shares concerns raised over the conflict between the implementation timeline and the expected legal challenges to the final 111(d) rule. However, much like its compliance with MATS, which has seen a contentious court battle, once the EPA issues a final rule, NIPSCO must work towards compliance to meet the EPA's timeline. Mr. Carmichael noted that NIPSCO will be required to reduce its carbon emissions and will likely need to start down this path prior to having legal certainty from the courts. NIPSCO plans to revisit carbon reduction scenarios in its 2016 Integrated Resource Plan ("IRP").

Mr. Carmichael testified that NIPSCO is in compliance with the EPA's 2011 New Source Review Consent Decree, which included completion $9.5 million of Environmental Mitigation Projects. He noted that NIPSCO is evaluating how to comply with various new rules from the EPA regarding water, including compliance with the EPA's Effluent Limitation Guidelines for Steam Generating Units and rule to govern industrial water intake structures). He noted that both the Michigan City and Schahfer generating stations employ closed cycle cooling systems (or cooling towers); however, the Bailly Generating Station does not have a cooling tower, and NIPSCO is currently working to obtain IDEM approval on a work plan to complete data collection and analysis, as required by the rule. Further, NIPSCO is evaluating options to comply with the working Coal Combustion Residuals ("CCR") rule. Near term, NIPSCO is required to install a groundwater monitoring network, containerize CCR processing areas, address inactive surface impoundments, conduct periodic inspections, and create a publicly accessible recordkeeping and reporting internet site, and is working on compliance requirements. Lastly, Mr. Carmichael testified that all of these environmental requirements impact resource planning, and are addressed in NIPSCO's IRP process. Mr. Carmichael concluded that litigation will overlap with or lag the compliance deadlines, therefore, these decisions will need to be made without the benefit of a final litigated rule, which can create challenges regarding risk and uncertainty.

K. Michael Hooper. Mr. Hooper testified about the steps NIPSCO has taken to control costs; he described NIPSCO's generation fleet; he described NIPSCO's electric transmission and distribution systems; he discussed NIPSCO's customer service and electric reliability programs; he described the significant investments NIPSCO has made to its generation and transmission and distribution systems in recent years; and he explained the need for pro forma expense adjustments in the areas of environmental expense annualization and normalization, vegetation management, underground locate expense, and critical infrastructure protection expenses.

Mr. Hooper noted that NIPSCO's net utility plant has grown by approximately $470 million or 18% over the last five years. As a result of these investments, operating and maintenance expenses have increased due to the need to support these investments on an ongoing basis. Additionally, he noted that increases in operating and maintenance expenses have been realized as a result of the increase in the general level of prices for goods and services over this time period.

NIPSCO has taken steps to control its costs; however, despite these efforts, NIPSCO has experienced cost increases which have contributed to its need to seek rate relief. Mr. Hooper described several examples of steps taken to control NIPSCO's costs, including technological innovation, customer programs, and process improvement initiatives. He testified that NIPSCO closely monitors its capital expenditures and operating expenses, with NIPSCO processes and controls in place to identify, monitor, and control costs.

Mr. Hooper testified that the NIPSCO generating facilities have a total installed capacity of 3,305 MWs and consist of six separate generation sites, including the Schahfer, Michigan City, Bailly, and Sugar Creek Stations, plus two hydroelectric sites. He testified that of NIPSCO's total generating capacity, 77.9% is from coal-fired units, 21.8% is from natural gas-fired units, and 0.3% is from hydroelectric units. He noted that Mitchell Units 4, 5, 6, and 11 and Michigan City units 2 and 3 were retired in 2010, and Michigan City Unit 9 was retired in 2013. He also described numerous investments NIPSCO has made to its generation fleet since its last rate case to comply with federal environmental regulations. These investments include flue gas desulfurization investments, selective catalytic reduction investments, selective non-catalytic reduction investments, continuous particulate monitoring investments, activated carbon injection investments, fuel additives, and particulate matter reduction investments. Mr. Hooper testified that all of NIPSCO's generating units and the environmental equipment associated with such units are used and useful in the provision of electricity to NIPSCO's retail electric customers.

Mr. Hooper testified about the reliability metrics associated with the NIPSCO generating units over the past five years, noting that NIPSCO's average Equivalent Forced Outage Rate ("EFOR") has improved significantly in the last 10 years, and NIPSCO's average EFOR over the last five years is 6.9%, much lower than the previous five-year average of 10.3%. Mr. Hooper testified that these reliability metrics are in line with industry metrics, with NIPSCO's 2010–2014 average EFOR materially lower than the 2014 national average.

Mr. Hooper further noted that the EFOR for the Sugar Creek Generating Station has been below 2% for each of the past five years and below 0.5% in 2010 and 2014, among the top performers in the nation. The plant achieved an 82% Net Capacity Factor ("NCF") since 2014, and exceeded 45% NCF every year since 2011. In contrast, when NIPSCO bought Sugar Creek, the plant had never had a NCF greater than 10% for any previous year. Mr. Hooper stated that Sugar Creek's safety record is also excellent; there has never been a lost time incident at Sugar Creek, and as of September 1, 2015, plant employees completed their six consecutive year without an OSHA recordable injury.

Mr. Hooper testified concerning the base cost of fuel and coal inventory levels. He noted that the level of fuel expense included in NIPSCO's pro forma test year operating expenses was $558,741,377. He testified that these fuel costs incurred by NIPSCO during the test period were reasonable. He explained that NIPSCO made, and continues to make, every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. As NIPSCO regularly explains in its quarterly fuel adjustment charge proceedings, NIPSCO purchases coal pursuant to long-term contracts entered into using competitive bidding and on the spot markets. For gas-fired generators, NIPSCO purchases natural gas pursuant to supply contracts that are entered into using a competitive bidding process. NIPSCO considers a number of factors in making fuel procurement decisions, including price, quality, suitability, environmental attributes, supplier availability, reliability, and diversity. He noted that market factors also affect fuel purchases.

Mr. Hooper testified concerning the coal inventory level NIPSCO proposed to include in rate base in this proceeding. He explained that NIPSCO is proposing to utilize the unadjusted retail jurisdictional coal inventory level of $96,447,384 as of June 30, 2015. He testified that this coal inventory level is consistent with NIPSCO's fuel inventory strategy. He further explained that NIPSCO's fuel inventory strategy is designed to balance the costs associated with maintaining coal inventory with the need to provide a level of assurance that when needed, during periods of high demand, extreme weather, or fuel transportation or mine production problems, NIPSCO will be able to call on its generating units and have adequate fuel supplies on hand.

Mr. Hooper testified about NIPSCO's safety culture and safety metrics. He emphasized that NIPSCO is very focused on safety training and safety culture, and that NIPSCO's safety metrics have improved in recent years. He also explained how NIPSCO's focus on safety benefits customers in several ways, for example, by ensuring a healthier, more productive workforce and keeping the public as safe as possible.

Mr. Hooper testified about the significant investments NIPSCO has made in its T&D systems since its last rate case. These investments include installation of AMR technology; approximately $95 million in other T&D investments through June 30, 2015; and partial completion of two major transmission projects designated as MVPs by MISO. Mr. Hooper also opined that NIPSCO's transmission and distribution plant and equipment are used and useful in the provision of electricity to NIPSCO's retail electric customers. In fact, he emphasized that such plant and equipment are essential to the reliable transport and delivery of electricity from NIPSCO's generation fleet to its customers.

Mr. Hooper addressed reliability metrics associated with NIPSCO's transmission and distribution systems. He explained that NIPSCO monitors three main metrics to evaluate the reliability of the T&D system: SAIFI, SAIDI, and CAIDI. The System Average Interruption Frequency Index ("SAIFI") represents the average number of times that a system customer experiences an outage during the year. The System Average Interruption Duration Index ("SAIDI") represents the number of minutes a utility's average customer did not have power during the year. The Customer Average Interruption Duration Index ("CAIDI") represents the average time of an outage during the year. Mr. Hooper testified that NIPSCO's performance under these metrics has improved since the last rate case and are in line with industry standards. He further explained that NIPSCO has in place a comprehensive set of proactive maintenance programs targeted at reliability. These include an active vegetation management program and capital investments aimed at enhancing system capabilities, improving reliability, and replacing aging infrastructure where needed. NIPSCO has also enhanced, since 2010 its "worst taps" program and has developed a new "worst circuits" program to better improve electric system reliability. These efforts, along with other initiatives, have resulted in significant improvements to the system reliability metrics. Mr. Hooper noted that this has resulted in an average annual reduction of 4.21% in the total number of customers affected, and an 8.65% reduction in total outage duration, per year, since 2010. He also noted that customer service and reliability goals are incorporated into NIPSCO's planning process including its annual performance management process.

Mr. Hooper described and supported NIPSCO's proposal for environmental expense annualization and normalization, specifically an increase of $9,492,866 to generation O&M to reflect normalization of operating expenses for Unit 14 FGD, and annualization of Unit 15 FGD and Unit 7, 8, and 15 Activated Carbon Injection ("ACI") systems. He explained it was necessary to normalize the O&M expenses associated with the FGD facility at Unit 14 because Unit 14 was in economic reserve for a significant portion of the test year, which is not representative of expected ongoing operations. He explained that it was necessary to annualize O&M expenses associated with the FGD facility at Unit 15 because the facility went into service in November 2014, meaning the test year ending March 31, 2015 only included 148 days of operating expenses associated with the facility. Similarly, he explained that the Unit 7, 8, and 15 ACI facilities went into service during and after the test year, and as a result, annualization adjustments were required for these facilities, as well, in order to reflect full year operating costs of such facilities.

Furthermore, Mr. Hooper described NIPSCO's proposal for vegetation management program expenses, specifically an increase of $3,179,145 to test year expenses. He explained the actual vegetation management costs for the test year were lower than the historical run rate. To calculate the adjustment, NIPSCO compared the test year expenses to the five-year the historical average expenses, and made an adjustment to achieve the five-year historical average level.

Additionally, Mr. Hooper testified regarding NIPSCO's proposal for line locate expenses, specifically an increase of $151,103 to test year operating expenses. He explained that NIPSCO's analysis revealed that 27.91% of all line locates performed with in the test year were for the electric utility, compared to the 25% used to allocate line locate costs between the electric and gas divisions in the test year. This 2.91% difference equates to a $152,103 increase in operating expenses.

Finally, Mr. Hooper discussed NIPSCO's proposal to annualize CIP operating expenses, specifically an increase of $440,352 to test year operating expenses. He explained that the test year amount of such expenses did not include several incremental and ongoing expenses that NIPSCO will incur after March 31, 2015, including additional labor dedicated to compliance with the CIP rules and outside services associated with a new Security Operations Center in Hammond, Indiana.

L. Frank A. Shambo. Mr. Shambo testified that NIPSCO was utilizing a historical test year and rate case best practices set forth in GAO 2013-5, along with a 300-day procedural schedule, consistent with Senate Enrolled Act 560 (Ind. Code § 8-1-2-42.7). He also noted that NIPSCO's request in this proceeding satisfied the statutory "fifteen month rule" in Indiana Code § 8-1-2-42(a). He explained that NIPSCO's existing electric base rates and charges were approved in the Commission's 43969 Order. Mr. Shambo explained that since 2011 NIPSCO has implemented a new multi-pollutant compliance plan, established an infrastructure modernization plan, continued to implement demand-side management and energy efficiency programs, implemented a Green Power Rider and a Feed-In Tariff, complied with a number of new environmental requirements (such as MATS), and met a number of new critical infrastructure requirements established by the North American Electric Reliability Corporation ("NERC"). In addition, he noted that MISO continues to evolve, which impacts NIPSCO's operations; and NIPSCO is continuing to construct two key MVPs for the MISO transmission system (although these MVPs are not jurisdictional for state ratemaking purposes). Although these activities have impacted NIPSCO's costs, operations, and rates, Mr. Shambo testified that, based on the Commission Electricity Division's 2015 Residential Bill Survey, of the 14 jurisdictional electric utilities, NIPSCO has the lowest residential bill change for the last 10 years (2005-2015).

Mr. Shambo testified that NIPSCO filed this rate case: (1) to honor its commitment in a Settlement Agreement in Cause Nos. 44370 and 44371 to file a rate case before the end of 2015; (2) to reflect in base rates the recent capital investments NIPSCO has made in its electric system, including system modernization and environmental controls; (3) to update and revise its depreciation rates; (4) to align its rates and charges with its updated cost of electric service and address prolonged under-earnings; and (5) to update the allocation of jurisdictional costs to the various rate classes. He stated that, since the 43969 Order, NIPSCO's annual O&M expenses have increased by over $100 million, resulting in a significant deficit in earnings, driving a need to file this rate case. In fact, from June 2011 through June 2015, NIPSCO under-earned its authorized net operating income ("NOI") by over $150 million.

Mr. Shambo testified that NIPSCO's policy objectives with respect to this proceeding are to achieve rates that are reasonable and just – rates that better align with the recovery of costs from the customers that drive those costs, as well as afford NIPSCO a reasonable opportunity to recover its expenses and earn an appropriate return on its used and useful assets. He noted that there are three key aspects to improving alignment of cost recovery to cost causation: (1) fixed cost recovery through fixed charges; (2) recovery of costs from customers that cause the costs; and (3) the proper alignment of pricing signals and incentives. He emphasized that establishing rates that will allow NIPSCO to recover both its prudently incurred costs to serve customers and a fair return to investors is necessary for NIPSCO to continue to provide safe and reliable electric service to its customers.

Mr. Shambo addressed NIPSCO's plan to retire Bailly Unit 8 at the same time as it retires Bailly Unit 7 (no later than 2023), and NIPSCO's associated proposal in this case to change the depreciation rates for its Bailly Unit 8 to account for the earlier retirement date. He explained that the depreciation study prepared for NIPSCO by Mr. Spanos changed the Bailly Unit 8 retirement date from 2029 to 2023 in order to match the Unit 7 retirement date.

Mr. Shambo discussed NIPSCO's proposed service structure, cost allocation, and rate design. He explained that NIPSCO did not conduct a jurisdictional/non-jurisdictional separation study for this case because NIPSCO's assets are 100% retail jurisdictional (although revenues from certain FERC-governed tariffs and contracts are used to offset NIPSCO's retail revenue requirements, and the two MVPs discussed earlier are non-jurisdictional for state ratemaking purposes). With respect to service structure, Mr. Shambo stated that NIPSCO proposed to retain the basic service structure established and approved in Cause No. 43969. For example, NIPSCO did not propose to materially modify its current Riders 675 or 676. According to Mr. Shambo, NIPSCO views these two riders as key elements to its service structure available to large customers. Mr. Shambo explained that NIPSCO proposed to modify its EDR to allow existing EDR contracts to continue until the respective contract's stated termination date, rather than terminate upon approval of new base rates in this proceeding. NIPSCO made this proposal in order to allow EDR customers to realize their contractual, discounted rates and thereby encourage economic development. Related to this, NIPSCO requested authority to defer for subsequent recovery the discounted revenue associated with EDR contracts in effect during the test period, because the increased load is included in the test year billing determinants. If deferral were not allowed, these EDR discounts would cause NIPSCO to under-recover its authorized revenues, due to the ongoing discounts beyond the effectiveness of new base rates. The requested deferral is estimated to be approximately $2.3 million annually. For new EDR contracts, NIPSCO proposes to modify the term of such contracts from five years to three years. Mr. Shambo also testified that providing the deferral treatment of discounted revenue after effectiveness of new rates and instituting a term length of three years are both consistent with SEA 560.

With respect to cost allocation, Mr. Shambo explained that NIPSCO proposed to reduce subsidies between and among customer classes and moderate any rate shock by incorporating gradualism. He explained that NIPSCO performed a fully ACOSS and its proposed cost allocation utilizes a four Coincident Peak ("CP") methodology to allocate production demand costs, a 12-CP methodology to allocate transmission demand costs, and a Non-Coincident Peak ("NCP") methodology to allocate sub-transmission, distribution primary, and distribution secondary demand costs. Mr. Shambo testified that a 4-CP methodology was used to allocate production demand costs based upon the application of the FERC tests to a time period of 2010 through the test year for this rate case; two of the three FERC tests over this timeframe favored a 4-CP allocation.

Mr. Shambo explained that NIPSCO reviewed the impact of the ACOSS on each rate class, and identified that basing rates on an unmitigated basis (*i.e.*, without any subsidies) would produce major rate impacts to some classes (*e.g.*, over a 25% increase to residential customers, and over a 7% decrease to small commercial customers).

With respect to rate design, Mr. Shambo testified that NIPSCO proposed to ensure rate design calculations are simple and transparent and to improve alignment of cost recovery to cost causation through (1) fixed cost recovery through fixed charges; (2) recovery of costs from customers that cause the costs; and (3) proper alignment of pricing signals and incentives. With respect to fixed charges, Mr. Shambo explained that NIPSCO proposed to take a relatively small step toward further fixed-variable alignment, by increasing the customer charge applicable to residential and small commercial customers, albeit not to the full cost of service level for the customer costs (let alone full fixed costs). Mr. Shambo testified that this increased customer charge would not disproportionately impact low-income customers because NIPSCO's data indicates that the average monthly usage for low-income customers is actually higher than the normal customer population's average monthly usage.

Mr. Shambo summarized the proposed updates to NIPSCO's Electric Tariff. These proposed updates include: (1) a proposal to terminate residential space heating rates with this rate case instead of over a period of years through 2020 as contemplated by the Commission's Order in Cause No. 44436; (2) certain miscellaneous clarifying tariff revisions to Riders 675 and 676; (3) a consolidation of Rider 672 and Rider 673; (4) modification of Rider 671 to reflect a credit amount of $4,741,390 in base rates for off-system sales margins, with a sharing of 50% of any positive or negative variances to this amount through the RTO Tracker; (5) an opt-out charge ($15 per month) for customers who refuse installation of an AMR upgrade to their electric meters, to cover the incremental costs of continuing manual meter reads; and (6) miscellaneous streamlined and clarifying language throughout the Tariff.

Mr. Shambo explained NIPSCO's proposal to reset lost revenues in its Demand Side Management Adjustment ("DSMA") Mechanism, effective upon the implementation of new base rates in this proceeding, to eliminate lost revenues attributable to all energy efficiency measures installed prior to December 31, 2014. He explained that test year kW and kWh billing determinants were normalized to capture the annualized impact of measures installed throughout the test year. Additionally, NIPSCO adjusted out the lost kWh and kW related to measures installed after December 31, 2014, as such measures will still be reflected and recovered through the DSMA. Mr. Shambo stated that if these adjustments were not included, the kW and kWh billing determinants would be overstated.

M. Violet Sistovaris. Ms. Sistovaris provided a brief overview of NIPSCO and its role in northern Indiana. She provided an overview of NiSource and its aspiration to become the premier regulated energy company in North America with top-tier safety, customer service and reliability metrics, a solid foundation of engaged, aligned and safe employees, a strong financial profile, a wide range of investment-driven growth, and robust and sustainable earnings and cash flow. She described recent changes to NiSource's corporate structure, particularly centralization changes following a July 2015 separation from Columbia Pipeline Group. Ms. Sistovaris discussed the importance of NIPSCO's credit quality and associated access to capital markets on reasonable terms, emphasizing the criticality of such access for NIPSCO given its need to make ongoing significant capital investments in service quality, environmental compliance, and reliability. She noted that NIPSCO has invested over $800 million in environmental compliance projects over the last few years, plus approximately $132 million in 2014 and 2015 in electric transmission and distribution improvements.

Ms. Sistovaris summarized why NIPSCO is filing this case at this time. In addition, she provided an overview of NIPSCO's electric operations and customer base, and explained some of the challenges faced by NIPSCO's electric operations, such as its large industrial customer base (less than 1% of customers but over 50% of energy sales, with the five largest customers constituting about 40% of NIPSCO's load). According to Ms. Sistovaris, this reliance on industrial sales represents a unique risk profile and makes NIPSCO's sales more susceptible to changes resulting from the business cycle. Due to the fixed nature of many costs of providing electric service, reductions in sales volumes can have a significant impact to revenues, earnings, and other customers' rates. Other challenges discussed by Ms. Sistovaris include continuing environmental regulations, and the implication of those regulations on NIPSCO and its customers, and the impact of the economy on customers' operations resulting in lower energy sales. She noted that U.S. Steel recently announced the closing of the Gary Works coke ovens and ArcelorMittal announced the closing of its arc furnace. Together, these two closures are anticipated to result in a 2.8% annual reduction in NIPSCO industrial sales volumes.

Ms. Sistovaris described NIPSCO's customer service goals and the steps NIPSCO has taken to improve customer service and enhance its system reliability. She also described the steps NIPSCO has taken to help customers save energy and reduce their monthly bills, as well as the steps NIPSCO is taking to help low-income customers – such as energy efficiency offerings for customers (particularly the low-income weatherization program and the low-income appliance replacement program), gas customer discounts for income-qualified customers, a $3.5 million company energy assistance program for low-income customers, and a reduced deposit program for low-income customers.

Finally, Ms. Sistovaris provided a brief overview of NIPSCO's case-in-chief. With her testimony, Ms. Sistovaris sponsored: (1) Attachment 1-B, a copy of NIPSCO's notice of its intent to file an electric rate case in accordance with the Commission's General Administrative Order 2013-5; (2) Attachment 1-C, a copy of each of the Publishers' Affidavits associated with the notices published in accordance with law and Commission practice; and (3) Attachment 1-D, a copy of the written notice that was provided to residential customers within 45 days of the filing of NIPSCO's petition in this Cause.

N. Ann E. Bulkley. Ms. Bulkley testified that Concentric was engaged by NIPSCO to perform a replacement cost study or appraisal of the current value of its electric utility transmission, distribution, general and common plant assets (sometimes collectively referred to as the "electric utility assets"), and that she directed that study. She addressed the current value of NIPSCO's electric utility assets and described the valuation study upon which her analysis and conclusions were based. Her analysis developed the current value of NIPSCO's electric utility assets in service as of June 30, 2015, using a cost-based valuation methodology, the Replacement Cost New Less Depreciation ("RCNLD") or "Current Cost" approach.

Ms. Bulkley testified that she reviewed information about NIPSCO's electric utility assets, including NIPSCO's continuing property records, FERC Form No. 1, capital budgets, programmed maintenance guidelines and schedules, and proposed useful lives. In addition, she reviewed portions of NIPSCO's 2014 Integrated Resource Plan. Additionally, she testified that NIPSCO's facilities were inspected to determine the overall operating characteristics and condition of the facilities. Her analysis included all of the NIPSCO generation facilities that were in service as of June 30, 2015; NIPSCO electric transmission system consisting of 2,802 circuit miles with voltages from 69kV to 345kV and 61 transmission substations; NIPSCO's distribution system consisting of more than 900 distribution circuits, approximately 244 distribution substations, approximately 7,800 miles of overhead line, with about 2,380 miles of underground cable; NIPSCO's general plant accounts – i.e., those assets that are not defined by the FERC Uniform System of Accounts to be included in other plant accounts, such as: land and land rights; structures and improvements; general office furniture and equipment; transportation equipment including automobiles, trucks and appurtenant equipment; stores, shop and laboratory equipment; power operated equipment that is self-propelled or mounted on moveable equipment; and communication equipment.

Ms. Bulkley's analysis concluded that the current value of NIPSCO's electric utility plant in service is $8,268,074,909. She testified that the RCN of NIPSCO's electric utility assets, which is the cost to reproduce the system assets in current dollars, is approximately $17.7 billion. This value is prior to the consideration of depreciation.

Ms. Bulkley testified that, in order to develop her estimate of depreciation, the physical condition of the assets was considered, which was determined based on the condition of the assets as well as a review of NIPSCO's records and statistics and the expected average service life of the assets as determined by Mr. Spanos.

Ms. Bulkley further testified that, based on the information received during the inspection, it was concluded that the physical plant and properties in service are well designed and consist of modern equipment and quality material, the properties are being maintained and operated on a coordinated and efficient basis, and for the foreseeable future, the properties can continue to operate effectively for the purposes for which they have been designed and constructed.

Ms. Bulkley testified that determination of the depreciation associated with the production plant involved comparisons of the current cost and/or replacement cost of the existing facility to a new facility of similar technology. In this analysis, she calculated the cost of replacing the subject facility at current prices with the cost of its functional equivalent, less loss in value from depreciation.

Ms. Bulkley testified that the current costs that she relied upon in her replacement cost analysis were based on the projected costs of operating the existing units, developed using NIPSCO's long term supply planning models. In developing her replacement cost analysis, she relied on the operating cost data developed using these models to estimate the cost of service for the existing NIPSCO generation units. These projected costs of the existing facility were then deducted from the cost of service for a new facility to determine the amount available to support an investment in the asset over each year that the existing assets are projected to be operating. This annual amount was then discounted to the present value using the weighted average cost of investor-supplied capital of 8.65% that is proposed by Mr. Moul, resulting in the total value of the NIPSCO production assets using the Replacement Cost Method.

With respect to NIPSCO's Transmission Plant, Ms. Bulkley testified that the facilities are, in general, constructed with materials that are the current standard in the industry. There are, however, a number of additional costs, which would be incurred if the facilities were constructed under current conditions.

She concluded in her analysis, therefore, that the current cost less depreciation of NIPSCO's Transmission Plant is conservative and requires no further reduction due to current construction conditions or piecemeal construction.

She also concluded that no further reduction in the current cost new less depreciation is necessary for NIPSCO's Distribution Plant due to current construction conditions or piecemeal construction. The technology adjusted RCNLD or Replacement Cost for NIPSCO's electric utility plant is $8.3 billion.

O. Paul R. Moul. Mr. Moul presented evidence, analysis, and a recommendation concerning the appropriate cost of common equity that the Commission should recognize for NIPSCO in this proceeding. He also addressed the fair rate of return applicable to NIPSCO's fair value rate base. Based upon his analysis, Mr. Moul concluded that the appropriate cost of common equity for NIPSCO in this case is 10.75%. The resulting overall cost of capital that NIPSCO has proposed is the product of weighting the individual capital costs, which includes his proposed cost of equity, by the proportion of each respective type of capital. In Mr. Moul's opinion, the overall return should provide a just and reasonable level of return for the use of capital and provide NIPSCO with the ability to attract capital on reasonable terms.

Mr. Moul explained that the cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for an electric utility, such as NIPSCO. In this regard, he considered four well-recognized models/methods to measure the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. He testified that the end result of the Commission's rate of return finding must provide NIPSCO with an opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital, be commensurate with the risk to which NIPSCO's capital is exposed, and support reasonable credit quality. Further, the Commission's finding should allow NIPSCO the opportunity to earn a fair return on the fair value of its utility plant.

The models/methods that Mr. Moul used to measure the cost of common equity for NIPSCO were applied with market and financial data developed from a proxy group of 11 electric utility companies. The proxy group (the "Electric Group") consists of 18 companies that (i) have publicly traded common stock, (ii) are included in Value Line Investment Survey, (iii) operate in the Midwest region of the U.S., (iv) have not recently reduced and are not expected to reduce their common dividend, and (v) are not currently the target of a merger or acquisition. According to Mr. Moul, these criteria make sense because they provide a common set of characteristics that represent the risk traits of NIPSCO, if its stock were publicly-traded. Mr. Moul applied the models/methods for estimating the cost of equity using the average data for the electric group; he noted that the use of a group average (or portfolio) of utilities will reduce the effect of anomalous results for an individual company. By employing group average data, rather than individual companies' analysis, he minimized the effect of extraneous influences on the market data for 19 individual companies.

