ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	CAUSE NO. 45159 APPROVED: DEC 4 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Stefanie N. Krevda, Commissioner
Brad J. Pope, Administrative Law Judge

On October 31, 2018, Northern Indiana Public Service Company LLC ("NIPSCO," "Petitioner," or "Company") filed its Verified Petition for General Rate Increase and Associated Relief ("Petition") under Ind. Code §§ 8-1-2-61 and 8-1-2-42.7, Notice of Provision of Information in Accordance with the Commission's Minimum Standard Filing Requirements ("MSFRs"), and Request for Administrative Notice with the Indiana Utility Regulatory Commission ("Commission"). Petitioner also filed its case-in-chief, workpapers, administrative notice documents, and information required by the MSFRs set forth in 170 IAC 1-5-1.

NIPSCO provided testimony and exhibits from the following witnesses:[1]

- Violet Sistovaris, President with NIPSCO[2]
- Michael Hooper, Senior Vice President of Regulatory, Legislative Affairs, and Strategy with NIPSCO[3]
- Paul S. Kelly, Vice President of Major Accounts with NIPSCO

[1] NIPSCO also filed Petitioner's Confidential Exhibit No. 20-S1 and Confidential Exhibit No. 20-S2 providing support for its accounting adjustments.
[2] NIPSCO late-filed attachments to Ms. Sistovaris' testimony on February 5, 2019.
[3] NIPSCO originally filed the direct testimony of Benjamin Felton. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019. NIPSCO filed corrections to Mr. Felton's direct testimony on January 2, 2019. NIPSCO filed corrections to Mr. Hooper's testimony on January 2, 2019, and April 18, 2019.

- Jennifer L. Shikany, Director of Regulatory with NiSource Corporate Services Company ("NCSC")[4]
- Clifton Scott, State Finance Director with NIPSCO
- Patrick N. Augustine, Principal in Charles River Associates' Energy Practice
- Kelly R. Carmichael, Vice President of Environmental with NIPSCO
- Andrew S. Campbell, Director of Regulatory Support & Planning with NIPSCO
- Kimberly K. Cartella, Director of Compensation with NCSC[5]
- Victor F. Ranalletta, Associate Engineer and Project Manager of Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell")
- John J. Spanos, Senior Vice President with Gannett Fleming Valuation and Rates Consultants, LLC
- Michael D. McCuen, Director of Income Taxes with NCSC
- Vincent V. Rea, Director of Regulatory Finance and Economics with NCSC
- Paula A. Strauss, Director of Regulatory with NCSC[6]
- Bickey Rimal, Manager at Concentric Energy Advisors, Inc. ("Concentric")[7]
- J. Stephen Gaske, Senior Vice President of Concentric[8]
- Curt A. Westerhausen, Director of Regulatory with NCSC[9]

Petitions to intervene were granted to the following parties:

- Citizens Action Coalition of Indiana, Inc. ("CAC")
- Indiana Coal Council, Inc. ("ICC")
- Indiana Coalition for Affordable and Reliable Electricity ("ICARE")
- Indiana Municipal Utility Group ("IMUG")[10]
- Board of Commissioners of LaPorte County, Indiana ("LaPorte")
- Modern Forge Indiana, LLC
- NIPSCO Industrial Group ("Industrial Group")[11]
- NLMK Indiana ("NLMK")
- Northern Indiana Commuter Transportation District ("NICTD")
- Peabody COALSALES, LLC ("Peabody")
- Dennis Rackers ("Rackers")
- Sierra Club
- Walmart Inc. ("Walmart")

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[4] NIPSCO filed corrections to Ms. Shikany's testimony on January 2, 2019.
[5] NIPSCO originally filed the direct testimony of Christopher D. Smith. NIPSCO filed corrections to Mr. Smith's testimony on April 18, 2019. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019.
[6] NIPSCO originally filed the direct testimony of Amy Efland. NIPSCO filed a Notice of Substitution of Witness on December 19, 2018.
[7] NIPSCO filed corrections to Mr. Rimal's testimony on January 22, 2019.
[8] NIPSCO filed corrections to Dr. Gaske's testimony on January 22, 2019.
[9] NIPSCO filed corrections to Mr. Westerhausen's testimony on January 2, 2019, January 22, 2019, June 7, 2019, and July 2, 2019.
[10] The companies that comprise IMUG are Town of Highland, Town of Schererville, Town of Munster, Town of Dyer, Town of Griffith, Town of Winfield, City of East Chicago, and City of Valparaiso.
[11] The companies that comprise the Industrial Group are Accurate Castings, Inc., Arcelor Mittal USA, BP Products North America, Inc., Cargill, Inc., Enbridge Energy, Praxair, Inc., and USG Corporation.

- United States Steel Corporation ("US Steel")
- United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial Service Workers International Union AFL-CIO/CLC, and its Locals 12775 and 13796

By docket entry dated November 21, 2018, the Commission established a procedural schedule in this matter.[12] On February 13, 2019, the Indiana Office of Utility Consumer Counselor ("OUCC") and Intervenors filed their respective cases-in-chief. The Commission conducted a Public Field Hearing on March 11, 2019, at Hammond High School Auditorium. At the Field Hearing, members of the public appeared and made statements to the Commission.

The OUCC provided testimony and exhibits from the following witnesses:[13]

- Michael D. Eckert, Assistant Director of Electric Division
- Neha Medhekar, Utility Analyst II
- Wes R. Blakley, Senior Utility Analyst[14]
- J. Randall Woolridge, Professor of Finance, Smeal College of Business Administration, the Pennsylvania State University
- William H. Novak, President, WHN Consulting
- Peter M. Boerger, Ph.D., Senior Utility Analyst
- Glenn A. Watkins, President and Senior Economist, Technical Associates, Inc.

CAC provided testimony and exhibits from the following witnesses:

- Jonathan Wallach, Vice President, Resource Insight, Inc.
- John Howat, Senior Policy Analyst, National Consumer Law Center

ICC provided testimony and exhibits from the following witnesses:[15]

- Emily S. Medine, Principal, Energy Ventures Analysis[16]

ICC / ICARE provided testimony and exhibits from the following witness:

- Charles S. Griffey, Energy Consultant

IMUG provided testimony and exhibits from the following witness:

- Theodore Sommer, Partner, London Witte Group, LLC

[12] The procedural schedule was modified by docket entries dated January 29, 2019, April 11, 2019, April 24, 2019, May 1, 2019, May 10, 2019, and May 31, 2019.
[13] The OUCC filed testimony and exhibits of David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC and Lauren M. Aguilar, Utility Analyst with the OUCC that were not offered into evidence.
[14] The OUCC filed revisions to Mr. Blakley's testimony on April 10, 2019.
[15] ICC also filed testimony of Bradley D. Scott, Chief Operating Office, Jiangnan Environmental Technology, Inc. that was withdrawn on March 5, 2019.
[16] ICC filed revisions to Ms. Medine's testimony on March 19, 2019.

Industrial Group provided testimony and exhibits from the following witnesses:

- James R. Dauphinais, Managing Principal, Brubaker & Associates[17]
- Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates[18]
- Michael P. Gorman, Managing Principal, Brubaker & Associates[19]

NLMK provided testimony and exhibits from the following witness:

- James A. Lahtinen, Consultant[20]

Peabody provided testimony and exhibits from the following witness:

- Michael J. Nasi, Partner, Jackson Walker L.L.P.

Sierra Club provided testimony and exhibits from the following witness:

- Avi Allison, Senior Associate, Synapse Energy Economics, Inc.

Walmart provided testimony and exhibits from the following witness:

- Steve W. Chriss, Director, Energy Services[21]

US Steel provided testimony and exhibits from the following witnesses:[22]

- Brown D. Thornton, Director, NewGen Strategies and Solutions, LLC ("NewGen")
- Tony M. Georgis, Energy Practice President, NewGen[23]

On March 15, 2019, NIPSCO filed the rebuttal testimony of Violet Sistovaris, Michael Hooper, Paul S. Kelly, Jennifer L. Shikany, Clifton Scott, Patrick N. Augustine, Kelly R. Carmichael, Andrew S. Campbell, Victor F. Ranalletta, John J. Spanos, Michael D. McCuen, Vincent V. Rea, Paula A. Strauss, Bickey Rimal, J. Stephen Gaske, and Curt A. Westerhausen.[24][25][26]

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[17] Industrial Group filed revisions to Mr. Dauphinais testimony on July 24, 2019.
[18] Industrial Group filed revisions to Mr. Phillips testimony on July 24, 2019.
[19] Industrial Group filed revisions to Mr. Gorman's testimony on May 17, 2019.
[20] NLMK filed revisions to Mr. Lahtinen's testimony on May 17, 2019.
[21] Walmart originally filed the testimony of Gregory W. Tillman and filed a Notice of Substitution of Witness on June 11, 2019.
[22] US Steel originally filed testimony of Constance T. Cannady, which was withdrawn on June 25, 2019.
[23] US Steel filed revisions to Mr. Georgis' testimony on March 7, 2019.
[24] NIPSCO filed corrections to Mr. Westerhausen's rebuttal testimony on June 7, 2019.
[25] NIPSCO originally filed the rebuttal testimony of Benjamin Felton. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019. NIPSCO filed corrections to Mr. Felton's rebuttal testimony on January 2, 2019.
[26] NIPSCO originally filed the rebuttal testimony of Alan Felsenthal, Managing Director at PricewaterhouseCoopers LLP that was not offered into evidence.

Also on March 15, 2019, CAC filed cross-answering testimony of Elizabeth A. Stanton, Director and Senior Economist of the Applied Economics Clinic and a Senior Research Fellow at the Global Development and Environment Institute at Tufts University; ICC filed cross-answering testimony of Phillip Graeter, Manager at Energy Ventures Analysis; ICARE filed cross-answering testimony of Charles S. Griffey; US Steel filed cross-answering testimony of Tony M. Georgis; Sierra Club filed cross-answering testimony of Avi Allison; NLMK filed cross-answering testimony of James A. Lahtinen; and Industrial Group filed cross-answering testimony of James R. Dauphinais and Nicholas Phillips, Jr.[27]

On April 9, 2019, the Presiding Officers directed NIPSCO and the OUCC to respond to requests for information, to which NIPSCO and the OUCC responded on April 11, 2019, and April 10, 2019, respectively.

On April 26, 2019, NIPSCO, Industrial Group, NLMK, US Steel, CAC, Walmart, NICTD, Sierra Club, and the OUCC (the "Revenue Settling Parties") filed a Stipulation and Settlement Agreement on Less Than all the Issues resolving revenue requirement and other miscellaneous issues (the "Revenue Settlement"). On April 30, 2019, the Revenue Settling Parties filed a Status Update notifying the Commission that IMUG had joined the Revenue Settlement and provided an additional provision in the Revenue Settlement, specifically Paragraph 11.[28]

On May 17, 2019, in support of the Revenue Settlement, NIPSCO filed testimony of Violet Sistovaris, Jennifer L. Shikany, and Curt A. Westerhausen;[29] the OUCC filed testimony of Michael D. Eckert and Wes R. Blakley; and the Industrial Group filed testimony of Michael P. Gorman. Also on May 17, 2019, Sierra Club filed a Notice of Support for the Revenue Settlement.

On May 17, 2019, NIPSCO, Industrial Group, NLMK Indiana, and US Steel (the "Rate 831 Settling Parties") filed a Stipulation and Settlement Agreement on Rate 831 Implementation (the "Rate 831 Settlement").[30] Also on May 17, 2019, in support of the Rate 831 Settlement, NIPSCO filed testimony of Curt A. Westerhausen; Industrial Group filed testimony of Nicholas Phillips, Jr.; and US Steel filed testimony of Tony M. Georgis.

On June 7, 2019, in opposition to the Revenue Settlement, ICC filed responsive testimony of Emily S. Medine; ICC and ICARE filed responsive testimony of Charles S. Griffey; and LaPorte filed responsive testimony of Reed W. Cearley, a consultant.

On June 17, 2019, in opposition to the Rate 831 Settlement, OUCC filed responsive testimony of Peter M. Boerger; CAC filed responsive testimony of Kerwin L. Olson, Executive Director of CAC, and Jonathan Wallach; Walmart joined in the CAC's responsive testimony of Mr. Wallach; and Sierra Club joined in the OUCC's responsive testimony of Dr. Boerger and CAC's responsive testimony of Mr. Olson and Mr. Wallach.

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[27] NICTD filed cross-answering testimony of Gerald R. Hanas, a consultant with GRH Commuter Rail Dynamics that was not offered into evidence.
[28] IMUG filed a Formal Notice of IMUG Joinder in Amended Partial Settlement Agreement on May 15, 2019.
[29] NIPSCO filed corrections to Mr. Westerhausen's Revenue Settlement testimony on June 7, 2019.
[30] The Rate 831 Settling Parties filed a revision to the Rate 831 Settlement on June 7, 2019.

On June 20, 2019, in reply to Revenue Settlement responsive testimony, NIPSCO filed reply testimony of Violet Sistovaris, Jennifer L. Shikany, Patrick N. Augustine, and Andrew S. Campbell.

On June 27, 2019, in reply to Rate 831 Settlement responsive testimony, NIPSCO filed reply testimony of Paul S. Kelly, the Industrial Group filed reply testimony of Nicholas Phillips, Jr., and US Steel filed reply testimony of Tony M. Georgis.

On July 16, 2019, the Presiding Officers directed Walmart and LaPorte to respond to requests for information, to which Walmart and LaPorte responded on July 17, 2019.

On July 16, 2019, Rackers filed a Motion for Administrative Notice. NIPSCO filed its objection to the Motion on July 17, 2019. Rackers filed his reply to NIPSCO's objection on July 22, 2019. The Commission denied the motion by docket entry dated August 1, 2019.

On July 24, 2019, Rackers filed a Second Motion for Administrative Notice. NIPSCO filed its objection to the Motion on July 24, 2019. The Commission denied the motion by docket entry dated August 1, 2019.

The Commission held an Evidentiary Hearing in this Cause beginning on July 25, 2019, at 9:30 a.m. and continuing through August 5, 2019, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. All participating parties appeared, presented their evidence, and offered their witnesses for cross-examination.

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

1. **Notice and Jurisdiction.** 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 Ind. Code § 8-1-2-1. NIPSCO is also an energy utility as defined in Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO is also a utility within the meaning of Ind. Code § 8-1-2-42.7(c). NIPSCO is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Pursuant to Ind. 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.

2. **Petitioner's Characteristics.** NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana and provides gas and electric service ("NIPSCO Electric") in Indiana. NIPSCO is authorized by the Commission to provide electric utility service to 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 electric basic rates and charges were approved in the Commission's July 18, 2016 Order in Cause No. 44688 (the "44688 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement between NIPSCO and the majority of the intervenors (the "44688 Rate Case").[31] Those new basic rates and charges went into effect on September 29, 2016. The 44688 Rate Case Order approved, among other items, an increase in NIPSCO's basic rates and charges. In addition, on May 1, 2018, NIPSCO's basic rates were modified to reflect the reduction in the federal income tax rate from 35% to 21% as approved in the Tax Cut and Jobs Act of 2017 ("TCJA") pursuant to the Commission's January 3, 2018 Order in Cause No. 45032.[32]

NIPSCO's petition in Cause No. 44688 was filed with the Commission on October 1, 2015. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than 15 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 the elimination of Riders 772 and 775, changing the series number of its rate schedules to Series 800, and miscellaneous changes to its General

[31] The Stipulation and Settlement Agreement was entered into as of the 19th day of February, 2016, by and between NIPSCO, the OUCC, IMUG, Industrial Group, NLMK, US Steel, and United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC.
[32] The Commission approved NIPSCO's 30-Day Filing No. 50167 on April 25, 2018.

Rules and Regulations and Standard Contract. The overall structure of NIPSCO's tariffs remains the same for residential and commercial customers (except for a proposed increase in fixed recovery by increasing customer charges), but NIPSCO is proposing a new service structure for its industrial customers currently taking service under Rates 732, 733, and 734.

B. New Industrial Service Structure. NIPSCO requests that the Commission approve NIPSCO's proposal for a new industrial service structure as an alternative regulatory plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6. To the extent any other proposals of NIPSCO herein may require alternative regulation, NIPSCO requests that they be approved as an ARP. NIPSCO elects to become subject to the provisions of Ind. Code § 8-1-2.5-6 for purposes of any such proposals. NIPSCO requests that its proposed industrial service structure be found to be in the public interest pursuant to Ind. Code § 8-1-2.5-6.

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

D. Previously Approved Environmental Compliance Projects and Federally Mandated Compliance Projects Depreciation Rates. NIPSCO has been recognizing for ratemaking purposes the cost of previously approved qualified pollution control property, clean coal technology, and clean energy projects (collectively, "Environmental Compliance Projects") and Federally Mandated Compliance Projects and associated operating expense through its Environmental Cost Recovery Mechanism ("ECRM") and its Federally Mandated Cost Adjustment ("FMCA") Factor. NIPSCO proposes to reflect in its basic rates and charges the capital costs and operating expenses associated with Environmental Compliance Projects and Federally Mandated Compliance Projects previously approved by the Commission in Cause Nos. 42150, 44012, 44311, 44340, 44872, and 44889 that were or are projected to be completed and in service at the end of the forward test year (December 31, 2019) and that are currently being recovered through the ECRM and FMCA. Since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECRM. When new tariff sheets are filed based upon the final order in this proceeding, NIPSCO proposes to adjust, as applicable, its then current FMCA adjustment factors to reflect the removal of the in-service plant and related expenses as of the same effective date, and modify its allocation factors consistent with the Commission's final order, subject to any necessary variance reconciliations in the ongoing FMCA proceedings.

E. Accounting Relief. NIPSCO seeks accounting authority to defer, as a regulatory asset, discounts offered to certain customers under its Economic Development Rider ("EDR") for recovery in a future rate case; authority to defer, as a regulatory liability, an amount equal to 100% of: (1) annual off-system sales ("OSS") margins net of expenses; (2) back-up and maintenance demand margins, both for pass back through the Regional Transmission Organization ("RTO") Tracker; and (3) authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired.

F. Demand-Side Management. NIPSCO proposes to exclude from its basic rates and charges all costs associated with its demand-side management ("DSM") program. NIPSCO has also adjusted its usage determinants for energy efficiency ("EE") measures installed through December 31, 2017, consistent with Evaluation, Measurement, and Verification. NIPSCO has also adjusted its usage upward for EE measures installed between January 1, 2018 and December 31, 2019. NIPSCO proposes to reset lost margins in its DSM tracker filing upon new, effective base rates in this proceeding to eliminate lost margins attributable to all EE measures installed prior to December 31, 2017. Ultimately, NIPSCO is seeking a neutral transition to lost margin recovery between the filing of this rate case and the operation of its DSM tracker filing.

G. RTO Tracker and OSS Margin Sharing. NIPSCO proposes to update Rider 771 – Adjustment of Charges for Regional Transmission Organization (the "RTO Tracker") to: (1) remove Midcontinent Independent System Operator, Inc. ("MISO") charges and credits and collect 100% of MISO charges that are not included in the Fuel Adjustment Clause ("FAC") through the RTO Tracker; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO Tracker; (3) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology.

H. Environmental Cost Recovery Mechanism. NIPSCO proposes to discontinue its Rider 772 – Adjustment of Charges for Environmental Cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor.

I. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with the Commission's orders.

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

5. Test Year and Rate Base Cutoff. NIPSCO proposed a forward-looking test period using projected data as authorized by Ind. Code § 8-1-2-42.7(d)(1). In the docket entry setting the procedural schedule, we found that the test year for determining NIPSCO's projected operating revenues, expenses, and operating income shall be the 12-month period ending December 31, 2019 ("2019 Forward Test Year" or "Forward Test Year"). The historic base period shall be the 12-month period ending December 31, 2017 ("2017 Historic Base Period" or "Historic Base Period"). The rate base cutoff shall reflect used and useful property at the end of the Forward Test Year.

6. NIPSCO Case-in-Chief.

A. Violet Sistovaris. Ms. Sistovaris provided a brief overview of NIPSCO and its role in northern Indiana. 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 56% of system 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.

Ms. Sistovaris testified that much of the infrastructure operated by the NiSource operating companies has been in service for many decades, and significant ongoing investment is required to maintain the systems in order to reliably meet current and long-term customer needs. For NIPSCO's electric service, this includes ongoing investments in Environmental Compliance Projects and investments in transmission and distribution assets. Ongoing investments in NIPSCO's electric distribution system is required as a result of: (1) new delivery infrastructure to serve new customers; (2) public improvements; (3) capacity enhancements; and (4) infrastructure replacements. Targeted transmission investment by NIPSCO individually and through its participation in MISO will continue. NIPSCO continues to balance the need for new investments with the cost to its customers. She stated that NIPSCO invested approximately $360 million in jurisdictional electric infrastructure through the 2017 Historic Base Period, and projects an additional investment of $520 million by the close of the 2019 Forward Test Year.

Ms. Sistovaris discussed significant changes to NIPSCO's generation fleet expected as a result of its 2018 Integrated Resource Plan ("2018 IRP"). She stated that on September 19, 2018, in a public meeting with interested stakeholders, NIPSCO announced the preliminary results of its 2018 IRP. The retirement analysis under the IRP currently indicates that NIPSCO will retire Units 17 and 18 at R.M. Schahfer Generating Station ("Schahfer") in 2023, as was indicated in the 2016 IRP. However, this updated retirement analysis also indicates that Units 14 and 15 at Schahfer may retire as early as 2023 and that Unit 12 at Michigan City Generating Station ("Michigan City") may also retire as soon as 2028. The earlier retirement of Units 12, 14, and 15 were driven mainly by economics in the wholesale markets.

Ms. Sistovaris testified NIPSCO's goal is to be the premier utility in Indiana in every aspect of its performance, including interaction with its customers. NIPSCO collects direct input and feedback from its customers through a range of methods, which is broadly referred to internally as its "Voice of Customer" process. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, MSR Group Surveys, NIPSCO's Community Advisory Panels, NiSource's My Energy Insights On-line Customer Panels, comments and complaints that are emailed or called into NIPSCO's Call Center, as well as the Commission's Consumer Affairs Division. Ms. Sistovaris testified that NIPSCO's focus on its customers has resulted in the fewest customer complaints per 1,000 customers at the Commission. She stated that in 2017, NIPSCO's customer care representatives handled 1,376,378 calls. NIPSCO's Average Speed of Answer was 28 seconds and its Abandon Rate was only 2.3%. In 2017, NIPSCO's First Call Resolution rate was 87%. In 2017, the Customer Satisfaction with CSR rate was 88%. These metrics have improved significantly since NIPSCO's last rate case.

Ms. Sistovaris explained steps NIPSCO has taken to help customers save energy and reduce their monthly bills. NIPSCO has continued to elevate its internal emphasis on EE including enhanced communication with the stakeholders such as governmental agencies, other utilities, and consumer parties. NIPSCO has dedicated staff to EE measures and manages the development and implementation of such measures. NIPSCO's electric EE programs have helped customers save more than one million megawatt hours ("MWh") from 2010 through June 30, 2018. NIPSCO offers a variety of programs for all customer and helps customers manage current energy costs and to assist NIPSCO in reducing or deferring future generation needs. NIPSCO's EE plan for 2019-2021 provide a robust portfolio of cost effective programs. In addition, NIPSCO has specifically tailored programs to assist low-income customers and smaller commercial entities.

Ms. Sistovaris testified NIPSCO offers a low-income EE weatherization program to both NIPSCO gas and electric customers and proposed a low-income appliance replacement program in its electric EE proceeding. NIPSCO also offers a deposit program that provides a reduction in the total deposit amount for qualified low-income customers. She stated that NIPSCO is committing to establish a low-income collaborative with interested stakeholders to advance low-income assistance and weatherization programs.

Ms. Sistovaris testified that NIPSCO is filing this case to: (1) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure; (2) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (3) revise its depreciation rates to reflect the most recent information regarding planned retirements of its generating units; and (4) align its rates and charges required to maintain safe and reliable service. NIPSCO's proposals in this proceeding were made after initial discussion with various stakeholder groups.

Ms. Sistovaris explained that NIPSCO is evolving from being highly reliant on coal-fired generation to facing the prospect of the retirement of those resources in the near term. Despite currently strong economic conditions, NIPSCO Electric operations continue to face declining industrial usage driven by the development of customer-owned generation and uncertainty in some industrial markets based on international trade conditions. In addition, the industry is transforming toward increased reliance on gas-fired and renewable generation as reflected in the MISO markets.

Ms. Sistovaris stated that regulatory restrictions and environmental costs will increase NIPSCO's cost of producing energy, which will impact generation mix, customer demand, NIPSCO's profitability, and NIPSCO's cash flow. NIPSCO is also addressing compliance with regulations that address the handling and disposal of coal combustion residuals ("CCRs") and may need to address more stringent effluent limitation guidelines ("ELG") in the foreseeable future.

Ms. Sistovaris testified that major environmental controls installed since NIPSCO's last rate case include but are not limited to: (1) installation of ground water monitoring facilities at Bailly Generating Station ("Bailly"), Michigan City, and Schahfer; (2) installation of remote ash conveying facilities and material management areas at Michigan City and Schahfer; (3) and closure of the landfill pond at Schahfer to address the disposal and handling of CCRs. NIPSCO is also engaged in the installation of selective catalytic reduction ("SCR") Catalyst Layers to comply with NIPSCO's NOx Compliance Plan at Units 7, 12, and 14. The ground water monitoring facilities were placed in service prior to the close of the 2017 Historic Base Period, and the remaining investments are expected to be in service prior to the close of the 2019 Forward Test Year.

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 notice provided to residential customers within 45 days of the filing of NIPSCO's Petition.

B. Michael Hooper. Mr. Hooper testified that by filing this case, NIPSCO satisfies the requirement in Ind. Code § 8-1-39-9(d) that NIPSCO file an electric rate case before the expiration of the public utility's approved seven-year plan.

He also explained why NIPSCO is requesting a change in rates at this time. First, NIPSCO seeks to align depreciation rates for its coal-fired generating assets more closely to the expected useful life of those assets as projected in NIPSCO's 2018 IRP. Second, NIPSCO needed to address the impact of the TCJA. Third, NIPSCO is proposing a change in its large industrial service structure to address the changing economic landscape. He noted that the changes in industrial service structure is a natural evolution from the interruptible service offering that was initiated in NIPSCO's 2010 electric rate case (Cause No. 43969) and expanded in its 2015 electric rate case (Cause No. 44688). The interruptible credits and attendant registration of approximately 530 megawatts ("MW") of Load Modifying Resources ("LMR") at MISO facilitated the retirement of Bailly Units 7 and 8, the cost savings from which are included in this filing.

Mr. Hooper testified NIPSCO's overall revenue increase requested in this proceeding is approximately $21.4 million, or 1.4% above the revenue requirement of NIPSCO's 2015 rate case plus the inclusion of trackers that NIPSCO customers will be paying by the time the Step 2 rates in this proceeding are implemented. Mr. Hooper explained that since 2010, NIPSCO has been allowing its industrial customers to assume more market risk in exchange for supporting less of NIPSCO's production costs. He stated the new industrial service structure proposed here is the next step in this evolutionary process. He explained that in exchange for taking a set amount of contract demand for a period of five years, NIPSCO's largest, most sophisticated customers will be allowed to make more decisions regarding their energy procurement. Transitioning much of NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment resulting in a near-term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward. Mr. Hooper stated that if the economics continue and NIPSCO does not respond, there is a high probability that more industrial load will leave the system and with a low likelihood that it would return, at least in the near term.

Mr. Hooper testified that NIPSCO's coal-fired generating units have seen decreased usage in the economically optimized MISO market. He stated that with current natural gas prices, NIPSCO's coal-fired generating units that have historically been used to serve baseload find themselves being the marginal units. He stated that ramping up and down aging coal units causes increased maintenance costs because the units were not designed to operate in that manner. In addition, the recent responses to NIPSCO's Request for Proposals ("RFP") for generation provided more cost effective resources available to serve NIPSCO's load.

Mr. Hooper testified that with the Preferred Plan in NIPSCO's 2018 IRP, NIPSCO is proposing to retire all Schahfer coal-fired generating units by December 31, 2023, and its Michigan City Unit 12 by December 31, 2028. He stated that while the alternative depreciation study conducted by Mr. Spanos also uses these retirement dates, for purposes of calculating the economic benefit of NIPSCO's alternative plans, NIPSCO used a 2030 retirement date for all coal-fired units and assumed recovery of and on those assets over that period. The depreciation rates, which NIPSCO proposes to implement in this proceeding are based upon a December 31, 2030 date.

Mr. Hooper testified that due to the magnitude of the effect of the change in retirement dates for NIPSCO's remaining coal-fired generating stations, NIPSCO is proposing to mitigate the effects of a significant rate increase by recovering all remaining future accruals by the end of 2030, as opposed to the physical retirement date of the units. He stated that because the recovery of depreciation expense extends beyond the anticipated physical retirement date of the asset, when NIPSCO retires the coal-fired generation units at Schahfer by 2023 there will be a significant amount of remaining net book value. Mr. Hooper stated NIPSCO proposes to treat these retirements as extraordinary retirements. At the retirement date, NIPSCO would create a regulatory asset equal to the remaining net book value of the Schahfer coal-fired generating units. He testified that NIPSCO proposes that this regulatory asset be included in rate base and be amortized through December 31, 2030, in an amount equal to the annualized monthly level of depreciation expense based on the month preceding the retirement. He noted that NIPSCO's 2018 IRP analysis included the recovery of and on these assets through 2030.

Mr. Hooper explained that this treatment is appropriate because it mitigates the amount of rate increase necessary in this case by delaying NIPSCO's recovery of its return of and on its investments in coal generation assets. Second, it assures NIPSCO will receive the return of and on its generating assets that have served its customers well over the last few decades. Finally, it fairly balances the interests of NIPSCO's stakeholders. He stated that while shifting recovery past the end of the useful life causes a mismatch between those customers receiving value versus those paying for assets, 2030 is not so far into the future that too large a distortion will take place.

Mr. Hooper testified NIPSCO did not include in the proposed depreciation accrual rates any of the costs related to certain Asset Retirement Obligations ("ARO") that must be performed in compliance with the U.S. Environmental Protection Agency's ("EPA") CCR Rule. He explained that the federal regulations underlying the AROs have recently been revised, and the full impact of the regulations is not yet certain. He testified that NIPSCO intends to seek recovery of these costs in a future base rate proceeding or through its FMCA mechanism when NIPSCO is more confident in the effects of the regulations and its costs become better estimated.

Mr. Hooper testified NIPSCO is proposing to return both protected and unprotected excess accumulated deferred income tax ("ADIT") over the remaining life of the assets. He stated the treatment of protected excess ADIT is required by the Internal Revenue Service ("IRS") and the proposed treatment of the unprotected excess ADIT makes sense from a policy perspective as those continuing to pay for the assets will receive the offsetting credit for the return of the excess ADIT. He noted that shortening of the depreciation lives of NIPSCO's coal generation assets increases the speed at which excess ADIT is returned to NIPSCO's customers.

Mr. Hooper described NIPSCO's derivation of its proposed revenue allocation. He stated that NIPSCO began with a fully allocated cost of service study ("ACOSS") and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MW of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement from this case over all customer classes equally, resulting in a rate increase for all other customer classes of 11.76%. He stated that this methodology was chosen to avoid rate shock to its Residential customers and that if not for the mitigation, the rate increase would be approximately 32.2% for Residential customers.

Mr. Hooper provided an overview of NIPSCO's proposed rate design. He stated that NIPSCO had three overall policy objectives in the development of its proposed rates: (1) restructure the industrial rate classes to accommodate the large industrial customers that want to reduce their dependence on NIPSCO generation; (2) moderate rate shock for the other rate classes; and (3) ensure rate design calculations are simple and transparent. With regard to its Residential customer charge, he testified NIPSCO proposes to take a relatively small step towards further fixed-variable alignment. Specifically, NIPSCO proposes to increase the customer charge that applies to residential and small commercial customers in a manner that simply improves recovery of the fixed costs to serve the customer and billing functions for customers. He testified the proposed residential customer charge of $17 per month would improve that alignment. He explained that based upon a full allocation of costs in the ACOSS, the customer costs alone support a charge of $21.47 and including the full fixed cost of the transmission and distribution system would support $49.76. He stated that those costs above $17 are still recovered through a variable charge. However, noting that the currently effective monthly customer charge is $14, in the spirit of gradualism, a $17 per customer per month charge is an appropriate step.

Mr. Hooper testified NIPSCO is proposing to increase its revenues by $21.4 million. He stated that a return equivalent to the weighted average cost of capital ("WACC") as applied to the net book value of NIPSCO Electric's assets reflects a fair return on the fair value of NIPSCO's used and useful property. This represents an overall increase of 1.4% to be allocated among NIPSCO's customers according to the rate design and COSS sponsored by Dr. Gaske and incorporated into the proposed tariffs sponsored by Mr. Westerhausen. He testified that NIPSCO collaborated with its stakeholders prior to making its filing including numerous meetings with the representatives of the settling parties to its last electric rate case to inform them about this filing and the issues driving it and to listen to any suggestions or concerns. Mr. Hooper testified NIPSCO seeks to promote simplicity, transparency, and collaboration with its stakeholders, respond to customers' needs, and reach a balanced set of proposals that is fair and reasonable.

C. Paul S. Kelly. Mr. Kelly testified the changing economic landscape includes the inefficiencies attributable to coal-fired generation and the availability of more economic alternatives within the MISO market. He stated that NIPSCO's large industrial customers utilize energy intensive processes, are sophisticated market participants, participate in energy markets globally, and compete on the basis of price globally. NIPSCO believes that now is the time to address the needs of its large industrial customers for a market-sensitive rate structure while it simultaneously addresses its on-going generation needs. He stated that in its 2018 IRP, NIPSCO performed analyses for each of its coal-fired units that evaluated the ongoing operations versus retirement and replacement under various potential future scenarios. NIPSCO used many factors in analyzing the retirement timing of the coal units including economics, cost risk, reliability risk, and impacts to NIPSCO's employees and the local economy. He testified that this filing requires its largest industrial customers to remain as NIPSCO's retail customers, while also providing more market choices and is synchronized with the preferred plan presented in NIPSCO's 2018 IRP. Mr. Kelly noted that an example of the changing landscape and resulting economics in the energy market is the March 29, 2018 Whiting Clean Energy, Inc. ("WCE") and BP Products North America ("BP") Joint Petition before the Commission (Cause No. 45071), which sought treatment of WCE as a Qualifying Facility ("QF") able to provide energy directly to BP.

Mr. Kelly provided the estimated annual margin losses for losses from aggregation of the WCE and BP Refinery based on the existing Rate 733 tariff and testified that it is both possible and probable for other industrial customers to reduce their firm loads. He stated that some large customers, like BP, may utilize new or existing cogeneration systems to reduce their firm requirements, and NIPSCO is already aware that other large industrial customers are considering expansion of their cogeneration facilities. Others may reduce those loads by shifting their industrial production to other, more economic locations outside Indiana. Mr. Kelly testified that because large industrial sales constitute such a significant portion of NIPSCO's retail electric sales, NIPSCO would experience decreased revenues and operating margins far faster than could be offset by growth in other sectors. He stated that in the long run, such load loss would subject remaining customers and customer classes to increased costs.

Mr. Kelly testified that after months of discussion with its largest industrial customers, NIPSCO is proposing a new Rate 831 market-sensitive industrial service structure. He stated that over the years, NIPSCO has allowed its largest customers to incur more market risk in exchange for supporting less of NIPSCO's production costs. In Cause No. 43969, NIPSCO expanded its long-standing use of interruptible service to be of use in the evolving MISO market. In Cause No. 43969, NIPSCO transitioned from special contract-based interruptible service offerings to tariff Rider 675. Seven customer historically interruptible premises took service subject to that new Rider, and NIPSCO's capacity requirements in the MISO market were reduced by approximately 377 MW. In Cause No. 44688, NIPSCO expanded the availability of the interruptible rate at the request of its industrial customers, and its interruptible customers allowed NIPSCO to reduce its capacity requirements by approximately 530 MW, which ultimately led to the earlier closure of Bailly Units 7 and 8. He stated that this interruptible/curtailable design, the reductions in NIPSCO's industrial load, and the current electric generation economic landscape lead NIPSCO and its industrial customers to believe that the time has come to allow further access into the energy marketplace while retaining NIPSCO's provision of retail service.

Mr. Kelly testified Rate 831 will replace Rates 732, 733, and 734 and Rider 775 for NIPSCO's largest industrial customers. He stated the availability requirements for Rate 831 are: (1) any transmission or sub-transmission voltage-connected customer with a load of at least ten MW; (2) interval data recorder ("IDR") metering; and (3) a five-year contract. He explained that three tiers of service are offered under the rate, and the customer will be given the opportunity to be served under Tier 1 with either, or both, of the other two, Tiers 2 and 3. Mr. Kelly described the three tiers as follows:

> **Tier 1:** Under Rate 831, a customer is required to take a minimum of ten MW of Tier 1 firm service. Tier 1 rates were designed based on approximately 184 MW (measured at the meter) being subscribed from NIPSCO's five largest industrial customers (approximately 190 MW measured at the generator bus bar). Tier 1 is billed as a fixed demand charge for production and customer-related charges and is considered first through the meter for purposes of energy except when the customer is taking back-up or maintenance services. Tier 1 is subject to all applicable Riders as listed on Appendix A of the tariff filed in this proceeding. Tier 1 will be billed as first through the meter up to the applicable amount of Tier 1 contract demand. A customer is required to provide five years of notice to increase Tier 1 contract demand and must execute a new five-year contract for the increased service.

Tier 2: Tier 2 is a non-firm curtailable service. NIPSCO will register as an LMR at MISO that portion of a customer's Tier 2 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party. Under Tier 2, the customer will take all Energy at the MISO Day-Ahead Locational Marginal Price ("LMP") at the applicable Company Load Zone. Tier 2 is subject only to the non-production Riders applicable to non-firm service (currently the energy portion of NIPSCO's RTO tracker, and any North American Electric Reliability Corporation ("NERC")/Critical Infrastructure Protection ("CIP") components of NIPSCO's FMCA tracker). Tier 2 will be billed as second through the meter up to the amount of Tier 2 contract demand after calculating the amount of Tier 1 energy.

Tier 3: Tier 3 is also a non-firm curtailable service. NIPSCO will register as a LMR at MISO that portion of a customer's Tier 3 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party, but NIPSCO will only register a single LMR for any non-firm load if a customer chooses to take both Tier 2 and 3 service. NIPSCO, as the MISO Market Participant, will register participating customers as an Asset Owner at MISO, which will allow the customer access to the MISO Market Portal to carry out MISO Asset Owner functions. Tier 3 is subject to any NERC/CIP components of NIPSCO's FMCA tracker but not the components of the RTO Tracker that Tier 2 will be responsible for given that Tier 3 customers will be invoiced for those charges directly from MISO as an Asset Owner. If, under the MISO Asset Owner framework, a customer has not arranged for any third-party energy with NIPSCO as the contracting Market Participant, the customer will take all energy under this Tier 3 service at the market price (LMP at the applicable Company Load Zone plus all applicable MISO charges / transmission charges). All settlements associated with the customer's Asset Owner energy offers and demand bids will be passed through to Tier 3 customer. All three tiers will pay volumetric transmission charges for all energy delivered to their premises with a discount available for adjacent customer-owned premises that contain cogeneration facilities capable of outputting energy to NIPSCO's system. Tier 3 will be billed as last through the meter.

Mr. Kelly testified that under the proposed rate, if multiple premises are held under common ownership and at the same qualifying service voltage, NIPSCO will allow customers to aggregate those loads with IDR metering as a single service. He stated that each IDR meter qualifying for aggregation under the rate will be included in the customer's contract to avoid confusion on which meters will or will not be included within the aggregation calculations. Mr. Kelly testified that NIPSCO is requiring a five-year contract to balance the needs of all stakeholders. He stated that NIPSCO and its other customers need these Rate 831 customers to continue to contribute to the fixed costs of production long enough to achieve an orderly transition to NIPSCO's preferred plan in the 2018 IRP. He stated that without a five-year contract, these customers could have an incentive to reduce their contract demands to a level that would immediately require NIPSCO to file another rate case to reallocate the under-collected revenue to remaining classes. Also, without the five-year notice provision to increase the firm Tier 1 contract demand, NIPSCO could be forced to procure uneconomic capacity to meet the increased need due to the inability to properly evaluate and potentially construct required capacity resources. He stated this is especially problematic given the lead times to navigate the MISO interconnection queue and construct various generation technologies with long useful lives. Considering these issues, he stated the five-year contract period provides a reasonable level of certainty for NIPSCO and its customers in moving to a structure that provides more market choices for Rate 831 customers.

Mr. Kelly testified NIPSCO is offering an alternative transmission charge solely to customers that are held under common ownership or affiliates (as defined in Ind. Code § 23-1-43-1), which are located on adjacent premises and have cogeneration facilities that can produce power at one premise and transfer that power across NIPSCO's transmission system to an adjacent premise owned by the customer or its affiliate. He stated that because such customers will need to use only a small portion of the NIPSCO transmission system to transmit power from one of its premises to an adjacent industrial premise, NIPSCO is proposing to provide a 70% discount on the transmission charge for power that is transmitted between the two adjacent, affiliated premises. He stated that while discounted, the rate will result in some transmission revenue from these customers that would not occur if they built their own lines between their premises.