Mr. Moul testified that his cost of equity determination was derived from the results of the models/methods identified above. In general, the use of more than one model/method provides a superior foundation to arrive at the cost of equity. At any point in time, any single model/method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment.

From all these measures, Mr. Moul recommends that the Commission find NIPSCO's cost of common equity is 10.75% for purposes of calculating its weighted average cost of capital. His recommended cost of equity takes into account the current state of the capital markets, and in particular, the risk profile of NIPSCO that exceeds that of the electric group that he used to measure the cost of equity. The specific factors that uniquely impact NIPSCO's risk profile include NIPSCO's large industrial customer sales percentage, the prevalence of steel-related industries, and NIPSCO's large capital expenditure requirements. Mr. Moul testified that his cost of equity recommendation takes into account the various cost tracking mechanisms that are available to NIPSCO, by virtue of the fact that such mechanisms are prevalent for the electric group companies. However, Mr. Moul's proposed cost of equity of 10.75% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events such as unexpected spikes in expenses, abrupt changes in customer usage, and abnormal weather events.

Mr. Moul also testified as to a fair rate of return on the fair value of NIPSCO's rate base, using the procedure adopted by the Commission in Cause No. 43624 for Westfield Gas Corp. He calculated the prospective rate of inflation to be 1.91%, and therefore reduced NIPSCO's 10.75% cost of equity to 8.84% to reflect investor-expected prospective inflation, to avoid double-counting of inflation that is reflected in the cost of equity and inflation in the fair value rate base. This translates to a rate of return of 5.95% on NIPSCO's fair value rate base, which Mr. Moul opined would be fair and reasonable.

P. Vicent V. Rea. Mr. Rea testified about the appropriate capital structure, weighted average cost of capital, and cost of debt for NIPSCO. He discussed NIPSCO's debt financing activities, as well as the recent changes to both NIPSCO's and NiSource's credit ratings as a result of the recent separation of the Columbia Pipeline Group from NiSource. With regard to capital structure and weighted average cost of capital, Mr. Rea showed the computation of the weighted average cost of capital for NIPSCO as of June 30, 2015. NIPSCO's weighted average cost of capital as presented by Mr. Rea is 6.82%. Mr. Rea presented the June 30, 2015 actual capital structure and the adjustments made to arrive at the weighted average cost of capital of 6.82%. He noted that NIPSCO proposed to use the capital structure as of June 30, 2015 to match its proposed rate base cutoff case of June 30, 2015. He also noted that this capital structure captures the $187.5 million of long-term debt NIPSCO issued during June 2015. He explained that the cost rate for common equity in NIPSCO's proposed capital structure is 10.75%, as determined and supported by Mr. Moul.

Q. Michael D. McCuen. Mr. McCuen testified about and supported NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income taxes included in the cost of service shown in Mr. Isensee's accounting exhibits. He explained that the income tax calculations were made under the provisions of the Internal Revenue Code of 1986, as amended, and the Indiana Administrative Code. Mr. McCuen testified that he quantified the federal income tax expense beginning with the application of the 35% federal income tax rate applied to pro forma net operating income before taxes less interest expense. He then adjusted this amount to account for: (i) differences between the use of accelerated appreciation for income tax return purposes and straight-line depreciation in determining tax expense for book purposes, various tax rate changes, and Allowance for Funds Used During Construction; (ii) certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense; (iii) reduction in tax expense for Amortization of Investment Tax Credits; and (iv) reduction in tax expense for allocation of parent company interest expense.

For state income tax expense, Mr. McCuen testified that the tax calculations include Indiana Adjusted Gross Income taxes at 7.125%, adjusted for the following three reconciling items: (i) the non-deductibility of the Indiana Utility Receipts Tax; (ii) the excess deferred taxes resulting from the decrease in the state tax rate from 8.5% to 4.9%; and (iii) the non-deductibility of certain expenses. With regard to legislative changes to Indiana Adjusted Gross Income tax rates, Mr. McCuen explained that a 2014 decrease in the tax rate will be phased in over 7 years, with tax rate decreases occurring each year on July 1.

Altogether, Mr. McCuen supported a decrease in test year operating expenses in the amount of $16,571,327 to reflect a decrease in income taxes representing the change in federal and state income taxes as a result of pro forma adjustments made to the test year.

With regard to real and personal property taxes, Mr. McCuen supported NIPSCO's proposal to reflect $29,729,007 in real and personal property taxes in NIPSCO's revenue requirements. He explained that NIPSCO is subject to real and personal property taxes in numerous counties in Indiana, and is also subject to property taxes on rail cars in various states. He testified that the property tax expense for the test period per books was $26,334,374. He stated that a pro forma adjustment to increase the property tax expense per books by $3,394,633 is necessary to account for items that distort the actual expense for the 12-month test period.

Mr. McCuen also supported an increase of $1,461,872 from the test year, to reflect a utility receipts tax amount corresponding to the operating revenues under NIPSCO's proposed rates. Finally, Mr. McCuen testified that the tax expense adjustments reflected in Mr. Isensee's accounting exhibits were correct and consistent with his description of the applicable tax provisions.

R. John J. Spanos. Mr. Spanos testified about the depreciation analysis he performed related to NIPSCO's electric and common plant as of March 31, 2015, in connection with his recommendation of depreciation rates for such plant. He explained the methods and procedures used in the depreciation study and set forth the recommended annual depreciation rates as of March 31, 2015. Mr. Spanos sponsored Attachment 10-B setting forth detailed methods, procedures, and results of his depreciation study (the "Depreciation Study").

Mr. Spanos testified about the principal conclusions of the Depreciation Study and the bases for them. He testified that the proposed depreciation accrual rates by account are based on his review of historical data, NIPSCO's operating maintenance practices, and the application of informed engineering judgment. He testified that in preparing the Depreciation Study, he followed generally accepted practices in the field of depreciation and valuation.

Mr. Spanos testified that he used the straight line remaining life method of depreciation, with the equal life group procedure. He explained that this method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational method. His recommended annual depreciation accrual rates as of March 31, 2015 for NIPSCO's electric plant and common plant are set forth in the Depreciation Study.

Mr. Spanos testified that he determined the recommended annual depreciation accrual rates in two phases. In the first phase, he estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Regarding the first phase, the service life and net salvage study consisted of compiling historic data from records related to NIPSCO's plant; analyzing these data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to determine average service life and net salvage characteristics. The historic data analyzed by Mr. Spanos for the purpose of estimating service life characteristics consisted of NIPSCO's accounting entries that record plant transactions during the 79-year period from 1936 through 2014. The transactions analyzed included additions, retirements, transfers, and the related balances. NIPSCO records analyzed also included surviving dollar value by year installed for each plant account as of December 31, 2014. Mr. Spanos used the retirement rate method for all electric and common accounts for NIPSCO, to analyze this service life data. He testified that this is the most appropriate method when aged retirement data are available because this method determines the average rates of retirement actually experienced by NIPSCO during the period covered by the study. In order to estimate the lives of significant facilities such as production plants, Mr. Spanos testified that he used the life span technique. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates. He noted that this approach – the life span technique – has been presented to and accepted by many public utility commissions across the United States and Canada, including the Commission. Mr. Spanos testified that the bases for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. He further testified that he made field reviews of a representative portion of

NIPSCO's property in July 2015, and that he had previously conducted field reviews in March 2008.

Mr. Spanos testified that he estimated the net salvage percentages based on judgment. He explained that, in doing so, for most accounts, he incorporated analyses of the historical data for the period 1984 through 2014 for electric plant and considered estimates for other electric companies. He also testified that he factored in final net salvage in his recommended net salvage percentages. He noted that the final net salvage or dismantling cost of steam production units were based on the July 2015 asset demolition studies performed by BMD.

Mr. Spanos explained that, consistent with the 43526 Order, he assigned sufficient depreciation reserve to the Mitchell and Michigan City Units 2 and 3 plants to account for the level of recovery accrued based on past rates for these units. As a result, no future depreciation expense will be assigned to these units.

Regarding the second phase of the depreciation study, in which he calculated the composite remaining lives and annual depreciation accrual rates, Mr. Spanos testified as to the following steps. After he estimated the service life and net salvage characteristics for each depreciable property group, he calculated the annual depreciation accrual rates for each group based on the straight line remaining life method using remaining lives weighted consistent with the equal life group procedure. The annual depreciation accrual rates were developed at March 31, 2015. He explained that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life. He further explained that the equal life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less than calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals. Mr. Spanos testified that amortization accounting was applied to accounts with a large number of units but with small asset values. He noted that amortization accounting was approved in the Commission's 43526 Order as being appropriate for certain common and general plant accounts, representing only 3% of depreciable plant.

S. Victor Ranalletta. Mr. Ranalletta testified about the results of studies performed by BMD estimating the cost of demolishing certain NIPSCO electric power generating stations and remediating the station sites (collectively referred to as "demolition cost"). Mr. Ranalletta explained that BMD was engaged by NIPSCO to update the prior studies that were performed in Cause No. 43526 and to prepare written reports documenting the results. Mr. Ranalletta testified that he supervised and directed the studies, and he personally inspected each of the generating stations for which demolition cost studies were completed.

Mr. Ranalletta described how BMD performed its studies of the demolition cost for NIPSCO's generating units and remediating the sites to industrial condition. BMD first determined the quantities of concrete, structural steel, equipment, electric cable and raceway, conveyors, tanks, and piping that would need to be removed. BMD based the industrial demolition cost estimates on demolishing each plant down to the surrounding grade elevation. BMD assumed all equipment and material located above and below grade would be dismantled and either sent to a landfill or sold as salvage in the case of steel and copper. The estimate also assumed all below-grade foundations would remain and the below-grade excavated areas would be used for landfill space for the demolished plant concrete. Mr. Ranalletta testified that BMD did not apply any escalation factor to the demolition cost estimates; rather all of the estimates are in January 2015 dollars. He testified BMD carefully prepared the demolition cost estimates using standard and accepted estimating techniques and the best information available and that the assumptions listed in each report are reasonable and the estimates are accurate within the estimating accuracy based on the assumptions made in the previously mentioned cost contingency allowance. The demolition cost prepared by BMD includes environmental remediation, as well as indirect costs, contingency, and positive salvage value.

7. **Public's Case-in-Chief.**

A. Lafayette Morgan, Jr. Mr. Morgan testified concerning NIPSCO's revenue requirements, rate base, and net operating income. He testified that NIPSCO has a base rate revenue deficiency of $15,612,682 for the test year ended March 31, 2015. He stated that this is the additional revenue needed to generate the OUCC's recommended overall rate of return of 5.89% after accounting for the OUCC's adjustments to NIPSCO's claimed rate base and operating income. He further stated that the return of 5.89% represents the OUCC's recommendation regarding NIPSCO's overall rate of return on rate base.

B. Dwight D. Etheridge. Mr. Etheridge reviewed the reasonableness of NIPSCO's administrative and general O&M expenses. He testified that he performed a benchmarking study to evaluate NIPSCO's administrative and general cost containment performance relative to that of other electric utilities and presented the results of that study in his testimony. In addition, as part of his review of O&M expenses, he analyzed NIPSCO's projected O&M savings associated with its AMR project. Specifically, he presented a recommendation that NIPSCO's test year O&M expenses be reduced to capture incremental O&M savings expected to be realized within the 12 months that follow the end of the test year.

Mr. Etheridge explained that his primary focus was on whether NIPSCO is cost effectively managing its overall electric utility operations at an administrative level. This focus is not on NIPSCO's production, transmission, or distribution O&M expenses, but rather on NIPSCO's administrative and general expenses, including corporate salaries, outside services, materials and supplies, and rents. He noted that after fuel and purchase power costs, administrative and general expenses are the largest component of NIPSCO's total O&M costs and therefore represent a significant component of NIPSCO's total costs and in turn the rates NIPSCO's customers pay.

Mr. Etheridge testified that NIPSCO's administrative and general expenses net of employee pensions and benefits expenses have been increasing in recent years, and that when

NIPSCO's performance at managing these expenses is benchmarked against other utilities, NIPSCO is far from being a top tier performer with respect to cost control.

Mr. Etheridge testified that one recent step that NIPSCO has taken to increase customer satisfaction and reduce costs was the implementation of its AMR project. He testified that he analyzed the cost savings NIPSCO expects to achieve with this project and determined that a substantial amount of savings will occur in the 12 months following the end of the test year, with additional cost savings still to occur thereafter. He testified that cost savings associated with the AMR project expected to be realized in the 12 months following the end of the test year should be passed through to customers in this case. He recommended that the Commission reduce NIPSCO's O&M expenses by approximately $1.6 million, so that NIPSCO's customers will receive the incremental cost savings expected to be realized as a result of the AMR project in the 12 months following the end of the test year.

Mr. Etheridge did not propose a specific adjustment associated with his benchmarking study. However, he testified that, when evaluating the overall revenue increase to be granted to NIPSCO in this case, he recommended that the Commission consider the fact that NIPSCO's administrative and general expenses have been increasing.

C. Wes R. Blakley. Mr. Blakley testified concerning NIPSCO's proposed treatment of regulatory assets that are a result of NIPSCO's FMCA, TDSIC, and MATS trackers. Specifically, he expressed concern with the inclusion of income taxes and O&M expenses treatment as a rate-based item. He testified that he believes it is improper to allow a return on these costs and rate base because they are not an investment in plant, and O&M costs are allowed carrying charges to be calculated on them during the deferral period. Mr. Blakley stated that he believes the proper treatment for deferred O&M would be to amortize it over a period of years. Further, he stated that income tax calculations on the deferred regulatory assets should not be included in rate base because a return will be calculated on these deferred assets, thus causing additional income taxes to be calculated on earnings that already had income taxes calculated on them. In his view, the income tax already deferred should be recovered through amortization only.

Mr. Blakley recommended that a 4-year amortization period should be used for these regulatory assets, rather than the 2-year period proposed by NIPSCO. He further stated that NIPSCO should also remove the regulatory assets from rate base at the same time they remove the amortization of the regulatory asset from base rates. In other words, when fully amortized, the revenue requirements for "return of" and "return on" the regulatory assets should come out of base rates.

D. Stacie R. Gruca. Ms. Gruca provided an analysis and made recommendations on certain proposed changes to NIPSCO's RTO and RA Trackers. Ms. Gruca recommended that the Commission approve NIPSCO's proposal to embed the test year level of OSS margin sharing credits in the amount of $4,741,390 in NIPSCO's base rates. She stated that based on her analysis, embedding a credit for OSS margins at the test year level of approximately $4.741 million seems reasonable.

Ms. Gruca analyzed OSS margins and noted that in response to discovery requests, OSS margins were lower in 2012 and 2015 because of low natural gas prices, which meant lower electric prices. This translated into fewer opportunities for NIPSCO generation to be dispatched into MISO. Also, the higher OSS margins in 2014 were the result of the Polar Vortex, which was the coldest winter in NIPSCO's service territory in 86 years. She claimed that NIPSCO's Projected OSS Margins were created in August 2015; however, electric on-peak pricing and natural gas prices have continued to fall since that time. Ms. Gruca recommended that the Commission require no sharing of OSS margins with NIPSCO; wherein 100% of OSS margins above the base rate amount of $4,741,390 is credited to customers and 100% of OSS margins below the base rate amount (down to zero) is charged to customers. She argued that ratepayers pay NIPSCO's retail rates to support the operation and maintenance expenses and provide a return of and a return on the assets that support these sales. Therefore, NIPSCO ratepayers should be the ones to benefit from such OSS margins. Also, MISO plays the primary role in administering off system sales of NIPSCO's excess generation, and it is NIPSCO's retail ratepayers who will pay the MISO administrative fees for this service. Lastly, in previous Indiana electric investor-owned utility base rate cases the Commission authorized equal sharing of OSS (50/50) between customers and shareholders as a way to incent the utility to maximize OSS.

Ms. Gruca recommended Commission approval of NIPSCO's proposal to remove the $506,640 credit realized through the purchase of capacity and the sale of excess capacity from the test year and include capacity purchase costs and capacity sales revenues in future RA Rider filings and noted that the OUCC does not have any concerns with NIPSCO's proposed adjustment. Ms. Gruca further noted that the OUCC recommends that the Commission allow NIPSCO to continue its current structure of the RA Rider wherein customers who are charged with 100% of capacity purchase costs, receive 100% of capacity sales revenues. Lastly, Ms. Gruca recommended that NIPSCO reevaluate the RTO and RA Trackers, including the structure of each tracking mechanism, and any amount embedded in base rates in each of NIPSCO's future rate cases.

E. Michael D. Eckert. Mr. Eckert testified that the OUCC's review indicated some need for additional revenue for NIPSCO in this proceeding. He testified that the OUCC recommends that NIPSCO's base rate revenue be increased by no more than $15.613 million. He testified that, with respect to the FAC, the OUCC recommends that the Commission allow the continuation of the Stipulation and Settlement Agreement with NIPSCO that allows the OUCC and interveners to file their FAC testimony and report 35 days after NIPSCO files its FAC application and testimony.

With respect to NIPSCO's proposed pro forma adjustment for rate case expense, Mr. Eckert recommended that the Commission base NIPSCO's rate case expense on NIPSCO's revised estimate of $2,075,647, less the Billing System New Rate Implementation of $420,000, for a total of $1,655,647. Additionally, he recommended that rate case expense be amortized over four years, which would result in $413,912 being included for rate case expense in the OUCC's proposed revenue requirement for NIPSCO.

Mr. Eckert addressed the amortization periods for certain deferred regulatory assets. He noted that NIPSCO proposed a 2-year amortization period for the following deferred assets: rate case expense, Sugar Creek stub amortization, Sugar Creek amortization reset, Federally Mandated Charges, Transmission and Distribution Costs, and MATS. He recommended that NIPSCO amortize its rate case expense and the other deferred assets over four years rather than the 2-year period proposed by NIPSCO. Mr. Eckert stated that this amortization period is more consistent with NIPSCO's past history of rate cases and generally more consistent with the frequency of electric rate case proceedings. He testified that the OUCC also recommends that NIPSCO make a filing to reduce base rates by the amount of the various amortization expenses included in base rates once these regulatory assets have been fully amortized to ensure that customers do not pay more in amortization expenses than the amount required to fully recover the deferred regulatory assets.

Mr. Eckert summarized his overall recommendation regarding amortization expenses as a decrease in operating expenses for amortization expense of \$13,927,740. He explained that the difference in the OUCC's recommendation and NIPSCO's proposed reduction of \$7,387,233 reflects the revised estimate of NIPSCO's rate case expense, less Billing System New Rate Implementation of \$420,000, and the amortization of the deferred regulatory assets over a 4-year period rather than the 2-year period proposed by NIPSCO.

F. <u>Margaret A. Stull</u>. Ms. Stull testified concerning NIPSCO's proposal to include \$216,303,291 of its net prepaid pension asset in rate base as of June 30, 2015. Ms. Stull explained that a prepaid pension asset or liability results from the implementation of accounting rules promulgated under Accounting Standards Codification 715 "Compensation-Retirement Benefits." ASC 715 governs the recording of both pension and OPEB and, among other things, requires that the difference between cumulative contributions to the pension plan and cumulative accrued pension expense be recognized as either a prepaid asset or liability on a company's balance sheet. To the extent that cumulative pension contributions are greater than cumulative pension expenses, the result is a prepaid pension asset. To the extent that cumulative pension expenses are greater than cumulative pension contributions, the result is a prepaid pension liability.

Ms. Stull noted that NIPSCO is seeking to include its prepaid pension asset in rate base and earn a return on that asset. She testified that the OUCC disagreed with this proposal and opined that NIPSCO's prepaid pension asset is not an investment in utility plant as defined by Indiana Code § 8-1-2-6, and does not otherwise qualify for rate base inclusion. She noted that Indiana Code § 8-1-2-6(b) refers to tangible property, and she stated that a prepaid pension asset does not qualify as tangible property and is thus ineligible for inclusion in rate base on those grounds. Ms. Stull testified that the prepaid pension asset does not qualify under other rate base categories either and stated that utilities may be authorized to include in rate base an amount for working capital; however, the utility must request working capital, it must be specifically calculated, and the Commission must determine if the utility is entitled to include it in rate base. She noted that NIPSCO did not request working capital in this case nor did it include working capital in its rate base calculation. She further noted that working capital is typically calculated or measured for regulatory purposes through the performance of a lead-leg study, and that NIPSCO did not perform a lead-leg study in this case. She concluded that while the cash disbursements related to NIPSCO's pension plan contribution might be one of the factors considered to determine

NIPSCO's overall working capital needs, the prepaid pension asset itself would not be considered working capital for regulatory purposes.

Ms. Stull testified that in addition to working capital, the Commission has also recognized a utility's investments in inventory as a component of rate base and has allowed a utility to earn a return on those investments. However, she stated that NIPSCO's prepaid pension asset is not and cannot be construed as inventory.

To summarize, Ms. Stull testified that NIPSCO's prepaid pension asset is not used in useful plant under Indiana Code § 8-1-2-6. Further, it cannot be considered inventory, nor is it working capital because NIPSCO has neither requested working capital nor presented evidence supporting the inclusion of working capital in its rate base. For these reasons, Ms. Stull testified that NIPSCO's proposed prepaid pension asset should not be included in rate base in this case. As a result, Ms. Stull testified that the OUCC proposes that no ratemaking treatment be allowed for NIPSCO's prepaid pension asset of $216,303,291.

G. J. Randall Woolridge. Dr. Woolridge, Professor and Consultant for the OUCC, testified that he used both a DCF analysis and a CAPM analysis to determine his recommended overall range of return on equity of 8.70% - 8.80%. He noted that Mr. Moul had recommended a 10.75% return on equity. Dr. Woolridge noted that despite NIPSCO's requested and OUCC's recommended return on equity, both NIPSCO's and the OUCC's DCF and CAPM - the two models to which this Commission has consistently given the greatest weight – produced similar results. He noted that the difference is two primary issues: (1) Mr. Moul's reliance on the Risk Premium and Comparable Earnings models; and (2) Mr. Moul's flotation cost and small size adjustments.

Dr. Woolridge stated that Mr. Moul's Risk Premium ("RP") analysis produces an 11.39% return on equity, more than 100 basis points above his CAPM and 200 basis points above his DCF. He argued that Mr. Moul's Comparable Earnings ("CE") results are an additional 65 basis points above those figures and recommended the Commission give no weight to either of these two models. Dr. Woolridge argued that if the Commission removed the small utility size adjustment and the flotation cost adjustment, which are included in NIPSCO's analysis, the return on equity produced by Mr. Moul's DCF (9.15%) and CAPM (8.9%) were not dramatically different from his recommended 8.70% return on equity, also based on those two models.

Dr. Woolridge further argued that there were three errors in Mr. Moul's analysis. First, base interest rate – Dr. Woolridge believes that Mr. Moul's base interest rates are inflated and argued that using a bond's yield-to-maturity as a base yield, results in an overstatement of investors' return expectations. Second, Dr. Woolridge argued that the risk premium was excessive. He argued that utility stocks are less risky; he generally felt that the historical risk premium of 7.28% was arbitrary, and that the base interest rate is based on the historical relationship between stock and bond returns is erroneous. Dr. Woolridge also noted that the Commission disregarded the CE method in a former NIPSCO rate case. Dr. Woolridge noted, however, that the Commission did not explicitly reject Mr. Moul's CE model, but instead determined that the CE model produced a 15.70% recommended return on equity, the Commission instead found a reasonable ROE range was between 9.9% and 10.5%. Third, the flotation cost adjustment. Dr. Woolridge admitted that the Commission has typically allowed utilities to recover measurable and reasonable flotation costs recently incurred or expected in the near future, but disagreed with NIPSCO's justification for the flotation cost adjustment.

Dr. Woolridge also disagreed with Mr. Moul's size adjustment and claimed that there is no need for a size adjustment or premium to the CAPM for utilities. However, he noted that the Commission has previously supported small size adjustments.

Dr. Woolridge noted that NIPSCO has proposed a capital structure from investor-provided capital 41.56% long-term debt and 58.44% common equity. NIPSCO has recommended a long-term debt cost rate of 5.71%. Dr. Woolridge adopted NIPSCO's proposed capital structure. He also argued that an 8.70% return on equity is fair because capital costs and inflation are low; utilities are low risk; as such the cost of equity capital is low; NIPSCO's investment risk is average; NIPSCO's capital structure has much more equity and less financial risk than other electric utility companies in the proxy group; and authorized return on equity for electric companies have decreased in recent years.

Overall, Dr. Woolridge disagreed with NIPSCO's rate of return because of NIPSCO's proposed capital structure that includes a common equity ratio of 58.44%. He also disagreed with NIPSCO's cost of capital, claiming that Mr. Moul's DCF equity cost rate overstated growth rate estimates. Dr. Woolridge further disagreed with the projected interest rates and market or equity risk premiums in Mr. Moul's risk premium and CAPM approaches; and disagreed with NIPSCO's equity cost rate adjustments regarding flotation costs and the size of NIPSCO.

H. Glenn A. Watkins. Mr. Watkins claimed that Dr. Gaske's sole criteria for utilizing the 4-CP method to allocate generation plant is his reliance on benchmark standards utilized by FERC wherein the allocation of generation or fixed production costs are at issue, to which Mr. Watkins argued this Commission is not in any way wed to, or encumbered by, the practices of another regulatory commission. Instead, he argued that the Commission should consider his studies based upon the 12-CP, probability of dispatch, base intermediate-peak, and peak & average methods. He testified that other than 4-CP, he has no other cost allocation disagreements with Dr. Gaske's study. Mr. Watkins noted that if the Commission accepts his recommended cost of service studies, a significantly different level of profits at current rates is obtained as well as attendant class revenue responsibility.

Mr. Watkins also stated that he disagreed with Dr. Gaske's recommendation of cost allocations. He stated that there are several criteria that should be considered in evaluating class or rate revenue responsibility and argued that class cost allocation results should be considered, but they should only be used as a guide and as one of many tools in evaluating class revenue responsibility. He stated that other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, affordability, a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development. Mr. Watkins stated that Mr. Gaske reflected on all of that subjective criteria, and broad parameters in his revenue distribution proposal. However, Mr. Watkins disagreed with Dr. Gaske's overall recommendations. He stated that NIPSCO's proposed large increases to the residential and small commercial fixed monthly customer charges should be rejected wherein the current rates should be maintained.