Mr. Kelly testified NIPSCO currently has 15 customers (23 premises) taking service under Rates 732, 733, and 734, and only five customers (nine premises) have also taken service under Rider 775. Of those 15 customers, four have less than ten MW of demand at a single premise. He stated that NIPSCO expects all five of its largest industrial customers (14 premises) to take service under Rate 831 with the remaining ten customers expected to take service under NIPSCO's new Rate 830 including the four below ten MW which will be grandfathered onto the rate.

Mr. Kelly testified that transitioning NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment. He stated it will result in a near-term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward.

Mr. Kelly described what happens if the five large industrial customers take more or less than the 184 MW used to allocate production costs. He stated that NIPSCO is proposing a two-phase rate design approach with the following characteristics to mitigate that risk if necessary:

> **Phase 1 Filed Rates:** The as-filed rates for Rate 831 were designed with the ACOSS allocating 184.556 MW (measured at the customer meter) of NIPSCO's fixed production cost to Rate 831's Tier 1 service for the five largest industrial customers (or 189.794 MW measured at the generator bus bar). This level of firm demand was based upon numerous conversations with NIPSCO's five largest customers. NIPSCO is proposing that customers will choose Tier 1, 2, and 3 contract levels within 30 days following the final order from the Commission in this rate proceeding. NIPSCO will also adjust the RTO Tracker allocations based upon the customer's choices regarding Tiers 1, 2, and 3. Any revenue shortfall resulting from an unsubscribed portion of the 184.556 MW will require a second phase true up.
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> **Phase 2 Rates True-Up:** If, after the final order, the total amount of Tier 1 firm service chosen by the five largest industrial customers is different than 184.556 MW, final rates will be set in the Phase 2 rates to collect the appropriate revenue.

NIPSCO will also adjust the RTO Tracker allocations based upon the customer's choices regarding Tiers 1, 2, and 3.

Mr. Kelly briefly described NIPSCO's new Rate 830. He stated NIPSCO recognized not all of its largest industrial customers would be interested in the market-sensitive service under Rate 831. As such, NIPSCO designed Rate 830 to provide an industrial service that is similar to the current Rate 732, with a few exceptions. He explained that between Rate 830 and 831, NIPSCO's largest industrial service customers will be able to select a service option that meets their needs for firm service and their tolerance for different levels of market risk.

Mr. Kelly testified NIPSCO's proposed new industrial service structure is in the public interest as required by Ind. Code ch. 8-1-2.5 for approval of an ARP. He stated that Rate 831 will only be offered to energy intensive, highly sophisticated customers that compete directly or indirectly in a global market. He stated that traditional retail service at fixed rates as determined by the Commission is no longer necessary for the large industrials loads capable of being served through curtailable services with products from the FERC-regulated MISO capacity and energy markets. He stated that the Commission's approval of this innovative service structure is beneficial to NIPSCO's industrial customers, its remaining firm customers, and to NIPSCO. He explained that NIPSCO is currently implementing the preferred plan from its 2018 IRP for best serving its customers with generation capacity and that to the extent its future generating needs can be reduced, all customers will benefit. Mr. Kelly stated that approval of this new service structure will provide more accurate price signals, in that customers will be paying the market rate for energy and will be economically incented to adjust their consumption based on market price signals.

Mr. Kelly testified NIPSCO's proposed service structure is critical for retaining the level of industrial production from NIPSCO's largest customers. He stated it is crucial for NIPSCO's other 468,000+ customers that these Rate 831 customers continue to make a contribution to NIPSCO's fixed production costs through their retail electric utility service. He stated that NIPSCO has directly observed the loss of load when customers relocate production out of northern Indiana to other facilities that they own across the country and the world. NIPSCO has also experienced the near total loss of major industrial customers due to the inability of the customer to maintain economic viability. He stated that if a major employer closes its doors or even reduces the number of operating shifts in NIPSCO's service territory, it will negatively impact the broader economic stability of the region as well as hinder NIPSCO's ability to provide reasonably adequate service at just and reasonable rates. Mr. Kelly stated that those job losses can create a ripple effect that eventually impacts local governments and commercial businesses. In short, Mr. Kelly testified this proposed structure will best position these large industrial customers to remain cost competitive within their global markets while also contributing to NIPSCO's fixed production costs to serve. He stated that with those customers remaining and potentially expanding their industrial production in the region, this service structure could also mean the difference between a growing local economy in northern Indiana or one that is losing jobs and seeing reductions in its skilled labor force and property tax base.

Mr. Kelly testified that NIPSCO is unique in that its large industrial customers have historically accounted for more than 50% of its energy sales. As those customers compete globally, they are demanding electric rates that more accurately reflect the marginal cost of energy production. He testified that as NIPSCO considers retirement of its coal-fired generation and its replacement alternatives, it presents a unique opportunity to address NIPSCO's industrial customers' needs, while offering protection to its remaining customers that they will not be responsible for replacement generation cost to serve industrial load that is more volatile and more able to leave the system with stranded cost. Mr. Kelly testified NIPSCO's proposed industrial service structure balances the interests of all stakeholders and positions NIPSCO to provide safe and reliable service at just and reasonable rates.

D. Jennifer L. Shikany. Ms. Shikany presented the results of NIPSCO's electric operations for the Historic Base Period and the projected results for the Forward Test Year adjusted on a pro forma basis for the normalization and annualization of certain amounts included in these periods. Ms. Shikany quantified the amount by which retail electric revenues should be increased so that NIPSCO may have the opportunity to earn a fair and reasonable return.

Ms. Shikany testified NIPSCO's proposed rates are based on a forward-looking test year beginning January 1, 2019 and ending December 31, 2019, consistent with Ind. Code § 8-1-2-42.7. She stated NIPSCO provided information for the Historic Base Period and the period beginning January 1, 2018 and ending December 31, 2018 (the "2018 Budget Period"), for comparison purposes. She stated NIPSCO proposed both ratemaking and forward-looking adjustments to the Historic Base Period and Forward Test Year to support the forecasted amounts for the Forward Test Year and the normalization and annualization of these test periods. NIPSCO elected to proceed under the Commission's rules on the MSFRs (170 IAC 1-5-1 through 16) and followed Appendix B to the Commission's Recommended Best Practices for Rate Cases Submitted under Ind. Code § 8-1-2-42.7 (GAO 2013-5) as it relates to the MSFRs and the supporting documentation for changes between the Historic Base Period and the Forward Test Year.

Ms. Shikany testified that NIPSCO proposes retail electric rates designed to recover through base rates the gross retail electric revenue in the amount of $1,545,815,189, an increase of $21,371,413 over the forecasted test year pro forma results based on current rates. She also noted that rates based upon this level of annual revenue requirements will provide NIPSCO with an opportunity to earn annual jurisdictional net operating income ("NOI") of $288,763,895. She stated NIPSCO's proposed rates were calculated using NIPSCO's requested return on the Forward Test Year original cost rate base and capital structure. She stated NIPSCO is proposing to implement the requested rate relief in this proceeding in a two-step process to reasonably reflect the utility property that is used and useful at the time rates are placed into effect.

Ms. Shikany sponsored Attachments 4-A-S1 through Attachment 4-C-S1, Attachments 4-A-S2 through Attachment 4-C-S2, Attachment 4-A-S2-A1, Attachment 4-A-S2-A2, and Attachment 4-D. The reference to "S1" represents the attachments for Step 1 rates (based on an actual rate base, and related depreciation and amortization expense, and capital structure as of the June 30, 2019 proposed cutoff date). The reference to "S2" represents the attachments for Step 2 rates (based on an actual rate base, and related depreciation and amortization expense, and the actual capital structure as of the December 31, 2019 Forward Test Year cutoff date). The reference to "A1" represents the attachments for an alternate revenue requirement if the Commission does not approve NIPSCO's proposed change in service structure. The reference to "A2" represents the attachments for a second alternate revenue requirement if the Commission does not approve NIPSCO's proposal to extend the collection of coal-fired generation depreciation expense until December 31, 2030, and the exclusion of costs to comply with the demolition study's AROs.

Ms. Shikany described the development of the revenue requirements for the Forward Test Year. She stated the proposed revenue requirement was based on NIPSCO's 2019 budget adjusted for ratemaking and service structure adjustments. She noted that for each revenue requirement component, NIPSCO provided support and models to describe the changes from the 2017 actual results to the 2019 forecasted amounts which are used for ratemaking purposes.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to revenue, fuel and purchased power costs, operations and maintenance expenses, depreciation and amortization expense, and tax expense as part of her direct testimony. She also sponsored Rate Base amounts quantifying NIPSCO's December 31, 2019 forecasted net original cost rate base.

Ms. Shikany testified that the Bailly retirement was accounted for as a normal retirement pursuant to the FERC Uniform System of Accounts. Upon retirement, depreciation reserve was debited and utility plant was credited for the original cost. Treating Bailly as a normal retirement had the effect of assigning sufficient depreciation reserve from other generating stations to Bailly for purposes of the depreciation rates herein proposed, as explained by NIPSCO witness Spanos. Certain Bailly assets that were classified as production plant prior to the retirement of the generation units are now being used as transmission assets. The original cost and accumulated depreciation related to the assets that now comprise the Bailly synchronous condenser were transferred from production plant to transmission plant. She stated that all remaining balances were retired – Bailly Unit 7 in May 2018 and Bailly Unit 8 in February 2018. She stated that NIPSCO removed the original cost of the assets from gross plant and accumulated depreciation at the respective retirement dates of the unit. She testified the remaining net book value of Unit 7 and Unit 8 was a debit balance in accumulated depreciation of $102,923,994 and $142,329,364, respectively. This debit represents unrecovered amounts at the date of the retirement. Until NIPSCO's rates are changed, they are calculated to collect depreciation expense associated with Bailly. Ms. Shikany testified the FERC Uniform System of Accounts prohibits the continued use of the Depreciation Expense and Accumulated Depreciation accounts once an asset is retired. She stated that by recognizing that NIPSCO has continued to collect the return of depreciation expense through base rates, a regulatory liability has been established to account for this amount. She stated the $28,675,931 regulatory liability reported in Adjustment RB 6-19R is equal to the total amount of depreciation expense that would have been recorded had NIPSCO not retired the assets. She testified NIPSCO is requesting authority to include the regulatory liability as a line item in Accumulated Depreciation, which lowers the net book value of NIPSCO's rate base. She noted that if this adjustment is not included, Forward Test Year Rate Base would be overstated.

Ms. Shikany testified that because the AROs are new, estimated costs to close the ash ponds have generally not previously been included in NIPSCO's demolition studies and therefore, have not been included in the calculation of prior depreciation accrual rates or recovery of depreciation expense. She stated that in the normal course of business, all of the anticipated demolition costs would be included in the demolition study, which is an input in the net salvage calculation in the depreciation study. She explained that depreciation accrual rates would be designed to collect the remaining future accruals, which are equal to the net book value of the asset plus any net salvage, over the remaining useful life of the asset. Ms. Shikany testified that the demolition study sponsored by Mr. Ranalletta (Petitioner's Exhibit No. 12, Attachments 12-A through 12-D) and resulting depreciation accrual rates sponsored by Mr. Spanos (Petitioner's Exhibit No. 13, Attachments 13-B and 13-C) includes the recovery of anticipated demolition costs, with the exception of costs required to comply with the AROs. She stated that NIPSCO has excluded the costs to comply with the AROs from the demolition study as the full impact of the regulations is not yet certain and in an effort to reduce the overall base rate increase to customers. She stated that NIPSCO will thus not be recovering through depreciation accrual rates approved in this Cause the costs to comply with the AROs.

Ms. Shikany testified NIPSCO is filing an alternate demolition study to demonstrate how inclusion of the costs to comply with the AROs in the demolition studies would impact the study results. She stated that inclusion of the costs to comply with the AROs in the demolition studies would increase the total demolition costs for steam production assets by $141,519,000 from $167,232,000 to $308,751,000. She stated that inclusion of the costs to comply with the AROs in the demolition studies would increase the remaining future accruals calculated in the depreciation study, which is equal to the net book value of the asset plus any net salvage. She testified that if these additional $141,519,000 costs were collected in the proposed depreciation rates, the annual depreciation expense would increase.

With regard to NIPSCO's announced plan to retire all coal-fired generation at Schahfer by 2023 and Michigan City by 2028, Ms. Shikany stated that in the normal course of business, the depreciation study would utilize the physical retirement dates of each generating station unit to calculate the remaining useful life of the unit. The future accrual, which is equal to the net book value of the asset plus any net salvage, would then be divided by the remaining useful life of the asset in order to determine the annual depreciation accrual required to collect all remaining accruals by the physical retirement date. She stated that due to capital additions, the inclusion of costs to comply with the AROs in the demolition study, and the acceleration of retirement dates for the coal generation assets, the annual depreciation accrual for Total Steam Production Plant increased by $311,908,329 from $132,449,341 in Cause No. 44688 to $444,357,670 in the alternate depreciation study in Petitioner's Exhibit No. 13, Attachment 13-D. An increase in annual depreciation expense of this magnitude would result in a significant increase in customer rates.

Ms. Shikany explained that in order to mitigate the effects of such a significant rate increase, NIPSCO is proposing to recover all remaining future accruals by the end of 2030, as opposed to the physical retirement date of the units. She stated that under this scenario, the Total Steam Production Plant depreciation accrual decreased by $268,567,997 from $444,357,670 in the alternate depreciation study to $175,789,673 in the depreciation study proposed in this case (see Petitioner's Exhibit No. 13, Attachment 13-D). She testified that because the recovery of depreciation expense extends beyond the asset's anticipated physical retirement date, when NIPSCO retires the coal-fired generation units at Schahfer by 2023, there will be a significant amount of remaining net book value. She stated that NIPSCO proposes to treat these retirements as extraordinary retirements. She explained that at the retirement date, NIPSCO would create a regulatory asset equal to the remaining net book value of the Schahfer coal-fired generating units. NIPSCO proposes that this regulatory asset be included in rate base and be amortized through December 31, 2030, in an amount equal to the annualized monthly level of depreciation expense based on the month preceding the retirement. She stated that any final true-up between incurred costs and recoveries will be considered in a future base rate proceeding. Ms. Shikany testified that with the exception of the costs to comply with the AROs, demolition costs will continue to be recovered through rates as a component of depreciation rates. The costs to comply with the AROs, however, will not be recovered through depreciation rates approved in this rate case under this proposal. The costs to comply with the AROs will instead be recovered in a future base rate proceeding or by seeking a Certificate of Public Convenience and Necessity ("CPCN") to approve the recovery of these costs through NIPSCO's FMCA.

Ms. Shikany testified that the retirement will be extraordinary for two reasons. First, the remaining net book value for the coal generation units at Schahfer will be significant. Second, after the retirement of Schahfer in 2023, the only coal-fired generation station that will remain is Michigan City Unit 12. She stated that once that unit is retired, there will be no other coal generation assets remaining from which depreciation reserve could be reassigned in order to treat the retirement as a normal retirement. Ms. Shikany testified that by extending the recovery of depreciation expense for the Schahfer coal generation units seven years beyond the anticipated physical retirement, NIPSCO will delay the recovery of these dollars to mitigate a significant increase in customer rates. She stated that in the normal course of business, all remaining future accruals would be recovered as depreciation expense through base rates over the remaining useful lives of the plants (anticipated physical retirement dates). If NIPSCO delays the cash recovery of these dollars for an additional seven years, NIPSCO should be compensated by earning a return on remaining net book value in a future rate case. She stated that in order to mitigate NIPSCO's financial risk, NIPSCO is seeking authority from the Commission to defer the remaining net book value of coal generation assets as a regulatory asset within rate base. This authority reduces the risk of a Generally Accepted Accounting Principles ("GAAP") write-off of the remaining net book value of coal generation assets, which would have a negative impact on the financial statements and the investor community. Furthermore, a delay in the cash recovery beyond the useful life of the related assets without assurance that the remaining net book value of the coal generation assets as a regulatory asset in rate base could result in a negative impact on NIPSCO's credit ratings resulting in an increase in its cost of capital. She stated that NIPSCO maintains that the inclusion of this regulatory asset in NIPSCO's next base rate proceeding will alleviate these financial pressures by providing NIPSCO a return on its prudently incurred investments along with predictable and stable levels of cash flow through 2030.

Ms. Shikany described the adjustment made to the Utility Plant In Service component of rate base. She testified one of those adjustments is for the prepayment for assets relating to NIPSCO's investment in a new cloud-based Procure-to-Pay ("P2P") system. She explained that the new system will allow for replacement of multiple fragmented and obsolete technology systems related to sourcing, procuring, and paying for goods and services and also allow NIPSCO to automate and standardize business processes, manage standard settlement terms with suppliers, take advantage of new methods of settling payments, leverage centralized purchasing data, and manage spend on goods and services. She stated that NIPSCO has identified cloud computing services as a means to enhance security and to increase reliability and flexibility. She stated that to realize these benefits, NIPSCO plans to utilize cloud-based technologies beyond the P2P system. Ms. Shikany testified NIPSCO is requesting authority to account for off premise cloud-based technology solutions in the same way that it accounts for on-premise technology solutions. She explained that this would mean that NIPSCO would capitalize implementation services, internal labor, and other fees (such as those for licenses, maintenance, and support) that were necessary to bring the asset into service in FERC Account 303 – Intangible Plant for ease of tracking and identification. She explained that under the current GAAP accounting guidelines, certain costs incurred for the development of on-premises software are required to be capitalized, while certain implementation costs for cloud-based services are considered prepaid expenses. Many cloud-based services offer advantages to traditional on-premises software such as greater flexibility for the workforce, improved productivity, and higher efficiency at lower costs relative to certain on-premises solutions. Accordingly, since cloud-based prepaid expenses are expected to provide benefits over extended periods of time and not just in the period in which the costs are incurred, NIPSCO believes that the prepaid expenses should be included in rate base and receive the same regulatory treatment as an on-premises solution, which is capitalized in FERC Account 303 – Intangible Assets. Ms. Shikany testified that NIPSCO believes that investments in prepaid expenses related to cloud-based assets are part of the reasonable cost of bringing NIPSCO's property to its current state of efficiency. NIPSCO proposes to amortize off-premises assets over the period of time that NIPSCO will use the new solution. In this case, the contract period for the cloud-based solution is five years so a five-year period will be used to amortize the asset.

Ms. Shikany described NIPSCO's proposed changes to its currently approved Riders. NIPSCO is proposing all Utility Receipts Tax ("URT") will be removed from the Riders as NIPSCO is proposing that URT will be a separate line item on the customer bill. NIPSCO is proposing to update Rider 770 – Adjustment of Charges for Cost of Fuel Rider to update the cost of fuel included in base rates. NIPSCO also is proposing to update Rider 771 – Adjustment of Charges for Regional Transmission Organization to reflect updated base levels of MISO non-fuel costs and revenues and OSS margins and proposing the pass back of any back-up and maintenance demand revenue. Finally, NIPSCO is proposing to eliminate the ECR Mechanism.

Ms. Shikany testified NIPSCO is seeking accounting authority to: (1) defer, as a regulatory asset, discounts offered to certain customers under its EDR for recovery in a future rate case; (2) defer, as a regulatory liability, an amount equal to 100% of (a) annual OSS margins net of expenses and (b) back-up and maintenance demand margins, both for pass back through the RTO Tracker; and (3) defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. She testified such deferred accounting is consistent with GAAP and FERC Uniform System of Accounts.

Ms. Shikany testified that in March of 2017, the Financial Accounting Standards Board issued ASU 2017-07, a GAAP standard that changed the income statement presentation of Pension and Other Post-Employment Benefits ("OPEB") expense and limited the amount of expense eligible for capitalization. She stated the new GAAP standard requires disaggregation of the cost components of Pension and OPEB and only the service cost component will be eligible for capitalization to Property, Plant, and Equipment. NiSource adopted the standard January 1, 2018. She testified NIPSCO is accounting for the costs consistent with guidance from the FERC Docket No. AI18-1-000, which states "Jurisdictional public utilities and licensees, natural gas companies, and centralized service companies should record pension and post-retirement benefits other than pensions costs in their entirety in Account 926". She explained that based on this FERC Docket, the ASU 2017-07 GAAP changes need not apply to the FERC books and that all components of Pension and OPEB costs that have historically been reported in operating expenses will continue to be recorded in operating expenses.

Ms. Shikany supported NIPSCO's calculation of the 2018 and 2019 WACC shown on Attachment 4-B-S2, CS Module. She explained that the forecasted Prepaid Pension Asset represents the difference between the forecasted cumulative amount of cash contributions to

NIPSCO's pension trust fund and the forecasted cumulative amount of pension expense that will be recorded on NIPSCO's books and records in accordance with GAAP. She stated that NIPSCO included the balance of the Prepaid Pension Asset as a component of its overall WACC.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to its proposed capital structure, and she stated that NIPSCO's accounting and financial reporting policies and procedures conform to GAAP, rules of the Securities and Exchange Commission, and the FERC Uniform System of Accounts. In addition, she 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. She also discussed the various controls NIPSCO utilizes to ensure the accuracy of its accounting books and records and financial statements. She testified NIPSCO's books and records are also subject to audit by the OUCC, the Commission, and FERC.

E. Clifton Scott. Mr. Scott explained and supported: (1) the financial planning and budgeting processes used at NIPSCO; (2) NIPSCO's 2018 Annual Financial Plan (the "2018 AFP") for its electric utility covering the 2018 and 2019 plan years, which is the underlying basis for its rate request; and (3) the 2018 and 2019 budget adjustments not supported in other witnesses testimony. He summarized the processes used at NiSource and NIPSCO for development of capital and operation and maintenance ("O&M") budgets and longer-term financial plans. He explained the process that NiSource and NIPSCO use to develop robust and accurate budgets and financial plans, including engaging leadership and operations personnel and prioritizing safety, reliability, customer service, and compliance. He stated NIPSCO's budgeting process produces budgets that are reliable forecasts of future capital and O&M needs and expenditures.

Mr. Scott testified the revenue forecasting methodology results in an accurate estimate of revenues to be achieved during 2019, with the caveat that the revenue forecast presented in this case does not reflect proposed or anticipated revenues coming out of this proceeding. Mr. Scott testified that under current rates, NIPSCO Electric's revenues in 2019 are forecasted to be $1,776,342,377 based on the major assumptions used for customer usage volumes, cost of fuel and purchased power, and approved retail electric utility tariff rates.

Mr. Scott testified the O&M budgeting methodology results in an accurate estimate of expenses to be incurred during 2019. He stated NIPSCO Electric has experienced a variance of 0.2%, compared to its approved O&M budget over the last five years and demonstrates a high level of historical O&M budgeting accuracy by NIPSCO Electric. He concluded that these results should provide a high level of confidence and reliability as to the overall accuracy of the O&M expenses included in NIPSCO Electric's 2019 O&M budget.

Mr. Scott testified the capital budgeting methodology results in an accurate estimate of capital to be expended during 2019. He stated NIPSCO Electric has experienced a variance of 1.1%, compared to its approved capital budget over the last five years, which demonstrates a high level of historical capital budgeting accuracy. He concluded that these results should provide a high level of confidence and reliability as to the overall accuracy of the capital expenses included in NIPSCO Electric's 2019 capital budget.

Mr. Scott testified NIPSCO Electric's 2019 forecasted income statement and consolidated balance sheet were prepared in accordance with NIPSCO's normal forecasting processes and based on the consolidation of data provided by business units and various corporate departments. The forecast is fully integrated between the income statement, balance sheet, and statement of cash flows. He testified NIPSCO's forecasted consolidated 2019 statement of cash flows is a function of the items reflected in the forecasted balance sheet.

Mr. Scott described the major components of NIPSCO Electric's fuel and purchased power expense. He testified NIPSCO Electric's fuel and purchased power expense in 2019 is forecasted to be $486,393,871. Mr. Scott then described the major categories of NIPSCO Electric's O&M expenses as generation, transmission, distribution, operating and maintenance expenses, customer account expenses, and administrative and general expenses. Mr. Scott testified NIPSCO Electric's O&M expenses in 2019 are forecast to be $557,756,972. Mr. Scott also described the major components of NIPSCO Electric's tax expenses other than income taxes to be property taxes, payroll taxes, public utility fees, and URTs. He testified NIPSCO Electric's tax expenses, other than income taxes, in 2019 is forecast to be $66,011,931.

Mr. Scott stated the major components used in the development of the forecasted 2019 capital expenditures are Growth (also referred to as New Business), Tracker, Maintenance Betterment (capacity or compliance), Replacement (age and condition), Public Improvement (mandatory relocation), and Corporate (Shared Services). He testified NIPSCO Electric's capital expenditure in 2019 is forecast to be $417,526,573. He also testified NIPSCO Electric's Materials and Supplies and Production Fuel balances are $105,237,192 and $45,253,522, respectively.

Mr. Scott explained the major components of NIPSCO Electric's capital structure consist of Common Equity, Long-Term Debt, Customer Deposits, Deferred Income Taxes, Post Retirement Liability, Prepaid Pension Asset, and Post-1970 ITC. He testified NIPSCO's capital structure balances in 2019 are forecast to be $5,932,644,938.

F. Patrick N. Augustine. Mr. Augustine provided an extensive discussion of the analysis that was performed in NIPSCO's 2018 IRP and explained how that analysis was used in making the retirement decisions regarding NIPSCO's coal facilities. He stated that all five of NIPSCO's coal-fired units were evaluated for retirement, including Michigan City Unit 12 and Schahfer Units 14, 15, 17, and 18. He explained that the operational dependency as well as technology and vintage similarity of the units at Schahfer would make unit level retirement impractical at that plant and as a result, the analysis created two unit pairs that would be jointly considered for retention or retirement at Schahfer – Pair 1 matched Units 14 and 15, and Pair 2 matched Units 17 and 18. He stated that analyses were performed for NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. He stated that NIPSCO used a number of factors in analyzing the retirement timing of the coal units including customer cost, cost risk, reliability risk, and impacts to NIPSCO's employees and the local economy.

Mr. Augustine described that customer cost and cost risk are measured by the overall Net Present Value of Revenue Requirements. He explained that the Cost to Customer metric is recorded under a Base Case set of market conditions. In addition, he noted that NIPSCO evaluated customer costs across three alternative market scenarios and at different points on a cost distribution developed through a stochastic analysis. He explained that Reliability Risk assesses NIPSCO's ability to confidently transition the resources and maintain customer and system reliability and considers the activities required as part of the MISO retirement process, potential transmission system, and reliability upgrades that are required as a result of plant retirements, remaining unit dependencies, outstanding fuel and other contracts, future resource procurement, and the percent of NIPSCO's supply resources turning over at once. He noted other factors, such as the loss of work for employees and the reduction of property tax base for surrounding communities, also factored into the decision making process. He said that while these do not directly impact power supply costs to customers, NIPSCO believes they are factors that should be included in the analysis.

Mr. Augustine described that the retirement analysis evaluated eight retirement combinations and that the projected future capital and operating costs for the affected units were modeled by Charles River Associates ("CRA") in the Aurora production cost and utility portfolio model. He explained that the economic analyses ultimately compared the ongoing costs and benefits of operating the existing units to the costs and benefits of retiring and replacing the relevant unit or sets of units with alternatives. He stated the analyses were evaluated across all scenarios and stochastics developed in NIPSCO's IRP.

Mr. Augustine testified that capital cost estimates were developed by operational teams within NIPSCO for existing unit maintenance and environmental spend as well as for necessary transmission reliability upgrades in the instances where certain coal units retired. He stated that the existing rate base was depreciated at NIPSCO's latest estimate for the steam generation fleet average, which is 4.6%, across all retirement portfolios, which is consistent with the depreciation study presented in this Cause. He indicated that existing rate base is depreciated at the fleet average depreciation rate until the book value is equal to the total estimated "cost of removal," which is equal to $227 million for the entire fleet. He said that this depreciation schedule and cost of removal value were the same across all retirement cases, and thus, the analysis assumes that return of and on capital is recovered in all cases.

Mr. Augustine provided an extensive explanation of the resource alternatives used to evaluate the retirement options, the commodities price assumptions used in the analysis, and the process CRA used to complete the modeling analysis. He also addressed how risk and uncertainty were assessed in the analyses. Mr. Augustine sponsored the detailed modeling results in Attachment 6-A. He testified that in the Base Case, Retirement Combination 8 (where 100% of the coal portfolio is retired by 2023) is the lowest cost option, and Retirement Combination 1 (where all coal units run to 60 years of service) is the highest cost option. He testified that in the Base Case, Retirement Combination 6 (which retires Schahfer Units 14, 15, 17, and 18 in 2023, and Michigan City Unit 12 in 2028) is the third lowest cost option. He explained that the cost to customer ranking remains broadly consistent across the four scenarios analyzed. He explained that generally, portfolios that retain more coal perform relatively better in the scenario without a carbon price (Challenged Economy) and relatively worse when carbon prices are higher (Aggressive Environmental Regulation); however, in all four of the scenarios, retirement of all coal units (Retirement Combination 8) and replacement with a model-optimized selection of RFP alternatives is the least cost portfolio and that Retirement Combination 6, is the third-least expensive option. He testified that overall, the analysis concludes that the all-in costs of the replacements evaluated from the RFP are lower than the ongoing costs associated with maintaining the existing coal fleet. Mr. Augustine also described the results of the IRP analyses with regard to the other, non-cost metrics.

Mr. Augustine testified how NIPSCO integrated the results of these analyses to arrive at a decision regarding coal retirements. He stated that NIPSCO created a scorecard to explore relative differences between the portfolios using a number of quantitative and qualitative measures. He stated that ultimately, NIPSCSO selected Retirement Combination 6 as the preferred retirement path, which would retire all of the Schahfer units by the end of 2023 and Michigan City by the end of 2028. He explained that Retirement Combination 6 was selected because it was the lowest cost and lowest cost risk option that held acceptable reliability risk for customers and the system. He said the analysis shows that Retirement Combination 6 saves customers $1.5 billion relative to NIPSCO's 2016 IRP preferred plan and that from a reliability risk standpoint it provides enough time to reasonably erect the necessary transmission upgrades that are critical for system and customer reliability. Additionally, the replacement resources can be reasonably secured and constructed by 2023. He stated that while the near-term transition still encompasses roughly 60% of NIPSCO's physical generation, it maintains Michigan City through 2028 and Sugar Creek Generating Station ("Sugar Creek") even longer. He noted that both are dispatchable units that can be used to support the transition while NIPSCO implements the replacement path. He also indicated that another benefit of staggering the retirements is that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade and adjust as appropriate rather than locking the entire transition in at once.

Mr. Augustine concluded that NIPSCO evaluated its generation portfolio under four fundamental market scenarios as well as with advanced risk treatment using stochastics. He stated that Retirement Combination 6 was selected as the preferred retirement portfolio combination. He testified that in this option, NIPSCO has balanced customer cost and cost risk with portfolio flexibility and the ability to successfully and reliably transform its supply resources to meet its customers needs. He noted that although not the least expensive solution, in all modeling analyses, the preferred portfolio results in savings to customers, greater cost certainty, and lower cost risk over alternatives that preserve more coal capacity for longer, as well as balancing other non-economic considerations such as portfolio flexibility, employees, and local property tax impacts.

G. Michael Hooper. Mr. Hooper adopted the testimony of Benjamin Felton, formerly NIPSCO's Senior Vice President, NIPSCO Electric, and that testimony was offered separately. In that testimony, Mr. Hooper described steps taken by NIPSCO to control costs, described NIPSCO's generation fleet, described NIPSCO's electric transmission and distribution systems, discussed NIPSCO's customer service and electric reliability programs, described the investments NIPSCO has made to its generation, transmission, and distribution systems in recent years, and explained and supported several various pro forma expense adjustments.

Mr. Hooper testified that NIPSCO's Net Utility Plant has grown by approximately $360 million or 12% over the last three years and is projected to grow by another $520 million by the end of the 2019 future test year. He noted that NIPSCO has taken steps to control costs resulting in decreases to O&M expenses, but explained that in spite of these efforts, increases in depreciation and amortization expense associated with the investment in new plant are projected to counter those savings. Mr. Hooper testified that department or cost center managers must prepare and submit proposed operating budgets to include proposed levels of capital and operating expenditures. He explained that each operating budget is reviewed by management and that once approved, each manager is responsible for monitoring their budget to ensure the costs are spent within approved limits. Budgets and actual expenditure variances are reviewed throughout the year to ensure that funds are being spent appropriately and in accordance with approved levels to ensure that controls are in place to identify, monitor, and control costs.

Mr. Hooper described NIPSCO's six electric generation sites totaling 2,825 MW, including the Schahfer, Michigan City, Bailly, Sugar Creek stations, and two hydroelectric dams. He testified that NIPSCO's historic test period generating mix produced 73.3% of its output from coal-fired units, 26.3% from natural gas-fired units, and 0.4% from hydroelectric units. He noted that the Bailly Units 7 and 8 were retired on May 31, 2018, consistent with NIPSCO's expectations expressed in Cause No. 44688.

Mr. Hooper discussed NIPSCO's investments in environmental and emissions control projects and provided tables identifying the associated capital costs. He testified that NIPSCO obtained approval of its Environmental Compliance Plan consisting of several capital projects being tracked through NIPSCO's FMCA Tracker, noting that with one exception all projects incorporated in that Plan would be in service prior to the close of the Forward Test Year. He also detailed the components of the Utility Mercury and Air Toxics Standards ("MATS"), nitrogen dioxide ("NOx"), and MPCP Compliance Plans that had previously been the subject of approved CPCNs with costs for those projects recovered through NIPSCO's ECR tracking mechanism. Mr. Hooper testified that each of the components of the three Environmental Compliance Plans was in service and used and useful in the provision of electric service because they assist NIPSCO in meeting increasingly stringent air emissions requirements. Mr. Hooper also identified other capital improvements to NIPSCO's generation fleet since its last base rate case not already included in either the FMCA or ECR tracking mechanisms, and explained that those improvements are expected to be in service by the close of 2019.

Mr. Hooper summarized that the reliability of NIPSCO's generating units (exclusive of Units 7 and 8) as measured by the Equivalent Forced Outage Rate ("EFOR") has increased relative to the 44688 Rate Case, with NIPSCO's average EFOR for the three-year period ending December 31, 2017, increasing to 10.6% with the limited run time for the coal units during this period due to economic dispatch into MISO as a contributing factor. He explained that EFOR expresses unit reliability as a percentage of available run time for unplanned outage hours and equivalent unplanned de-rated hours. In contrast to NIPSCO's coal units, NIPSCO's Sugar Creek combined cycle gas turbine has been below 2.5% EFOR for each of the preceding three years, and under 1% in 2016, with a net capacity factor consistently above 65% and as high as 84% as of June 2018. He testified that the EFOR of NIPSCO's coal units was 9.79% in 2017, below the 2017 U.S. average of 10.92% for similarly sized units of between 300 – 599 MW.

Mr. Hooper explained that during the three-year period 2015 – 2017, NIPSCO's average EFOR was 10.63%. He noted that with recently announced coal plant retirements, there is the potential for EFOR to move upward over the near to medium term. Mr. Hooper explained that NIPSCO will continue to operate its facilities in a safe, environmentally compliant manner and with a reasonable level of reliability, while making sound decisions with regard to significant capital investments into facilities with limited operating lives. He testified that because NIPSCO's coal units were engineered to be used as baseload units that run consistently over long periods of time, as those units become less economical, the cost to operate them increases because in addition to the increased maintenance required of older units, the added expenses to ramp the units up and down are incurred more frequently.

Mr. Hooper addressed NIPSCO's base cost of fuel and coal inventory levels. He testified that the adjusted retail jurisdictional cost of fuel in the Historic Base Period reported in Attachment 4-B-S2, FP Module was $494,884,095. He opined that this value was reasonable as discussed in NIPSCO's quarterly FAC proceedings. He added that both NIPSCO's long-term coal contracts and shorter-term gas supply contracts were the result of competitive bidding, and that NIPSCO considers a number of factors in making fuel procurement decisions, including price, quality, suitability, environmental attributes, supplier availability, reliability, and diversity in addition to market prices. Mr. Hooper testified that NIPSCO's retail jurisdictional coal inventory level reported in Attachment 4-B-S2, RB Module for the Historic Base Period was $80,046,953, and that it was reasonable and consistent with NIPSCO's desire to have adequate fuel supplies on hand while balancing the costs associated with maintaining coal inventory.

Mr. Hooper discussed NIPSCO's safety culture and described how NIPSCO and its consultant derived a plan to deliver human performance based error reduction through the use of improved safety metrics and a focus on an improved safety culture. He explained that in the past year, NIPSCO has engaged other consultants with expertise in safety regulations to work with internal teams to review and refine internal work practices, safety manuals, and safety policies/procedures while ensuring alignment with industry standards and best practices. He also explained that NIPSCO continues to collaboratively work with its front line employees to develop rules and policies for stronger work practices, and has developed a number of in-house safety training programs to improve driving performance and regulatory changes and requirements are continually monitored to manage safety training on a continual improvement basis.

Mr. Hooper testified that NIPSCO's contractors and construction execution teams have been engaged in its efforts to strengthen the safety culture, and NIPSCO has supported such measures by forming cooperative contractor safety committees for both its generation and field operations teams. He added that NIPSCO's focus on cooperation and safety has resulted in strong safety performance from its contracted teams. He testified that NIPSCO Electric has made an 80% improvement in recordable injury rate, an 83% improvement in DART (days away, restriction, or transfer) injury rate, and a 71% improvement in vehicle crash rate from year end 2008 to year end 2017, including a 66% improvement in recordable injury rate, a 72% improvement in DART injury rate, and a 71% improvement in vehicle crashes during that period.

Mr. Hooper described NIPSCO's transmission and distribution systems. He explained that NIPSCO's transmission system consists of approximately 353 circuit miles of 345 kilovolt ("kV"), 756 circuit miles of 138 kV, and 1,693 circuit miles of 69 kV transmission lines in addition to 63 transmission substations. He testified that NIPSCO is interconnected with six neighboring utilities, with transmission interconnects with American Electric Power or its affiliates (at 345 kV, 138 kV, and 69 kV), interconnects with Commonwealth Edison (at 345 kV and 138 kV), and with Duke Energy Indiana (at 345 kV, 138 kV, and 69 kV), in addition to 138 kV interconnections with Ameren and International Transmission Company and a single 765kV interconnection with Pioneer Transmission. He stated NIPSCO's distribution system serves more than 468,000 customers in northern Indiana, primarily through more than 900 distribution circuits operated at nominal voltages of 34.5 kV, 12.5 kV, and four kV radiating from approximately 240 distribution substations, and encompassing about 8,209 miles of overhead line and about 2,532 miles of underground cable.

Mr. Hooper described the transmission and distribution investments made by NIPSCO since its 44688 Rate Case. These included investments in an Enhanced Outage Management System to provide faster restoration and more accurate communication scheduled to be in service in early 2019, more than $283 million in transmission, distribution, and storage system improvement charge ("TDSIC") direct cost investments through May 31, 2018, and other maintenance capital investments to expand and enhance capacity and reduce risk. Mr. Hooper explained that while significant investment had also been made in multi-value projects ("MVP") through MISO, those investments were not being included in jurisdictional rate base. He testified that all of NIPSCO's other transmission and distribution assets inclusive of the non-MVP additions are essential to the reliable transport and delivery of electricity from NIPSCO's generation fleet or from other generators to its retail customers in order to meet customers' needs for electric power and are used and useful in the provision of electric service.

Mr. Hooper explained that NIPSCO monitors three main metrics to evaluate the reliability of the transmission and distribution system: SAIFI, SAIDI, and CAIDI. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year. CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. Mr. Hooper testified that all three reliability indices have improved since the 44688 Rate Case and from 2014 to 2017. He explained that reliability indices are reported by industry standard without including Major Event Days, which primarily include storms or severe weather events. He noted that the decrease in Major Event Days in recent years is likely due in part to NIPSCO's aggressive vegetation management program and implementation of a comprehensive emergency restoration plan in 2017. He concluded that NIPSCO's transmission and reliability metric performance has been at or above industry standard performance for medium-sized electric utilities for the past five years.

Mr. Hooper testified about the programs NIPSCO uses to support transmission, distribution, and substation reliability and ensure compliance with NERC standards. These programs include wooden pole inspection, vegetation management programs, and periodic inspections and maintenance of transmission lines and structures, substation equipment, protective relay systems, distribution pad-mount transformers, pole-mounted re-closers, voltage regulators, switched capacitors, and other underground equipment that include remedial work necessary to repair or replace minor plant items found to be deficient. In 2017, NIPSCO developed and implemented a robust emergency response plan, and NIPSCO has also developed a formal Outage Investigation Program that reviews any outages that impact more than 1,000 customers, result in a pole fire or similar safety-related event, or have an "unknown" outage cause. Linemen, Substation Electricians, Supervisors, Dispatchers, and Engineers all benefit from these report findings by applying these lessons learned to their designs, materials, and construction methods to improve reliability, more accurately perform analytics on outage causes, and make improved decisions on materials, designs, construction methods, and maintenance techniques.

He also described NIPSCO's Line & Sub voltage regulator maintenance replacement program to reduce in-service failures. He testified that the program is intended to enhance customer reliability by incorporating newer regulators and enhanced tap changers that reduce contact wear and premature failure. He added that microprocessor-based controls have proven to be more reliable than analog controls, with the added benefit of enhanced customer voltage profile. He explained that NIPSCO continues its "Worst Circuits" and "Worst Taps" Programs whereby circuits and taps with the worst performance values and outages are assessed and recommendations for improvement are developed. Mr. Hooper noted that recommendations flowing from those programs have included targeted tree trimming, replacement of equipment prone to failure, replacement of equipment that is in poor condition, an analysis of fuse coordination and loading, and installing additional sectionalizing devices (cut-outs, triple-shots, re-closers, switches, etc.) where appropriate to minimize the impacts of outages and the number of customers affected per outage. Mr. Hooper explained that investment in an Enhanced Outage Management System expected to be in service in early 2019 to improve customer experience by providing faster restoration and more accurate communication of estimated time of restoration during outages.