I. Eric M. Hand. Mr. Hand, Utility Analyst for the OUCC, discussed the OUCC's concerns regarding NIPSCO's proposed Low-Income Program, its proposed funding mechanism and discussed the OUCC's counter recommendation. Mr. Hand noted that NIPSCO proposes to implement a Low-Income Program that will provide a one-time $50 credit to the June bill of its electric customers who receive bill assistance through LIHEAP. NIPSCO proposes to fund the program by a mandatory twenty cents per month fixed surcharge on residential customers, yielding approximately $970,000 annually. He stated that the Commission should modify NIPSCO's proposed Low-Income Program to create a fund through which low-income electric customers could receive bill assistance to be accomplished via voluntary contributions instead of a mandatory tariff rate surcharge. He stated NIPSCO should provide the opportunity for all customers (not just residential), employees and shareholders to voluntarily participate in funding a low-income assistance fund. Mr. Hand also stated that he believes NIPSCO should participate in funding the low-income fund by matching the voluntary contributions, and that NIPSCO should be required to make an annual compliance filing showing the funds collected and the benefits distributed.

Mr. Hand opposed NIPSCO's request for a waiver for its current EDR contracts to prevent them from terminating with the establishment of new base rates. He stated that given the plain language in the current tariff, commercial and industrial customers that are currently enjoying discounted rates were clearly aware of the termination provisions within the tariff and made their decisions accordingly. He stated that considering that NIPSCO's last rate case was more than four years ago, certainly no EDR customers are, or were, "caught off guard" with this tariff requirement. However, the OUCC does not object to NIPSCO's proposed EDR 777 for customers that qualify under the provisions of the proposed tariff rider.

J. Edward T. Rutter. Mr. Rutter discussed the OUCC's objection to NIPSCO's request to adjust depreciation rates for steam production plant to reflect the change in retirement date for Bailly Unit 8 from 2029 to 2023. He noted that in NIPSCO's 2014 IRP, Bailly Unit 8 was set to retire in 2029 and in this case NIPSCO has changed the retirement date for Bailly Unit 8 from 2029 to 2023 to reflect the position taken by NIPSCO relative to the depreciation expense for Bailly Unit 8. Mr. Rutter stated that the OUCC objects to the adoption of an accelerated retirement date for Bailly Unit 8 because any change to a resource option that is inconsistent with a current IRP should not be approved unless a new IRP analysis is provided.

Mr. Rutter also discussed the OUCC's concerns with NIPSCO's use of a RCNLD methodology in developing the current value of its electric utility assets. Mr. Rutter stated that he is concerned because Indiana Code § 8-1-2-6 states that the Commission can take into account the reproduction cost of utility property at current prices less depreciation. However, there is a distinct difference between Replacement Cost and Reproduction Cost. Based on these concerns, Mr. Rutter recommended that the Commission should not accept the fair value of the electric utility assets at June 30, 2015 as presented by Ms. Bulkley.

K. Cynthia M. Armstrong. Ms. Armstrong noted the OUCC's concerns over the early retirement of Bailly Unit 8 and the associated impact on depreciation rates. She also expressed concern that Bailly's earlier retirement date was not addressed in an IRP and noted that despite Mr. Hooper's documented support regarding the additional costs that NIPSCO would have to incur to comply with environmental compliance, the OUCC did not support the earlier retirement date. Ms. Armstrong noted that the 2014 IRP considered the environmental challenges facing the unit, and it does not conclude that early retirement is warranted. She noted NIPSCO did not present an analysis of all the costs and benefits of the premature retirement of the unit.

Ms. Armstrong also noted the OUCC's concerns over NIPSCO's proposed O&M adjustments for environmental operating expenses for Bailly Units 7 and 8 and Schahfer Units 14 and 15. She stated that the OUCC disagrees with NIPSCO's proposed Adjustment OM-3 to reflect an increase of $9,492,866 to generation O&M to account for a normalization of operating expenses for the Unit 14 FGD, annualization of operating expenses associated with the Unit 15 FGD, and annualization of ACI expenses for Units 7, 8, and 15. Ms. Armstrong stated that NIPSCO proposes to use a five-year historical period to calculate its normalization adjustment, which the OUCC believes that a three-year historical average unit capacity factor is more appropriate and should be used.

Ms. Armstrong also noted that the OUCC does not have concerns regarding NIPSCO's request to eliminate the EERM and track environmental equipment O&M and depreciation expenses through the ECRM instead. She noted that other utilities also track their O&M expenses as part of one rider on a six-month basis, and the OUCC does not have an issue with NIPSCO doing so. However, the OUCC would propose that NIPSCO cease the tracking of both capital and O&M costs of equipment embedded in rate base.

8. LaPorte County's Case-in-Chief.

A. Reed W. Cearley. Mr. Cearley testified regarding NIPSCO's assertion that NIPSCO's J.D. Power rankings continue to improve and the underlying implication that NIPSCO is providing good customer service. He stated that NIPSCO has ignored the J.D. Power Electric Business Satisfaction Surveys and argued that since 2014, NIPSCO's business customer satisfaction decreased, while the majority of other electric utilities' satisfaction results were increasing. Mr. Cearley recommended that customer satisfaction should be a consideration in determining an appropriate overall return on equity. In this case, Mr. Cearley recommended a lower return based on NIPSCO's Customer Satisfaction Surveys.

Mr. Cearley's second recommendation was that NIPSCO should not be allowed to merely decrease its test year revenues of $15,629,740 for its claimed lost load associated with the closing of the ArcelorMittal and U.S. Steel facilities until it has reasonably demonstrated what it has done to either retain or replace this lost load. Mr. Cearley argued that while NIPSCO may have been unable to prevent the loss of two large industrial customers, it should try to seek out new business to replace or try to retain the load. Finally, Mr. Cearley noted that the best option for both NIPSCO and its customers would be to aggressively pursue and replace any lost load if at all possible, but noted the next most prudent option would be to offer and sell any freed up power into the MISO energy markets and flow the sales revenues back to ratepayers under the Rider 671 process.

9. CAC's Case-in-Chief.

A. Karl R. Rábago. Mr. Rábago argued that NIPSCO's fixed customer charge proposals are not supported by administrative law. He stated that the development of the ACOSS involves three important and somewhat subjective steps—cost functionalization, cost classification, and cost allocation. He noted that while he "did not review every unique decision involved in the functionalization, classification, and allocation of NIPSCO's costs, it is important to note that reasonable people could differ on many of the imbedded decisions that purport to show the high levels of customer and fixed costs that NIPSCO purports to assign to small customers." He argued that NIPSCO's proposals regarding fixed-variable alignment are based upon NIPSCO's argument that there is greater certainty of revenue recovery for fixed costs that are collected through fixed charges than for fixed costs collected through volumetric or variable rates, with which he disagreed. Mr. Rábago testified that NIPSCO's proposed fixed customer charges would create significant barriers and impediments to energy efficiency, conservation, and renewables that would result in improper discrimination against customers investing in these options. He argued that NIPSCO offers no evidence that customers who have or who are likely to invest in these options have created any harm that can best be remedied through NIPSCO's fixed charge proposals. He concluded that the proposals to increase fixed customer charges in proposed Rates 711 and 721 are unjustified and would be unjust and unreasonable. Mr. Rábago further testified about NIPSCO proposed increase of approximately 82% in unavoidable customer charges for its residential customers, and a 50% increase in the customer charge for small-business customers. He stated that similarly with the residential customer charge proposal, he recommended that the Commission disapprove the fixed small business customer charge.

Mr. Rábago argued that the proposed increases in fixed customer charges have a larger impact on some customers over others with the largest burden on low use customers without regard for why they are low users, and minimize impacts on high use customers. He argued that he could not find authority regarding "fixed-variable alignment" with the exception of utility proposals to increase fixed customer charges. He contested that aligning fixed costs and fixed charges will help align cost recovery with cost causation. He stated that doing so, "would create an appealing symmetry in nomenclature, but whether a cost is labeled as fixed or as variable tells us nothing about the most economic, just, and reasonable way to collect the cost from the customer class that caused it." Mr. Rábago noted that increasing the fixed charges would decrease revenue risk for the utility, which he believes should be offset by a reduced rate of return. He argued that instead of increased fixed charges, NIPSCO should, "instead improve its forecasting skills, file more frequent rate cases, or use a future test year in rate cases." He further contended that increasing fixed charges have a disproportionate impact on low usage customers and those that have pursued energy efficiency. He noted that NIPSCO did provide a measure to mitigate the impact on low-income customers, namely, a single bill credit of $50 to be applied to the June bills of customers who receive LIHEAP funding. Mr. Rábago stated that he was not satisfied with a one-time $50 credit offset, an amount that is less than half of the proposed fixed customer charge increase, and the credit will not encourage energy efficiency, and will not address high bills in other months. He stated that increases in unavoidable fixed customer charges create powerful price signals against investment in energy efficiency, distributed generation, and other distributed energy resources products and services. Mr. Rábago noted that using volumetric rates instead of fixed customer charges would be more beneficial, noting policy and being less burdensome to low-income customers.

B. John Howat. Mr. Howat discussed the affordability of NIPSCO's proposed rates. He stated that he noticed NIPSCO's customers making late payments, and that there has been an increase in disconnect notices. He recommend that the Commission direct NIPSCO to implement a comprehensive low-income bill payment assistance program that targets current bill benefits to NIPSCO customers eligible to participate in LIHEAP and includes an arrearage management design component. Mr. Howat's proposed program would provide fixed credits and a 25% discounted rate for LIHEAP-eligible customers. He also recommended that NIPSCO report monthly to the Commission and stakeholders data regarding general residential and low-income customer accounts, billing, receipts, arrearages, notices of disconnections, bill payment agreements, disconnections of service for nonpayment, reconnections of service after disconnection for non-payment, accounts written off as uncollectible, and accounts sent to collection agencies. He further recommended that Commission staff conduct a public technical session with NIPSCO and interested stakeholders during the design phase of the data collection and reporting protocol. Mr. Howat stated that such data reporting is needed to assess the "effectiveness of the credit and collection policies and practices of NIPSCO, with an eye toward improving such practices when appropriate."

Mr. Howat further argued that increasing utility cost recovery from the volumetric to the monthly customer charge portion of bills disproportionately harms low volume consumers within a rate class. He argued that low-income households, households headed by an African American, and seniors use less electricity than their counterparts. Therefore, he claimed that increased monthly fixed or customer charges cause disproportionate harm. Lastly, he argued that higher fixed charges discourage energy efficiency. Consequently, he recommended that the Commission reject NIPSCO's proposal to increase the monthly fixed customer charge.

10. IMUG's Case-in-Chief.

A. Robert Kramer. Dr. Kramer testified that he supports the replacement of NIPSCO's old technology streetlights with new LED streetlights. He described the older technologies of street lighting and why newer technology is better. He stated that the technological advances of the LED streetlights provide substantial advantages and noted that LED technology is nationally the most widely implemented replacement for high pressure sodium luminaires. He explained that high quality modern LED based luminaires provide up to a 60%+ decrease in energy usage, long life estimated at 100,000 hours or more, competitive price, excellent light color characteristics, instant starting, full dimming capability, highly directional light, resistance to vibration and relatively small size and light weight luminaires that facilitate storage and installation. Dr. Kramer noted that this modern technology is being implemented in numerous locations and metropolitan areas globally including major replacement programs involving retrofits of 141,089 street lights in Los Angeles and 300,000 in New York. He detailed the savings to be achieved by competitive requests for proposals ("RFPs") for the purchase and installation of LED retrofits. Dr. Kramer stated that in his opinion LEDs are the best choice for large scale light replacements for many beneficial reasons.

Dr. Kramer noted that the time is right for these new street-lights and they should not be delayed. He noted that the value of the lost savings, approximately 60% or more reduction in energy use, reduced maintenance costs, and many other safety, economic, and social benefits exceeds the value of possible future improvements. He detailed how it is possible to obtain material economy of scale savings in LED procurement and installation costs by upgrading to LEDs in large groups and offered his opinion of the per unit installation costs that are possible.

B. Theodore Sommer. Mr. Sommer supported approval of "reasonable" LED street light tariff rates and the implementation of the mass LED retrofit of NIPSCO's current streetlights. Mr. Sommer stated that most of the streetlights are owned by NIPSCO and some are owned and maintained by the municipalities. He stated the members of IMUG will change out their streetlights to LED by using a competitive RFP bidding process for LED procurement and installation of a mass LED retrofit project. He proposed NIPSCO also use competitive RFPs for procurement and mass LED retrofit in order to obtain the available economy of scale savings. The savings could then be reflected in establishing low mass retrofit LED street light rates. Mr. Sommer testified the current street lights were installed in the mid-1980s and are now largely fully depreciated, obsolete, poorly illuminating and very energy inefficient. He indicated to replace them a few at a time would forego the material mass retrofit savings that are available. He pointed out that NIPSCO proposes to replace all of its NIPSCO-owned street lights with LEDs as part of its pending 7-Year Electric TDSIC Plan filed in Cause No. 44733. However, he noted that no mass retrofit LED rate is yet proposed by NIPSCO in this rate case or in Cause No. 44733. He testified a low cost LED mass retrofit rate should be approved.

Mr. Sommer stated his concern that the Rate 750 LED rates NIPSCO proposes in this case appear intended for retrofitting street lights on a limited basis, one or a few at a time, without reflecting the savings from a mass retrofit installation. He testified that NIPSCO's proposed LED tariff rates are too high and should not be applied to either mass LED retrofits or to single retrofits. Rather, a separate set of tariff rates for mass LED retrofits, apart from single retrofits should be approved. He explained NIPSCO's proposed rate priced the fixture change outs using its own workforce, including substantial cost adders, rather than the per unit price from a competitively bid mass installation. Mr. Sommer calculated his own LED street light rates, in part based on IMUG's installation cost estimate and the per-unit light costs that Dr. Kramer found reasonable. He testified that he and Dr. Kramer agree that a 50% reduction to the O&M included in NIPSCO's proposed LED rates in this proceeding are reasonable. Mr. Sommer's proposed LED rates are approximately 30% lower than NIPSCO's replacement rates. He testified that these retrofit street light rates should be approved in this rate case. He explained that street lighting is the highest electricity cost borne by IMUG members. Overall, Mr. Sommer recommended that the Commission approve his proposed LED street light rates, order NIPSCO to use a competitive RFP bidding process on the LED streetlight modernization program proposed as part of its 7-Year Electric TDSIC Plan filed in Cause No. 44733, and approve his recommended mass retrofit program and rates.

11. Industrial Group's Case-in-Chief.

A. Michael P. Gorman. Mr. Gorman recommended the Commission set NIPSCO's operating income at $207.3 million using an overall rate of return of 6.03% and an original cost rate base of $3.437 billion. His recommendation was based on an adjusted capital structure, a ROE of 9.3% and NIPSCO's embedded debt cost.

Mr. Gorman recommended the proposed increase in depreciation expense to provide for accelerated recovery of Bailly Unit 8 be denied, reducing NIPSCO's depreciation expense and revenue deficiency by $11.1 million. He testified that the decision on whether to shorten Bailly's operating life should be deferred to a future proceeding. He stated that NIPSCO is requesting accelerated recovery of Bailly Unit 8 on a going-forward basis, but is also requesting substantial amortization of generating unit costs incurred prior to the test year. Delaying the accelerated recovery of this unit in this case will mitigate rate increases to customers in this case, and provide for a smooth transition for out-of-test-period costs reflected in this case, and future cases for recovery of these non-recurring costs. Mr. Gorman recommended that NIPSCO should be ordered not to start accelerating the recovery of Bailly Unit 8 until after its existing amount of significant amortization cost for regulatory assets have been completed in the next two to three years. He stated that he also supports the depreciation rate adjustments outlined by Mr. Andrews on behalf of the Industrial Group, which, if approved, would reduce depreciation rates and related depreciation expense by $6.2 million.

Mr. Gorman testified that his recommended rate of return of 6.03% based on a 9.3% return on equity will produce credit metrics that will support an investment grade bond rating for NIPSCO. He testified that NIPSCO's requested 10.75% return on equity does not balance customers' and shareholders' interests and provides NIPSCO with an excessive level of operating income.

Mr. Gorman testified that he derived his fair return on common equity using the DCF, a Risk Premium analysis and the CAPM. Based on these methodologies, Mr. Gorman estimated NIPSCO's current market cost of equity to fall in the range of 9.00% to 9.6%. His recommended return on equity of 9.3% is the midpoint of this estimated range, and in his view reflected fair consideration of NIPSCO's investment risk, and is fair compensation in today's very low capital market cost environment.

Mr. Gorman stated that he did not agree with Ms. Bulkley's estimate of the current valuation of NIPSCO's rate base, and testified that she has overstated the RCNLD of the production assets. If rates were based on a fair value methodology, he testified that a fair net operating income for NIPSCO would fall in the range of $208.7 million up to $236.3 million. Mr. Gorman stated that in the event that the Commission does not accept his recommendation concerning a reasonable capital structure, then a reasonable fair value return on equity would be 7.23% (9.0% less 1.77%) and a fair value overall rate of return reflecting this return on equity and NIPSCO's proposed capital structure is 5.31%.

B. Brian C. Andrews. Mr. Andrews testified that NIPSCO had overstated its depreciation rates for several accounts and thus these rates produced an excessive amount of depreciation expense and overstated the test year revenue requirement. Specifically, he testified that NIPSCO has underestimated the average service lives of three T&D accounts. Therefore he recommended that NIPSCO's T&D book depreciation rates should be reduced by increasing the average service lives associated with the property contained in Accounts 356, 365, and 367 such that the survivor curves better fit the retirement data.

Mr. Andrews also testified that NIPSCO has overstated the net salvage rate required for Account 353, to an excessive estimate of future inflation. He proposed decreasing the amount of net salvage collected for Account 353 to better reflect the actual net salvage history. Mr. Andrews noted that his proposed adjustments to NIPSCO's depreciation rates result in a reduction of $6.2 million to NIPSCO's depreciation expense.

C. Stephen M. Rackers. Mr. Rackers recommended that the prepaid pension asset and associated accumulated deferred income taxes that NIPSCO has included in rate base and its capital structure, respectively, should be eliminated from the determination of the revenue requirement. In support of this position, he testified that NIPSCO's proposal for customers to pay a return on the prepaid pension asset is unreasonable for several reasons. First, he stated that the prepaid pension asset represents the level of contribution to the pension trust, in excess of the historical amounts charged to operating expense. He testified that the level of contributions since 2007 has significantly exceeded the level of contributions that NIPSCO was required to make. He opined that ratepayers should not be required to provide a return on excess contributions to the pension fund. Second, he testified that the value of the prepaid pension assets will move based on market changes and investment results. He stated that it is too simplistic to say that each additional dollar of pension fund contribution reduces the amount of pension expense. Additionally, he testified that NIPSCO has not justified or reconciled the significant increase in the prepaid pension asset. He stated that during the period of the significant growth in the prepaid pension asset, NIPSCO was involved in a utility merger which resulted in significant growth in the pension asset. He also noted that in a previous rate case, the Commission denied NIPSCO's request to include a prepaid pension asset in rate base. Accordingly, Mr. Rackers recommended that NIPSCO's proposal to include a $216.3 million prepaid pension asset in its rate base be rejected. In his view, this prepaid pension asset should be removed from rate base and the associated $82.6 million of accumulated deferred income taxes should be eliminated from the capital structure.

Mr. Rackers also recommended that the amortization of the remaining balance of the Sugar Creek Plant deferred depreciation and carrying costs should be eliminated from the cost of service. He testified that he believed NIPSCO has already recovered approximately all of the $5,965,662 remaining balance of the deferred depreciation and carrying cost for the Sugar Creek Plant. He noted that NIPSCO's current rates include recovery of deferred depreciation and carrying charges associated with Unit 18, as a result of an amortization through September 30, 2014. Because rates were not adjusted at the end of that amortization period, NIPSCO's revenues continue to collect $3,171,684 annually. He testified that, from the end of the September 30, 2014 recovery date through the expected rate implementation date of August 1, 2016, NIPSCO will have collected additional revenue of $5.8 million, which is approximately all of the remaining Sugar Creek Plant deferred depreciation and carrying charges. Accordingly, Mr. Rackers proposed to eliminate the expense associated with the 2-year amortization of the August 1, 2016 remaining balance of the Sugar Creek Plant deferred depreciation and carrying charges.

Mr. Rackers recommended that the deferred T&D costs should be amortized over a longer period than that proposed by NIPSCO, five years rather than two, and the deferred cost should not be included in rate base. He testified that he believed the amortization period should be significantly longer than what NIPSCO has proposed. Specifically, because these costs are related to long-lived assets, he proposed an amortization period longer than two years. However, he noted that a shorter amortization period would be acceptable if the deferred costs are not also included in rate base. Based on the regulatory treatment previously afforded similar costs, Mr. Rackers recommended a 5-year amortization period and no rate base inclusion of the deferred cost. If the Commission determines that rate base inclusion of the transmission and distribution deferred costs is appropriate, he recommended that only the average balance during the amortization period should be included in rate base. Further, he recommended that after the full amortization period has been reflected in rates, NIPSCO should make a compliance filing to reduce its rates to reflect the roll-off of the amortization.

Mr. Rackers recommended that the current effective Indiana State income tax rate of 6.5% be used in the determination of the revenue requirement. Mr. Rackers testified that on July 1, 2015, the state income tax rate declined to 6.5%. He stated that this is a fixed, known and measurable change that occurred within one year of the test year cutoff of March 31, 2015. He recommended using this 6.5% current state income tax rate as opposed to the 7.125% rate utilized by NIPSCO in its determination of revenue requirements.

Mr. Rackers recommended that the March 31, 2015 balance of excess deferred state income taxes should be amortized over a 5-year period rather than the remaining life of the associated assets as proposed by NIPSCO. He stated that his understanding of NIPSCO's position regarding the return of excess deferred state income taxes is that the Indiana Code is in conformity with the Internal Revenue Code and therefore NIPSCO is restricted to the use of the average rate assumption method with regard to the excess deferred state income taxes. Mr. Rackers stated that he did not agree with this interpretation. As support for his view, he noted that a New Hampshire Public Utilities Commission decision approved a stipulation that reflected an amortization period of 5 years for the write-down of New Hampshire accumulated deferred income taxes. He also noted a case regarding the Consolidated Edison Company, where the New York Public Service Commission ordered a 3-year amortization of excess deferred state income taxes resulting from a reduction in the New York State corporate income tax rate. Mr. Rackers proposed a 5-year amortization of the excess state accumulated deferred income taxes which have been identified as of March 31, 2015. He stated that his recommendation allows NIPSCO to return these excess funds, which NIPSCO has enjoyed as a source of the zero cost capital, gradually over a 5-year period, instead of requiring customers to wait decades for the return of amounts that have already been determined to be excess. Further, he recommended that any additional excess state accumulated deferred income taxes identified after March 31, 2015, be accumulated in a regulatory liability. The amortization of these additional deferrals can be addressed in a future general NIPSCO rate proceeding.

Alternatively, if the Commission is concerned that allowing a more rapid return of these funds than would occur using the Average Rate Assumption Method ("ARAM") may be a violation of either the Internal Revenue Code or the Indiana Code, then as an alternative to beginning a 5-year amortization in this case, Mr. Rackers recommended that the Commission require NIPSCO to request a ruling from appropriate taxing authorities to determine if his recommendation results in any code violations. Specifically, he recommended that the Commission direct NIPSCO to request a private letter ruling from the IRS and a revenue ruling from the Indiana Department of State Revenue. Under this alternative, he testified that the entire $28.6 million identified as of March 31, 2015 and any additional excess state accumulated deferred income taxes identified following that date, should be accumulated in the regulatory asset. These funds can then be distributed based on the taxing authority's response to the letter rulings.

D. James R. Dauphinais. Mr. Dauphinais recommended that NIPSCO's RTO Tracker should be modified so that all expenses and revenues except those directly related to off-system energy sales margins should be removed because NIPSCO does not have a reasonable need for a rate adjustment mechanism for those expenses and revenues. He also recommended that the name of the RTO Tracker should be modified accordingly, and that NIPSCO should be required to absorb 100% of any negative off-system sales margins. Second, he recommended that NIPSCO's proposed Rider 776 should be modified to clarify that NIPSCO's adjustment riders do not apply to Back-up Service and Buy-Through Temporary Service, and to clarify that NIPSCO must confirm all Back-up Service requests that are made in full conformance with Rider 776. He also recommended that the demand charges for Rider 776 should be set by applying the final demand charged percentage increase for Rates 732 and 733 from current Rates 632 and 633 to the current Rider 676 demand charges. Third, Mr. Dauphinais recommended that NIPSCO's definition of Qualifying Facility in its General Terms and Conditions and its proposed Rider 778 should be modified to be consistent with Indiana Code § 8-1-2.4-2(g). Finally, Mr. Dauphinais recommended that on July 1 of each year, NIPSCO should provide a non-binding, good faith 5-year projection of its electric rates under its base rates and riders.

Regarding his proposed changes to the RTO Tracker, Mr. Dauphinais opined that NIPSCO has not met necessary prerequisites to be granted a continuation of the non-fuel MISO costs portion of its RTO Tracker. More specifically, he stated that the expected changes in the costs are not of sufficient magnitude to be a financial threat to the utility, are not sufficiently volatile, and are not outside the ability of the utility to manage without an adjustment rider. Further, he testified that some of the charges recovered in the RTO Tracker are actually fuel-related and therefore should be recovered through NIPSCO's FAC. He identified these three charges as NIPSCO's MISO Miscellaneous Amount, Revenue, Neutrality New Uplift, and MVP Distribution Expenses and Revenues. Similarly, he testified that NIPSCO has not demonstrated that it has met the prerequisites of magnitude, volatility, and outside the control of the utility necessary to be granted a continuation of the off-system energy sales portion of its RTO Tracker. He did, however, acknowledge that changes in off-system energy sales margins are much closer akin to fuel and purchase power costs than non-MISO fuel costs with respect to being a potential financial threat to NIPSCO, volatile, and difficult to manage. Accordingly, he stated that the Industrial Group does not at this time oppose continuation of the off-system energy sales margin portion of NIPSCO's RTO Tracker. However, he did object to NIPSCO's proposed change in the sharing mechanism for off-system energy sales margins and recommended that the Commission condition the change on NIPSCO being prohibited from passing onto its customers any net off-system energy sales losses that NIPSCO may incur.

With regard to NIPSCO's Backup, Maintenance and Temporary Industrial Service Rider, Mr. Dauphinais raised two language issues. First he objected to the application of adjustment riders for the Back-up Service and Buy-Through Temporary Service because energy is priced for those two services at incremental costs based on the MISO locational marginal price plus an adder, rather than NIPSCO's average fuel cost. Thus, in his opinion, customers taking these services do not get the benefit of NIPSCO's generation facility and fuel cost averaging; instead they are subject to the hourly spot wholesale market price for energy (the MISO locational marginal price). To require these customers to also pay the NIPSCO FAC would charge these customers twice for fuel and purchase power costs. Additionally, Mr. Dauphinais stated that none of the costs recovered by NIPSCO's adjustment riders will likely result in an increase in excess of that already covered by the MISO locational marginal price and the applicant adder under Rider 776 for these two services. Mr. Dauphinais also expressed a concern with respect to NIPSCO's addition of the phrase "the amount confirmed by company shall be deemed firm load, subject to curtailments." He testified that the phrase implies that under certain circumstances NIPSCO might not confirm a request for Back-up Service from a Rider 776 customer. Accordingly, he recommended that the Commission require NIPSCO to instead insert a sentence that stated "confirmation of a customer request for Back-up Service under this rider shall not be withheld by the company provided the request for Back-up Service is made in full conformance with the terms and conditions for Back-up Service under this rider."