Mr. Hooper supported a number of proposed adjustments found in Petitioner's Confidential Exhibit No. 20-S2. He testified that Adjustment OM 2A-17 increases non-labor Storm expense for the Historic Base Period by $1,336,602 to approximate a five-year average of storm expense, adding that both five- and seven-year analyses produced similar results. He explained that the Historic Base Period was a mild storm year, so Adjustment OM 2A-18 increases the 2017 normalized expense by $74,979 to reach the five-year average of $3,056,037 included in the 2018 Budget Period. Mr. Hooper also addressed the elimination of the Pure Air expenses in the amount of $10,702,282 and $8,568,689 for 2018 and 2019, respectively, because with the retirement of Bailly Units 7 and 8, the Pure Air flue gas desulfurization ("FGD") facility will no longer be required to operate and the associated expenses will no longer be incurred.

Mr. Hooper testified that Adjustment OM 2C-18 reduces forecasted Generation Base Maintenance expense by $6,785,009 as a reflection of: (1) a $1.9 million budget reprioritization decision; (2) a $2.4 million pull forward of 2018 budgeted dollars for the pre-purchase of materials, and; (3) a $1.1 million reduction in planned outages. He explained that while operationally advantageous, they were isolated opportunities and should not be reflected in the ongoing level of operating expenses. He added that Adjustment OM 2C-19 reflects an increase of $1,590,485 to reflect 2019 increases in cooling water chemical expenses anticipated for 2019. Mr. Hooper also discussed adjustments OM 2D-18 and OM 2D-19 to reduce Bailly non-labor Base Maintenance Expense by $3,600,000 and $3,800,000 in 2018 and 2019, respectively, due to the retirement of Bailly Units 7 and 8. He explained that the $3,600,000 reduction to the 2017 represents seven months of savings based on the retirement of the units in May, and that an additional $3,800,000 of savings in 2019 will bring the total Bailly Base Maintenance Expense savings to $7,400,000. He noted that the remaining Bailly base maintenance budget of $848,092 will be used to maintain the synchronous condenser unit and the Unit 10 combustion turbine still in service.

Mr. Hooper addressed adjustments to NIPSCO's Planned Outages normalization presented in Adjustment OM 2E-17 and its ongoing level of Planned Outages expenses in Adjustments OM 2E-18, 2E-19, and 2E-19R. He explained that Adjustment OM 2E-17 reduced the normalized level of Planned Outages for the base period by $25,455 based on the retirement of Units 7 and 8. He testified that Adjustments OM 2E-18 and OM 2E-19 reflect changes in amounts budgeted for 2018 and 2019 because the planned outage schedule varies from year to year by station, unit, and major component, and that Adjustment OM 2E-19R normalized non-Bailly planned outage expenses going forward to a three-year average of $30,437,740. For Forced Outages expenses, Mr. Hooper explained that Adjustment OM 2F18 reflects an increase of $119,959 to reflect 2018 budget expenditures, and Adjustment OM 2F-19R increases the ongoing level of Forced Outages expense to the average value of $5,261,129 actually experienced from 2015 through 2017.

Mr. Hooper described Adjustments OM 2G18, OM 2G-19, and OM 2G-19R regarding proposed adjustments to NIPSCO's Vegetation Management expenses. Mr. Hooper explained that since its last electric rate case, NIPSCO has increased the budget portion of its 69 kV, 34 kV, and 12 kV vegetation management programs to include more circuit-line miles and has begun analyzing circuits on a yearly basis to determine which circuits have had a higher experience of interruptions regardless of when the circuit was last trimmed. He explained that those circuits are surveyed, sources of tree interruptions are identified, and remedial work is performed. When compared to the same time frame (January through June) as last year, NIPSCO has experienced an overall reduction in tree related outages and customers impacted. He testified that in 2017 NIPSCO began to experience higher external labor and equipment costs to perform clearance work due to market conditions, and those changes were reflected in Adjustments OM 2G-18 and OM 2G-19 that increase Historic Base Period non-labor vegetation management expenses for 2018 and 2019. He noted that while NIPSCO has been prudent in managing vegetation costs, the overall impact of market constraints would lead NIPSCO to fall approximately 500 miles short of its 2019 circuit-mileage goal at current funding levels. As such, Adjustment OM 2G-19R was made to increase vegetation management expense by $5,720,500 to retain the 1,500 mile goal for 2019 allowing NIPSCO to continue to reduce vegetation-related outages.

Mr. Hooper also supported Adjustments OM 2H-17, OM 2H-18, and OM 2H-19R for Line Locate expenses. He testified that Adjustment OM 2H-17 decreases the Historic Base Period operating expense by $128,042 to reflect a full year of pricing and efficiencies gained under the terms of two locate contracts that became effective on March 8, 2017. He explained that the average ticket cost under NIPSCO's new locate contracts is $29.38 per ticket for combination gas and electric locates and $12.93 per ticket for electric only locates compared to the previous contract cost of $19.90 per ticket. He stated the incremental cost per ticket was then multiplied by the number of locates in the 12-month period between May of 2017 and April of 2018 to capture a full 12-month period of actual data to develop the normalized value. Mr. Hooper explained that Adjustment OM 2H-18 decreases the normalized Historic Base Period line locate expense by $522,189 to reflect the amount budgeted for line locating in 2018, and that Adjustment OM 2H-19R increases future test year locate expenses by $1,489,294 to reflect an increase in the projected number of 811 tickets in 2019 based on a projected increase in volume of 10.3% per year over the Historic Base Period volumes. These incremental 811 volumes were multiplied by 95¢ per ticket, and the incremental line locates volumes were multiplied by 2019 average screened prices to calculate the adjustments.

Mr. Hooper testified that Adjustment OM 2I-18 was made to reflect a decrease in Variable Chemical expense in the Historic Base Period by $1,164,262 driven by a change in the mix and quantity of chemicals required upon the retirement of Bailly Units 7 and 8. He explained that Adjustment OM 2I-19R reflects a reduction Variable Chemical expense of $551,509 to levelize it for reduced generation of 6.1 million MWh in 2019 based on updated PROMOD inputs and to reflect the redistribution of the megawatt hours produced across NIPSCO's remaining units. Mr. Hooper stated Adjustment OM 2I-19SS was made to reflect the decrease in Variable Chemical expense for the Forward Test Year based on the proposed change in NIPSCO's service structure and the attendant loss of industrial load. Mr. Hooper also supported Adjustments OM 2J-18, OM 2J-19, and OM 2J-19SS that addressed Activated Carbon Injection ("ACI") expenses. He testified that Adjustment OM 2J-18 adjusted Historic Base Period ACI expenses to reflect reduction in ACI expenses as a result of the closure of Units 7 and 8 and an increase in ACI expenses at other units including increases associated with the increased output at Unit 15 during the Historic Base Period. The overall adjustment was an increase of $568,111. Mr. Hooper explained that Adjustments OM 2J-19R and OM 2J-10SS reflect a decrease in projected ACI expense for 2019 of $193,163 reflecting a projected decrease in Unit 15 output, and Adjustment OM 2J-19SS reflects a slight increase in projected ACI expense of $48,158 as a result of the implementation of NIPSCO's proposed service structure.

Mr. Hooper explained that the Long Term Service Agreement ("LTSA") expenses for Sugar Creek were incurred based on the unit's Run Time. He stated that Adjustment OM 2K-18 reflects an increase to the Historic Base Period of $115,416 in LTSA expenses for the 2018 budget based upon the increased Run Time of the Sugar Creek units, and that Adjustment OM 2K-19R was a ratemaking adjustment made to reflect changes in the LTSA contract executed after the preparation of the 2019 budget that decreases annual LTSA expenses by $3,774,547. He also sponsored Adjustment OM 2L-17 to decrease Historic Base Year Miscellaneous Expenses by $1,379,154 to remove expenses not budgeted as ongoing expenses.

Mr. Hooper explained that NIPSCO adjusted its projected 2019 O&M expenses downward by $3,890,900 to annualize the impact of a variety of cost savings initiatives including the use of a number of contracting options with vendors as well as in-sourcing some activities to increase efficiency. He also sponsored Adjustment OM 4B-19R to increase Forward Test Year operating expenses by $8,228,823 to reflect the ongoing level of O&M expenses associated with NIPSCO's MATS Compliance Project and MPCP Project currently being recovered through NIPSCO's ECRM. He explained that these costs will no longer be recovered through the ECR Tracker once new rates are implemented, and noted that all MATS compliance costs associated with Bailly have been removed. Mr. Hooper testified that Adjustment OM 4-19SS reflects an increase in the on-going level of O&M expenses associated with NIPSCO's MATS Compliance Project and MPCP Project by $24,124 to reflect the implementation of the proposed service structure and the loss of load associated with NIPSCO's largest industrial customers.

Mr. Hooper testified that Adjustment OM 5-18 and OM 5-19 increase the Historic Base Period by $4,039,088 and 2,384,304, respectively, for budgeted increases in FMCA tracker expense, and that OM 5B-19R increases Forward Test Year operating expenses by $8,344,575 to reflect the ongoing level of O&M expenses associated with NIPSCO's NERC Compliance Project currently being recovered through NIPSCO's FMCA. Upon implementation of new base rates, these costs will no longer be recovered through the FMCA Tracker.

H. Kelly R. Carmichael. Mr. Carmichael testified about the current, major environmental regulations with which NIPSCO must comply and proposed regulations that NIPSCO anticipates will be implemented in the near term. He also addressed how NIPSCO has evaluated the cumulative impact of increasingly complex future environmental requirements on its resource planning and the increased operating pressure such regulations place on existing coal-fired plants.

Mr. Carmichael explained the environmental drivers for the cost increases that NIPSCO has experienced since its last rate case was filed in 2015. Specifically, NIPSCO has been faced with a number of major environmental mandates, which have and will continue to result in cost impacts to its customers. The most significant of these recent mandates are the EPA's CCR Rule and MATS. He summarized the Environmental Compliance Projects that NIPSCO has implemented leading into NIPSCO's last rate case and the CPCN approved by the Commission in Cause No. 44872, primarily related to compliance with the CCR Rule.

Mr. Carmichael explained the major environmental statutes and regulations and their impact on NIPSCO's operations. The federal environmental statutes with the most significant economic impact on NIPSCO's operations are the Clean Air Act ("CAA") and its amendments, the Clean Water Act ("CWA"), and the Resource Conservation and Recovery Act ("RCRA"). For the CAA, Mr. Carmichael explained that there are numerous recent and anticipated air regulations that affect, or have the potential to affect, NIPSCO's electric generating units. Over the past few decades, the EPA has set increasingly more stringent National Ambient Air Quality Standards ("NAAQS") for particulate matter, ozone, sulfur dioxide ("SO2"), lead, NOx, and carbon monoxide ("criteria pollutants"). These tighter federal requirements generally translate into federal and state requirements that impose additional environmental controls on emission sources. He explained that NIPSCO has incorporated the expected requirements resulting from NAAQS into its planning process, including its 2016 and 2018 IRPs and that each NIPSCO generating unit is equipped with controls to reduce emissions and ambient concentrations of criteria pollutants.

Mr. Carmichael described the Cross-State Air Pollution Rule ("CSAPR"), an emission allowance trading program that establishes SO2 and NOx emission allowance allocations for each NIPSCO generating unit. He also described MATS, which was issued to reduce mercury, other non-mercury metals, and acid gas emissions from coal- and oil-fired generating units, and required compliance at four NIPSCO coal units by April 2015. NIPSCO received a one-year compliance extension from the Indiana Department of Environmental Management ("IDEM") for its other three coal units. Mr. Carmichael testified that NIPSCO is in compliance with CSAPR, as its entire coal-fired generation fleet is equipped with FGD controls for SO2 removal. By implementing NIPSCO's MATS compliance projects approved in Cause No. 44311 in 2013, NIPSCO has also achieved compliance with MATS.

Mr. Carmichael also testified about EPA's "Clean Power Plan" that was issued in 2015 under section 111(d) of the CAA and stayed by the U.S. Supreme Court in 2016, but scheduled to be replaced with the Affordable Clean Energy ("ACE") rule. He noted that the specific ramifications of this rule are not known at this time. Mr. Carmichael explained that NIPSCO did consider the impacts of regulation of greenhouse gas ("GHG") in its 2018 IRP. He stated that the IRP GHG analysis included various carbon reduction outcomes and timing sensitivities. Paired with a range of carbon costs, NIPSCO considered various alternatives, such as: (1) natural gas generators including natural gas combined cycles; (2) renewable energy options; (3) customer EE and DSM; and (4) distributed generation. He testified that the feasibility of the technology or programs, the commercial availability, economic comparisons to other technologies, and compliance with environmental regulations were all taken into account; however, specific ACE Rule scenarios were not included in the IRP because requirements are not known at this time.

Mr. Carmichael further testified about the CWA, which establishes water quality standards for surface waters as well as the basic structure for regulating discharges into the waters of the United States. Under the CWA, the EPA implements pollution control programs such as setting wastewater standards for industry including for electric utilities. CWA requirements are generally implemented by the National Pollutant Discharge Elimination System ("NPDES") permit program. He explained how CWA regulations impact NIPSCO's operations, including through the Effluent Guidelines and Standards ("ELG Rule"), which was most recently revised on January 4, 2016. The ELG Rule regulates wastewater discharges from power plants that use a fossil fuel to generate electricity and is implemented as the regulatory requirements are incorporated into NPDES permits. He stated that the ELG Rule imposes new wastewater treatment and discharge requirements on NIPSCO's generating facilities applicable between 2018 and 2023. He explained that the requirements of this rule were incorporated into Michigan City's NPDES permit effective April 1, 2016. The ELG Rule itself, though, is under reconsideration by EPA, which anticipates finalizing changes to it in late 2019.

Mr. Carmichael testified about NIPSCO's current compliance with the ELG Rule. Specifically, once certain improvements related to CCR compliance go into service, Schahfer Units 14 and 15 and Michigan City Unit 12 will meet the requirements of the existing ELG Rule for bottom ash transport water. Schahfer Units 14 and 15 operate with a wet FGD system and would likely require significant FGD wastewater upgrades if operated beyond the ELG compliance dates. Michigan City Unit 12 has a dry FGD and will meet the requirements of the existing ELG Rule for both FGD wastewater as a result of a dry FGD system and bottom ash transport water as a result of the CCR compliance project. He noted that NIPSCO's preliminary study estimated ELG Rule compliance costs to be approximately $170 million.

Mr. Carmichael next described RCRA, which sets forth a framework for the management of hazardous and non-hazardous wastes. Under Subtitle D of RCRA, EPA imposed the CCR Rule. The CCR Rule is federally mandated and became effective October 19, 2015, with multiple compliance dates phased in over time. As Mr. Carmichael explained, in 2016 the Water Infrastructure Improvements for the Nation Act amended the CCR Rule and authorized states to submit, to the EPA for approval, a permit program for regulating CCR units in lieu of the CCR Rule. This amendment also allows states to adopt different technical standards from the CCR Rule so long as the standards are at least as protective as the federal rule. In circumstances where a state does not seek approval of a permit program or where EPA denies a state application, the amendments require EPA to adopt a permit program in lieu of the self-implementing rule, provided Congress provides funding for EPA to carry out a permit program. If no permit program is in effect in a state, the CCR Rule remains self-implementing.

Mr. Carmichael also explained that the Indiana Environmental Rules Board adopted a rule incorporating the EPA CCR Rule requirements for CCR surface impoundments into the Indiana Code in 2016 and that IDEM adopted an amendment to Indiana's Solid Waste Management Plan describing IDEM's plan to update regulations regarding CCR disposal facilities to standards equivalent to the CCR Rule in 2017. He stated that this plan enables IDEM to approve and enforce compliance schedules and to extend deadlines in the CCR Rule under certain circumstances and was approved by EPA on March 7, 2017.

Mr. Carmichael testified about NIPSCO's compliance with the CCR Rule's requirements related to location restrictions, impoundment design criteria, operating criteria, groundwater monitoring and corrective action, closure and post-closure care, and recordkeeping, notification, and posting of information. He explained that NIPSCO is in the process of executing a set of projects, approved by the Commission in Cause No. 44872, to ensure compliance with the CCR Rule. Ultimately, groundwater monitoring results, location restrictions, future CCR management practices, and beneficial use of CCRs will determine compliance outcomes. He explained that, in the near term, NIPSCO is required to install a groundwater monitoring network, containerize CCR processing areas, address inactive CCR surface impoundments, conduct periodic inspections, and create a publicly accessible recordkeeping and reporting internet site. In addition, NIPSCO is currently reviewing data and will update closure plans and assess corrective measures for IDEM review and approval, as required by the CCR Rule and IDEM. In the meantime, NIPSCO continues to meet the compliance obligation established in the final CCR Rule. He also provided cost estimates and other information for the CCR compliance projects approved in Cause No. 44872.

Mr. Carmichael next explained that NIPSCO is not proposing to recover ARO costs through its base rates in this proceeding but that the compliance requirements are mandatory and NIPSCO must expend the necessary funds to ensure compliance. Mr. Carmichael stated that there are certain events that may require CCR surface impoundments to cease operation and close and explained that, based on currently-available groundwater monitoring data, there may be a triggering event that would require NIPSCO to cease placing CCRs into the surface impoundment within six months and initiate closure within 30 days. He testified that the CCR Rule also has an alternative closure provision that allows a CCR surface impoundment to continue to operate if the owner certifies that the facility will permanently cease operation of the boiler and complete closure by October 17, 2023, for a surface impoundment that is 40 acres or smaller, or by October 17, 2028, for a surface impoundment that is greater than 40 acres. He also outlined recent developments to the CCR Rule, including certain litigation and EPA review that is ongoing.

Mr. Carmichael also explained that NIPSCO has a total of 13 CCR surface impoundments and one CCR Landfill at Bailly, Schahfer, and Michigan City that are subject to the CCR Rule and/or RCRA. He explained the two closure methods available to NIPSCO under the CCR Rule: (1) closure by removal; and (2) closure in place (a.k.a., "capping"). Closure by removal entails dewatering of the free liquids within/on top of the ash, followed by excavation of all ash within the pond limits, including the liner if present. The excavated ash is then properly managed, and the pond can then be backfilled and graded. Closure in place entails the removal of the free liquids within/on top of the pond as well as free liquids in materials placed in the pond. Once the pond is dewatered, the remaining CCRs must be graded, and in most circumstances, have additional fill materials brought in to provide a suitable base for the cap. The CCRs are then capped with soil, clay, or an engineered barrier, then mulched and seeded with a vegetative cover. In addition to the cap, there are some indications that a slurry wall or in-situ stabilization may be required for surface impoundments that have a hydraulic connection to the groundwater and are closed in place. Mr. Carmichael outlined the number of CCR impoundments and landfills at each NIPSCO generating station and the currently-anticipated method of closure for each, which are subject to change based on the effectiveness of its closure activities and collection of further groundwater data. He again noted that NIPSCO is not proposing to recover these federal CCR compliance costs through base rates in this proceeding and that the costs have not been included in the Asset Demolition Studies for each generating station sponsored by NIPSCO witness Ranalletta. As delineated in Mr. Ranalletta's Attachments 12-A, 12-B, and 12-C, federally mandated CCR ARO costs, inclusive of contingency and indirect costs, at Schahfer are expected to be $90.893 million; at Bailly are expected to be $24.736 million; and at Michigan City are expected to be $25.89 million.

Mr. Carmichael outlined other significant environmental remediation obligations at its generating stations. NIPSCO has some coal ash-related remediation obligations that are not directly tied to the federal CCR Rule, which include requirements under Indiana's Solid Waste Management Program. At Bailly, there are also obligations under the federal RCRA that are related to Solid Waste Management Units based on an order entered into between NIPSCO and EPA in 2005 under RCRA, which required NIPSCO to investigate and, if needed, remediate areas at Bailly that were impacted by historic waste handling. He also discussed federal and state obligations related to asbestos containing material at Bailly, Schahfer, and Michigan City.

Mr. Carmichael addressed the interplay between environmental regulation and NIPSCO's resource planning. He testified that NIPSCO incorporates the cumulative impact of future environmental requirements in the IRP process and that the IRP considers impacts of anticipated environmental rules and regulations. Notably, the CCR and ELG Rules require significant capital expenditures for compliance. Future anticipated regulation of GHG emissions and updated CSAPR and ozone NAAQS regulation on Schahfer Units 17 and 18, were also specifically considered.