With respect to the proposed demand charges for NIPSCO's Backup, Maintenance and Temporary Industrial Service Rider, Mr. Dauphinais noted the proposed charges represent an increase of approximately 9% over current demand charges. He recommended that, to the extent the Commission changes the proposed percent increase in the Rate 732 and 733 demand charges from those for Rate 632 and 633, that same percentage should be applied to the Rider 676 demand charges to establish the final Rider 776 demand charges.

Concerning NIPSCO's proposed definition of Qualifying Facility under its general rules and regulations, Mr. Dauphinais stated that NIPSCO's proposed definition does not reflect a recent change in Indiana statute that requires electric utilities to interconnect and purchase excess output from Qualifying Facilities larger than 80 megawatts in capacity. Accordingly, he recommended that NIPSCO's proposed tariff definition of Qualifying Facility be modified to address this change in Indiana statutes (or alternatively be deleted), and that Rider 778 be modified to conform to current law.

Finally, Mr. Dauphinais recommended that the Commission request NIPSCO to provide a non-binding, good faith 5-year projection of its base rate and adjustment riders on July 1 of each year. He explained that the members of the Industrial Group have found that for budgeting purposes they have each had to individually attempt to project NIPSCO's electric rates, which is problematic. Because NIPSCO is in the best condition to project its own future electric rates, Mr. Dauphinais testified it would be far more efficient for one entity to develop such a projection than several, then NIPSCO's projection could be made available to all of its customers. He noted that, in making this recommendation, the Industrial Group fully expects NIPSCO's actual rates to deviate from NIPSCO's good faith projections. Nevertheless, for customers the projections would serve as a useful guide for future expectations and budgeting.

E. Nicholas Phillips. Mr. Phillips stated that while NIPSCO's proposed cost of service method has merit, it required adjustment in its application to produce fair and reasonable results. He stated that NIPSCO's study contains buy-through loads which should be excluded from the 4-CP demand generation allocator. Buy-through loads refer to those loads for which NIPSCO declines to provide service, allowing the customer to buy-through the market. He stated that load NIPSCO chooses not to serve with its generation assets should not be used to allocate the costs associated with those generation assets. Mr. Phillips also testified that NIPSCO's allocation factors are abnormal with respect to metal melting load and require a normalizing adjustment to obtain reasonable results. He stated that metal melting loads should be based on on-peak hours and exclude loads that are created during hours that are off-peak according to the tariff.

Mr. Philips stated that NIPSCO's proposed mitigation plan reduces subsidies paid by industrial customers subject to global competition while generally maintaining the subsidy received by residential customers. Mr. Phillips agreed with NIPSCO's plan to significantly reduce the subsidies provided by the large industrial customers noting it would be ill advised to over allocate costs to those customers when the current subsidy level can be reduced without harsh impacts. He added that NIPSCO's proposed mitigation plan is essential in light of the two recent plant closings involving steel operations.

Mr. Phillips also testified that the revised 4-CP generation / 12-CP transmission cost of service study indicates that the three large industrial rates and the metal melting rate should receive a rate increase, based on NIPSCO's proposed revenue increase, in the range of 0% to 3.8%. Using NIPSCO's mitigation plan, the increase is in the range of 1.3% to 4.4%. He stated that by using a 4-CP generation, 4-CP transmission study, the industrial increase should be no more than 2% based on cost of service and no more than 3% based on the mitigation plan.

12. U.S. Steel's Case-in-Chief.

A. Mark G. Tabler. Mr. Tabler testified regarding the recent historic downturn in the steel industry, in which low steel prices, unfair trade, and other global market challenges are hurting the steel industry. He stated that this weakened state of the industry has resulted in the "temporary idling of major steelmaking operations across the country, including our own facilities in southern Illinois, Ohio, Texas, Minnesota and East Chicago Tin." He noted that because of this idling, U.S. Steel has extended layoffs of more than 3,000 employees at various points in time over the last year. From the third quarter of 2015, U.S. Steel reported a loss in 13 of the last 19 quarters. He stated that U.S. Steel provides approximately 7,000 jobs in Northern Indiana among its three facilities. U.S. Steel's expenses for electric power from NIPSCO are the most expensive of all of its plants in the United States. He noted that NIPSCO will not offer a special contract with U.S. Steel. Mr. Tabler testified that U.S. Steel would like more interruptible power, including interruptible power to each of its facilities to lower its overall electricity costs. Lastly, he explained that electric rates have a major impact on whether and to what extent U.S. Steel will remain in Indiana.

B. Joseph Mancinelli. Mr. Mancinelli noted that industrial customers have always been a significant portion to NIPSCO's load. He claimed that since 2005, industrial customer's energy use has represented approximately 58% of the NIPSCO total energy sales. He explained that industrial customers use the energy more efficiently than other customers. Mr. Mancinelli stated that high load factor customers pay for a significant portion of NIPSCO's fixed costs and spread these costs over many kWhs. He stated that U.S. Steel is very sensitive to NIPSCO power prices, as the steel industry is in trouble, in part because of China's oversupply of the market hurting the steel industry in the U.S., the U.K., Indiana, Brazil and elsewhere. He stated that, "given this harsh economic reality, USS cannot pass on electricity price increases to customers." Electric costs at the Gary Complex are the highest of U.S. Steel's American operations and more than 60% higher than the facility with the lowest electricity costs. U.S. Steel has already reduced output at Gary Works by shedding over 12 MW of load related to coke manufacturing operations. He stated that U.S. Steel is considering relocating production or obtaining power from other sources. Mr. Mancinelli proposed various rate design options to support lower electric rates to U.S. Steel. He proposed that the current NIPSCO Interruptible Industrial Service program be expanded to benefit the NIPSCO system and large industrial customers like U.S. Steel. He stated that the current interruptible industrial service rider is inadequate because it is limited to a $38 million credit cap. Therefore, he recommended a fifth interruptible rate option (referred to as "Option E"), which would be available to large industrial facilities.

Mr. Mancinelli stated that U.S. Steel would not qualify for any of the benefits of economic development. He further stated that he felt that the NIPSCO rate was not fair because it does not take into account that U.S. Steel is more efficient and less expensive than at lower voltage rates. With respect to rate design, the proposed Rate 733 has a single demand charge and a series of energy charges for all customers in the class. The charges do not reflect the lower cost of serving higher voltage customers. Therefore, high voltage customers like U.S. Steel end up subsidizing lower voltage customers in the class. Therefore, he prosed rates be designed within the class that reflect different delivery voltages.

Mr. Mancinelli noted that he supports NIPSCO's use of the 4-CP allocation factor in the allocation of demand related production function costs and 12-CP for allocating demand-related costs. He also recommended changes in the calculation and allocation of certain items including ACOSS model, assumptions regarding demand and energy losses, weather normalizing energy and demand, and allocating off-system sales to rate classes consistent with the allocation of the underlying assets that generate these revenues. Mr. Mancinelli also supported other NIPSCO allocation factors, related to the TDSIC calculation. NIPSCO'S ACOSS model classifies the majority of transmission and distribution plant as demand and customer related, in recognition that these costs are fixed and do not vary with class energy usage. He noted that he agreed with NIPSCO's ACOSS allocators to recover TDSIC costs.

Mr. Mancinelli also recommended that mitigation costs not be allocated to industrial customers that qualify for interruptible capacity under Option E of Rider 775. He stated that NIPSCO proposes a mitigation plan that results in approximately $58 million of subsidy for the residential class. He stated that while he understands gradualism in establishing rates, given the "dire economic condition of U.S. Steel," he recommends that industrial customers not be burdened with mitigation costs.

13. Walmart's Case-in-Chief.

A. Steve W. Chriss. Mr. Chriss testified that Walmart has 14 stores and one distribution center in NIPSCO's service territory. Mr. Chriss stated that the Commission should consider customer impact when examining NIPSCO's requested revenue requirement and return on equity to ensure that any increase is the minimum amount necessary to maintain adequate and reliable service, while also providing for a reasonable return. He stated that he thought that NIPSCO's proposed return on equity of 10.75%, which results in a proposed overall weighted average cost of capital of 6.82%, was excessive. He stated that according to data from SNL Financial, there have been 95 reported electric rate cases, with a range of reported authorized return on equity for the period of 8.72% to 10.95%, and the median authorized return on equity of 9.75%, which included distribution-only utilities. Mr. Chriss noted that the average return on equity for vertically-integrated utilities was 9.89%.

Mr. Chriss stated that Walmart does not oppose NIPSCO's proposal to allocate production capacity cost using a 4-CP demand allocator. He testified to concerns with the discrepancy between current class revenue requirement levels and the revenue requirement levels needed for each class to recover its respective cost of service. He noted that under present rates, customers on Rate 624 and Rate 626 are paying rates that are significantly higher than the costs incurred to serve those classes. Specifically, NIPSCO shows Rate 624 customers are currently paying $14.5 million annually, or approximately 7.5% of the class revenue requirement, to subsidize other rate classes. Similarly, Rate 626 customers are currently paying $4.5 million annually, or approximately 6.8% of class revenue requirement, to subsidize other rate classes. Mr. Chriss noted that NIPSCO's proposed revenue allocation would reduce some of the subsidies and reduces the burden by 75% for two large industrial classes, but limits the reduction in burden to only 3.6% for all other classes that pay for the subsidies. He argued that the Commission should instead allocate the reduction in subsidy in proportion to the total revenues of the customer classes that bear the subsidy burden.

Mr. Chriss also argued that the recovery of a demand-related energy charge provides a disadvantage to higher load factor customers. For this reason, he recommended that the Commission adopt NIPSCO's demand charge block structure, with his recommended charges on each of the first two blocks. He also stated that it is helpful to customers to break out tariff rates by function. He stated that the Commission should require NIPSCO to separately present the fuel portion of the base energy rate in its tariff for commercial and industrial rate schedules.

14. Cross-Answering Evidence.

A. IMUG's Cross-Answering Evidence. Kerry A. Heid responded to Mr. Watkins' criticism of NIPSCO's use of the 4-CP demand allocation methodology for production plant. He stated that over the past decades the driving force behind the construction of any new production capacity on NIPSCO's system has been the need to meet peak demands, especially summer peak demands supporting that a greater portion of production plant costs (fixed production costs) should be assigned to the four summer peak hours. Mr. Heid agreed with Dr. Gaske's proposal to use the 4-CP demand allocation method for production plant. He stated that use of the 4-CP demand allocation methodology gives appropriate recognition to the system's peak season, as an examination of the historical relationships of seasonal loads shows that this 4-month period is consistently and significantly higher in load than the loads during the balance of the year, and that this period represents the planning peak season of NIPSCO.

Mr. Heid responded to Mr. Watkins' classification and allocation methodologies stating the Commission should disregard Mr. Watkins' 12-CP, Base-Intermediate-Peak and Peak & Average studies should be disregarded due to the lack of support.

Mr. Heid also responded to Mr. Watkins' proposed use of the Probability of Dispatch methodology stating there are numerous problems, namely, the methodology (1) is an arcane and rarely used, (2) utilizes gross plant investment for each generating unit, not revenue requirements of each generating unit, (3) is based on the number of hours each generating unit is dispatched during the test year, which can vary materially from year to year, (4) is primarily a tool for analyzing cost by time periods and does not reflect the design basis for the generating units, and (5) results in inconsistent treatment of fuel costs. He stated the energy-weighted production demand allocation methodologies send illogical price signals. Mr. Heid stated Mr. Watkins' methodologies are inconsistent with previous Commission precedents noting that all major Indiana electric utilities classify 100% of production plant as demand-related and use a CP methodology for allocation of production plant and none of these electric utilities use an energy-weighted demand cost allocation methodology for production plant.

B. NLMK's Cross-Answering Evidence. Jeffry Pollock addressed the recommendations by Mr. Watkins regarding production plant allocation. Specifically, he noted that the Industrial Group and U.S. Steel agree with the use of the 4-CP method, however, Mr. Watkins disagrees. He noted that Mr. Watkins claimed that because 4-CP does not allocate any production plant and related expenses to the lighting classes, these classes are effectively getting a free ride. Mr. Pollock stated that is not a reason to reject 4-CP because lighting classes account for less than 0.5% of NIPSCO's test-year energy sales and that the lighting classes are not receiving a free ride as they are allocated their respective share of costs. He also disagreed with Mr. Watkins' capital substitution theory because he believes that it is an oversimplification of utility planning. Mr. Pollock noted that two of the methods Mr. Watkins advocated have not been "widely adopted" by state regulatory commissions. Overall, he recommended that the Commission adopt NIPSCO's proposed 4-CP method with the adjustments proposed by Mr. Phillips and Mr. Mancinelli.

Mr. Pollock also addressed the proposal of Mr. Mancinelli to revise Rider 775 to create a new Option E. He noted that as proposed by U.S. Steel, the new Option E would be available first to large industrial facilities that are unable to take service under the existing interruptible rate options, and available second to large industrial facilities that are taking service under the existing interruptible rate options, and all existing interruptible capacity would be required to elect their current option when executing new contracts to re-enroll in the rider. Essentially, customers currently taking interruptible service under Option C could not move any current load to Option E, which offers a higher demand credit, and more interruptions. Mr. Pollock noted that overall NLMK agrees with U.S. Steel regarding Option E, however, NLMK believes that the Interruptible Credits for Options C and D should be increased as well, and that all customers should have the option of their choice. Mr. Pollock agreed with Mr. Mancinelli that the cost cap for interruptible credits should be lifted and that the amount of interruptible capacity should be increased. He recommended that the credits and terms of service for existing rider Option C should be updated by increasing the Option C credit to $9.00/kW-month and increasing the notice to curtail time from one to two hours. Mr. Pollock explained that the adjusted credit level for Option C was still substantially less than NIPSCO's marginal cost of capacity based on updated estimates of the cost of new entry for capacity in MISO.

15. NIPSCO's Rebuttal Evidence.

A. Mr. Shambo. Mr. Shambo provided an overview of NIPSCO's rebuttal positions. He noted that the parties recommended various changes related to NIPSCO's cost of equity. He noted that Mr. Woolridge and Mr. Gorman ultimately disagreed with NIPSCO's proposed cost of equity and testified it should be lower. Mr. Shambo stated that these recommendations would jeopardize NIPSCO's financial health and eventually increase NIPSCO's financing costs, which must be recovered from customers. He noted that Mr. Cearley argued that NIPSCO has poor customer satisfaction performance levels and that the Commission should adjust NIPSCO's cost of equity accordingly. Mr. Shambo disagreed stating that NIPSCO's customer service metrics have shown improvement from its last electric rate case.

Mr. Shambo also took issue with some parties' recommendation that the Commission deny NIPSCO's proposal to place its $216.3 million prepaid pension asset into rate base and earn a return on it. He stated that NIPSCO's treatment of its prepaid pension asset in rate base is appropriate and should be approved, as prepaid pension asset is effectively a prepaid labor expense, which are appropriate costs for recovery in base rates.

Mr. Shambo agreed with Mr. Mancinelli that NIPSCO should (1) increase the capacity available under current Rider 675 to 600 MW, (2) remove the $38 million cap, and (3) add an additional Option E. He noted that all of the parties understand that reasonable minds could differ as to the appropriate cost allocations.

Mr. Shambo noted that the OUCC and CAC recommended that the Commission reject NIPSCO's proposal to raise the fixed customer charge in its residential and small commercial rates, despite the fact that neither the OUCC or CAC's witness disagreed with Dr. Gaske's cost classification. He stated there was no disagreement that the majority of NIPSCO's costs are fixed, except Mr. Watkins' theoretical statement that all costs are variable in the long-run. These are fixed costs because the costs are related to assets that have very long lives and are not likely to change over the next decade or longer. Furthermore, the resources required to provide the service, such as field labor and customer service also do not change within any reasonable length of time. In response to CAC's contention that an increase in customer charge will lead to less energy efficiency, Mr. Shambo stated that there are better ways to address energy efficiency and renewable energy than to subsidize it implicitly through rate design. Mr. Shambo also does not believe that the higher customer charge has a negative impact on low-income customers. He provided data that showed that NIPSCO's 18,000 low-income customers show higher usage than NIPSCO's average customer.

Mr. Shambo explained how NIPSCO determined the number of electric LIHEAP customers to include in its proposed program, using the number of electric customers enrolled in LIHEAP the previous year to model its proposed program since this number reflected the most current information available. He stated that NIPSCO considered alternatives, such as a Universal Service Program ("USP") similar to its current Gas USP. He noted NIPSCO also proposed the one-time bill credit applied in June to assist low-income electric customers at the time of year when electric bills are generally the highest. He noted that the OUCC did not support NIPSCO's proposed low-income program. He explained that a specific low-income rate should not be established, as it sends a negative price signal. He also stated that there should not be an arrears program, as that is currently available through assistance agencies and programs and added that NIPSCO's current billing system is not set up to administer such a program so a great deal of time and expense would be needed to make necessary modifications.

Mr. Shambo also discussed the parties suggestions related to NIPSCO's proposed changes to the RTO Tracker. He noted that NIPSCO is willing to accept the OUCC's stated position related to the OSS sharing mechanism, but stated that it should be evaluated in future base rate proceedings. He stated that although it is unlikely to ever occur, NIPSCO would modify the OUCC's proposal to limit the sharing down to zero margin. Mr. Dauphinais supported NIPSCO's proposal to symmetrically share with its customers 50% of the difference between NIPSCO's annual OSS margins and the embedded credit. Mr. Shambo disagreed with Mr. Dauphinais' recommendation that the Commission prohibit NIPSCO from recovering any negative OSS margins from its customers and his proposal to alter NIPSCO's FAC and RTO Trackers noting it is contrary to multiple Commission orders, and is an obvious attempt to simply penalize NIPSCO for being a utility within an RTO.

Mr. Shambo also responded to the OUCC's concerns regarding NIPSCO's proposed changes to its Rider 677. He stated that although NIPSCO agrees that these customers should be aware that their currently discounted rates will terminate when new base rates go into effect, it is important to note that NIPSCO filed this rate case as part of a commitment in another Settlement Agreement entered into in 2015, and it is not the appropriate time to hastily terminate contracts that have attracted additional load to the service territory to the benefit of all customers. He pointed out that the tariff notes that the currently-effective contracts "shall" terminate upon the effectiveness of new base rates and as such, NIPSCO does not have discretion to continue the contracts.

Mr. Shambo agreed with Messrs. Sommer and Kramer on the benefits of LED streetlights and the savings available if NIPSCO pursues a mass replacement strategy. He noted that NIPSCO has planned to submit, subject to the Commission's review and approval, a set of LED streetlight tariff rates in its initial electric TDSIC tracker proceeding that would incorporate the effects of any mass replacement strategy and the benefits or synergies associated with that roll-out.

Mr. Shambo addressed arguments related to NIPSCO's administrative and general expenses. Namely, the OUCC's concern that NIPSCO's administrative and general expenses have been increasing at an extraordinary rate. He noted that the corporate separation Mr. Etheridge referenced took place three months after the end of the test year in this proceeding, and NIPSCO requested no pro forma adjustments based upon the separation. He stated further that NIPSCO monitors its expenses and has set controls in place to manage budgets and expenses to provide reasonably adequate services and facilities for customers. Mr. Shambo also noted that it is an axiom of a rate case that the Commission look at a utility's revenues and expenses holistically. He stated that administrative and general expenses are just one component of NIPSCO's operating and maintenance costs and that Mr. Etheridge did not look at NIPSCO's service costs as a whole, but only picked apart one component.

In response to Mr. Dauphinais' recommendation that buy through energy for back-up and temporary service should not be subject to the application of riders according to Appendix A, Mr. Shambo stated that NIPSCO is proposing that all buy through energy in both Riders 775 and 776 should be treated the same.

B. Alan Felsenthal. Mr. Felsenthal discussed the GAAP accounting requirements for pension costs; how the prepaid pension asset arises; how it provides both quantifiable and other benefits to NIPSCO's customers; and why the source of the prepaid pension asset is NIPSCO's investors—thus requiring a return. His testimony also explained why the prepaid pension asset is essentially the mirror image of NIPSCO's OPEB liability which, in the ratemaking process has been treated in a manner which reduces return and revenue requirements, a treatment that the Commission has addressed and approved.

Mr. Felsenthal concluded that NIPSCO's prepaid pension asset of $216.3 million should be included in rate base and that Ms. Stull's and Mr. Rackers' positions on this issue should be rejected. He noted that NIPSCO has recorded both pension expense and the prepaid pension asset on its books and records in accordance with GAAP and that, in its filing, NIPSCO has included pension expense as an operating expense in the determination of revenue requirements and such amounts have not been challenged by the OUCC or the Industrial Group. He stated that GAAP also results in NIPSCO having a prepaid pension asset, representing the excess of contributions made to the pension trust over the computed pension expense. He testified that the prepaid pension asset results in a reduction of the pension cost reflected in the revenue requirement in this case directly benefitting customers and supporting the integrity of the pension fund. He noted that because investors have provided the capital supporting the prepaid pension asset, such investors are entitled to a return on their investment.

He addressed Ms. Stull's arguments that rate base should only include net plant and cash working capital, and that the prepaid pension asset is neither. He explained why, in addition to net plant and cash working capital, rate base can include other investor-supplied investment such as inventory, prepayments and regulatory assets, and why the prepaid pension asset meets the common regulatory definition of working capital. He also explained why, under GAAP, pension expense is directly reduced as a result of the prepaid pension asset. He noted that neither Ms. Stull nor Mr. Rackers objects to NIPSCO including pension expense as a recoverable cost, nor do they object to the reduction in pension expense attributable to NIPSCO's prepaid pension asset. He characterized their position as, in effect, requesting that NIPSCO's customers benefit from NIPSCO's actions to reduce cost of service (through a reduced pension expense) without customers paying investors for the cash they contributed to effectuate the cost of service reduction.

Mr. Felsenthal testified that in addition to this quantifiable benefit that NIPSCO customers receive, there are qualitative benefits as well. First, and foremost, NIPSCO's employees are protected by funding the benefits that they have already earned. Second, a well-funded pension plan allows NIPSCO to attract and retain qualified employees providing the level of service expected by NIPSCO customers. Third, NIPSCO's perceived financial strength has been increased by eliminating unfunded obligations, preserving its status with rating agencies.

Mr. Felsenthal explained that Mr. Rackers is wrong that the difference in the previously reported prepaid pension asset at December 31, 2008 and the growth in the prepaid pension asset from December 31, 2008 until June 30, 2015 are attributable to the mergers of NIFL and Kokomo. Instead, he testified, the increase from the previously reported prepaid pension asset balances at December 31, 2007 and December 31, 2008 is due to including a previously omitted NIPSCO prepaid pension asset account balance having nothing to do with the mergers of NIFL and Kokomo. He stated that the main reason for the growth in the prepaid pension asset from December 31, 2008 to June 30, 2015 is due to contributions to the pension trust required to restore the pension trust to reasonable funding levels after the poor stock market performance that occurred in 2008.

Finally, Mr. Felsenthal took issue with Mr. Rackers' allegations that the pension asset is the result of "excessive" contributions to the pension trust. He stated that, in fact, the contributions to the pension trust result in NIPSCO's pension plan being funded, on an ERISA basis at around 100% as of June 30, 2015, which he characterized as a prudent decision benefitting NIPSCO and its customers.

C. Mr. Isennsee. Mr. Isensee addressed various revenue requirements issues and pro forma adjustments raised by the OUCC and the Industrial Group. First, he testified that NIPSCO disagreed that the prepaid pension asset should be excluded from rate base. He explained that the approach of only including pension expense in the calculation of the cost of service ignores the costs associated with the investor capital required to finance any difference between the amounts contributed to the plans and the amounts recovered in rates as expense. He explained that similar to the calculation of the net book value of a capital asset, NIPSCO has included the net value of the prepaid pension asset in rate base by subtracting from its overall investment (contributions to the plan) the amount which has been recovered through rates via historical pension expense amounts included in revenue requirements. He noted, however, that NIPSCO would not be opposed to an alternative treatment of including the prepaid pension asset as a zero-cost component of the capital structure instead of including it in rate base. He opined that, due to the similarity of the OPEB liability and the prepaid pension asset, consistent treatment in the capital structure would not be inappropriate.

Regarding amortization periods for deferred regulatory assets, Mr. Isensee noted that NIPSCO originally proposed a 2-year amortization period on the basis that two years represents a likely period of time between this rate case and NIPSCO's next retail electric rate case. While NIPSCO still believes that to be the case, Mr. Isensee offered that it would not be unreasonable to utilize a longer amortization period for these regulatory assets provided: (1) the assets are either included in rate base (and would earn a return) or the deferred amounts are recovered outside of rate base over such a longer period of time with carrying costs; and (2) any unrecovered amounts at the time of NIPSCO's next electric rate case are allowed to be reflected in rates and fully recovered in such future rate case. He noted that rate base treatment is appropriate for the T&D costs, the federally mandated costs, and the MATS regulatory assets, given that they are largely comprised of capital investments. He agreed that removal of these regulatory asset amortizations from base rates once they are fully amortized is reasonable.

Regarding the amount of rate case expense, Mr. Isensee addressed the Billing System New Rate Implementation costs of $420,000, which reflects the expected cost to implement the impacts from the rate case into the customer billing system. Further, he explained that the estimate is based upon an estimate of hours required to implement key changes to NIPSCO's customer information system. He also provided an update to rate case expense, supporting an amount of $2,244,038.

Regarding the capitalization rates used for pro forma adjustments relating to payroll expense, payroll taxes, pension expense, OPEB expense, and medical insurance expense, Mr. Isensee testified that the rate proposed by Mr. Morgan does not perfectly reflect the capitalization ratio actually experienced or applied during the applicable period. Accordingly, he did not believe using the rate of 68.64% for the O&M component is appropriate. Instead, Mr. Isensee suggested it would be more appropriate to update the capitalization rate based on post-test-year actual experience, which produces an updated capitalization rate of 26.11% (with the O&M component being 73.89%).

Regarding Mr. Morgan's proposal to use the most recent 12 months as the base amount to which a 4.5% health inflation rate should be applied, Mr. Isensee agreed that this may be an acceptable approach. However, he pointed out that there were certain medical insurance expenses which were not included in Mr. Morgan's data. Therefore, Mr. Isensee recalculated Mr. Morgan's proposed adjustment to include these amounts, and requested that the Commission consider this update in arriving at revenue requirements determination.

In response to Mr. Etheridge's proposal to use a 3-year average for the LNG Liquefaction, Environmental Normalization and Annualization, and Vegetation Management expense adjustments, instead of the 5-year average proposed by NIPSCO, Mr. Isensee stated that NIPSCO believes that a 5-year average is more reasonable in that it statistically takes into account more data points than does a 3-year average. Even more important, Mr. Isensee stated, NIPSCO does not believe it is appropriate to arbitrarily utilize varying time periods for historical averages of expenses, noting that this gives a perception of "cherry picking" the data.

With regard to uncollectable expense, Mr. Isensee disagreed with Mr. Morgan's proposal to use a 3-year rate instead of the test-year amount. He demonstrated that when reviewing the last five years of historical data, both the percentage of write-offs to revenues and the percentage of bad debt expense to revenues are trending upward. For this reason, he opined that a test-year expense level is more appropriate.

Mr. Isensee generally agreed with Mr. Morgan's proposal to normalize test-year outage costs for each generating unit that had a planned outage during the test year. However, he pointed out that Mr. Morgan excluded certain outage costs in his calculation. Accordingly, Mr. Isensee recommended a more simplistic approach of reviewing actual planned outage costs over the last five years to determine the appropriate amount to include in the revenue requirement. Additionally, he suggested a more holistic approach that takes into consideration outage costs recorded to all FERC accounts. Mr. Isensee requested that the Commission consider this additional information should it determine that a normalization approach is more appropriate than NIPSCO's approach in which test-year fixed, known, and measurable costs were used.

Mr. Isensee disagreed with Mr. Morgan's proposal to normalize the test-year expenses for NIPSCO's hydro units by removing a one-time maintenance cost that occurred during the test year because the items identified and removed are actually recurring in nature. He stated that these costs include labor increases, annual expense costs, related repairs, and other various maintenance items.

Mr. Isensee also took issue with Mr. Morgan's proposal to exclude certain of NIPSCO's labor expenses, specifically signing bonuses paid to bargaining unit employees and work continuity expenses. He disagreed that these are non-recurring expenses. He noted that NIPSCO's labor contracts typically include these payments and that NIPSCO's proposal was to normalize these costs over the contract period, thus recognizing that these expenses will not be incurred each year.

Mr. Isensee disagreed with Mr. Etheridge's recommendation that NIPSCO's O&M expense be reduced to capture incremental savings associated with its AMR project. He stated that the savings estimated by Mr. Etheridge are not fixed, known, and measurable. Moreover, he noted that due to increased bargaining unit headcounts, any savings realized from this project have been and will continue to be offset by costs associated with the addition of incremental positions.

Mr. Isensee agreed with Mr. Morgan's update to the public utility fee as well as updating NIPSCO's state income tax expense to reflect a state income tax rate of 6.5%. He noted that this rate will be in effect on March 31, 2016, the conclusion of the 12-month period following the end of the test year.

Regarding the method of recognizing annual merit increases for NCSC employees, Mr. Isensee conceptually agreed with Mr. Morgan that such costs should be annualized for the entire test-year period. However, he disagreed with Mr. Morgan as to how to precisely calculate this adjustment using his test-year annualization method. Specifically, Mr. Isensee pointed out that the annualization calculation should use a net cost-of-service amount for payroll taxes and employee benefits, not just for labor and calculated an alternative adjustment along these lines.

D. Mr. McCuen. Mr. McCuen disagreed with Mr. Morgan's position that the proper state income tax rate to use for ratemaking purposes in this case is 6.25% noting that the state income tax rate in effect within one year of the test year cutoff date is 6.50% and that therefore this is the appropriate fixed, known and measurable rate to use. He noted that the 6.50% rate is consistent with the rate proposed by Mr. Rackers.

Mr. McCuen disagreed with Mr. Rackers' position with respect to use of the ARAM for excess deferred state income taxes. He stated that Indiana Code is in conformity with the Internal Revenue Code and therefore NIPSCO is restricted to the use of ARAM with regard to excess deferred state income taxes. He criticized Mr. Rackers' reliance on a New Hampshire regulatory decision and a New York regulatory decision, noting that neither New Hampshire nor New York law applies in Indiana. Mr. McCuen also noted that, from a historical and consistency standpoint, NIPSCO has treated both excess and deficient/unprovided state taxes in the same manner. Mr. McCuen also disagreed with Mr. Rackers about the amount of excess State deferred income tax that NIPSCO should amortize over five years if such were allowed, and provided an alternative calculation reflecting the tax rate in effect in 2015 and the federal benefit.

Mr. McCuen also noted that once the Federal PATH Act passed, NIPSCO recorded the effects in December 2015, and that its passage and NIPSCO's booking of the effects increased NIPSCO's deferred tax account by $32 million.

E. Mr. Moul. Mr. Moul responded concerning NIPSCO's rate of return presented by Mr. Woolridge, Mr. Gorman, and Mr. Chriss. He also updated selected schedules that were part of NIPSCO's Exhibit No. 13, Attachment 13-A.

Mr. Moul offered several criticisms about the assumptions and methodologies employed by Dr. Woolridge and Mr. Gorman. Mr. Moul's primary criticism was that the returns on equity recommended by Dr. Woolridge and Mr. Gorman seriously understate NIPSCO's cost of equity. Further, he stated that neither recommendation provides NIPSCO the level of return on invested capital it needs to be competitive in the current financial markets. He also noted that Mr. Gorman proposed the use of a hypothetical capital structure, which should be rejected. In contrast, he stated that the Commission can reasonably rely on the evidence that he developed, including the updated results of his models that show that the allowed return should be 10.75% and not the unreasonably low returns suggested by Dr. Woolridge and Mr. Gorman.

Mr. Moul testified that the financial community would be extremely concerned, if not shocked, if the Commission set NIPSCO's cost of equity at the level proposed by Dr. Woolridge (8.70%) because such a rate of return is seriously deficient and will not provide NIPSCO with the opportunity to earn its investor required cost of capital for the rate effective period. He emphasized that, technical disputes about methodology and data aside, Dr. Woolridge's proposed cost of equity is simply not representative of the returns investors can earn on other investments of comparable risk, including investments in other utilities like NIPSCO.

Similarly, Mr. Moul testified that the rate of return on common equity proposed by Mr. Gorman is too low. This low rate of return on common equity can be traced to improper inputs and/or emphasis in the models used by him to measure the cost of equity. Mr. Moul stated that these inputs do not fully reflect investor expectations or are lacking in other regards.

Mr. Moul also addressed Mr. Chriss' citation of recent returns authorized for other electric utilities noting that while the trend in these returns have been downward for the past several years in response to declining interest rates, in his opinion, we are experiencing a trough in those returns because future returns will respond to increases in capital costs. He also noted that, even setting aside the future up-tick in capital costs, the OUCC's and Industrial Group's proposed returns do not measure up to returns being granted currently by other state commissions.

F. Ms. Bulkley. Ms. Bulkley responded to the testimony of Messrs. Rutter and Gorman. She clarified both the assets valued and the methodology she relied on. She noted that Attachment 14-B to her direct testimony provides an opinion as to the current value of NIPSCO's electric utility assets, including intangible plant, production plant, transmission, distribution, general and common plant. She also testified that the methodology that she relied on is consistent with the methodology that was used to develop the current value of NIPSCO's assets in Cause Nos. 43969 and 43526 and is generally consistent with the methodology used to develop the value of NIPSCO's assets in both cases.

G. Dr. Gaske. Dr. Gaske submitted updated workpapers to reflect changes in revenue requirement, corrections, and positions with which he agreed. He noted that the OUCC recommends that all four methods, specifically 12-CP, POD, BIP, and P&A should be considered in allocating NIPSCO's demand-related production costs, and that Mr. Watkins expressed concern with the use of the 4-CP method. Dr. Gaske disagreed with Mr. Watkins' criticism of the 4-CP method. He stated that once installed and part of the utility's portfolio, any generation asset is available for dispatch at any time. The 4-CP method recognizes the classes call on the assets throughout the year, and it considers that the utility will call on all resources during the highest peak and only use the more efficient plants at times of lower demands.

Dr. Gaske noted that Mr. Mancinelli agrees with the 4-CP method for the allocation of demand-related production costs, however, Mr. Mancinelli argued that the test year peak demands need to be weather normalized. Dr. Gaske testified that he disagreed stating that NIPSCO's system is designed such that it is able to meet the actual system peak demand. A weather normalization adjustment would assume that the system is designed for normal weather conditions when, in reality, it is designed to meet demand during abnormal conditions. Dr. Gaske also stated that test year demand balancing adjustments are not incorrect. He stated that the balancing adjustments Mr. Mancinelli is referring to are intended to ensure that the estimates of total demand for all rate classes matches the total amount of electricity produced for the system at that time.

Dr. Gaske disagreed with the recommendation of Mr. Phillips for modifying the calculation of the peak demands used in the allocation of production costs as it would inappropriately double count the value that interruptible customers receive from the interruptible credit. Because the interruptible credit pays a customer every month for the potential that it might be interrupted; it would be double-counting to also reward the customers by adjusting their actual demands downward when they buy through during interruptions that occur for economy energy reasons. Dr. Gaske agreed with Mr. Phillips that the load associated with Rate 625 (Metal Melting Service) used to calculate the 4-CP demand allocator needs to be adjusted, consequently, he updated the ACOSS. Further the loss adjustments have been revised in the ACOSS to recognize that some "transmission" customers take service at 138 kV and therefore have lower line losses, as discussed by Mr. Mancinelli. Dr. Gaske disagreed with Mr. Mancinelli's recommendation of how each component of other revenues should be allocated to the various rate classes. He stated that his objective is to use these other revenues to offset the fixed costs incurred by all classes on an equal basis relative to their contributions to the margin. Dr. Gaske stated that Mr. Mancinelli's recommendation generally ignores the overhead and O&M costs associated with generating the other revenues. In addition, because many of these revenues are not collected on a strict cost of service basis, there is not necessarily a direct relationship between costs and other revenues. For these reasons, Dr. Gaske testified it is more appropriate to treat the other revenues as a general source of funds that is available to offset the overall costs of serving all classes on a pro rata basis.

Dr. Gaske also discussed rate mitigation. He described Mr. Mancinelli's recommendation that the industrial customers not be burdened with mitigation costs. He noted that Mr. Chriss agrees with NIPSCO's proposals with the exception of the allocation of the subsidy reductions. Mr. Watkins also proposed to move all classes closer to rate parity, limit all class increases (except

NIPSCO's interdepartmental rate) to no more than 1.5 times the system-wide average percentage increase. Dr. Gaske disagreed with all of these recommended changes to the rate mitigation and revenue allocation. He explained that all of these alternative proposals offer differing opinions and generally narrow interests of individual parties, but NIPSCO's proposal uses the ACOSS as a guide and adjusted the results to mitigate maximum rate increases but balancing everyone's goals.

Dr. Gaske also disagreed with the assertions of Messrs. Watkins, Howat and Rábago regarding an increase in fixed charges. Dr. Gaske stated that the production and delivery of electricity consists of both fixed costs and variable costs. He stated these witnesses recommend a rate structure that recovers fixed costs in variable energy charges, but would have the rate structure overstate the marginal cost of electricity and discourage consumption that would be efficient in the sense that the marginal benefit of consuming additional units of electricity exceed the marginal cost of the energy required to produce that electricity.

Dr. Gaske also contested Mr. Rábago's assertion that Bonbright's objectives for rate structures bear no resemblance to NIPSCO's concept of fixed-variable alignment citing to Bonbright and noted that the recovery of fixed costs in a fixed customer charge or semi-variable demand charge, and variable costs in a variable energy charge is consistent with nearly every one of Bonbright's criteria. Dr. Gaske noted that NIPSCO's rate design is far from straight-fixed variable rates, and not every fixed charge is in the higher fixed charge fee. Therefore, many of the theoretical arguments adduced by Messrs. Watkins and Rábago fail to address NIPSCO's actual rate design proposals in this proceeding because they assume all or most of the fixed costs are to be recovered in the customer charge. Further, Dr. Gaske stated that the proposed increases in customer charges do not violate that regulatory principle of gradualism. He stated that Mr. Watkins only looks at the increase in fixed charges, not in the overall charge. The proposed increases in customer charges significantly reduce the percentage increases in energy charges that otherwise would be required. Further, NIPSCO's proposed monthly customer charges reasonably compare to other electric utilities in the region, and the proposed charges were supported by a fully-allocated cost of service study, analyses of customer impacts, and testimony.

Dr. Gaske addressed Mr. Chriss' concerns regarding the proposed rate design for Rate 726. NIPSCO's proposal would increase the demand charges 9.2% to 10.2% and increase the energy charge 23.7%. This design results in approximately 46% of the revenues for the class being collected through the energy charge. Since the ACOSS shows that approximately 58% of the costs are demand related, Mr. Chriss believes this will result in a shift in demand cost responsibility from lower load factor customers to higher load factor customers in this class. Dr. Gaske did not oppose the higher demand charge for Rate 726 as proposed by Mr. Chriss which would lessen cross-subsidization within the class. He also generally agreed to Mr. Mancinelli's recommended rate design proposal for Rate 733 and stated he is willing to review and consider the rate design change in a future rate case. Dr. Gaske also does not oppose Mr. Chriss' recommendation to break out the presentation of base tariff rates by generation, distribution, transmission and fuel functions.

Dr. Gaske also noted that he updated NIPSCO's cost of service and rate design schedules to reflect NIPSCO's rebuttal position, including, but not limited to: changes to the revenue requirement, minor changes to the billing determinants for some of the rate classes, a change in the calculation of the line-loss adjustment for the relevant demand and energy allocators for "transmission" customers, a change in the calculation of peak demands in certain months for the Metal Melting Rate 725, a change to the allocation of current income taxes and a change to the LED rate calculation.

16. The Settlement Agreement. The Settlement Agreement is attached hereto and incorporated by reference. The Settlement Agreement provides as follows:

A. NIPSCO's base rates will be designed to produce annual revenue requirements of $1,644,927,046 (prior to application of surviving Riders), which represents a decrease of approximately $54 million from the amount originally requested by the NIPSCO.

B. NIPSCO's authorized net operating income will be $217,123,565.

C. NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case, and the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.74%, yielding an overall return for earnings test purposes of $217,123,565, based upon an original cost rate base of $3.2 billion, inclusive of materials, supplies, production fuel, and regulatory assets as proposed in NIPSCO's case-in-chief; NIPSCO's actual capital structure (including the prepaid pension asset, as discussed below); and an authorized return on equity of 9.975%.

D. NIPSCO's overall weighted average cost of capital is computed as follows:

	% of Total	Cost %	WACC %
Common Equity	47.42	9.975	4.73
Long-Term Debt	33.72	5.71	1.93
Customer Deposits	1.59	4.58	0.07
Deferred Income Taxes	19.12	0.00	0.00
Prepaid Pension Asset	-4.93	0.00	0.00
Post-Retirement	2.99	0.00	0.00
Liability			
Post-1970 ITC	0.09	8.20	0.01
Totals	**100.0%**		**6.74%**

E. During the time these rates remain in effect, NIPSCO should finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Indiana Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39, with at least 60% debt capital.

F. The depreciation accrual rates recommended by Mr. Spanos and presented in this proceeding (the Depreciation Study) should be approved, except that pro-forma depreciation expense should be reduced by approximately $17.3 million due to proposed changes to not include the increase in depreciation expense associated with Bailly Unit 8 (approximately $11.1 million) and to adjust the depreciation rates as proposed by Mr. Andrews as outlined in his testimony (approximately $6.2 million). The Settling Parties agree that NIPSCO may seek an adjustment to its depreciation rates subsequent to its filing of its next IRP (and all Settling Parties reserve their rights to raise any issue in that proceeding).

G. Annual amortization expense shall be $15.4 million and includes (1) rate case expenses of $2,244,038 for this case amortized over a period of seven years and after the completion of the 7-year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense; and (2) all other deferred regulatory asset costs, amortized over seven years with the exception of the amortization of the electric vehicle regulatory asset which is amortized over a 3-year period.

H. Rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that NIPSCO should design its rates using the structure of its existing 600 Series tariffs. Further, Joint Exhibit B to the Settlement Agreement specifies the revenue allocation agreed to by all Settling Parties. This revenue allocation is determined strictly for Settlement Agreement purposes and is without reference to any particular, specific cost allocation methodology. This revenue allocation shall be utilized for purposes of the demand component of the ECRM, EERM, FMCA, and RTO rate adjustment mechanisms. Regarding the RA Tracker, this mechanism shall utilize the demand allocators set forth in Joint Exhibit C to the Settlement Agreement, which will be modified to reflect the amount of interruptible load contained in Rates 732, 733, and 734. For purposes of establishing any rate schedules allowing for the recovery of 80% of NIPSCO's approved capital TDSIC expenditures and costs pursuant to Indiana Code § 8-1-39-9(a), the Settling Parties agree that Joint Exhibit D to the Settlement Agreement reflects, pursuant to Indiana Code § 8-1-39-9(a), the customer class revenue allocation factors that should be applied to firm load. The Settling Parties agree that allocation factors shown on Joint Exhibit D to the Settlement Agreement should be applied for the periodic recovery of any approved capital TDSIC expenditures and costs to properly account for differences between transmission and distribution customers. All other components of NIPSCO's cost allocation and rate design shall be as NIPSCO filed in its case-in-chief with the following exceptions or adjustments:

(1) The monthly customer charge for Rate 711 shall be $14.00;

(2) The monthly customer charges for Rates 720, 721, and 722 shall be $24.00;

(3) The demand charges for Rates 723, 724, 725, 726, 732, 733, 734, and 744 shall be modified as agreed by the Settling Parties; and

(4) The minimum charges for Rate 741 shall each be increased from their currently-approved levels by a percent equal to 4.51% (the system total increase in revenue requirement).

I. NIPSCO should be authorized to modify Rider 675, and the credits paid under the provisions of the new Rider 775 (relating to interruptible capacity) should be recovered from customers, with 75% of the costs recovered through NIPSCO's RA Tracker and 25% of the costs recovered through NIPSCO's FAC mechanism. Further:

(1) The limit on MW eligibility shall be 530 MW and the maximum amount to be paid in any calendar year under Rider 775 shall be $57 million;

(2) A new Option E should be incorporated into Rider 775 substantially as proposed by U.S. Steel;

(3) Rider Option C shall be revised to provide for two hours' notice for interruptions or curtailments and shall receive a demand charge credit of $9.00/kW-month;

(4) Customers having existing interruptible capacity under Rider 675 shall be entitled to re-enroll that same capacity in the same or other options under the new Rider 775 consistent with MISO requirements; and

(5) Incremental interruptible capacity (which is estimated to be 153 MW of the new interruptible capacity created as a result of this Settlement Agreement in excess of the presently subscribed 377 MW) shall be allocated first to customers showing a demonstrated economic need, but no more than 85% of that capacity shall be allocated to one customer.

J. The LED rates NIPSCO proposed in this Cause will be reduced to reflect all the reduced revenue impacts of the Settlement Agreement and an approximate 37% O&M reduction. The LED Rates to be proposed in NIPSCO's initial TDSIC tracker proceeding in Cause No. 44733 would apply to any mass retrofit program that may be approved by the Commission and a new placeholder tariff page will be proposed in this Cause.

K. The Settling Parties acknowledge that a significant motivation to enter into the Settlement Agreement is the expectation that, if the Commission finds the Settlement Agreement is reasonable and in the public interest, an order authorizing the increase in NIPSCO's rates and charges will be issued, but will not be effective until the first October, 2016 billing cycle, however, Rider 775 will be implemented and effective with the first billing cycle following issuance of a Commission Order.

17. <u>Testimony in Support of Settlement Agreement</u>.

A. <u>NIPSCO's Evidence in Support of the Settlement Agreement</u>.

(1) <u>Mr. Shambo</u>. Mr. Shambo provided an overview of the Settlement

Agreement and focused on the major components. He noted that the vast majority of the differences in the proposed revenue requirement among the parties can be reduced to three issues: (1) NIPSCO's authorized return on equity; (2) treatment of NIPSCO's prepaid pension asset; and (3) depreciation expense associated with the earlier retirement date for Bailly Unit 8.

With regard to the agreed-upon return on equity, Mr. Shambo emphasized that too low of a return would provide a level of financial insecurity that would place inappropriate risk upon NIPSCO's ability to attract capital needed to provide reasonably adequate service and facilities. However, he also noted that NIPSCO recognizes that returns have trended downward since its last rate case. For these reasons, the Settling Parties agreed upon a return on equity of 9.975%. Mr. Shambo noted that NIPSCO had improved key service metrics for the benefit of customers, such as CAIDI, SAIDI, and customer perception scores, all supporting the agreed-upon return on equity and also support NIPSCO's need to remain financially stable to support further investments. Mr. Shambo also stated that NIPSCO continues to recognize the need for and importance of good customer service and performance, and NIPSCO will continue to work on improving its relationships with customers and its customer service and economic development efforts.

With regard to the prepaid pension asset, Mr. Shambo noted that the Settling Parties agreed that the electric portion of the asset would be included in NIPSCO's capital structure as an offset to its deferred taxes. He noted that this treatment is consistent with the Commission's recent Indiana-American Water Company base rate case order in Cause No. 44450.

With regard to the appropriate depreciation rates for Bailly Unit 8, Mr. Shambo reiterated that NIPSCO intends to retire Unit 8 at the same time as Unit 7, no later than 2023; however NIPSCO also understands the other parties' reluctance to agree to revised depreciation rates until after a thorough review of NIPSCO's 2016 IRP. Accordingly, NIPSCO agreed not to petition to change its depreciation rates to reflect the earlier retirement of Bailly Unit 8 until after the submission of its 2016 IRP.

Another significant issue addressed in the Settlement Agreement is the allocation of costs recovered through Riders. Mr. Shambo explained that Joint Exhibit C to the Settlement Agreement contains the demand allocators to be utilized in the RA Tracker on a going forward basis, which will be modified to reflect the amount of interruptible loads to be contained in Rates 732, 733, and 734. Further, Joint Exhibit D to the Settlement Agreement reflects the customer class revenue allocator factors that the Settling Parties have agreed should be applied to firm load for the recovery of 80% of NIPSCO's approved capital TDSIC expenditures and costs.

Mr. Shambo next testified about the revenue allocation determination contained in the Settlement Agreement. He emphasized that the Settlement Agreement balances interest among various classes to achieve the agreed-upon revenue allocation. One of these key balancing factors, according to Mr. Shambo, is the importance of NIPSCO's large industrial customers to the Company's service territory. In addition, another key balancing factor relates to mitigating the burden of the rate increase for residential customers. In Mr. Shambo's opinion, the class allocation agreed to in the Settlement Agreement met these key objectives, as is illustrated by the percent impact on key customer classes – the increase to residential customers of 5.37%, the increase to large industrial customers that compete globally averaging 2.0% and the increase to larger general service classes averaging 5.5%.

Additionally, as part of the Settlement Agreement, NIPSCO has agreed to reduce its proposed LED default lighting rates while maintaining the proposed rate increase to the traffic lighting rate.

Mr. Shambo also testified that the Settlement Agreement provides for gradualism in the impact to customer classes, as well. He noted that the average revenue increase to NIPSCO's ten largest customer classes is only 4.4% and that Rate 720 (Commercial and General Service – Heat Pump) is the only customer rate that will receive an increase greater than 6.5%. He noted that while some classes may still be subsidizing other classes, the industrial classes saw an increase of over 20% in the last rate case. In this case, he explained that the Settling Parties have attempted to address some subsidies that harm customers that compete on a global basis.

With regard to rate design, Mr. Shambo explained that the Settling Parties' objectives were to maintain NIPSCO's existing rate structure, increase the amount of interruptible, and mitigate the rate increase on residential customers. With regard to the customer charge, Mr. Shambo noted that the customer charge for residential customers would increase to $14.00 per month under the Settlement Agreement.

With regard to Rider 775 and interruptible credits, Mr. Shambo testified that the revisions to Rider 775 are a key Settlement Agreement component based on compromises from all Settling Parties. He noted that the interruptible credits provide value to all customers in terms of both reliability and economics. He also supported the agreed-upon 530 MW limitation on interruptible capacity available under Rider 775 and the dollar cap of $57 million. He explained in detail the changes to the various options under Rider 775.

Mr. Shambo also explained the modification, per the Settlement Agreement, to Rider 776 clarifying that NIPSCO must confirm all backup service requests made in full conformance with the rider.

Mr. Shambo also addressed NIPSCO's initial proposed low-income program. He noted that both the OUCC and CAC opposed the program as proposed. Accordingly the Settlement Agreement does not provide for such a program and NIPSCO is no longer proposing such a program in this case. However, he emphasized that NIPSCO will agree to meet with the OUCC and any other interested parties, independent of this rate case, to discuss the parameters of a similar program that could be requested in the Company's next base rate case.

Mr. Shambo also discussed the Settlement Agreement in the context of the public interest. He noted that the Settlement Agreement is consistent with the public interest by providing all customer segments with a reasonable outcome and providing NIPSCO with a solid foundation from which it can invest in northern Indiana's energy infrastructure, help fuel job creation and economic growth, and provide customers with means to manage their energy consumption and bills. He discussed at length the challenging economic period for NIPSCO's service territory, how those conditions have impacted large industrial customers, residential customers, and other rate classes, as well as NIPSCO itself. He noted one component of the Settlement Agreement designed to directly address economic issues, the LaPorte County Kingsbury Industrial Park infrastructure substation upgrade and corresponding transmission and distribution upgrade needs in Cause No. 44733. He noted that it is to the benefit of all NIPSCO customers that this site be returned to an economically viable industrial site. Finally, Mr. Shambo emphasized that the Settlement Agreement reflects a delicate balance, with interrelated provisions that accommodate the varying interests of all Settling Parties in a reasonable way. He concluded by emphasizing that the Settlement Agreement is consistent with the public interest because it represents a comprehensive resolution of all of the issues in this proceeding in a way that balances the interests of NIPSCO with those of its customers without the expense and risk of continued litigation and potential appeal. He noted that time is of the essence in approving the Settlement Agreement without any material changes by no later than July 27, 2016, in particular so, pursuant to the terms of the Settlement Agreement, that industrial customers such as U.S. Steel may begin to enroll in the revised Rider 775, which will be implemented and effective with the first billing cycle following issuance of a Commission Order.

(2) Mr. Isensee. Mr. Isensee explained that consistent with the Settlement Agreement, NIPSCO has modified its original and rebuttal requests and now proposes to recover the gross revenue amount of $1,681,746,699, which reflects a revenue increase of $72,500,000 as compared to test year pro forma results based on current rates. He further explained that this will provide NIPSCO the opportunity to earn net operating income of $217,123,565. He noted that the Settlement Agreement revenue requirement of $1,681,746,699 reflects a reduction of $54,087,616 from NIPSCO's original request as filed in its case-in-chief.

Mr. Isensee also described the expense adjustments agreed to in the Settlement Agreement that differed from NIPSCO's case-in-chief and rebuttal positions. First, he noted that the Settlement Agreement reflects implementation of new depreciation rates for electric and common property. He noted that these depreciation rates include an agreed upon reduction from NIPSCO's position of approximately $17.3 million related to the change in the expected retirement date of Bailly Unit 8 from 2023 to 2029 and the incorporation of adjustments to depreciation rates identified by Mr. Andrews.