Mr. Carmichael testified about key assumptions NIPSCO made for environmental regulations that impact the IRP. For the CCR Rule, he stated that NIPSCO is required to incur capital cost for Schahfer Units 14 and 15 and Michigan City Unit 12 of approximately $193 million. Based upon a preliminary study of the November 3, 2015 ELG Rule, capital costs for ELG compliance were expected to be approximately $170 million for Zero Liquid Discharge control technology on Schahfer Units 14 and 15 and $375 million for Units 17 and 18. Michigan City Unit 12 is equipped with a dry FGD and is not anticipated to require any significant capital expenditure for ELG Rule compliance. CCR-related infrastructure investment will allow Unit 12 to comply with other aspects of the ELG Rule by the November 1, 2018 compliance date established in its NPDES permit. He also testified that no capital expenditure is expected for ELG compliance on Schahfer Units 14, 15, 17, and 18 because, based on preliminary 2018 IRP results, NIPSCO anticipates retiring these by 2023. He stated that NIPSCO did consider several possible ELG rulemaking outcomes in the IRP, which include the requirement to install Zero Liquid Discharge ("ZLD") technology or non-ZLD technology, compliance via unit retirement, and extended compliance dates. Regarding GHG reduction, although the timing and magnitude of required reductions are uncertain, it does not appear likely that significant electric sector GHG reductions will be required by regulation or legislation until the year 2026 or later.

Mr. Carmichael testified that, in the IRP modeling, NIPSCO assumed three carbon price scenarios: base, low, and high. The base case assumes a new federal rule or legislative action effective in 2026. The low case assumes a replacement CPP rule with a focus on coal plant efficiency improvements; however, due to the lack of specificity of requirement at present, no direct costs were assumed for these improvements within the IRP. No specific tax or emission cap requirement would be present under such regulations. The high case assumes a stricter new federal rule or legislative action effective by 2026. He explained that price levels are generally consistent with a 50-60% reduction in electric sector carbon dioxide ("CO2") emissions relative to 2005 by the 2030s. In addition, retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures beyond CCR, ELG, and GHG compliance to reduce NOx emissions. He noted that the IRP assumed compliance with updates to CSAPR and ozone regulations that have not yet been proposed, utilizing SCR technology with a capital cost estimate of $448 million.

I. Andrew S. Campbell. Mr. Campbell explained the purpose of MISO and provided an overview of the MISO Resource Adequacy Process. He explained that NIPSCO, as a Load Serving Entity in MISO, is obligated to have sufficient Capacity Resources to cover its forecasted peak demand plus its Planning Reserve Margin Requirements ("PRMR"). If NIPSCO does not have sufficient Capacity Resources to cover its forecasted peak demand and PRMR, 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 through a bilateral transaction with other Market Participants. Mr. Campbell 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. Campbell also testified about NIPSCO's MISO-related costs.

Mr. Campbell explained that NIPSCO has two Wholesale Purchase and Sale Agreements for wind energy. NIPSCO is crediting any OSS created by its wind purchase power agreements ("PPAs"). In addition to its PPA wind purchases, NIPSCO recovers cost of capacity and energy purchases made through its 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 FAC proceedings consistent with NIPSCO's treatment of its wind PPA purchases approved 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. Campbell 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 PRA 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 in the NIPSCO RA Tracker. Mr. Campbell explained NIPSCO's three Demand Response programs: (1) an interruptible offering under Rider 775 whereby large industrial customers can sign up to offer interruptible service used for both economic and reliability reasons; (2) a Demand Response Resource offering under Rider 781 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 782 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy for use during emergency operations. He testified that under the proposed rates, NIPSCO will continue to offer three Demand Response programs within Rate 831, Rider 881, and Rider 882. He stated that options within NIPSCO's proposed Rate 831 qualify as a LMR under MISO's tariff, and allows NIPSCO to receive Zonal Resource Credits ("ZRCs").

Mr. Campbell then described proposed Rate 831 – Industrial Power Service – Large. He stated that as proposed, Rate 831 is available to industrial customers currently taking service under Rates 732, 733, and 734. Rate 831 has three tiers of service: (1) Tier 1: Firm Service; (2) Tier 2: Non-Firm Market Price Service; and (3) Tier 3: Non-Firm Third Party Generation Service. He stated that customers must demonstrate or document, to NIPSCO's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to NIPSCO's satisfaction, that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3. This information will be utilized to register the curtailable demand as an LMR with MISO. The Customer can choose to procure additional capacity to reduce or eliminate its curtailable obligations as an LMR through the PRA or by purchasing capacity through a third-party bilateral agreement.

Mr. Campbell described how NIPSCO will determine a Customer's capacity requirement. He stated that NIPSCO is obligated to have sufficient Capacity Resources to cover its forecasted Coincident Peak demand plus PRMR with MISO. He explained that by September 30 of each year, NIPSCO will share with each Customer its PRMR, forecasted Coincident Peak demand, and supporting documentation. The Customers will have 30 days to review and dispute these values. NIPSCO will make all reasonable efforts to resolve any such disputes; however, as the MISO Market Participant, NIPSCO is responsible for all forecasted needs and its forecast methodology, which is subject to audit and due diligence by MISO. He indicated NIPSCO will submit the Customer's Resource Adequacy Requirements on November 1 of each year to comply with MISO's Resource Adequacy timeline. He summarized that this process results in Customers taking service under Rate 831 covering their load ratio share of NIPSCO's Resource Adequacy Requirements with MISO.

Mr. Campbell then described Tier 1, Tier 2, and Tier 3 service under Rate 831. Tier 1 is a firm service served by NIPSCO's generation and market activity in MISO. The default Contract Demand election is 30,000 kilowatt ("kW") with an option to elect above or below that amount down to 10,000 kW. Tier 1 service is subject to applicable Riders as identified in Appendix A of the tariff. Tier 1 service will be first through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service.

Mr. Campbell explained that the Customer's Tier 2 Contract Demand is the Customer's PRMR using NIPSCO's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 Contract Demand election and any Tier 3 Contract Demand election by the Customer. This service is subject to applicable non-production Riders as identified in Appendix A of the tariff (potential components of FMCA and the energy components of the RTO). The Customer will take all Energy under this Tier 2 service at Day-Ahead LMP at the applicable Company Load Zone plus Transmission Charges. Tier 2 service will be second through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service and then Tier 2 service.

Mr. Campbell testified that Tier 2 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an

LMR at MISO that portion of the Customer's Tier 2 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 2 Contract Demand is non-firm, subject to MISO Curtailment.

Mr. Campbell stated that the Customer may elect a Tier 3 Contract Demand up to the Customer's PRMR using NIPSCO's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 firm Contract Demand election. To the extent a Customer declines to elect the Tier 3 Contract Demand to which it is entitled under this Rate, it must elect to take Tier 2 Contract Demand. If the Customer elects to take any Tier 3 Contract Demand, NIPSCO, as the Market Participant, will register that Customer as an Asset Owner at MISO. Mr. Campbell explained that Tier 3 service is subject to applicable non-production Riders as identified in Appendix A of the tariff (potential transmission related components of FMCA). Tier 3 service will be third through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service, then Tier 2 service, and finally Tier 3 service.

Mr. Campbell explained that if, under the MISO Asset Owner framework, a Customer has not arranged for any third-party energy with NIPSCO as the contracting Market Participant, the Customer will take all Energy under this Tier 3 service at market price (LMP at the applicable Company Load Zone plus all applicable MISO market settlement charges plus the Transmission Charge within the Rate). The Customer will be responsible for all market settlement charges incurred by either NIPSCO as the Market Participant or the Customer as Asset Owner for any third-party energy or capacity arrangements including, but not limited to, transmission charges to deliver energy. MISO Market Portal access will be provided as required to carry out MISO Asset Owner functions. All settlements associated with energy offers and demand bids will be passed through to the Customer and will be billed to the Customer on a weekly basis.

Mr. Campbell stated that Tier 3 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of the Customer's Tier 3 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 3 Contract Demand is non-firm, subject to MISO Curtailment.

Mr. Campbell explained the difference between Tier 2 and Tier 3 service under Rate 831. He stated that the primary difference between Tier 2 and Tier 3 is the options each Tier provides for the optimization of demand and capacity in the MISO Market. Tier 2 is essentially a market price service for energy and allows for the "firming-up" of capacity through the MISO PRA or third-party capacity arrangements. Tier 3 increases optionality available for Customers to optimize their demand in MISO. Tier 3 allows the Customer, with NIPSCO acting as the Market Participant, the ability to optimize their demand using available MISO market options. He stated that this could include procuring all or a portion of expected energy needs in the Day-Ahead Market or entering into third-party bilateral energy arrangements (alternative generation). Customers will also be able to procure capacity through the MISO PRA or arrange third-party capacity arrangements. Tier 2 and Tier 3 are similar in the sense that any demand not covered by a capacity purchase will be registered at MISO as a LMR and subject to MISO Curtailment. Furthermore, Tier 2 and Tier 3 are both market-based options that are not backed by NIPSCO-owned generation resources.

Mr. Campbell stated that customers will be able to move demand between Tier 2 and Tier 3. He explained that as proposed in Rate 831, Customers will have the ability to make quarterly adjustments between Tier 2 and Tier 3. Customers are allowed to have both Tier 2 and Tier 3, Tier 2 only, or Tier 3 only. NIPSCO will register a single LMR for any Tier 2 and Tier 3 demand not covered by a capacity purchase at MISO as a LMR. He noted that NIPSCO, as the Market Participant at MISO, is ultimately financially responsible for all the associated activity of its retail customers. While Tier 2 and Tier 3 of Rate 831 do allow degrees of market access, customers taking service are still participating through a retail rate and are subject to charges related to the delivery of energy using NIPSCO's transmission system.

Mr. Campbell said that by creating separate CP Nodes and individual settlement statements with MISO, other customers will be insulated from activity of Tier 3 customers. Furthermore, any additional charges related to the activity of Tier 3 Customers will be passed on to the appropriate party (i.e., transmission charges associated with any out-of-market activity). Mr. Campbell stated that while NIPSCO will be liable for Tier 3 customers' decisions in the MISO Market, the proposed tariff creates a direct link that makes Tier 3 customers wholly responsible for all of the costs associated with their activity in the MISO Market. He explained that the Asset Owner arrangement allows for a clear carve out of the individual customer activity. As such, Tier 3 customers receive the full benefits and risks associated with activity in the MISO Market.

Mr. Campbell addressed how curtailments will change under Rate 831. He stated that any non-firm demand under Tier 2 and Tier 3 that is not otherwise covered by procured capacity will be registered by NIPSCO as an LMR with MISO. There is no change in the obligations associated with the LMR registrations from today under current Rider 775. He added that Rate 831 is written in a way that if MISO's LMR rules change, Tier 2 and Tier 3 customers will be obligated to comply for any non-firm demand.

Mr. Campbell described the curtailment order that NIPSCO will follow. He detailed that ideally, the first set of customers to be curtailed will be Tier 2 and Tier 3 customers since both of these are non-firm unless capacity is arranged otherwise. Second, customers taking service under Rider 876 and Back-Up, Maintenance, and Temporary Services under Rate 830 will be curtailed in the event curtailments under Tier 2 and Tier 3 are insufficient. He stated that it is possible that service under Rider 876 and Back-Up, Maintenance, and Temporary Services under Rate 830 will be curtailed before exhausting curtailments under Tier 2 and Tier 3 depending on the specifics of the curtailment order issued. Addressing curtailment notice requirements, he indicated that NIPSCO will dispatch Customers for MISO curtailments in accordance with the limitations specified under Rate 831 and NIPSCO's General Rules and Regulations.

Mr. Campbell testified that since the start of the MISO Market, none of NIPSCO's customers have been curtailed and that NIPSCO does not anticipate that there is any increased risk of curtailment as a result of the proposed industrial service structure. Unless there is a localized emergency, where NIPSCO can issue curtailments under Rule 13 of its General Rules and Regulations, curtailments are controlled by MISO, and NIPSCO cannot predict the future utilization of curtailments by MISO.

Mr. Campbell indicated that as a result of the new industrial service structure, NIPSCO will alter its participation within the MISO Market. Generally, for Industrial Customers choosing

Tier 3 service, NIPSCO will no longer procure energy nor capacity for their Tier 3 loads. However, for Tier 2 Customers, NIPSCO will procure energy from the market on their behalf. That energy will be allocated to Tier 2 Customers and be priced at the Day-Ahead LMP at NIPSCO's applicable Load Zone. NIPSCO will continue to offer the energy produced by its generation facilities into the MISO Market, and it will continue to purchase the energy necessary to serve its non-Tier 3 retail customers from the MISO Market on a day-ahead and real-time basis. He added that Rate 831 will simply place the burden of optimizing customer specific loads on customers electing service under non-firm Tier 3 and that NIPSCO will continue to optimize remaining retail customer load.

Regarding implementation, Mr. Campbell first noted that an order in this proceeding could result in an implementation date that does not coincide with MISO's Planning Year. He stated that NIPSCO will make reasonable efforts to register interested customers that qualify for Rate 831 service as Asset Owners consistent with MISO's commercial model updates, so that those registrations are available for a day one of the implementation of new rates. He explained that customers with existing LMR registrations will be required to maintain the same level LMR registration (or more) until the start of the next MISO Planning Year unless Replacement Capacity is provided by the Customer. Customers will remain curtailable until firm capacity is procured at which time NIPSCO will transition Customers to the forecasted Coincident Peak demand plus the PRMR method as discussed above to be consistent with the proposed Rate 831. He stated that Tier 3 Customers will be able to arrange third-party/bilateral energy contracts prior to or shortly after an order is issued. Energy contracts do not have any restrictions requiring alignment to MISO's Planning Year, and as such, there is no implementation risk as energy contracts can start and stop in line with the negotiated terms of the contract.

Mr. Campbell provided an overview of the changes proposed in Rider 876 – Back-Up and Maintenance Industrial Service Rider. He stated that Rider 876 is only available to customers taking service under Rate 831. He explained that other changes proposed in Rider 876 include the removal of Temporary Service and an updated pricing structure so it is consistent with Rate 831. He indicated that as an alternative to Back-Up and Maintenance Service under this Rider, a Customer can elect to instead cover the risk associated with derates and outages of its Cogeneration System without risk of Curtailment by utilizing Rate 831 Tier 2 or Tier 3 service and procuring capacity through the MISO PRA or via a third party subject to the provisions outlined in Rate 831. He stated that existing Back-Up and Temporary Service provided in current Rider 776 is retained in NIPSCO's new Rate 830 to align to specific customer needs.

He stated that NIPSCO is also proposing to remove the revenues associated with its Rider 876 due to NIPSCO's inability to predict the usage of the Rider by customers. He explained that the proposed changes to the service structure may alter customer's utilization of proposed Rider 876 and that, services are available under Rate 830, but there still is an inability to predict customer activity. He noted that NIPSCO will also pass back any margins resulting from Back-Up and Maintenance Services through the RTO tracker.

Mr. Campbell stated that as proposed, new Rate 830 – Industrial Power Service – Small is similar to existing Rate 732 and is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. He explained that Rate 830 differs from Rate 732 in that the Customer shall contract for a definite amount of electrical capacity which shall be not less than 10,000 kW and not exceed 25,000 kW. He noted that under Rate 732, Customers contracted for a definite amount of electrical capacity that was not less than 15,000 and that existing Rate 732 customers that do not meet the minimum demand threshold are grandfathered into the rate.

He stated that existing Back-Up, Maintenance, and Temporary Services under Rider 776 is retained in Rate 830 to align with Customer specific needs. Customers taking Back-Up, Maintenance, and Temporary Services under this Rate shall be subject to Curtailments when curtailment of NIPSCO's customers under Rate 831 is insufficient. He indicated that except for Buy-Through energy under Temporary Service or Back-Up Service, this Rate shall be subject to other Riders as identified on Appendix A of the tariff.

Mr. Campbell provided an overview of the changes proposed in Rider 881 – Demand Response Resource Type 1 (DRR 1) – Energy Only. He explained that although Rider 881 is largely an updated version of the existing Rider 781, changes were warranted to better align with proposed Rate 830 and Rate 831. He noted that NIPSCO has removed the Marginal Forgone Retail Rate ("MFRR") provisions within Rider 881 to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. He noted that currently, only one customer is actively participating in existing Rider 781.

He stated that NIPSCO is proposing to remove margins associated with its Rider 781 – Demand Response Resource Type 1 – Energy Only (proposed Rider 881). He explained that NIPSCO offers the demand response program to allow NIPSCO's industrial customers a means of offering load drop into the MISO Market as a Demand Response Resource. He stated that the margin NIPSCO receives through Rider 881 is meant to compensate NIPSCO for its MFRR during the load drop event making it appropriate to remove these margins from the Revenue Requirement due to NIPSCO's inability to predict the usage by customers. Mr. Campbell noted that changing market dynamics and individual customer operating characteristics could increase or eliminate the activity. Furthermore, the margin received through the Rider is offset by retail sales that occur should customers choose to discontinue usage of the Rider. He noted that the inability of NIPSCO to predict usage under this Rider and the fact that activity under this Rider is essentially a wash between MFRR and retail sales are both valid reasons that support the removal of margin collected through this Rider. Mr. Campbell sponsored Adjustment REV 16-19SS to decrease the Forward Test Year by $3,383,524 to remove all Demand Response Resource margins.

Mr. Campbell provided an overview of the changes proposed in Rider 882 – Emergency Demand Response Resource Type 1 (EDR 1) – Energy Only. He explained that although Rider 882 is largely an updated version of the existing Rider 782, changes were warranted to better align with proposed Rate 830 and Rate 831. He noted that NIPSCO has removed the MFRR provisions within Rider 882 to better align with MISO's treatment of emergency demand response resources and to reduce potential barriers to customer participation. Currently, no customers participate in existing Rider 782.

Mr. Campbell testified that proposed Rate 831 provides two options of curtailable service: (1) Tier 2 is "curtailments and/or MISO PRA capacity;" and (2) Tier 3 is "curtailments, MISO PRA capacity, and/or third-party capacity," both of which allow a customer to procure capacity to reduce or eliminate the curtailable portion of its load. He stated that in either circumstance, the load is covered from a MISO Resource Adequacy perspective.

Mr. Campbell explained NIPSCO's change in the Resource Adequacy Adjustment in this proceeding. He noted that NIPSCO is proposing that the charge of $1,500,000 realized through the purchase of capacity and the sale of excess capacity be removed from the Historic Base Year and the Forward Test Year due to the variability of capacity prices in the broader market. Mr. Campbell sponsored Adjustments REV 2-19R and FP 1B-19R to decrease revenue and expense to remove all budgeted capacity purchases from the Forward Test Year.

Mr. Campbell testified regarding NIPSCO's RTO Tracker, including OSS. He explained that OSS occur when NIPSCO's real-time generation resources exceed the real-time native load obligation excluding Rate 831 Tier 2 and Tier 3 activity. The fuel costs associated with making an OSS are passed back to NIPSCO's FAC customers in the form of a fuel credit. 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 OSS 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. He stated that the Commission's 44688 Rate Case Order approved recovery of $16,585,108 of MISO non-fuel transmission costs (net of revenues) in base rates, reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO Tracker, and reset the OSS margin credit to base rates to reflect the level of OSS margins included in base rates of $4,741,390. Mr. Campbell testified that in this proceeding, NIPSCO is proposing to fully track MISO non-fuel costs (net of revenues) and recover the costs through the RTO Tracker. He explained that NIPSCO is making this change because Rate 831 Tier 2 and Tier 3 customers will be responsible for various charges and will be paid differently than today. He noted that if NIPSCO were to include the charges in base rates, there would be a misalignment unless NIPSCO ran a COSS for each charge type, which would be extraordinarily time consuming.

Mr. Campbell noted that in this proceeding, NIPSCO is also proposing to reset the OSS margin credit to base rates to zero. He explained that with the retirement of Bailly Units 7 and 8, NIPSCO's opportunities for OSS could be reduced. He noted the retirement aligns NIPSCO's supply side resources with its load obligations in MISO and could result in less of an opportunity for OSS. On the other hand, NIPSCO's new industrial service structure could result in opportunities for additional OSS. He testified that given the uncertainties, when OSS do occur, NIPSCO would pass back 100% of the margins back to customers. Mr. Campbell sponsored Adjustments REV 9E-19R and FP 3B-19R to decrease revenue and expense to remove all OSS revenues and fuel expenses budgeted for capacity purchases from the Forward Test Year. Mr. Campbell testified that in this proceeding, NIPSCO is also proposing that 100% of OSS margins would be credited to the customer. He explained that the credit would be determined annually and incorporated into NIPSCO's semi-annual tracker filing. Mr. Campbell testified that in this proceeding, NIPSCO is also proposing to pass back any margins resulting from back-up and maintenance services through the RTO tracker. Like the OSS margins, the credit would be determined annually and incorporated into NIPSCO's RTO Tracker semi-annual tracker. Finally, he added that NIPSCO is proposing to update the allocation.