Mr. Isensee explained that the Settlement Agreement reflects a longer amortization of rate case cost related to this case. He stated that rate case expenses, the remaining deferred Sugar Creek depreciation and carrying charge amounts, annual amortization of Sugar Creek depreciation and carrying charges, amortization of the deferral of 20% of federally-mandated costs; amortization of T&D costs; and amortization of the deferral of 20% of approved MATS costs will be recovered over 7 years rather than 2 years as proposed by NIPSCO. After the completion of the 7-year period, NIPSCO agrees to make a tariff filing to reflect the reduction in these amortization expenses.

Mr. Isensee testified that the Settlement Agreement decreases test year operating expenses to reflect the decrease in income taxes driven by the other expense adjustments to which the Settling Parties have agreed, and decreases test year net operating income to arrive at a total revenue requirement of $1,681,746,699 as agreed upon by the Settling Parties. Finally the Settlement Agreement reflects the reclassification of the prepaid pension asset balance of $216,303,291 from a rate base item to a zero cost balance item included in the capital structure.

Mr. Isensee explained the calculation of the Settlement Agreement increase in gross revenue from base rates in the amount of $72,500,000, which is calculated to provide NIPSCO with the opportunity to earn a return of 6.74% on a net original cost rate base of $3,221,417,882. Corresponding adjustments were then made for federal income taxes, state income taxes, utility receipts tax, public utility fee and uncollectible accounts.

Finally, Mr. Isensee provided the computation of the overall weighted cost of capital for NIPSCO, reflecting the Settlement Agreement return on equity of 9.975% and the inclusion of the prepaid assets as a zero cost balance item in the capital structure.

(3) Mr. Westerhausen. Mr. Westerhausen described the Settlement Agreement changes to NIPSCO's Proposed Tariff and sponsored Attachment 19-S-A representing the Settlement Agreement Tariff. He explained that rates and charges were revised consistent with the agreed to base rate revenue of $1.68 billion and class allocations contained in the Settlement Agreement. He noted that the customer charge for residential customers was decreased from the originally proposed $20.00 to $14.00, an increase from NIPSCO's current customer charge of $11.00. He also described the changes in other customer classes' customer charges.

Mr. Westerhausen explained that Rider 775 was modified to include a total capacity limit of 530 megawatts and a total sum of demand credits availability of $57,000,000 in any calendar year. Additionally, Option C is revised to provide for two hours' notice for interruptions and curtailments and a demand charge credit of $9.00 per kw-month. Additionally a new Option E which, among other things, provides for 400 hours of interruption with at least two hours advance notice has been added. This option is subject to unlimited curtailment as far as quantity and duration. However, interruptions are limited to no more than one per day, no more than 12 consecutive hours, no more than four in any seven days of the week, and no more than 400 hours per rolling 365 days. In addition, he noted that Rider 775 includes revisions to provide customers with greater flexibility to re-allocate interruptible capacity among facilities and to migrate between options.

Mr. Westerhausen explained that Rider 776 was modified to be consistent with the recommendations of Mr. Dauphinais. Further, the Settlement Agreement provides that customers should be treated consistently whether they buy through Rider 775 or 776 and should not be subject to Riders.

With regard to Rider 777, NIPSCO's proposal for treatment of the EDR contracts and revisions to the Rider remains unchanged, including the deferral mechanism as described in

NIPSCO's case-in-chief, providing that NIPSCO is authorized to defer, as a regulatory asset, the discounted revenue associated with the EDR contracts that were in effect during the test year and that continue beyond the date of the new effective base rates.

With regard to Rate 750, NIPSCO added a column that would apply to any mass LED retrofit program that may be approved by the Commission in NIPSCO's latest electric 7-year TDSIC plan. This is essentially a placeholder for the finalized LED mass retrofit rate that will be proposed for final approval in conjunction with and subject to the approval of the TDSIC LED mass retrofit plan. Further, the LED rates proposed by NIPSCO initially were reduced to reflect the lower capital costs, capital structure and other reduced revenue impacts agreed to in the Settlement Agreement and an approximately 37% reduction in O&M expense.

Finally, Mr. Westerhausen sponsored Attachments 19-S-B, 19-S-C and 19-S-D that provided a revenue proof incorporating the agreed to revenue requirement and the modifications in the Settlement Agreement Tariff as described in his testimony.

(4) Ms. Smith. Ms. Smith testified that the Settlement Agreement balances the interest of NIPSCO's shareholders and ratepayers. She stated that the Settlement Agreement is a product of intense negotiations, with each party offering compromise to challenging issues. She further stated that while the Settlement Agreement represents a balance of all interests, given the number of benefits provided to ratepayers as outlined in the Settlement Agreement, the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, supported by evidence and should be approved.

Ms. Smith testified to the ratepayer benefits of the Settlement Agreement, noting that the Settlement Agreement resulted in a $54,000,000 reduction in revenue requirements from NIPSCO's requested increase of $126,587,616. This reduces the residential customers' rate impact from 11.02%, as NIPSCO originally proposed, to 5.37%, and reduces the rate impact for all major classes from NIPSCO's original proposal. She stated that NIPSCO's evidence recommended a 10.75% return on equity and the OUCC and Industrial Group advocated for a considerably lower return on equity. She testified that as a result of the negotiations, a compromise was reached, resulting in a 9.975% return on equity, meaning shareholders will receive less return from ratepayers not only from rate base, but also the lower return on equity will carry forward to existing trackers.

Ms. Smith noted that there are other benefits of the Settlement Agreement, including NIPSCO's agreement to finance any new projects over $100,000,000 and requiring a CPCN with at least 60% debt until its next rate order. Further, NIPSCO has agreed to exclude the increased depreciation expense associated with Bailly Unit 8. She noted that the OUCC appreciates that NIPSCO will now wait until after its 2016 IRP analysis and associated stakeholder process to determine how early retirement will affect NIPSCO's entire resource plan. This decision results in an approximate $11,100,000 savings to ratepayers. She stated NIPSCO also agreed to further adjust the depreciation rates downward by $6,200,000, meaning a total depreciation reduction of $17,300,000 from NIPSCO's filed position.

Ms. Smith also stated that the OUCC staff experts agree that the Settlement Agreement revenue allocation is a fair compromise, even though the agreed allocation is without reference to any particular, specific cost allocation. The revenue allocation was important to the OUCC, and Ms. Smith stated that the Settling Parties spent a great deal of time negotiating the allocations amongst all rate classes. Further, Ms. Smith noted that as part of the comprehensive Settlement Agreement, the OUCC and NIPSCO reached a compromise on the fixed charge. The residential charge will be \$14, an increase of 27% versus 82%, and the small commercial charge will be \$24, or an increase of 20% versus 50%. Also, the Settlement Agreement provides for changes in the interruptible rider structure, including increasing the cap to \$57,000,000 annually for credit allocation. This will help the larger industrial customers, who are exceedingly challenged to remain financially viable. Ms. Smith noted that the impact to the Indiana economy if one or more of these Industrial Group facilities close could be devastating, including the loss of thousands of Indiana jobs. And if some of the large Industrial Group customers leave, NIPSCO's fixed costs would then be allocated among the remaining customers. Also, the interruption may alleviate some necessity to build new generation capacity.

Ms. Smith also noted that the Settling Parties agreed to the \$4,741,390 credit in base rates for OSS margins, but rather than the 50/50 split, NIPSCO will flow through the RTO tracker 100% of all OSS margins, with customers receiving 100% of all OSS margins greater than zero dollars. Ratepayers will now receive 100% of the margins that result from OSS and will no longer be required to share such margins with shareholders.

Ms. Smith concluded that the OUCC recommends that the Commission find the Settlement Agreement to be in the public interest and approve it in its entirety.

(5) Mr. Phillips. Mr. Phillips stated that the Industrial Group has an interest in the Settlement Agreement, as their members take service under rate classes 624, 625, 632, 633, and 634, and the large industrial customers make up over 40% of NIPSCO's sales. Mr. Phillips recommended that the Commission approve the Settlement Agreement, as the Settlement Agreement is based on appropriate regulatory policy and sound ratemaking principles. The Settlement Agreement is a comprehensive agreement that resolves both revenue and the complex allocation and rate mitigation issues in this rate case, including the economic factors impacting industrial sales. Mr. Phillips also noted that the Settlement Agreement is the result of arms-length negotiations between the Settling Parties in order to reach a comprehensive Settlement Agreement.

Mr. Phillips noted that in summary, the Settlement Agreement should be approved because the Settlement Agreement is fair, reasonable and in the public interest; the Settlement Agreement mitigates the increase to the residential class and results in a significantly lower percentage increase to the residential class than NIPSCO's direct testimony; and the Settlement Agreement contains an array of industrial rate offerings that collectively provide a reasonable opportunity for these large customers that are subject to global competition to manage power costs and remain a viable and necessary segment of the Northwest Indiana economy.

Mr. Phillips noted that the Settlement Agreement does not adopt a particular cost of service methodology but takes into account the cost of service positions presented by the various parties in order to reach a fair and reasonable result. He explained that even though the Settling Parties disagreed on various methods, the resulting revenue increases under the Settlement Agreement reflect the range of evidence on generation and transmission cost allocation and appropriately reflects the issues and concerns raised by the Industrial Group. He noted that achieving cost-based rates has been a consistent challenge on the NIPSCO system and concluded that it was the Industrial Group's viewpoint that the results from the Settlement Agreement reasonably addressed the cost allocation concerns filed in its direct testimony. Mr. Phillips also noted that the Settlement Agreement addresses the cost allocation issue for NIPSCO's trackers, and was provided in Joint Exhibits B and D to the Settlement Agreement.

Mr. Phillips also noted that the Industrial Group has achieved other benefits as a result of the Settlement Agreement, including that NIPSCO will prepare tracker forecasts for industrial customers, so that customers can better budget electricity spend. Also, the Settlement Agreement provides for more interruptible service, which provides a benefit to all ratepayers. Mr. Phillips also noted that NIPSCO's revenue requirement is reduced from its direct case by $54.1 million, which benefits all major rate classes. To the extent that NIPSCO has capital trackers after the rate case, such as its pending TDSIC, the lower return and debt financing provision provides further benefits to all ratepayers by lowering the rate of return NIPSCO may be authorized to use in its capital trackers. The Settlement Agreement provides that prepaid pension is not included in rate base, and adopts the Industrial Group's recommendations on depreciation. Lastly, Mr. Phillips noted the Settlement Agreement provides that the increase in base rates will not be effective before October 2016, with a mechanism for implementing interruptible provisions upon issuance of a Commission Order, which provides a benefit to all ratepayers.

Mr. Phillips concluded that the Settlement Agreement, when taken as a complete package, reasonably resolves the Industrial Group's issues in this rate case and results in a fair and reasonable resolution for all of NIPSCO's customers. He recommended that the Commission approve the Settlement Agreement without any material changes.

(6) Mr. Mancinelli. Mr. Mancinelli testified that the Settlement Agreement terms represent an equitable compromise among the parties in this proceeding and are necessary for U.S. Steel to remain a customer on the NIPSCO system. U.S. Steel is one of the largest customers on the NIPSCO system, and is currently served under Rates 632 and 633. Mr. Mancinelli noted that the Settlement Agreement addressed his concerns going into this proceeding, namely that the steel industry is struggling, and therefore is sensitive to electricity prices. He noted that originally NIPSCO requested more than a $126 million increase in the system revenue requirement, but the Settlement Agreement reduced that by $54.1 million, leading to an agreed revenue requirement increase of exactly $72.5 million, or 4.51%. Mr. Mancinelli testified many other adjustments were made to the revenue requirement, including changes in amortization periods, depreciation rates, treatment of prepaid assets, and a lower return on rate base. Mr. Mancinelli further stated that the Settlement Agreement revenue requirement allocated to each customer class was a product of negotiations that represented a reasonable compromise among the

Settling Parties, giving consideration to very different views on the proper cost of service allocation methodologies. In recognition that one allocation method compared to another dramatically shifted costs among rate classes, the Settlement Agreement represents a reasonable balance among the different perspectives. The Settlement Agreement yields results that do not unduly harm one rate class over another; yet, the Settlement Agreement does not endorse one allocation method over another. Mr. Mancinelli testified that under the Settlement Agreement, compared to NIPSCO's filed direct testimony, nearly all rate classes are better off, with U.S. Steel having a resulting rate increase of 1.36% and 1.86% to Rate 632/732 and Rate 633/733, which allows U.S. Steel to manage its cost.

Mr. Mancinelli noted that the overall class rate increases combined with the Settlement Agreement rate structures for Rates 732 and 733 are reasonable. Rate design successfully generates target revenues for each class without unduly harming individual customers within the classes. Further, the Settling Parties recognized the benefit of additional interruptible capacity on the system from a resource planning and load retention perspective. Mr. Mancinelli noted that increasing the capacity cap is a good idea because it represents a win-win for all customers. Industrial customers benefit from reduced electricity costs in exchange for service interruptions. All other customers benefit from a lower net present value revenue requirement attributed to the deferral of new capacity additions as shown in NIPSCO's 2014 IRP.

Mr. Mancinelli also testified that the New "Option E" under Rider 775 is more valuable to NIPSCO given the terms of the interruptions. Option E provides a higher capacity value than the other existing options. Mr. Mancinelli noted that the changes to Rider 675/775 as proposed by the Settling Parties will significantly increase the interruptible demand credits available to U.S. Steel. These credits, in exchange for service interruptions, enable U.S. Steel to manage its electricity costs and remain on the NIPSCO system.

Mr. Mancinelli also testified regarding the specific provision in the Settlement Agreement regarding TDSIC allocations, which is specified in Joint Exhibit D to the Settlement Agreement. He noted that customers that do not use NIPSCO's distribution system should not pay for costs associated with those aspects of the system, and the Settlement Agreement is consistent with cost-causation principles and appropriately establishes how future NIPSCO electric TDSIC costs should be allocated between transmission and distribution customers.

Mr. Mancinelli further testified regarding his support of the implementation schedule, in that Settlement Agreement rates will not be effective until the October 2016 billing cycle, yet Rider 775, with interruptible capacity will be implemented and effective with the first billing cycle following an order from the Commission. For this reason, he noted that it is imperative that the Commission issue an order as expeditiously as possible.

Overall, Mr. Mancinelli recommended that the Settlement Agreement be accepted and approved by the Commission. He noted that the Settling Parties worked very hard to agree on an outcome that represented the best possible result for the each customer class and NIPSCO. He noted that the terms agreed to in the Settlement Agreement reflect a compromise that achieves a desirable and beneficial outcome for NIPSCO and its customers. The Settlement Agreement will allow U.S. Steel to remain a customer on the NIPSCO system. If the Settlement Agreement is approved, U.S. Steel estimates that its electric costs at the Gary Complex would be roughly 40% higher than the U.S. Steel facility with the lowest electric costs and that the electric costs at the Gary Complex would comparatively fall near the middle of the electric costs at the rest of U.S. Steel's other Northern American operations. Virtually all rate classes realize lower class rate increases. Residential customers realize a significantly lower class rate increase of 5.37% compared to NIPSCO's original proposal of 11.02%. Mr. Mancinelli also requested a timely Order from the Commission on or before July 27, 2016.

(7) Mr. Sommer. Mr. Sommer noted that IMUG was mainly concerned with street lighting in this cause. He noted that the significant modernization, economic, reliability, safety, and social benefits that an LED street light mass retrofit program offers are without question and are not opposed by any party in this Cause. He pointed out that the reduction to NIPSCO's proposed LED rates in this Cause will benefit those who choose to only have street lights converted to LED one or a few at a time. He also pointed out that the Settlement Agreement reduced the increase applicable to old technology street lights that otherwise was requested. He reviewed the many specific benefits that LED street lights will create. He noted that the Settlement Agreement provides the framework by which the broad LED street light customer, public convenience, and utility benefits can be brought to fruition with the finalization of NIPSCO's Cause No. 44733 TDSIC. Mr. Sommer encouraged the Commission to approve the Settlement Agreement.

18. Testimony Opposing the Settlement Agreement.

A. Mr. Chriss. Mr. Chriss noted that Walmart takes service under Rates 624/724 and 626/726. He argued that Walmart was not invited to participate in Settlement Agreement negotiations. Mr. Chriss disagrees with the OUCC that the Settlement Agreement represents all ratepayers' interest, mainly because Walmart was not a party to the Settlement Agreement negotiations and because the revenue allocation is a concern. He noted that Walmart does not oppose Settlement Agreement Terms 6, 7, 8, 9, 11, 12, 13, 14, 15, 16, 17, 18, and 19. Mr. Chriss stated that the Commission should reject the revenue allocation and approve his recommended allocation. He noted a concern that the ACOSS showed rate class subsidization, and that both Rates 724 and 726, along with several other classes currently paying subsidies in rates, receive increases above the system average increase of approximately 4.5%. He noted that his proposed allocation moves the customer classes closer to their respective costs of service. Further, he recommended that the Commission require NIPSCO to break out the presentation of base tariff rates for commercial and industrial rates by the generation, distribution, transmission, and fuel functions.

B. Mr. Rábago. Mr. Rábago argued that the Settlement Agreement includes an increase in the fixed customer charge from $11 to $14 per month per residential customer, which is a 27% increase in the fixed customer charge. He stated that the Settling Parties provided no evidence for the change, only that the number was achieved as the result of negotiation and compromise. Mr. Rábago noted that his arguments are the same as those in his direct for opposing an increase to the customer charge, including his concerns which claim: a lack of justification, a regressive impact on low-income customers, and a disincentive for energy efficiency. Mr. Rábago argued that the compromise between NIPSCO and the OUCC is an inadequate foundation for the approval of the fixed customer charge increase. He claimed that there is no economic theory that economic efficiency is improved by modifying rate structure to align with cost structure. He noted that the Settlement Agreement does not address the originally proposed low-income program, despite that the Settlement Agreement states on Paragraph 19, "[t]he Settling Parties agree that all other components of NIPSCO's filed tariff shall be approved as NIPSCO filed in its case-in-chief as corrected during the course of this proceeding." He noted that in his testimony supporting the Settlement Agreement, Mr. Shambo stated that the OUCC and CAC opposed the program, so NIPSCO is not proposing such a program. Mr. Rábago stated that CAC supports the program presented by Mr. Howat. He concluded that the proposed increase in the fixed customer charge and the elimination of any low-income assistance program is not just and reasonable, and not in the public interest. He recommended that the Commission disapprove any proposed increase in a fixed customer charge, and adopt Mr. Howat's proposal.

19. <u>Settlement Agreement Rebuttal Testimony</u>.

A. <u>Mr. Shambo</u>. Mr. Shambo addressed the comments of Mr. Chriss. He noted that there is not one right answer to cost allocation and rate design, and the allocation contained in the Settlement Agreement balances divergent interests on allocation, revenue and other issues and is reasonable. He stated that as testimony in support of the Settlement Agreement demonstrates, the agreed upon allocation of costs when combined with the agreed upon rate design results in reasonable rate increases for all customer classes. Mr. Shambo stated that Walmart simply proposes an alternative that is beneficial to them. He noted that Walmart's suggestion of an alternative allocation would significantly impact other elements of the Settlement Agreement and would undermine the agreed compromise. At the hearing held in this Cause, Mr. Shambo sponsored NIPSCO's Redirect Exhibit 1, which summarized Walmart's proposal and the Settlement Agreement proposal.

In response to Mr. Rábago's opposition to the residential customer charge agreed to in the Settlement Agreement, Mr. Shambo pointed out that the evidence in this case establishes that NIPSCO's fixed customer and distribution costs for each residential customer are greater than $14.00 per month, and that a $3.00 customer charge increase, from $11.00 to $14.00, is reasonable. He pointed to the Indianapolis Power & Light ("IPL") recent rate case order in Cause No. 44576 as support, wherein the Commission approved a change in IPL's customer charge from $11.00 to $17.00 and found that change to be consistent with gradualism. He further noted that the IPL order supports the proposition that rate structure should be consistent with cost structure in order to improve economic efficiency. Finally he pointed out that Mr. Rábago was incorrect in his assumption that high use customers are largely more economically well to do than low use customers. He noted that the evidence in this case demonstrates that the energy usage characteristics of NIPSCO's low- income electric customers are essentially the same as those of NIPSCO's average electric customers. Finally, he noted that Mr. Rábago presented less than the full picture in his bill comparison because his analysis omits the effect of rolling certain tracker-related revenue requirements into base rates.

In response to Mr. Howat's recommendation that the Commission direct NIPSCO to create a low-income rate that gives certain customers a 25% bill discount, Mr. Shambo stated that the Settlement Agreement does not provide for a low-income program in this case, but that NIPSCO has proposed to meet outside of this case with the OUCC and any other interested parties to discuss the parameters of a program similar to that filed in his case-in-chief prior to NIPSCO's next base rate case. In response to cross-examination at the hearing held in this Cause, he further noted that NIPSCO would be willing to work with stakeholders and if all stakeholders agreed, NIPSCO would be willing to file a low-income proposal prior to its next rate case. He further noted that Mr. Howat's low-income proposal is burdensome, including the adverse impact on industrial customers who would see no benefit from the program. He noted that the total fund under Mr. Howat's proposal would be nearly as much as the requested increase to the customer charge from \$11.00 to \$14.00, and the increase for funding a low-income program would be a greater bill impact because the shift to a customer charge is just a rate design shift between fixed and variable. He also cited the recent IPL rate case order as support for his position that the best course of action is for NIPSCO to discuss this issue with stakeholders prior to its next rate case. Finally Mr. Shambo addressed Mr. Howat's complaint that the residential energy charge and the Settlement Agreement is slightly greater than the charge originally proposed by NIPSCO. He noted that Mr. Howat failed to mention that NIPSCO's proposed monthly customer charge is now \$6.00 less. He noted that the change in the proposed energy charge (1/10 of a penny greater in the Settlement Agreement) increases revenue by \$4.9 million, while the change in the proposed customer charge decreases revenue by \$29.55 million. The residential revenue requirement agreed to in the Settlement Agreement is \$24.6 million less than NIPSCO originally proposed.

B. Ms. Smith. Ms. Smith disagreed with Mr. Chriss' allegation that not all interests were represented in Settlement Agreement negotiations. She noted that the OUCC takes seriously its statutory obligation to represent all ratepayers' interests, as well as its mission to advocate on behalf of all ratepayers. She also noted that in the Settlement Agreement the percent rate increase applicable to Walmart's rate classes is the same as the percent increase applicable to the Residential class. She also noted that NIPSCO's reduction of \$54,000,000 from the requested increase benefits all ratepayers, including Walmart.

Ms. Smith disagreed with Mr. Rábago's allegation that the increase to fixed customer charge is not reasonable. She noted that the OUCC initially opposed the increase; however, to reach a Settlement Agreement, the parties must be willing to compromise. Through Settlement Agreement negotiations a much smaller fixed customer charge was agreed upon compared to the request made by NIPSCO. She stated that while it is still the OUCC's position that fixed customer charges should not be increased, when taken into consideration with the other customer benefits garnered from the Settlement Agreement the overall result is reasonable for all NIPSCO rate classes. She concluded that the Commission should approve the Settlement Agreement.

C. Mr. Phillips. Mr. Phillips disagreed with Walmart and CAC's Settlement Agreement opposition testimony. He noted that the Settlement Agreement is a comprehensive resolution of many issues, including revenue requirement, rate base issues, capital structure, capital project financing, depreciation, amortization, cost allocation, rate design, trackers, and reporting. He stated that Walmart addresses only one aspect of the Settlement Agreement, while CAC focuses on two aspects. He stated Walmart's proposal fails to correct flaws in the cost of service study for Rates 725 and 734. He stated that the Settlement Agreement mitigates the increase in the residential rate class, while moving the rates of industrial customers who compete globally and are the backbone of Indiana's manufacturing economy, toward cost of service. Mr. Phillips disagrees with Mr. Chriss' alternative proposal, in part because Mr. Chriss did not use the corrections to the metal melting class load, or apparently any other correction included in NIPSCO's revised cost of service filed by Mr. Gaske on February 16, 2016. Mr. Phillips also noted several other problems with the original 4-CP study used by Mr. Chriss. Mr. Phillips testified that the Settlement Agreement revenue allocation is a compromise on overall revenue requirement, cost of service methodology, and gradualism with regard to inter-class subsidies. He stated Walmart is attempting to unravel the integrated Settlement Agreement framework by accepting the favorable elements of the Settlement Agreement and changing only the subsidy methodology in a manner that benefits Walmart. Hence, he recommended that the Commission reject the alternative revenue allocation proposed by Mr. Chriss.

Mr. Phillips disagreed with Mr. Howat's request to impose a charge of $0.00079 per kWh for funding a low-income program. He testified that recovery of social program costs, especially on a per kWh basis, is divorced from any cost causation principles and distorts electric price signals to customers. He stated that use of a kWh charge overburdens high load factor customers that have large annual energy usage making them pay a disproportionate share of the program costs. The cost impact on NIPSCO's large industrial customers from the proposed surcharge is $5.8 million, annually, and he recommended this charge be rejected.

D. Mr. Mancinelli. Mr. Mancinelli noted that Walmart argued over the rate allocation for Walmart being higher that the average system increase. However, Mr. Mancinelli noted that the increases for Walmart are lower by 1.6% and 0.9% respectively for Walmart than they were in NIPSCO's original case-in-chief. He stated that Walmart wants its allocation lower, but to offset this reduction in revenues, Walmart proposes to increase the revenues associated with the residential class, and four large industrial classes. Mr. Mancinelli noted that there are four reasons why Mr. Chriss' proposal is not reasonable and should be rejected by the Commission. He noted that there are four reasons why Walmart's proposal is not reasonable. First, it does not represent an improvement compared to the Settlement Agreement, in which Settling Parties considered many factors. Second, it is not objective, and benefits only the classes under which Walmart is served and places an unjust burden on Rates 732 and 733. Third, its revenue allocation recommendation prevents Rate 733 customers, including U.S. Steel, from receiving the benefits associated with the Settlement Agreement's $54 million reduction in revenue requirements. Fourth, its calculation is flawed and cannot be relied upon due to Mr. Chriss' use of outdated information. Mr. Mancinelli further noted that CAC's recommendation of the low-income program funded by a surcharge is not reasonable. He claimed that large industrial customers will bear a significant portion of the program costs, and it is overly burdensome. He noted that U.S. Steel has been subsidizing residential rates for years and is continuing to do so as part of the Settlement Agreement, and the increase in rates would further aggravate the already high power costs to U.S. Steel and provide further incentive for it to leave NIPSCO's system.

20. Commission Discussion and Findings. Settlement Agreements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any Settlement Agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a Settlement Agreement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the Settlement Agreement." *Citizens Action Coalition*, 664 N.E.2d at 406. Furthermore, any Commission decision, ruling or order - including the approval of a Settlement Agreement - must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code Chapters 8-1-2, and that such Settlement Agreement serves the public interest. We will discuss the major components of the Settlement Agreement.

We have previously discussed our policy with respect to Settlement Agreements:

> Indiana law strongly favors Settlement Agreement as a means of resolving contested proceedings. *See, e.g., Manns v. State Department of Highways*, 541 N.E.2d 929, 932 (Ind. 1989); *Klebes* v. *Forest Lake Corp.*, 607 N.E.2d 978, 982 (Ind. Ct. App. 1993); *Harding* v. *State*, 603 N.E.2d 176, 179 (Ind. Ct. App. 1992). A Settlement Agreement "may be adopted as a resolution *on the merits* if [the Commission] makes an independent finding supported by 'substantial evidence on the record as a whole' that the proposal will establish 'just and reasonable' rates." *Mobil Oil Corp.* v. *FPC*, 417 U.S. 283, 314 (1974) (emphasis in original).

See, e.g., Indianapolis Power & Light Co., Cause No. 39938, at 7 (IURC 8/24/95); *Commission Investigation of Northern Ind. Pub. Serv. Co.*, Cause No. 41746, at 23 (IURC 9/23/02). This policy is consistent with expressions to the same effect by the Supreme Court of Indiana. *See, e.g., Mendenhall v. Skinner & Broadbent Co.*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and Settlement Agreement of disputes.") (citation omitted); *In re Assignment of Courtrooms, Judge's Offices and Other Facilities of St. Joseph Superior Court*, 715 N.E.2d 372, 376 (Ind. 1999) ("Without question, state judicial policy strongly favors Settlement Agreement of disputes over litigation.") (citations omitted). Furthermore, we are mindful regarding a Settlement Agreement which has been entered by representatives of all customer classes, including OUCC (who represents all ratepayers), even though there may be some intervenor or group of intervenors who opposes it. *American Suburban*

Utils., Cause No. 41254, at 4-5 (IURC 4/14/99).

A. Revenue Requirement. In this case, the Settling Parties have agreed to an overall annual base rate revenue requirement of $1,644,927,046 (prior to application of surviving Riders and net of other revenues), which translates to an increase in base rate revenues of $72.5 million – an average 4.51% rate increase. This agreement on an appropriate revenue requirement for NIPSCO is based upon agreements among the Settling Parties regarding original cost rate base, fair value rate base, capital structure, cost of capital, and operating expenses (including depreciation expense and tax expense). As is discussed in further detail below, we find that the Settlement Agreement provisions regarding NIPSCO's revenue requirements are reasonable, supported by evidence of record, and should be approved.

(1) NIPSCO's Rate Base. NIPSCO presented evidence, which no party disputes, that its generating properties, transmission system, distribution system, offices and general facilities included in its proposed rate base were all used and useful and reasonably necessary for the convenience of the public and should be included in NIPSCO's retail electric rate base, and we so find.

A first step in determining revenue requirements requires the Commission to value all property used and useful for the convenience of the public at its fair value. NIPSCO, along with the other Settling Parties, have agreed that, for purposes of establishing rates in this case, the original cost of NIPSCO's retail electric rate base should be used, which is $3,221,417,882. This value includes materials, supplies, production fuel inventory and regulatory assets as proposed in NIPSCO's case-in-chief, but does not include NIPSCO's prepaid pension asset. This original cost value of NIPSCO's rate base is supported by NIPSCO's initial, rebuttal and settlement testimony. We further note that no party disputes the components or value of this agreed upon original cost rate base. Accordingly, we find that NIPSCO's original cost rate base for purposes of this proceeding is $3,221,417,882, and that this original cost rate base should be used for purposes of determining a fair return on the fair value of NIPSCO's used and useful property for purposes of this case.

(2) Rate of Return. Having determined the fair value of NIPSCO's used and useful property, we now turn to a determination of the level of net operating income that represents a reasonable return on that property. We are charged with providing the utility with the opportunity to earn a fair return on the fair value of its property. *See Gary-Hobart Water Corp. v. Ind. Util. Reg. Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App. 1992) and *Office of Util. Consumer Counselor v. Gary-Hobart Water Corp.*, 650 N.E.2d 1201 (Ind. Ct. App. 1995). One accepted way of doing this is to determine NIPSCO's actual capital structure, along with the cost of the various components of its capital, as the Settling Parties have done. The Settling Parties have agreed that the following actual capital structure and cost of capital for NIPSCO should be used in setting rates in this case:

	% of Total	Cost %	WACC %
Common Equity	47.42	9.975	4.73
Long-Term Debt	33.72	5.71	1.93
Customer Deposits	1.59	4.58	0.07
Deferred Income Taxes	19.12	0.00	0.00
Prepaid Pension Asset	-4.93	0.00	0.00
Post-Retirement Liability	2.99	0.00	0.00
Post-1970 ITC	0.09	8.20	0.01
Totals	100.0%		6.74%

The evidence of record indicates that this agreed upon capital structure represents the actual capital structure of NIPSCO on June 30, 2015, including equity, long-term debt, customer deposits, deferred income taxes, the prepaid pension asset, the OPEB liability, and post-1970 investment tax credits. No party disputes that the above capital structure represents the actual capital structure of NIPSCO on June 30, 2015.

It is further undisputed that NIPSCO's evidence demonstrated that its embedded cost of long-term debt was 5.71%, its cost of customer deposits was 4.58%, and that deferred income taxes, the prepaid pension asset, the OPEB liability, and post-1970 investment tax credits should be treated as zero-cost capital.

With regard to NIPSCO's cost of equity, the record contains a number of different methods of estimating NIPSCO's cost of equity. We recognize that the cost of equity cannot be precisely calculated and estimating it requires the use of judgment and the consideration of more than one methodology. The testimony of various witnesses in this case reflected initial views that NIPSCO's cost of equity was between 8.7% and 10.75%, with the Settling Parties concluding that 9.975% was a reasonable cost of equity to use to set rates in this case.

Given due consideration to this evidence of record, including the Settlement Agreement, we find that the agreed upon cost of equity of 9.975% is within a reasonable range. We note that the use of a 9.975% cost of equity to set rates for NIPSCO is supported by the risks facing NIPSCO in particular and the electric utility industry generally. Accordingly, we find that a 9.975% cost of equity, along with the other cost of capital components shown above, producing an overall weighted cost of capital of 6.74% for NIPSCO, is reasonable in this case. Further, the evidence of record indicates that this overall weighted cost of capital, when applied to NIPSCO's rate base, produces a net operating income of $217,123,565. Accordingly, we also find that, for purposes of the earnings test contained in the FAC statute, NIPSCO shall be authorized to earn this net operating income of $217,123,565, prior to any additional returns approved by the Commission in future capital cost tracking proceedings. In addition, per the Settlement Agreement terms, it is reasonable for NIPSCO to finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Indiana Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39, with at least 60% debt capital.

(3) Operating Income at Present Rates. For the 12 months ending March 31, 2015, NIPSCO's jurisdictional operating income from its electric utility operations on an on-going basis, adjusted for changes which were fixed, known, and measurable within 12 months following the close of the test period, was shown by NIPSCO to be as follows:

Total Operating Revenue		$1,609,246,699
Less Total Fuel and Purchased Power	$556,368,462	
Gross Margin		$1,052,878,237
Less Total Operations and Maintenance	$503,485,699	
Less Total Depreciation Expense	$212,266,317	
Less Total Amortization Expense	$15,362,286	
Less Total Taxes Other Than Income	$66,280,927	
Less Federal and State Taxes	$75,494,053	
Total Operating Expenses including Income Taxes		$872,889,282
Less Settlement Agreement Adjustment	$6,094,203	
Net Operating Income		$173,894,752

(4) Pro Forma Adjustments. NIPSCO proposed a number of pro forma adjustments to its operating income and revenues which were undisputed. It proposed other pro forma adjustments that, although disputed at some point in the process of this rate case, were compromised or were no longer in dispute at the conclusion of the evidentiary hearing in this Cause. All such pro forma adjustments have been fully identified in the testimony supporting the Settlement Agreement, and the evidence of record demonstrates that all such adjustments are based upon fixed, known and measurable changes, reasonable normalizations and annualizations, and are agreed to be reasonably representative of NIPSCO's ongoing operations.

Notably, no party to this proceeding presented evidence opposing the Settlement Agreement with respect to NIPSCO's rate base, capital structure, cost of capital, rate of return, operating income, or revenue requirements. Accordingly, we find all pro forma adjustments agreed upon in the Settlement Agreement to be reasonable, as set out below, and supported by substantial evidence of record. In particular, we find that the agreed upon operating revenues and expenses, depreciation rates and depreciation expense, tax expense, and amortizations are reasonable, supported by substantial evidence of record, and should be approved.

Operating & Maintenance Expenses	$503,692,730
Depreciation Expense	$212,266,317
Amortization Expense	$15,362,286
Taxes Other Than Income Taxes	$67,374,068
Income Taxes	$103,465,069
Total Operating Expenses and Taxes	$902,160,470
Settlement Agreement Adjustment	$6,094,203
Net Operating Income	$217,123,565

(5) Revenue Level to be Authorized. Mr. Westerhausen sponsored Attachments 19-S-B and 19-S-C, which show the revenue proof and support the agreed-to revenues. As part of each individual rate's revenue proof, the energy charges are shown with and without their base cost of fuel which have been adjusted for losses. In the Settlement Agreement, NIPSCO agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties concur that NIPSCO should be authorized a fair rate of return of 6.74%, yielding an overall return for earnings test purposes of $217,123,565. Based on the foregoing findings, the Commission finds that NIPSCO should be authorized rates to produce an operating revenue of $1,681,746,699 computed as follows:

Operating Revenues	$1,681,746,699
Less: Fuel and Purchased Power	$556,368,462
Gross Margin	$1,125,378,237
Operating Expenses and Taxes	
Operating & Maintenance Expenses	$503,692,730
Depreciation Expense	$212,266,317
Amortization Expense	$15,362,286
Taxes Other Than Income Taxes	$67,374,068
Income Taxes	$103,465,069
Total Operating Expenses and Taxes	$902,160,470
Settlement Agreement Adjustment	$6,094,203
Net Operating Income	$217,123,565

(6) Revenue Allocation. Mr. Gaske presented a fully allocated cost of service study to determine the embedded costs of serving the various customer classes. NIPSCO proposed using a 12-CP factor for allocating demand-related transmission costs, but a 4-CP

allocation factor was used in the allocation of demand-related production function costs. In support of the 4-CP allocation, Dr. Gaske noted that during the past six years, the months of June – September were almost always within 90 percent of the annual peak, but none of the other eight months were ever within 90 percent of the annual peak.

The Settling Parties based the allocation of revenue by class on the cost of service evidence presented by multiple parties, mitigating the impact on various customer classes in a manner that the Settling Parties agreed to be reasonable. The result is a cost-based allocation reflecting the extensive evidence offered by Settling Parties having diverse interests. Importantly, the Settling Parties by virtue of the participation of the OUCC collectively represent all classes and some of them represent specific needs within those classes. The Settlement Agreement revenue allocation is shown in Joint Exhibit B to the Settlement Agreement; however, it is appropriate to highlight a few of the key customer classes: the increase to residential customers (Rate 711) is 5.37%, the increase to large industrial customers that compete globally (Rates 732, 733, and 734) averages 2.0%, and the increase to larger general service classes (Rates 721, 723, and 724) averages 5.5%. Notably, all major customer classes will receive a lower class rate increase under the Settlement Agreement than under NIPSCO's filed case.

Having considered the evidence and the differences of opinion on the issue of cost allocation, and specifically the consideration of inter-class subsidies, the Commission finds that given the diverse nature of the Settling Parties, and their willingness to agree to the proposed allocation of revenue, along with the evidence supporting the proposed allocation, the Settlement Agreement cost allocation methodology is appropriate for the development of NIPSCO's retail rates and charges in this case. The evidence of record indicates that the agreed upon cost allocation is not based on any one fully allocated cost of service study but rather reflects information from a range of cost allocation methodologies presented, mitigated so as not to unduly impact any one customer class. Further, the evidence of record demonstrates that the cost allocation contemplated by the Settlement Agreement will produce fair and reasonable rates for each class of customers. Although not all parties were signatories to the Settlement Agreement, the Settling Parties collectively represent every customer class. Accordingly, the Commission gives substantial weight to the Settling Parties' agreement with respect to the revenue allocation. The provisions of the Settlement Agreement providing reductions in the proposed revenue requirements are closely interrelated to the agreed cost allocations. Based upon all the evidence presented, we find the Settlement Agreement revenue allocation will produce just and reasonable rates under Indiana Code § 8-1-2-4.

(7) Rate Design. The Settling Parties agreed to maintain NIPSCO's existing rate structure. They also agreed to increase the amount of interruptible (both for its provision of service and recovery of associated credits) and modified the Rider so that it is explicit and clear.

NIPSCO had originally proposed an increase to the customer charge (specifically, from $11 a month to $20 a month per residential customer under Rate 711 and from $20 a month to $30 a month under Rate 721), based on the actual fixed costs to serve customers. Under the terms of the Settlement Agreement, the customer charge for residential Rate 711 would increase from $11 per month to $14.00 per month, which is a compromise between NIPSCO and the OUCC. Mr. Rábago was the only witness in opposition to the proposed Settlement Agreement increase to the customer charge, suggesting that it is inconsistent with "sound ratemaking principles." We disagree with Mr. Rábago. As we found recently in IPL's rate case in which we approved increases in the customer charge from $6.70 to $11.25 (for less than 325 kWh/month) and $11.00 to $17.00 (for greater than 325 kWh/month), the increase in the customer charge was a "move toward a more fixed and variable rate design consistent with traditional cost causation principles [sic]," while being "demonstrably short of SFV rates." *Indianapolis Power & Light Co.*, Cause No. 44576, 2016 WL 1118795, at *76 (IURC March 16, 2016) *order corrected,* 2016 WL 1179961 (IURC March 23, 2016) ("IPL 2016 Rate Order"). We further found that, "[c]ost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided." *Id.* Lastly, we noted that, "this structure does not violate principles of gradualism, because gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill." *Id.* at 77. For these same reasons, the Commission finds that the increase in the monthly customer charge from $11.00 to $14.00 for residential customers and from $20.00 to $24.00 for small commercial customers is cost-based based upon the evidence presented, consistent with gradualism, and is reasonable and should be approved.

(8) Cost and Revenue Adjustment Mechanisms.

(a.) FAC Tracker. NIPSCO files a quarterly FAC proceeding in accordance with Indiana Code § 8-1-2-42(d) in Cause No. 38706-FAC-XXX to adjust its rates to account for fluctuations in its fuel and purchased energy costs. Mr. Westerhausen testified the FAC Tracker continues substantially unchanged. The FAC Tracker has been updated with the average cost of fuel in base rates. The OUCC recommended that the Commission continue allowing the OUCC and interveners to file their testimony and report 35 days after NIPSCO files its FAC application and testimony. No party opposed that recommendation and the Commission agrees to keep it in place. For purposes of NIPSCO's FAC proceedings, we find NIPSCO's base cost of fuel to be $0.031049.

(b.) RTO Tracker and Treatment of Off-System Sales Profits. As agreed upon in the Settlement Agreement, treatment of non-fuel MISO charges as proposed by NIPSCO in its case-in-chief and a level of $4,741,390 for off-system sales margins built into base rates shall be approved. Consistent with the Settlement Agreement, for purposes of off-system sales margin sharing after the effective date of new base rates, NIPSCO shall flow through the RTO Tracker 100% of margins, below (down to zero) or above the level built into base rates. While the 100% flow through framework is not consistent with similar recently approved Commission mechanisms because of the downside exposure to customers when off-system sales margins do not develop, especially in market conditions similar to those presently being experienced, the relatively small amount at issue and the agreement of the Settling Parties supports the outcome. Based upon our review of the evidence of record, we find the RTO Tracker and the treatment of off-system sales profits as proposed in the Settlement Agreement is reasonable and should be approved.

(c.) ECRM Tracker. As agreed upon in the Settlement Agreement, NIPSCO shall consolidate the ECRM and EERM Trackers into one mechanism, including the frequency of filing, as proposed by NIPSCO in its case-in-chief. Any finding related to NIPSCO's ability to or not to include treatment for replacement projects or components in these mechanisms shall be addressed in a future ECRM Tracker proceeding. Based upon our review of the evidence of record, we find the consolidation appropriate and reasonable and should be approved.

(d.) RA Tracker. As agreed upon in the Settlement Agreement, the RA Tracker shall utilize the demand allocators set forth in Joint Exhibit C to the Settlement Agreement, which will be modified to reflect the amount of interruptible load contained in Rates 732, 733, and 734. Based upon our review of the evidence, we find the RA Tracker and allocators set forth in Joint Exhibit C as proposed in the Settlement Agreement is reasonable and should be approved.

(e.) Interruptible. Rider 775 balances the needs of and provides benefits to all customer groups. Large industrial customers that guarantee that they will interrupt service on demand, for the benefit of others, should be compensated. Rider 775 provides credits to those customers for the operational and economic risks they face from such interruption, which reflect the value such an interruptible load provides, and continues the stable foundation from currently-effective Rider 675. The credits are recovered from all customers that are receiving the benefit. Amounts provided as credits will still be recovered in the RA and FAC Trackers. The Settling Parties agreed upon several changes to Rider 775, which include, but are not limited to increasing the MWs available to 530, increasing the dollar cap to $57 million, incorporating new Option E, as proposed by U.S. Steel in its case-in-chief, and updating the provisions applicable to Rider Option C.

The Commission finds that these changes improve upon NIPSCO's reliability while valuing the unique characteristics of the large industrial load in its service territory. Rate structures which capture the ability to physically curtail or economically interrupt a customer's service support system integrity and economically efficient operations. In addition, the corresponding credit value is strongly related to the cost of new capacity. This 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. Therefore, we approve the changes to interruptible services as described in the Settlement Agreement.

The Settling Parties agreed that the revisions to Rider 775 will be implemented and effective with the first billing cycle following issuance of a Commission Order in this Cause. Since the remainder of NIPSCO's rates and charges are to become effective with the first October, 2016 billing cycle, we direct NIPSCO to revise its current Rider 675 to reflect the revisions approved herein upon issuance of a Commission Order.

(f.) Backup and Maintenance. The Settling Parties agree that NIPSCO should be authorized to modify Rider 676, as proposed by the Industrial Group and accepted by NIPSCO in its rebuttal testimony. In particular, the Rider now clarifies that NIPSCO must confirm all back-up service requests made in full conformance with Rider 776. No other parties objected to the agreed changes to Rider 776 concerning backup and maintenance. The Commission approves such changes.

(g.) Economic Development Rider. In its case-in-chief, NIPSCO requested approval to change certain aspects of its Rider 677 – EDR, including: (i) waiver of the current tariff provision that, upon effectiveness of new base rates, existing EDR contracts would terminate; (ii) authority to defer, as a regulatory asset, the discounted revenue associated with the EDR contracts in effect during the test year and surviving beyond the effectiveness of new base rates; (iii) a tariff change inside of the EDR that would, on a going-forward basis, provide that EDR contracts would not terminate upon new base rates; and (iv) a tariff change reducing the maximum term of new EDR contracts from 5 years to 3 years. The Settling Parties agreed NIPSCO's proposal for treatment of the EDR contracts and revisions to Rider 777 should be approved, including the deferral mechanism. The Commission approves all such changes.

(h.) Low-Income. In its case-in-chief, NIPSCO proposed a low-income program. However, the OUCC and CAC both opposed the program as proposed by NIPSCO, and offered their own proposals for alternative programs. NIPSCO withdrew its request for approval of a low-income program in this case. NIPSCO stated it may present a similar program in the future and indicated its willingness to continue discussing such a program with its stakeholders. No other party supported the form of program proposed by CAC, which was actively opposed by several parties. Mr. Rábago addressed the elimination of NIPSCO's proposed low-income program of an annual credit of $50 applied to the June bill in his opposition to the Settlement Agreement. He noted that the residential customers face an annual fixed customer charge increase of $36, but stated there are also increases in volumetric rates. We discussed this issue recently in IPL's 2016 Rate Order in Cause No. 44576. There, we recognized the importance of the issue raised by the CAC, but found that there are numerous implementation and policy related concerns and declined to adopt the CAC's program design in that case. The CAC provided us with no better record or rationale in this case as to why we should adopt such a program, when we declined to do so in the IPL 2016 Rate Order. The OUCC filed testimony in this case opposing NIPSCO's proposed low-income program and on cross-examination, Ms. Smith provided testimony concerning certain utilities' voluntary "Round Up" programs that might be more appropriate from the OUCC's perspective. The implications and policy concerns expressed in our IPL 2016 Rate Order persist in this Cause.

Notwithstanding, the Commission is perplexed over the sequence of events that led to NIPSCO's decision to ultimately not offer a low-income proposal. NIPSCO, not the CAC, was the first to propose a low-income program. The CAC offered an alternative program in response. It would have made sense for NIPSCO to engage the CAC and other parties to discuss alternatives and to reach a consensus on an alternative. The evidence points to the CAC being left out of any settlement discussion. While the existence of time constraints may have presented some challenges, it is possible that a settlement with the CAC on this issue could have been produced through negotiations. It is confounding to understand the exclusion of parties with mutually held goals. Few initial proposals are accepted by all parties at the onset. When offering a proposal, the expectation would be for the utility to act in good faith and afford all the parties the opportunity to dialogue, with the goal of reaching consensus.

Further, as for CAC's recommendation that NIPSCO collect and report on trend data on arrearages, disconnections, and related data points, as we noted in the IPL 2016 Rate Order, "we decline to order such collection and reporting solely on the basis of the evidence before us. We believe that any such effort is best pursued by the utility and interested stakeholders outside the regulatory constraints of a specific Commission directive." *Indianapolis Power & Light*, 2016 WL 1118795, at *72.

(i.) AMR Opt Out Charge. As provided in Section 15.5 – AMR Opt-Out Charge, in NIPSCO's proposed General Rules and Regulations, the Commission having heard evidence and carefully considering, finds that the opt-out charge for customers that do not permit NIPSCO to install a meter employing AMR on a customer's premise should be approved.

(j.) LED Lights. As agreed to by the Settling Parties, the LED rates NIPSCO proposed in this rate case will be reduced in this Cause to reflect the lower capital costs, capital structure, and other reduced revenue impact elements agreed to in the Settlement Agreement, as well as an approximate 37% reduction in O&M street light expense. Those lower LED rates may reasonably serve as a "default" rate to any conversion of a NIPSCO-owned light to an LED regardless of any TDSIC treatment. Those who wish to replace their old street lights with LEDs one or two at a time may find those rates useful. For those who choose to have the street lights changed out in large scale, the rates proposed in NIPSCO's future, initial electric TDSIC tracker proceeding would apply to any mass LED retrofit program that may be approved by the Commission in NIPSCO's latest electric 7-Year Plan. We find that balance to be reasonable for purposes of Settlement Agreement. Without providing specific tariff rates, NIPSCO added a new tariff sheet in its Settlement Agreement testimony to serve as a placeholder for the finalized LED mass retrofit rate that will be proposed for final approval in conjunction with and subject to an approval of the LED mass retrofit plan in the first TDSIC tracker proceeding. We find that to be reasonable. Therefore, we approve the "default" rates agreed to by the Settling Parties.

(k.) General Terms and Conditions/Tariff Changes. The Settling Parties agree that all other components of NIPSCO's Proposed Tariff not noted in the Settlement Agreement shall be approved as NIPSCO filed in its case-in-chief and as corrected during the course of this proceeding. Having considered NIPSCO's proposed changes, and testimony on why the changes are necessary, the Commission approves the Settlement Agreement Tariff.

(l.) Space Heating. NIPSCO proposes to discontinue Rate 611 Space Heating, and Rates 612 and 613 in their entirety. In the Commission's Order in Cause No. 44436, residential space heating rates would continue until 2020 and would cease discounts to the energy rates for space heating customers at the end of a 5-year period. During the five years, NIPSCO would evenly increase the impact to space heating customers' bills each year in order to smoothly transition them to full service tariff rates. The 5-year period was chosen in part because it was presumed that NIPSCO would be filing a rate case at the end of those five years. However, NIPSCO entered into a Settlement Agreement in its TDSIC proceedings (Consolidated Cause Nos. 44370 and 44371), in which NIPSCO agreed to file an electric general rate case proceeding by December 31, 2015. Since NIPSCO filed a rate case earlier than anticipated, the five year plan had to be reexamined. The base rates proposed will in effect reflect an increased cost of service along with a new allocation and new determinants; therefore, it is appropriate to propose to consolidate the rate schedules in this proceeding. In this proceeding, NIPSCO has shown that it has collapsed the allocators for Rates 611, 612, and 613 into one allocation. NIPSCO did not propose a transition plan for its commercial space heating rates in this proceeding because the block energy structures create a significant level of complexity. No party in this proceeding took issue with the changes to space heating. The Commission finds that these changes are appropriate to make in a rate case, and based upon our review of the evidence, we find that discontinuing Rates 611 Space Heating, 612 and 613 is appropriate and should be approved.

(m.) AC Cycling Program. Rider 684 was available to customers taking service under Rates 611, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, and 644 with central air conditioning having an electric motor driven compressor for the option to participate in the Direct Load Control Program initially approved on July 27, 2011 in Cause No. 43912. The program was closed to new customers beginning in 2015, and NIPSCO proposes that this Rider be eliminated. No party in this proceeding took issue with eliminating Rider 684. The Commission finds that these changes are appropriate, and based upon our review of the evidence, we find that discontinuing Rider 684 should be approved.

(n.) Industrial Group Proposal / Qualifying Facility Language. Mr. Dauphinais noted that NIPSCO's definition of a Qualifying Facility under its tariff did not reflect a recent change in Indiana statute requiring electric utilities to interconnect and purchase excess output from Qualifying Facilities larger than 80 megawatts in capacity. NIPSCO accepted the recommendation of Mr. Dauphinais. On February 11, 2016, NIPSCO filed a correction to delete the definition of Qualifying Facilities from its General Rules and Regulations and revised Rider 778 to be consistent with Indiana Code § 8-1-2.4-2(g). We approve NIPSCO's revised Rider 778.

(o.) Industrial Group Proposal / 5-Year Projection of Rates. Mr. Dauphinais recommended that NIPSCO provide a non-binding, good faith 5-year projection of its base rate and adjustment riders on July 1 of each year. In rebuttal, Mr. Shambo testified that NIPSCO historically has provided some projections, when requested, to its customers, and therefore accepts the recommendation of Mr. Dauphinais that by July 1 of each year, NIPSCO will provide an annual five-year good faith projection of its electric rates and riders for its large industrial rates – Rates 725, 732, 733, and 734. The Settlement Agreement provides that NIPSCO agrees, on July 1 of each year, to provide five-year tracker factor forecasts to large industrial customers under Rates 725, 732, 733, and 734 on a good faith estimate basis. The Commission approves the provision of such tracker factor forecasts as agreed to by the Settling Parties in the Settlement Agreement.

(p.) Unbundling of Rates. Walmart proposed that NIPSCO unbundle its rates and argued that it is helpful to customers to break out tariff rates by function. Walmart stated that the Commission should require NIPSCO to separately present the fuel portion of the base energy rate in its tariff for commercial and industrial rate schedules. NIPSCO agreed in rebuttal that in future proceedings it may attempt to unbundle rates. The Commission agrees that NIPSCO and its stakeholders should continue to work together to present billing information in such a way that customers better understand their bills.