Mr. Campbell described and supported proposed pro forma Adjustment REV-8A-19R and FP-2-19R. He stated that NIPSCO liquefied less gas in the Historic Base Period (January 1, 2017 – December 31, 2017) compared to the volumes expected going forward. The five-year average of actual gas liquefaction was 1,166,142 MCF. NIPSCO believes the five-year average is an accurate estimate of future liquefaction compared to the 611,701 MCF that occurred during the Historic Base Period. Because the liquefaction process is a heavy consumer of electricity, the volume of gas liquefied creates variations in inter-company electric revenues and the associated fuel costs. Adjustments REV 8A-19R and FP 2-19R increases the Forward Test Year revenue by $1,272,135 and expense by $313,541 to align the budget with a five-year average for gas liquefaction volumes.

J. Susanne M. Taylor. Ms. Taylor provided background on the relationships between NCSC and NIPSCO. She supported the O&M expenses associated with the Corporate and Operating services provided by NCSC to NIPSCO, and she sponsored adjustments to those expenses for the Historic Base Period, 2018 Budget Period, and the Forward Test Year. Ms. Taylor explained the structure and role of NCSC. She testified NCSC was established to provide centralized services to its affiliates because providing services on a centralized basis enables the affiliates to realize benefits, including use of personnel and equipment. She stated 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 billing pools. She explained that contract billed charges may be direct-billed (billed directly to a single affiliate or function, including NIPSCO Electric, NIPSCO Gas, or NIPSCO Common), or allocated (split among several affiliates), depending upon the nature of the expense. She also explained that 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 with each affiliate billed for its proportional share of the payments made per month. NCSC makes the payment to the vendor, and the charges for the services are recorded directly on the affiliate's books.

Ms. Taylor testified NCSC has executed an individual Service Agreement with each affiliate that is routinely updated so that all affiliates that receive service from NCSC are subject to the same Service Agreement, which designates the types of services to be performed and the method of calculating charges. She stated NCSC is not responsible for appropriately assessing the split between costs attributable to NIPSCO's Electric and Gas operations unless the costs are directly billed to NIPSCO Electric or NIPSCO Gas, which NCSC started on January 1, 2009.

Ms. Taylor testified NCSC is regulated by FERC. Pursuant to FERC Order No. 684, centralized service companies like NCSC must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with FERC, NCSC uses a billing pool system to collect costs that are applicable and billable to affiliates, including NIPSCO. Costs are directly charged to a particular affiliate whenever possible, and in cases involving more than one affiliate, the billing pool system details how expenses are allocated among the participating affiliates. Ms. Taylor testified NCSC allocates costs for a particular billing pool in accordance with the bases of allocation filed annually with FERC, and noted that descriptions of each basis of allocation is provided in each service agreement. She explained that NCSC currently updates the statistical data used in the approved allocation bases at least on a semi-annual basis and provides NIPSCO's leadership team the opportunity to review, discuss, and provide feedback prior to publishing the new allocation percentages.

Ms. Taylor testified that system controls are in place to restrict the use of billing pools to companies benefitting from the services being provided. She noted that NIPSCO's Internal Audit group conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing. Ms. Taylor noted that NiSource, including NCSC, underwent a FERC audit, Docket No. FA11-5-000 covering the period January 1, 2009 through December 31, 2010, which issued no adverse comments to NCSC related to its allocation methods. She stated that NCSC continues to use the allocation methods subject to that FERC audit.

Ms. Taylor testified all services are provided at cost, including compensation for use of capital. She stated affiliates have the right to meet with NCSC to review and assess the quality, costs, and/or allocations of the services being provided. The NIPSCO accounting team performs a review of the bill and makes selections to review charge details for reasonableness and accuracy and alert NCSC accounting if they disagree with a charge.

Ms. Taylor testified the NCSC budget development process are consistent with the NIPSCO planning process from a timing and planning standpoint. She explained that the budget process used to develop the Forward Test Year was the 2018 AFP, consisting of a five-year horizon where the first two years were broken down by month, and the balance was completed on an annual basis. She stated targets for the NCSC functions are grounded in a trailing 12-month historical spend with merit and inflation adjusted for each year thereafter. The 12-month historical spend is also adjusted to account for one-time items, future planned work, or strategic initiatives.

Ms. Taylor also provided details about the processes that drive the derivation and approval of NCSC budgets. She testified in detail about the substance and calculation of the NCSC O&M expenses allocated to NIPSCO Electric: (1) in the Historic Base Period of $106,556,125; (2) in the 2018 Budget Period of $108,514,206; and (3) in the Forward Test Year of $98,973,383. She supported Adjustment OM 7-17 to reduce Corporate Incentive Payout expenses in the amount of $2,623,753 to reflect a payout consistent with target levels included in the Forward Test Year, and Adjustment OM 7-19R to reduce NCSC O&M expenses in the amount of $10,129,461 to reflect: (1) customer value savings for a decrease of $4,700,000; (2) other ratemaking adjustments for a decrease of $4,732,776 including: LTIP and profit sharing, promotional advertising, and other adjustments that NIPSCO is not seeking to recover; (3) net pension and medical benefit increase of $203,613; (4) 2017 historical actual allocation adjustment between NIPSCO Electric and Gas for a decrease of $741,022; and (5) a NCSC allocation adjustment of $159,276 to reflect updated NCSC semi-annual allocations billed to NIPSCO as of August 1, 2018, and related decrease to NIPSCO Electric.

Ms. Taylor detailed the calculation of the Forward Test Year level of O&M expense, and testified that amount is reasonable and representative of NIPSCO's ongoing cost of providing service. She explained that The Forward Test Year level of O&M expense is justified by the projected needs of NIPSCO to serve its customers.

K. Kimberly K. Cartella. Ms. Cartella testified about the reasonableness and competitiveness of NIPSCO wages and salaries, incentive compensation, and benefits provided to employees. She also testified in support of the pro forma adjustment to test-year expenses relating to incentive compensation. She explained that NiSource has a "total rewards" compensation philosophy that aims to compensate employees competitively in comparison to the utility industry. According to Ms. Cartella, this compensation philosophy enables NIPSCO to meet its obligation to provide safe, reliable, and cost-effective service to its customers and is consistent across the NiSource companies. She further testified that NIPSCO's total rewards program includes: (1) market-driven base compensation; (2) market-driven performance adjustments/merits; (3) long- and short-term incentives; (4) profit sharing; and (5) health and welfare benefits.

Ms. Cartella explained that NiSource employs compensation and benefits consultants to assist in determining employee compensation across the NiSource Operating Companies. Mercer LLC assists NiSource in setting competitive salary ranges and in evaluating and recommending changes to employee health and welfare benefit plans. Aon Hewitt Associates assists NiSource in pension plan and post-retirement medical actuarial analysis, and Alight Solutions assists with administration of pension and health and welfare benefits.

Ms. Cartella discussed the Corporate Incentive Plan for NiSource and NIPSCO and the annual review, or Performance Management Worksheet, process. The potential to earn incentive pay is needed for NIPSCO to be effective in recruiting, retaining, and motivating its employees. She also explained the three levels of incentive compensation – trigger, target, and stretch – and that NIPSCO's Forward Test Year is based on a "target" level payout. In Attachments 11-A, 11-B, and 11-C, Ms. Cartella provided comparative analyses that demonstrate the reasonableness of NIPSCO's total cash compensation to employees.

Ms. Cartella also testified about the collective bargaining agreements ("CBAs") that are in effect with NIPSCO bargaining units, including how base pay is calculated and the required wage increases under those CBAs. She provided similar information for employees who are not covered by CBAs. In Attachment 11-D, Ms. Cartella provided information about how annual base pay increases at NIPSCO compare to those provided by other employers. She also described the post-retirement benefits other than pensions that NIPSCO provides to its retirees.

Ms. Cartella explained the benefits offered by NIPSCO. These benefits include health and welfare plans, a defined benefit pension plan (for certain employees), a 401(k) savings plan, and paid time off. She stated that benefits are an important component of any compensation structure and are necessary to ensure NIPSCO is able to attract and retain qualified employees. She also testified about steps NIPSCO has taken to manage its health care costs.

Ms. Cartella testified that NiSource has compared benefits NIPSCO offered to other energy companies and that the results of the most recent study performed by Aon Hewitt Associates demonstrated that the overall, employer-paid value of NIPSCO's benefits plans is 3.1% lower than the average of a comparator group of 11 national utility companies. Finally, she concluded that NIPSCO's benefits are competitive and reasonable as compared with the offerings from other comparable utility companies in the labor market.

L. Victor F. Ranalletta. Mr. Ranalletta testified about the results of studies performed by Burns & McDonnell estimating the cost of demolishing and remediating certain NIPSCO Electric generating stations (collectively, "demolition cost"). Mr. Ranalletta explained that Burns & McDonnell was engaged by NIPSCO to update the prior studies that were performed for NIPSCO in Cause Nos. 43526 and 44688, and to prepare written reports documenting the results for this Cause. He testified that he supervised and directed the studies and personally inspected each generating station for which demolition cost studies were completed. Mr. Ranalletta prepared separate reports for Schahfer (Attachment 12-A), Bailly (Attachment 12-B), Michigan City (Attachment 12-C), and Sugar Creek (Attachment 12-D). He also prepared a demolition cost breakdown for each of the station sites to show what the costs would be if NIPSCO were to include costs related to the AROs.

Mr. Ranalletta described how Burns & McDonnell performed its studies of the demolition cost for NIPSCO's generating units and remediating the sites to industrial condition. Burns & McDonnell first determined the quantities of concrete, structural steel, equipment, electric cable and raceway, conveyors, tanks, and piping that would need to be removed. Burns & McDonnell based the industrial demolition cost estimates on demolishing each plant down to the surrounding grade elevation. Burns & McDonnell assumed all equipment and material located above and below grade would be dismantled and either sent to a landfill or sold as salvage. The estimate also assumed all below-grade foundations would remain and the below-grade excavated areas would be used for landfill space for demolished plant concrete. Mr. Ranalletta testified that Burns & McDonnell did not apply any escalation factor beyond January 2018 to the demolition cost estimates; rather (unless noted otherwise) all of the estimates are in January 2018 dollars. He testified Burns & McDonnell prepared the demolition cost estimates using standard and accepted estimating techniques consistent with available data and industry experience, and that the assumptions listed in each report are reasonable and the estimates are accurate based on the assumptions made. The demolition cost includes environmental remediation, indirect costs, contingency, and positive salvage value. Burns & McDonnell estimated the total net cost to demolish each station, net of positive salvage and excluding costs related to the AROs, to be:

Station	Industrial Condition
Schahfer	$85,070,000
Bailly	$40,643,000
Michigan City	$41,519,000
Sugar Creek	$3,490,000

M. John J. Spanos. Mr. Spanos testified about the depreciation analysis he performed related to NIPSCO's electric plant as of December 31, 2017, and his recommendation of depreciation rates for its forecasted electric and common plant in service as of December 31, 2019. He explained the depreciation study's methods and procedures and sponsored Attachment 13-B setting forth the results of that study (the "Depreciation Study"), Attachment 13-C setting forth the results of his depreciation analysis related to NIPSCO's projected electric and common plant in service as of December 31, 2019, and Attachment 13-D setting forth alternative depreciation rates and expense as of December 31, 2017, and December 31, 2019.

Mr. Spanos provided the principal conclusions of his 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 December 31, 2017, 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 phase one, 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 phase two, 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 studies consisted of compiling historic data from records related to NIPSCO's plant; analyzing this 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 82-year period from 1936 through 2017. 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, 2017. 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 study period.

Mr. Spanos testified that he used the life span technique to estimate the lives of significant facilities such as production plants. 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 the life span technique has been presented to and accepted by many public utility commissions including the Indiana 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 conducted 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 for most accounts, he incorporated analyses of the historical data for the period 1984 through 2017 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 costs of steam and other production units were based on the 2018 asset demolition studies performed by Burns & McDonnell. Mr. Spanos explained that he assigned sufficient depreciation reserve to the Bailly Units 7 and 8 to account for the level of recovery to be fully accrued for these units by December 31, 2019. As a result, no future depreciation expense beyond December 31, 2019 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 December 31, 2017. 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 (original cost less book reserve) 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 the 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 43526 Order and continued in the 44688 Rate Case Order as being appropriate for certain common and general plant accounts, which represents slightly more than 1% of depreciable plant.

Mr. Spanos explained his calculation of the forecasted depreciation rates as of December 31, 2019. First, the plant in service and book reserve were brought forward from December 31, 2017 to December 31, 2019 based on the capital budget by account and by year. The book reserve by account as of December 31, 2019 was developed by adding the annual accruals and gross salvage each month and subtracting retirements and cost of removal each month for the two-year period. Once the plant in service as of December 31, 2019 was developed by vintage within account and the book reserve is developed by account, then the December 31, 2019 depreciation rates were calculated using the same methods and procedures as in the 2017 Depreciation Study. He noted that annual depreciation accrual rates for steam assets at Michigan City and Schahfer are based on the recovery period of December 31, 2030, which is after the retirement date two and seven years, respectively.

Mr. Spanos also calculated alternative December 31, 2017 and December 31, 2019 depreciation rates (set forth in Attachment 13-D) because the steam assets at Michigan City and Schahfer are to be retired by December 2028 and December 2023, respectively. The alternative depreciation rates represent recovery of the full-service value of these assets (including costs related to certain AROs that must be performed in compliance with the federal CCR rule) by the date of retirement, which is prior to the Depreciation Study calculations.

N. 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 between the Historic Base Period and pro forma results based on current rates included in the cost of service shown in Ms. Shikany's accounting exhibits. He also presented and supported

NIPSCO's ADIT and Post 1970 Investment Tax Credit ("ITC") balances and related pro forma adjustments included as components of NIPSCO's Capital Structure.

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. He stated that the federal tax rate in effect for the Historic Base Period was 35% and that the pro forma test period reflects a 21% federal tax rate in effect starting January 1, 2018. Mr. McCuen testified that he quantified the federal income tax expense beginning with the application of the federal income tax rate applied to pro forma NOI before income taxes less interest expense. He then adjusted this amount to account for: (1) differences between the use of accelerated appreciation for income tax return purposes and straight-line depreciation in determining tax expense for book purposes and AFUDC; (2) various tax rate changes including the most recent TCJA; (3) certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense; (4) reduction in tax expense for amortization of ITC; and (5) reduction in tax expense for allocation of parent company (NiSource) interest expense.

For state income tax expense, Mr. McCuen testified that the tax calculations include Indiana Adjusted Gross Income taxes calculated at 5.625%, adjusted for the following four reconciling items: (1) the non-deductibility of the Indiana URT; (2) the excess deferred taxes resulting from the decrease in the state tax rate from 8.5% to 5.625%; (3) the non-deductibility of certain expenses; and (4) AFUDC.

Mr. McCuen explained NIPSCO's proposal to reflect $26,870,010 in real and personal property taxes and explained in detail the calculation of and basis for Adjustment OTX-1 that resulted in a pro forma adjusted property tax expense of $26,870,010 for the Forward Test Year. He stated these pro forma property tax adjustments are required to account for planned property additions between the Historic Base Period and Forward Test Year.

Mr. McCuen explained NIPSCO's proposal to reflect no URT in base rates and explained Adjustment OTX-4 that resulted in pro forma adjusted URT of $0 for the Forward Test Year. He explained that NIPSCO is subject to a 1.4% URT on all receipts, except sales for resale and sales to federal government agencies. The URT is calculated then grossed-up and accounted for in the revenue requirement. He explained that NIPSCO proposes to separately state URT as a line item on customer bills, thereby eliminating the gross-up. He testified that the estimated benefit to NIPSCO's customers in this filing is approximately $500,000.

Mr. McCuen also explained NIPSCO's proposal to reflect $55,856,537 in federal and state income taxes and explained Adjustments ITX 1-19R in the amount of $87,484,708, ITX 1-19SS in the amount of $131,669, and PF4 in the amount of $28,247,441. He explained the federal and state income taxes for the Historic Base Period per books was $114,962,135. The three adjustments were made to the Historic Base Period to: (1) decrease to federal and state income taxes to reflect tax expense on pro forma taxable income at current rates; (2) increase to tax expense due to the changes in the proposed service structure at current rates; and (3) increase to total federal and state income tax due to the increase in proposed revenue requirement.

Finally, Mr. McCuen also explained adjustments to NIPSCO's capital structure. He explained Adjustments CS 4-18 in the amount of $71,828,337 and CS 4-19 in the amount of

$44,252,216 increase Deferred Income Taxes for the period ending December 31, 2018 and December 31, 2019. He stated the deferred income tax balances are forecasted by using a combination of pre-tax income and changes in balance sheet accounts. NIPSCO utilizes Accounting Standards Codification 740 and 980 to account for income taxes in order to reflect its after-tax financial position in its balance sheet. He explained that Adjustments CS 7-18 in the amount of $259,068 and CS 7-19 in the amount of $656,208 decrease Post 1970-ITC for the period ending December 31, 2018 and December 31, 2019. He stated the Post 1970-ITC balances are forecasted by amortizing the remaining balance over the service life of the property that generated the credits, and testified that the tax expense adjustments reflected in Ms. Shikany's accounting exhibits were correct and consistent with his description of the applicable tax provisions.

O. <u>Vincent V. Rea</u>. Mr. Rea testified about the appropriate rate of return on common equity and overall rate of return that the Commission should establish for NIPSCO Electric in relation to its revenue requirement calculation. He also addressed the appropriate ratemaking capital structure, WACC, and embedded cost of debt. Based on his evaluation, he concluded that the cost of common equity for NIPSCO's jurisdictional electric utility operations is in the range of 10.55% to 11.05%, and that a point estimate at the midpoint of this range, or 10.80%, is the appropriate cost of equity to apply in this case. Based upon this finding, he determined that NIPSCO's WACC is 7.02%, which is based on NIPSCO's forward test-year-end regulatory capital structure as of December 31, 2019. This resulting overall cost of capital, if adopted by the Commission, will allow NIPSCO to earn the prevailing opportunity cost of capital, maintain its financial integrity, and attract capital at reasonable terms. Mr. Rea also presented the capital structure and WACC as of December 31, 2019.

Mr. Rea explained the general approach taken in determining the cost of common equity, and supported it with a detailed explanation of the analytical models used and their specific application for this case. He stated that he analyzed market-derived data and other financial information for 18 companies comprising two separate proxy groups. He explained that during the course of his evaluation, he applied three well-recognized analytical models to the market and financial data of the selected proxy group companies: the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium Method ("RPM"). He also evaluated two other model variants of the CAPM, specifically, the CAPM with size adjustment, and the Empirical CAPM. Finally, to confirm the reasonableness of the cost of equity estimates yielded by these market-based models, he reviewed the earned returns of non-rate-regulated companies having comparable risks by completing a Comparable Earnings Approach analysis. Mr. Rea developed his cost of equity recommendations after evaluating the individual cost of equity estimates that were derived from applying the various analytical models to the market and financial data of the proxy group companies. Using a variety of analytical models in conjunction with multiple comparable risk proxy groups ensures that a diversity of investor perspectives are incorporated into the cost of capital evaluation, thus providing a solid foundation upon which the analyst can apply his/her informed judgment in making a cost of equity recommendation.

Mr. Rea testified that NIPSCO is proposing that its Forward Test Year capital structure, as of December 31, 2019, be employed for rate-setting purposes. His specific recommendations were presented in Schedule 2, detailing NIPSCO's projected capitalization levels, corresponding capital structure ratios, and embedded cost of debt. To confirm the reasonableness of NIPSCO's Forward Test Year capital structure, he evaluated the actual and projected equity capitalization levels for the Electric Utility Group companies, as published by Value Line, which are calculated on the basis of permanent capitalization, and therefore exclude short-term debt. He stated that NIPSCO's proposed equity capitalization level, based upon investor-supplied sources of capital, as of December 31, 2019, is 57.11%, which is within the range of equity capitalization ratios anticipated for the Electric Utility Group companies, as reflected in near-term forecasts published by Value Line. Mr. Rea testified the cost rate for common equity is 10.80%, which is the cost of equity he is recommending in this proceeding and the cost rate for Long-Term Debt is 4.97%, which is based on NIPSCO's projected long-term debt outstanding at December 31, 2019.

P. Paula Strauss. Ms. Strauss explained how the Historic Test Period kWh consumption was adjusted to reflect the kWh consumption under normal weather conditions, the baseload temperature-sensitive load normalization procedure, and the forecast method used to derive the Forward Test Year customer counts and volume and to propose an adjustment to align the forecast with the definition of normal weather proposed for ratemaking purposes. She testified that NIPSCO used the baseload/temperature-sensitive load normalization procedure approved in the 44688 Rate Case Order using three sources of data in its analysis: (1) monthly billing data from its actual billing records; (2) NOAA National Weather Service Weather Stations data for actual temperatures used to calculate Cooling Degree Days ("CDD"); and (3) the 30-year average of temperature data from 1988-2017 using NOAA's National Weather Service temperatures. She explained that NIPSCO has updated its definition of normal weather as the 30-year average ending in 2017, which is an update to the normal CDDs calculated by NOAA's National Weather Service, which uses data for the 30-year period ended 2010, using data from Valparaiso, South Bend, and Fort Wayne weighted by the number of residential customers assigned to those stations.