(9) TDSIC Revenue Allocation Factors. The Settling Parties included in the Settlement Agreement, as Joint Exhibit D, the customer class revenue allocation factors to be applicable to firm load for purposes of recovering 80% of approved capital TDSIC expenditures and costs under Indiana Code § 8-1-39-9(a). That provision resolves an issue that has been raised in TDSIC proceedings, and that resolution was not opposed by any party in this case. The Commission approves the customer class revenue allocation factors shown in Joint Exhibit D.

(10) Effective Date. The Settling Parties agreed that the rates and charges approved herein will not become effective until the first October, 2016 billing cycle, except that Rider 775 will be implemented and effective with the first billing cycle following issuance of a Commission Order. The Commission approves the effective date for NIPSCO's rates and charges as requested.

B. NIPSCO's Administrative and General Expenses. Mr. Etheridge reviewed the reasonableness of NIPSCO's administrative and general O&M expenses. He also performed a benchmarking study to evaluate NIPSCO's administrative and general cost containment performance relative to other electric utilities. Mr. Etheridge's testimony concentrates on whether NIPSCO is cost effectively managing its overall electric operations at an administrative level. The focus was not on NIPSCO's production, transmission, or distribution O&M expenses but on NIPSCO's administrative and general expenses including corporate salaries, outside services, materials and supplies, and rents. After fuel and purchased power costs, administrative and general expenses are the largest component of NIPSCO's total O&M costs, and therefore represent a significant component of NIPSCO's total costs. In rebuttal testimony, NIPSCO did not address the specific analysis and findings presented by Mr. Etheridge. Instead, Mr. Shambo emphasized the Commission should concern itself with NIPSCO's overall revenue requirement in a rate case.

It is the Commission's obligation to facilitate effective and efficient management of the utility including continuous improvement to the extent it fosters just and reasonable rates. While looking at the performance of an individual utility in isolation in a traditional rate case may, under certain circumstances, be required to accomplish this key regulatory objective, it is more effective and informative if performance can be assessed with appropriate comparisons and data to measure comprehensive performance across a spectrum of activities over time. The level and trend of utility performance as measured against itself and compared to other utilities is a crucial element if the Commission is to optimally understand how well management is performing.

In the IPL 2016 Rate Order, the Commission initiated a collaborative effort for the purpose of establishing performance metrics for IPL. The ROE approved in the IPL 2016 Rate Order includes an incentive that is linked to IPL's constructive participation in the collaborative process. The Commission noted "[r]ather than ordering the establishment of specific metrics, we believe the collaborative should discuss the appropriate metrics for IPL and determine a final list of metrics through the collaborative process." *Indianapolis Power & Light Co.*, 2016 WL 1118795, at *19. Additionally, we stated that "[t]his is a multi-year effort to assess the efficacy of existing performance indices, enhancements to current metrics, and evaluation of new performance measures going forward." *Id.*

While we do not conclude that the evidence in this case provides sufficient support to apply conditions like those in IPL's proceeding, we believe the evidence presented by the OUCC does support further action. The groundwork for an on-going effort to enhance the understanding of interested stakeholders has been established by the OUCC and it would be efficient to build upon it. In short, we believe performance metrics can be of significant value to the Commission and NIPSCO's ratepayers. Thus, we find that NIPSCO shall facilitate a meeting with interested stakeholders within six weeks of the effective date of the Order in this Cause to collaborate on a path for moving forward with a performance metrics initiative. We anticipate that it will enable comparisons of NIPSCO's performance over time and in comparison to comparably situated utilities. The collaborative process should further develop the performance metrics already being used by NIPSCO. Because the ongoing collaborative effort will not be occurring in the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, Commission's technical staff shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and 4.

In order that the Commission and interested stakeholders may stay abreast of the collaborative process, we direct NIPSCO to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. We also order NIPSCO to file quarterly reports for the first year and an annual report by July 1, 2017, and for each year thereafter until otherwise indicated by the Presiding Officers.

(C) Settlement Negotiations. While it is not this Commission's role to dictate to the parties how or when they conduct settlement negotiations, the Commission is concerned with the omission of participants to the settlement process. It makes sense to include all parties in initial settlement discussions. If agreement can be reached among some but not all the parties there is nothing to prevent the agreeing parties to proceed with negotiations in pursuit of a settlement. Indeed over the years this Commission has approved many settlements that do not include all of the parties. In the future, the Commission would encourage the participation of all parties in the initial settlement discussions.

21. Confidentiality. NIPSCO, U.S. Steel, IMUG and the Industrial Group, all filed motions for protective orders, all of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Indiana Code §§ 5-14-3-4(a)(4) and (9) and Indiana Code § 24-2-3-2. The Presiding Officers issued Docket Entries finding the information described in the requests for confidentiality to be confidential on a preliminary basis. After reviewing the designated confidential information, we find all such information qualifies as confidential trade secret information pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. NIPSCO, U.S. Steel, IMUG and the Industrial Group take reasonable steps to maintain the secrecy of the information and disclosure of such information would cause harm to them. Therefore, we affirm the preliminary ruling and find this information should be exempted from the public access requirements contained in Indiana Code Chapter 5-14-3 and Indiana Code § 8-1-2-29, and held confidential and protected from public disclosure by this Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION THAT:

1. The Stipulation and Settlement Agreement between NIPSCO, the OUCC, IMUG, Industrial Group, NLMK, U.S. Steel; and USW filed in this Cause on February 19, 2016, and attached hereto, is approved.

2. NIPSCO is authorized to place into effect rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual increase to its rates and charges of $72.5 million which represents an increase in operating revenues of 4.51%. Said rates are anticipated to produce total jurisdictional electric operating revenues of $1,681,746,699 and are anticipated to result in annual jurisdictional electric utility operating income of $217,123,565.

3. NIPSCO is authorized to place into effect on October 1, 2016, the depreciation rates agreed to in the Settlement Agreement and approved in this Order.

4. NIPSCO is authorized: (1) to defer, as a regulatory asset, discounts offered to certain customers under the Economic Development Rider for recovery in a future rate case; and (2) to defer, as a regulatory asset or liability, an amount equal to 100% of annual off-system sales margins above or below (down to zero) the level of off-system sales margins included in the test year for recovery through the Regional Transmission Organization tracker.

5. NIPSCO shall revise its current Rider 675 – Interruptible Industrial Service Rider to reflect the revisions approved herein. Prior to implementing the revised Rider 675, NIPSCO shall file the applicable rate schedule under this Cause to be effective with the first billing cycle following approval by the Commission's Energy Division.

6. The proposed Electric Service Tariff, Original Volume No. 13 as filed on March 4, 2016, is approved consistent with the Stipulation and Settlement Agreement and this order.

NIPSCO's Electric Service Tariff, Original Volume No. 13 shall be effective the first October, 2016 billing cycle following approval by the Commission's Energy Division.

7. NIPSCO shall also file with the Energy Division under this Cause revised FAC factors in accordance with the findings herein, and such changes shall be effective simultaneously with the new base rates authorized herein.

8. NIPSCO shall also file with the Energy Division under this Cause revised ECRM factors combining the ECRM and EERM and eliminating costs that are being rolled into the base rates approved herein, and such changes shall be effective simultaneously with the new base rates authorized herein.

9. NIPSCO shall also file with the Energy Division under this Cause revised FMCA, RA, RTO and DSM factors eliminating costs that are being rolled into the base rates approved herein, and such changes shall be effective simultaneously with the new base rates authorized herein.

10. NIPSCO shall participate in a collaborative for the purpose of implementing performance metrics. Further, NIPSCO shall keep the Commission apprised of the progress of the collaborative through the compliance filings made under this Cause as described above.

11. The information submitted under seal in this Cause pursuant to motions for protective order is determined to be confidential and exempt from public access and disclosure pursuant to Indiana Code §§ 24-2-3-2 and 5-14-3-4.

12. This Order shall be effective on and after the date of its approval

STEPHAN, HUSTON, AND ZIEGNER CONCUR; WEBER NOT PARTICIPATING:

APPROVED: JUL 18 2016

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	)	CAUSE NO. 44688

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of the 19th day of February, 2016, by and between Northern Indiana Public Service Company ("NIPSCO" or "Company"), the Indiana Office of Utility Consumer Counselor

("OUCC"), Indiana Municipal Utilities Group;[1] NIPSCO Industrial Group ("Industrial Group");[2] NLMK, Indiana; United States Steel Corporation ("U.S. Steel");[3] United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC (collectively the "Settling Parties"), who stipulate and agree for purposes of settling the issues in this Cause that the terms and conditions set forth below represent a fair and reasonable resolution of all issues subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to the Settling Parties.

A. Background.

1. NIPSCO's Current Base Rates and Charges. NIPSCO's current basic rates and charges were approved by the Commission in its Order dated December 21, 2011 in Cause No. 43969 ("2011 Rate Case Order"). Those basic rates and charges remain in effect today, as modified by various riders approved by the Commission from time to time.

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[1] The municipal utilities that comprise the Indiana Municipal Utilities Group are Dyer, East Chicago, Griffith, Highland, Munster, Schererville, Valparaiso, and Winfield.

[2] The companies that comprise the NIPSCO Industrial Group are Accurate Castings, Inc., Arcelor Mittal USA, BP Products North America, Inc., Cargill, Inc., Praxair, Inc., and USG Corporation.

[3] United States Steel Corporation's signature page will be late-filed upon receipt of authorization from U.S. Steel's executive management.

2. NIPSCO's Current Depreciation Accrual Rates. The Commission's Orders in Cause Nos. 42150, 43188, 44012, 44311 and 44340 approved specific depreciation accrual rates to be applied to plant and equipment identified in those proceedings. For other items of property, NIPSCO's current depreciation accrual rates were approved in the 2011 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings. NIPSCO files a quarterly Fuel Adjustment Clause ("FAC") proceeding in accordance with Ind. Code § 8-1-2-42(d) in Cause No. 38706-FAC-XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs.

4. NIPSCO's Tracking Mechanisms. In coordination with its FAC proceedings, NIPSCO files semi-annual proceedings in: (a) Cause No. 44156-RTO-XX to recover costs associated with MISO non-fuel costs and revenues and to provide for off-system sales sharing through its Rider 671 – Adjustment of Charges for Regional Transmission Organization and Appendix C – Regional Transmission Organization Adjustment Factor ("RTO Tracker") approved by the Commission in its 2011 Rate Case Order,[4] and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs

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[4] In Cause No. 43526, the Commission found that NIPSCO's MISO non-fuel costs and revenues and off system sales sharing should be included in one mechanism designated as the RTO Adjustment. The 2011 Rate Case Order approved the implementation of the RTO Adjustment approved in Cause No. 43526 by approving Rider 671 and Appendix C.

through its Rider 674 – Adjustment of Charges for Resource Adequacy and Appendix F – Resource Adequacy Adjustment Factor approved by the Commission in its 2011 Rate Case Order.[5]

The Commission approved two tracking mechanisms by its November 26, 2002 Order in Cause No. 42150 that authorize NIPSCO to recover costs associated with qualified pollution control property, clean coal technology and clean energy projects (collectively "Environmental Compliance Projects") to allow NIPSCO to comply with various environmental obligations. Since that time, NIPSCO has been recovering a return on its investment in approved Environmental Compliance Projects and depreciation expense and operation and maintenance expense relating thereto through its Rider 672 - Adjustment of Charges for Environmental Cost Recovery Mechanism ("ECRM") and Appendix D – Environmental Cost Recovery Mechanism Factor and Rider 673 - Adjustment of Charges for Environmental Expense Recovery Mechanism ("EERM") and Appendix E – Environmental Expense Recovery Mechanism Factor.

Pursuant to the Commission's May 25, 2011 Order in Cause No. 43618, NIPSCO files a semi-annual proceeding in Cause No. 43618-DSM-XX to recover program costs and

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5 In Cause No. 43526, the Commission found that NIPSCO's prudently incurred capacity should be recovered through the Resource Adequacy or RA Adjustment. The 2011 Rate Case Order approved the implementation of the RA Adjustment approved in Cause No. 43526 by approving Rider 674 and Appendix F.

lost revenues[6] associated with approved demand side management and energy efficiency programs through its Rider 683 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G - Demand Side Management Adjustment Mechanism (DSMA) Factor.

Pursuant to the Commission's December 3, 2014 Order in Cause No. 44520, NIPSCO files a semi-annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 686 – Green Power Rider and Appendix H – Green Power Rider Rate.[7]

Pursuant to the Commission's January 29, 2014 Order in Cause No. 44340, NIPSCO files a semi-annual proceeding in Cause No. 44340-FMCA-XX to recover federally mandated costs associated with critical infrastructure protection compliance projects (the "CIP Compliance Project") through its Rider 687 – Adjustment of Charges for Federally Mandated Costs and Appendix I – Federally Mandated Cost Adjustment Factor.

In Cause No. 44371, the Commission approved a transmission, distribution, and storage system improvement charge pursuant to Ind. Code § 8-1-39-9 set forth in Rider

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6 The Commission granted NIPSCO authority to recover lost margins in its August 8, 2012 Order in Cause No. 44154 and in its December 30, 2015 Order in Cause No. 44634.

7 The Green Power Rider Rate was initially approved in the Commission's December 19, 2012 Order in Cause No. 44198.

688 - Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix J - Transmission, Distribution and Storage System Improvement Charge (the "TDSIC"), to effectuate the timely recovery of 80% of approved capital expenditures and TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution, and storage system improvements ("TDSIC Projects").[8]

5. This Proceeding. On October 1, 2015, NIPSCO filed with the Commission its Verified Petition to modify its rates and charges for electric utility service and for approval of: (1) changes to its electric service tariff including a new schedule of rates and charges, changes to the general rules and regulations and changes to certain riders; (2) revised depreciation accrual rates; (3) inclusion in its basic rates and charges of the costs associated with certain previously approved qualified pollution control property, clean coal technology, clean energy projects, and federally mandated compliance projects; (4)

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8 On April 8, 2015, the Court of Appeals of Indiana issued a published opinion in Cause No. 93A02-1403-EX-158, reversing in part, affirming in part, and remanding the Commission Orders in Cause Nos. 44370 and 44371 (NIPSCO's Electric TDSIC cases) ("Appellate Order"). Subsequently, NIPSCO entered into a Stipulation and Settlement Agreement with the Indiana Office of Utility Consumer Counselor, NIPSCO Industrial Group, United States Steel Corporation (the "Settling Parties") to resolve how all issues addressed in the Appellate Order should be handled on Remand. On September 23, 2015, the Commission issued an Order on Remand in Consolidated Cause Nos. 44370 and 44371 whereby the Commission denied the Stipulation and Settlement in its entirety and ordered NIPSCO to refund monies collected through Rider 688. On September 29, 2015, the Settling Parties and Indiana Municipal Utilities Group filed a Verified Petition for Rehearing and Reconsideration or, Alternatively, Commission Clarification and Guidance. On December 16, 2015, the Commission issued a Remand Order, approving in part, the Stipulation and Settlement. NIPSCO's TDSIC program from Cause No. 44370 has terminated, and NIPSCO is currently crediting amounts through Appendix J pursuant to the Stipulation and Settlement Agreement. A new electric TDSIC 7 Year Plan is pending in Cause No. 44733.

accounting relief to allow NIPSCO to defer, as a regulatory asset or liability, certain costs for recovery in a future proceeding; and (5) other requests as described in its Verified Petition. NIPSCO also filed its prepared testimony and exhibits constituting its case-in-chief on October 1, 2015. A Prehearing Conference and Preliminary Hearing was conducted on October 29, 2015 and a Prehearing Conference Order was issued on November 18, 2015.

B. Settlement Terms

6. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement.

The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,644,927,046 (prior to application of surviving Riders), which is the Revenue Requirement of $1,681,746,699 less $36,819,653 million of Other Revenues. This Revenue Requirement is a decrease of approximately $54 million from the amount originally requested by the Company.

(b) Net Operating Income.

The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.6.(a) results in a proposed authorized net operating income ("NOI") of $217,123,565.

7. Fair Value Rate Base, Capital Structure and Fair Return.

(a) Fair Value Rate Base

NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties concur that NIPSCO should be authorized a fair rate of return of 6.74%, yielding an overall return for earnings test purposes of $217,123,565, based upon:

(i) an original cost rate base of $3.2 billion, inclusive of materials, supplies, production fuel and regulatory assets as proposed in NIPSCO's case-in-chief;

(ii) NIPSCO's capital structure; and

(iii) an authorized return on equity ("ROE") of 9.975%.

(b) Capital Structure and Fair Return.

Based on the following capital structure, the 9.975% ROE and cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	% of Total	Cost %	WACC %
Common Equity	47.42	9.975	4.73
Long-Term Debt	33.72	5.71	1.93
Customer Deposits	1.59	4.58	0.07
Deferred Income Taxes	19.12	0.00	0.00
Prepaid Pension Asset	-4.93	0.00	0.00
Post-Retirement	2.99	0.00	0.00

Liability			
Post-1970 ITC	0.09	8.20	0.01
Totals	**100.0%**	**100.0%**	**6.74%**

(c) Capital Project Financing.

The Settling Parties agree that during the time these rates remain in effect, NIPSCO should finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Ind. Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39 with at least 60% debt capital.

8. Depreciation and Amortization Expense.

(a) Depreciation Expense.

The Settling Parties stipulate that the depreciation accrual rates recommended by NIPSCO Witness John Spanos and presented in this proceeding (the "Depreciation Study") should be approved, except that pro-forma depreciation expense should be reduced by approximately $17.3 million due to proposed changes to not include the increase in depreciation expense associated with Bailly Unit 8 (approximately $11.1 million) and to adjust the depreciation rates as proposed by Industrial Group witness Mr. Brian C. Andrews as outlined in his testimony (approximately $6.2 million).

The Parties agree that NIPSCO may seek an adjustment to its depreciation rates subsequent to its filing of its next Integrated Resource Plan (and all Parties reserve their rights to raise any issue in that proceeding).

(b) Amortization Expense.

The Settling Parties stipulate that annual amortization expense shall be $15.4 million that includes the following items:

(i) Rate case expenses of $2,244,038 for this case amortized over a period of seven (7) years. After the completion of the seven (7) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(ii) All other deferred regulatory asset costs, amortized over seven (7) years with the exception of the amortization of the electric vehicle regulatory asset which is amortized over a three (3) year period.

9. Operating Results at Current and Proposed Rates. Joint Exhibit A contains a Statement of Operating Income for the twelve months ended March 31, 2015 shown on an actual basis, and with pro forma adjustments at current and proposed rates per NIPSCO's filed request and to reflect the provisions of this Agreement.

10. Cost Allocation and Rate Design. The Settling Parties agree that rates

should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that NIPSCO should design its rates using the structure of its existing 600 Series tariffs. Joint Exhibit B specifies the revenue allocation agreed to by all Settling Parties. This revenue allocation is determined strictly for settlement purposes and is without reference to any particular, specific cost allocation methodology. This revenue allocation shall be utilized for purposes of the demand component of the ECRM, EERM, FMCA, and RTO mechanisms. Regarding the RA Tracker, this mechanism shall utilize the demand allocators set forth in Joint Exhibit C, which will be modified to reflect the amount of interruptible load contained in Rates 732, 733 and 734. For purposes of establishing any rate schedules allowing for the recovery of 80% of NIPSCO's approved capital TDSIC expenditures and costs pursuant to I.C. 8-1-39-9(a), the parties agree that Joint Exhibit D reflects the customer class revenue allocation factors that should be applied to firm load. The parties agree that the Joint Exhibit D allocation factors to be applied for the periodic recovery of any approved capital TDSIC expenditures and costs properly account for differences between transmission and distribution customers. All other components of NIPSCO's filed cost allocation and rate design shall be as NIPSCO filed in its case-in-chief with the following exceptions or adjustments:

- The monthly customer charge for Rate 711 shall be $14.00
- The monthly customer charges for Rates 720, 721 and 722 shall be $24.00

- The demand charges for Rates 723, 724, 725, 726, 732, 733, 734 and 744 shall be modified as agreed by the Settling Parties
- The minimum charges for Rate 741 shall each be increased from their currently-approved levels by a percent equal to 4.51% (the system total increase in revenue requirement)

11. Interruptible Rider 775. The Settling Parties agree that NIPSCO should be authorized to modify Rider 675, and that the credits paid under the provisions of Rider 775 should be recovered from customers, with 75% of the costs recovered through NIPSCO's RA Tracker and 25% of the costs recovered through NIPSCO's FAC mechanism.

The Settling Parties further agree that:

- The limit on megawatt ("MW") eligibility shall be 530 MW, and the maximum amount to be paid in any calendar year under Rider 775 shall be $57 million.
- Incorporation of new Option E as proposed by US Steel.
- Rider Option C shall be revised to provide for two hours' notice for interruptions or curtailments and shall receive a demand charge credit of $9.00/kW-month.
- Customers having existing interruptible capacity under Rider 675 shall be entitled to re-enroll that same capacity in the same or other options under the new Rider 775 consistent with MISO requirements.
- Incremental interruptible capacity (which is estimated to be 153 MW of the new interruptible capacity created as a result of this Stipulation and Settlement Agreement in excess of the presently subscribed 377 MW) shall be allocated first to customers showing a demonstrated economic need, but no more than 85% of that capacity shall be allocated to one customer.

- The rider shall provide greater flexibility for customers operating commonly owned facilities to re-allocate interruptible capacity among those facilities and to permit interruptible capacity to migrate among available options consistent with MISO requirements.

12. Temporary, Backup and Maintenance Service. The Settling Parties agree that NIPSCO should be authorized to modify Rider 676, as proposed by the Industrial Group and accepted by NIPSCO in its rebuttal, to implement a new Rider 776.

13. Consolidation of ECRM and EERM tracking mechanisms. NIPSCO shall consolidate the ECRM and EERM tracking mechanisms into one mechanism, including the frequency of filing, as proposed by NIPSCO in its case-in-chief. Any finding related to NIPSCO's ability to or not to include treatment for replacement projects or components in these mechanisms shall be addressed in a future ECR proceeding.

14. RTO Tracker Mechanism. NIPSCO's proposed Rider 771 shall be effective and treatment of non-fuel MISO charges and off-system sales as proposed by NIPSCO in its case-in-chief shall be approved, including a level of $4,741,390 built into base rates. For purposes of off-system sales margin sharing after the effective date of new base rates, NIPSCO shall flow through the RTO Tracker 100% of margins, below (down to zero) or above the level built into base rates.

15. Industrial Forecasts. NIPSCO agrees, on July 1 of each year, to provide five-year tracker factor forecasts to large industrial customers under Rates 725, 732, 733 and

734 on a good faith estimate basis.

16. Economic Development Rider. NIPSCO's proposal for treatment of economic development rider contracts and revisions to Rider 777 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief that provides NIPSCO is authorized to defer, as a regulatory asset, the discounted revenue associated with the economic development rider contracts that were in effect during the test year that continue beyond the date of new, effective base rates. All Settling Parties reserve their right to contest recovery of the deferral in NIPSCO's next general rate case.

NIPSCO agrees to include the LaPorte County Kingsbury Industrial Park infrastructure substation upgrade and corresponding transmission and distribution upgrade needs as part of its plan in Cause No. 44733. The value of the upgrades included in the filing shall be no less than $2.5 million. NIPSCO will also lead a specific economic development review/study committee.

17. LED Streetlight Rates. The LED rates NIPSCO proposed in this rate case will be reduced in this Cause to reflect the lower capital costs, capital structure and other reduced revenue impacts, agreed to in this Settlement Agreement and an approximate 37% reduction in O&M expense. Those LED rates would serve as a "default" rate to any conversion of a company owned light to an LED regardless of any TDSIC treatment; whereas, the rates proposed in NIPSCO's future, initial electric TDSIC tracker proceeding

would apply to any mass LED retrofit program that may be approved by the Commission in the Company's latest electric 7-Year Plan (Cause No. 44733). Without providing specific tariff rates, NIPSCO will add a new tariff page in its settlement testimony to serve as a placeholder for the finalized LED mass retrofit rate that will be proposed for final approval in conjunction with and subject to an approval of the LED mass retrofit plan in TDSIC.

18. Customer Service. NIPSCO continues to recognize the need for and importance of good customer service and performance, and specifically the value of customer surveys like the J.D. Power Electric Customer Satisfaction Surveys. These types of surveys provide valuable feedback to the Company and show where there is room for improvement. NIPSCO shall continue to work on improving its relationships with customers and its customer service to both its existing customers as well as potential new customers. NIPSCO recognizes and agrees it is important to both the Company, its customers and Northwest Indiana in general to commit to and focus on increasing opportunities for viable economic development in its service territory and support all reasonable efforts to participate in and promote such efforts, including initiatives underway by LaPorte County and other local governmental bodies.

19. General Rules and Regulations and Tariffs. The Settling Parties agree that all other components of NIPSCO's filed tariff shall be approved as NIPSCO filed in its

case-in-chief as corrected during the course of this proceeding.

C. **Procedural Aspects and Presentation of the Agreement.**

20. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the expectation that, if the Commission finds this Agreement is reasonable and in the public interest, an order authorizing the increase in NIPSCO's rates and charges will be issued, but will not be effective until the first October, 2016 billing cycle, however, Rider 775 will be implemented and effective with the first billing cycle following issuance of a Commission Order. The Settling Parties have spent valuable time reviewing data and negotiating this Agreement in an effort to eliminate time consuming and costly litigation. The Settling Parties agree to request that the Commission review the Agreement on an expedited basis and, if it finds the Agreement is reasonable and in the public interest, approve this Agreement without any material changes by July 27, 2016.

21. The Settling Parties agree to jointly present this Agreement to the Commission for its approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

22. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or

discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

23. The Settling Parties agree that this Agreement and each term, condition, amount, methodology and exclusion contained herein reflects a fair, just and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology or exclusion in future proceedings. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, p. 10, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, or the Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission, or any court of competent jurisdiction on these particular issues. This

Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties hereto has entered into this Agreement solely to avoid further disputes and litigation with the attendant inconvenience and expenses.

24. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provide an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Agreement, as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

25. The issuance of a Final Order by the Commission approving this Agreement without any material modification or further condition shall terminate all proceedings in this Cause.

26. NIPSCO and the OUCC agree to jointly prepare a press release ("Joint Release") with language agreed upon by them describing the contents and nature of this Agreement, which will be jointly issued to the media. The Settling Parties may respond individually to questions from the public or media, provided that such responses are consistent with the Agreement.

27. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby.

28. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Settling Parties shall not support any appeal of the portion of such order by a person not a party to this Agreement.

29. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

30. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 19th day of February, 2016.

Northern Indiana Public Service Company

Kathleen O'Leary

Kathleen O'Leary, President

Indiana Office of Utility Consumer Counselor

A. David Stippler, Utility Consumer Counselor

NIPSCO Industrial Group

NLMK Indiana

James W. Brew, Counsel

United States Steel Corporation

United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC

______________________ 2/19/16

Indiana Municipal Utilities Group

Robert M. Glennon, Counsel