Ms. Strauss testified that with actual CDD lower than normal by 6%, the Historic Test Period was cooler than normal, and usage for the adjusted rates was adjusted up by 0.8% to reflect normal weather which were used by NIPSCO witness Westerhausen to calculate pro forma expense and revenue levels. She explained in detail how kWh usage varied with CDD and explained that in her opinion the data supported the result reached in her study because of the strong correlation between CDD and kWh during the period 2008 through 2017. She concluded that the net result of her analysis was that Historic Test Period volumes should be increased by 59,151,141 kWh to reflect normal weather as reflected in Attachment 16-A.

Ms. Strauss explained that customer and energy projections utilized in NIPSCO's budget are developed by NIPSCO's Forecasting Group using projections of residential and commercial new customer additions provided by the New Business department, budget projections for large industrial customers provided by the Major Accounts department, and an outlook for all other small industrial customers utilized in the budget provided by the Financial Planning department. She testified that the Forecasting Group uses average saturation and efficiency data, economic variables and deflator information, and weather data obtained from external consulting services when estimating the Forward Test Year level of usage. Ms. Strauss provided descriptions of the derivation process used to develop each input into the forecast used to develop NIPSCO's budget. She explained that the forecast was provided to Mr. Westerhausen as reflected in Attachment 16-B to her testimony, and noted that forecasts are updated annually with the most current data. She explained that internal reviews of the forecast performance occur regularly and variances are calculated and assessed in order to measure accuracy. She testified that for the last five years, the average annual one-year weather normalized variance is 1.8% for the residential model, 1.5% for the commercial model, and 3.8% for the more volatile industrial model.

Q. Bickey Rimal. Mr. Rimal testified in support of the ACOSS used in conducting NIPSCO's electric COSS. 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 supported a minimum system study to separately classify certain distribution costs as demand-related and customer-related. 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, Services, and Meters Asset Allocation Analysis. Mr. Rimal described the general need for, and methodology of, the special studies related to NIPSCO's ACOSS. He stated that two main sources of the data and inputs were utilized: (1) the historical books and records of NIPSCO including the general ledger and engineering systems; and (2) interviews with relevant NIPSCO personnel. Mr. Rimal also supported a fixed-variable analysis to determine the proportion of NIPSCO's production O&M that varies with energy consumption. Mr. Rimal also provided basis for allocating certain customer accounts expenses to the various rate classes by conducting Operating Expense Allocation Study.

R. J. Stephen Gaske. Dr. Gaske testified that NIPSCO requested that Concentric conduct a fully-ACOSS 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. Dr. Gaske sponsored the class COSS and rate design, and he stated that the restructured industrial rate and service offerings are reflected in the ACOSS model.

Dr. Gaske discussed the purpose of an ACOSS and described the Concentric Cost of Service Model used in conducting NIPSCO's electric COSS. 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., 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 discussed various cost allocation principles, factors influencing the cost allocation framework, and the methodology and basis used in NIPSCO's COSS. He noted that Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter 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 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 vary with the amount of kWh sold to customers. For example, base fuel rates and some production operating costs that tend to vary with the amount of energy produced are included in the COSS. However, except for 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 ("4CP"), June through September, which were used to allocate the demand-related costs associated with the production functions. However, the 4CP demands of the new Rate 831 industrial classes were reduced to reflect the revised firm contract demands that these customers will place on the NIPSCO generating station after their services are restructured. The coincident peak demands that customers placed on the transmission system during each of the 12 months of the test period ("12CP") were utilized to allocate demand-related costs associated with the transmission functions. However, the 12CP demands used in the transmission cost allocation reflect a reduction to the Rate 831 demand to account for the proposed discount for Adjacent Qualifying Facility short-haul transmission service. Dr. Gaske explained that he reviewed the system peaks for all months during the 2010 – 2017 period and applied FERC's cost allocation tests to NIPSCO's load characteristics. Those tests indicated that either a 4CP or a 12CP 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 12CP allocator. He explained that the 2017 results failed one of the FERC tests and 2016 failed two of the three tests. Dr. Gaske further noted that during the past eight 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 4CP allocator for NIPSCO's demand-related production costs in this proceeding.

Dr. Gaske described other adjustments to the test period demand and energy determinants. He explained that the generation kWh and 4CP demand allocators used to allocate production costs to these customers (Rate 831) was adjusted to reflect the customers' new generation contract demand and energy use rather than their historical demands. He testified that the 12CP and non-coincident peak demand allocators continue to reflect the actual demands that each class places on the transmission and distribution system with one exception – one large customer decided to recategorize an exempt wholesale generation facility that is owned by an affiliate as behind-the-meter cogeneration. To address this issue and similar possibilities, NIPSCO is offering an alternative transmission charge solely to commonly-owned or affiliated customers that are located on adjacent premises that have cogeneration facilities that can produce power at one premise and transfer that power to its adjacent premise. He stated that because such customers will need to use only a small portion of the NIPSCO transmission system to transmit power from one of its facilities to an adjacent industrial facility, and because some fixed cost contribution is better than none, NIPSCO is proposing to provide a 70% discount on the transmission charge for power that is transmitted between two premises that satisfy the requirements. He testified the 12CP value used to allocate transmission costs has been adjusted to reflect such a discount for these situations.

Dr. Gaske provided class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for: (1) the 700 series rate classes that were forecasted to be in effect during the test year; and (2) the proposed 800 series rate classes, 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 used to set rates in this proceeding.

Dr. Gaske testified that NIPSCO used the results of the ACOSS as a first step in deciding the class revenue responsibility. He explained the ACOSS results were then adjusted to mitigate the largest rate increases. Specifically, because of residential class subsidies that were retained in prior rate proceedings, and because of the combination of industrial service restructuring and other cost increases, the ACOSS indicated that residential customers would require a rate increase in excess of 30%. He stated that in order to mitigate this impact, it was determined that all classes except the large industrial (Rate 831) should receive the same across-the-board percentage rate increase. He indicated that rates for the large industrial class would then be based on the allocated cost of service.

Dr. Gaske described the process and showed the calculations used to design the proposed rates. For the new classes, proposed Rate 830 would be a two-part rate consisting of a demand charge and a flat energy charge, and proposed Rate 831 for partial-requirements industrial customers will consist of a demand charge based on the customer's firm contract demand for NIPSCO generation, a transmission charge per kWh of energy it has delivered regardless of generation source, and an energy charge per kWh for energy that is purchased from NIPSCO. He noted that there also is an Adjacent Premise Qualifying Facility discounted transmission rate available. The rate designs for the other classes would remain unchanged.

Dr. Gaske discussed the impact of NIPSCO's proposed removal of the Interruptible Rider (Rider 775). As a result of the restructuring of industrial service offerings, there will no longer be any industrial customer loads taking interruptible service. He stated that projected revenue at current rates includes approximately $52 million in Rider 775 interruptible credits for industrial customers that would be allocated for recovery from all customers but that the industrial restructuring will eliminate those credits and recovery amounts. As a result of the revisions to NIPSCO's Back-up, Maintenance, and Temporary Services available under Rider 776, he noted that the existing Back-Up and Maintenance services under Rider 776 are retained for Rate 830 and Rate 831 customers, and Temporary services are retained for Rate 830 customers. He stated that because 831 customers will manage much of their own generation needs, Temporary service will no longer be available to customers that migrate to that rate schedule. He explained that the rate for Back-up service will continue to be the applicable demand charge divided by the number of days in the month, plus an energy charge equal to the real-time LMP and the non-fuel energy charge. The current daily demand charges for Maintenance service will be increased by the proposed system-wide percentage increase in margin, and the energy and transmission charges for that service would be the energy and transmission charges for the applicable rate schedule. Finally, no change to the existing daily demand charges for Temporary service is being proposed. He stated that because the revenues associated with the proposed Rider 876 are expected to be small and inherently unpredictable, NIPSCO has not included a credit for these revenues in designing the base rates. Instead, any margin revenue collected under Rider 876 will be flowed through the RTO rider (Rider 871) as a credit on customers' bills.

Dr. Gaske concluded by discussing customer impacts of the proposed rates. He 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.

S. Curt A. Westerhausen. Mr. Westerhausen stated that NIPSCO had three overall policy objectives in the development of the rates proposed in this proceeding: (1) restructure the industrial rate classes to accommodate the large industrial customers that want to reduce their dependence on NIPSCO generation; (2) moderate rate shock for the other rate classes; and (3) ensure that rate design calculations are simple and transparent.

Mr. Westerhausen described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 14, including the Schedule of Rates, Riders, and General Rules and Regulations and explained how the proposed tariff differs from NIPSCO's currently effective IURC Electric Service Tariff, Original Volume No. 13. He explained that the service structure would remain the same for residential and commercial customers, except for a proposed increase in fixed recovery by increasing customer charges. He noted that NIPSCO is proposing a new industrial service structure and proposing to discontinue its ECR Mechanism and Interruptible Industrial Service (Rider 775). He noted that the current rates have been updated to reflect NIPSCO's proposed revenue requirement allocated to the rate classes through the ACOSS and mitigation model.

In describing NIPSCO's new industrial service structure, he explained that NIPSCO is proposing new Rates 830 and 831 to replace current Rate 732 (Industrial Power Service), Rate 733 (High Load Factor Industrial Power Service), and Rate 734 (Industrial Power Service for Air Separation & Hydrogen Production Market Customers) utilized by NIPSCO's largest industrial customers. He stated that under proposed Rate 831, there is no longer a need for the interruptible Rider 775, which NIPSCO is proposing to eliminate. He also stated that Back-Up and Maintenance Service is available to Rate 831 customers under revised Rider 876 and Back-Up and Maintenance Service is built into the rate structure under Rate 830. He noted that Riders 881 and 882 are still available to these customers with minimal changes.

Mr. Westerhausen stated that NIPSCO's current ECR Mechanism is applicable to all Rates and is filed semi-annually to recover Environmental Compliance Projects, as authorized by the Commission. He explained that since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECR Mechanism, which will have no significant change in timing for NIPSCO or customers and relieves NIPSCO and its stakeholders of the ECR semi-annual tracker filing.

Mr. Westerhausen summarized each of NIPSCO's Proposed Rates including a discussion of each rate's components and an overview of the changes made and the rationale for making them. He testified that other than updated billing rates, Rates 820, 821, 822, 823, 824, 825, 826, 841, 842, 844, 855, 860, and 865, continue substantially unchanged. He described the material changes to the other Proposed Rates as follows:

<u>Rate 811 – Rate for Electric Service, Residential (RS)</u>: Rate 811 is available to Residential and farm Customers. This rate consists of a Customer Charge, an Energy Charge, and applicable Riders. Other than updated billing rates, Rate 811 continues substantially unchanged.

<u>Rate 830 – Rate for Electric Service, Industrial Power Service – Small</u>: Rate 830 is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. The Customer shall contract for a definite amount of electrical capacity, which shall be more than 10,000 kW and not exceed 25,000 kW. Those Premises served under Rates 732 or 733 on October 31, 2018, that satisfy the maximum capacity limitation may elect to be grandfathered into this rate.

Customers taking Back-Up, Maintenance, and Temporary Services under this rate shall be subject to Curtailments when curtailment of NIPSCO's Customers under Rate 831 is insufficient. This rate consists of a Demand Charge, an Energy Charge, and applicable Riders (except for Buy-Through Energy under Temporary or Back-Up Service). This rate is further discussed by witnesses Campbell and Kelly.

<u>Rate 831 – Rate for Electric Service, Industrial Power Service – Large</u>: Rate 831 is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. Customers shall contract for a definite amount of electrical demand, which shall not be less than 10,000 kW for a five-year term. Rate 831 has three tiers of service: (1) Tier 1 – Firm Service; (2) Tier 2 – Non-Firm Market Price Service; and (3) Tier 3 – Non-Firm Third-Party Generation Service. Customers must demonstrate or document, to NIPSCO's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating NIPSCO's satisfaction that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3. This rate consists of a Demand Charge (Tier 1), an Energy Charge (Tier 1), a Transmission Charge (Tier 1, Tier 2, and Tier 3), an Adjacent Affiliate Qualifying Facility Premise Transmission Charge ("AAQFPTC") (Tier 1, Tier 2, and Tier 3), and applicable Riders. This rate is further discussed by witnesses Campbell and Kelly.

Rate 850 – Rate for Electric Service, Street Lighting (SL): Rate 850 is available for street, highway and billboard lighting service to Customers for lighting systems located on NIPSCO's electric supply lines. 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. Other than updated billing rates, Rate 850 continues substantially unchanged.

While NIPSCO is not proposing any changes to the structure of this rate, communities that are currently receiving subsidies from NIPSCO's TDSIC rates will stop receiving those subsidies once NIPSCO's new base rates are approved. NIPSCO is proposing to roll the Electric TDSIC tracker rate base as of December 31, 2019, into the revenue requirement. As such, NIPSCO is proposing that all customers served under the TDSIC program as of December 31, 2019, will move to its standard street lighting program. For those customers that have LED street lighting TDSIC replacement installations completed on or after January 1, 2020,[33] NIPSCO is not proposing any changes. That is, they would be charged under the proposed TDSIC installed LED rates.

Mr. Westerhausen summarized NIPSCO's Proposed Riders. He testified that Riders 877, 878, 879, 880, 883, 886, 887, and 888 continue substantially unchanged.[34] He described the changes to the other Proposed Riders as follows:

Rider 870 – Adjustment of Charges for Cost of Fuel Rider (FAC): Rider 870 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 energy at the generator, as discussed by witness Gaske. Due to the elimination of Rider 775, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 will no longer be passed through this Rider. NIPSCO is also proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider, as discussed by witnesses Shikany and McCuen. The Fuel Cost Charge is shown in Appendix B.

Rider 871 – Adjustment of Charges for Regional Transmission Organization (RTO): Rider 871 is a semi-annual mechanism to recover net non-fuel MISO costs and revenues above and below $16,585,108 on an annual basis and 50% sharing of off-system sales margins over and under $4,741,390 on an annual basis. NIPSCO is proposing to fully track MISO non-fuel costs (net of revenues) and recover the costs through the RTO. NIPSCO is also proposing to reset the off-system sales and back-up and maintenance margin credits in base rates to zero and credit 100% of margins annually, as discussed by witness Campbell. NIPSCO is proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider, as discussed by witnesses Shikany and McCuen. The production and energy allocators utilized for purposes of allocating the costs inside

[33] NIPSCO currently estimates that 19,000 LED street light installations will be completed on or after January 1, 2020.
[34] In Riders 883, 886, 887, and 888, NIPSCO is proposing to separately state the URT on customer bills instead of including it in the calculation of the factors.

of this Rider will be updated based upon the ACOSS. The RTO Adjustment Factors are shown in Appendix C.

Rider 874 – Adjustment of Charges for Resource Adequacy (RA): Rider 874 is a semi-annual mechanism to recover the cost of capacity purchases and sales and 75% of costs associated with credits paid for interruptible load. Due to the elimination of Rider 775, 75% of costs associated with credits paid for interruptible load under Rider 775 will no longer be passed through this Rider. NIPSCO is also proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider. This is further discussed by NIPSCO witnesses Shikany and McCuen. The production and energy allocators utilized for purposes of allocating the costs inside of this Rider will be updated based upon the ACOSS. The RA Adjustment Factors are shown in Appendix F.

Rider 876 – Back-Up and Maintenance Industrial Service Rider (BMIS): This Rider is only available to Customers taking service under Rate 831 who desire to take service subject to Curtailments from NIPSCO for Back-Up or Maintenance purposes. Nothing in this Rider excuses the Customer from its Rate 831 Tier 2 and Tier 3 Curtailment obligations or the penalties associated with failing to meet those obligations. Back-Up and Maintenance Services under this Rider shall be subject to Curtailments when Curtailment under Rate 831 is insufficient. Energy under this Rider shall be subject to other Riders as identified on Appendix A. Customers taking service under this Rider shall operate their cogeneration facilities to meet their demand in excess of the sum of their Rate 831 Tier 1, Tier 2, and Tier 3 Contract Demands except when their cogeneration facilities are experiencing a forced outage or derate, or when the Customer is taking confirmed Maintenance Service under this Rider, as further discussed by witness Campbell. A contract is required for Back-Up Service under this Rider. The billing rates have been updated.

Rider 881 – Demand Response Resource Type 1 (DRR-1) – Energy Only (DRR 1): Rider 881 is available to Customers taking service under Rates 823, 824, 825, 826, 830, or 831 who have sustained ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 831 and registered as an LMR; unless MISO rules change and do not permit load used by NIPSCO as an LMR to also participate as a Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rate 830 or 831. The Customer shall enter into a written contract with NIPSCO to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with NIPSCO acting as the Market Participant for the Customer. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rate 830 and Rate 831. NIPSCO also has removed the Marginal Forgone Retail Rate ("MFRR") provisions within the Rider to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by witness Campbell.

Rider 882 – Emergency Demand Response Resource (EDR) – Energy Only (EDR-1): Rider 882 is available to Customers taking service under Rates 823, 824, 825, 826, 830, or 831 who have a sustained ability to reduce energy requirements through indirect participation in MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 831 and registered as an LMR; unless MISO rules change and do not permit load used by NIPSCO as an LMR to also participate as an Emergency Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rate 830 or 831. The Customer shall enter into a written contract with NIPSCO to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with NIPSCO acting as the Market Participant for the Customer. Customers who do not qualify as an LMR may, however, participate as an EDR with any load. Customers taking service under this Rider shall not take power under the temporary, surplus power, back-up and maintenance services during an event under this Rider. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rate 830 and Rate 831. NIPSCO also has removed the Marginal Forgone Retail Rate ("MFRR") provisions within the Rider to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by witness Campbell.

Mr. Westerhausen stated the majority of changes in the Proposed Rules relate to the addition of definitions that are needed relating to the addition of Rate 831. He sponsored NIPSCO's proposed standard electric contract for service as Attachment 19-B. He noted the agreement has been revised to: (1) update the applicable rates; (2) incorporate information required under Rate 831; (3) remove information previously required under Rider 775; (4) include Rate 830 under Back-Up Service; and (5) add a notice and correspondence information.

Mr. Westerhausen sponsored a summary of billing determinants for the Historic Base Period, 2018 Budget Period and Forward Test Year as Attachment 19-C. He stated the 2019 adjusted projected billing determinants were utilized for the development of the proposed rate design in this proceeding.

Mr. Westerhausen also presented a detailed description of the three sets of customer migrations for this case: 2017 Large Customers, 2019 large Customers, and 2019 Small Customers and explained how these customers were migrated. Mr. Westerhausen described and supported the following proposed pro forma adjustments:

Adjustment Rev 1A-17 and FP 1A-17 on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to increase test year operating revenue levels by $5,966,365 to reflect a normalized level of revenue at NIPSCO's tariff rates.

Adjustment Rev 1B-17 on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $44,239,220 to normalize 2017 revenues for the TCJA.

Adjustment Rev 1D-17 and FP 1B-17 on Petitioner's Exhibit No. 4, Attachment 3-C-S2, REV 1. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $352,249 for large customer rate migration in order to match migrations included in the budget for the 12 months ending December 31, 2018 and 2019.

Adjustment Rev 1A-19R and FP 1A-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $933,450 to normalize weather by converting the budget weather normal definition for CDD and HDD of 35-years ended 2010 to the regulatory 30-years ended 2017 definition for CDD and HDD, which is consistent with past ratemaking practice.

Adjustment Rev 1C-19R and FP 1C-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $45,845,611 to update the pricing model utilized in the budget process. When NIPSCO modeled the anticipated change in industrial customer usage described in Adjustments Rev 1D-19R and Rev 1A-19SS, NIPSCO updated the PROMOD inputs utilized to determine the volumes generated at each station. This resulted in changes in revenues, fuel costs, fuel handling expense, variable chemicals, and coal inventory. If this adjustment is not included, Forward Test Year electric operating revenues would be overstated. A corresponding adjustment was to decrease Forward Test Year fuel and purchased power expense in the amount of $45,845,611 in Adjustment FP 1C-19R.

Adjustment Rev 1D-19R and FP 1D-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $76,792,660 related to the migration and annualization of large industrial customers. If this adjustment is not included, Forward Test Year electric operating revenues would be overstated. A related adjustment was made to decrease Forward Test Year fuel and purchased power expense in the amount of $31,507,991 in Adjustment FP 1D-19R.

Adjustment Rev 1F-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to increase Forward Test Year electric operating revenues in the amount of $4,507,281 to reflect the discount passed through to retail electric customers taking service under NIPSCO's EDR.

Adjustment Rev 1G-19R and FP 1F-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $1,488,190 to reflect an anticipated decrease in street lighting billing determinants because the budget did not anticipate the increase in customer participation under the LED street lights resulting in less usage.

Adjustment Rev 1A-19SS and FP 1A-19SS on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $83,630,802 to reflect changes in industrial fuel based on the proposed new service structure.

Adjustment Rev 1B-19SS on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $3,000,000 to remove all Rate 732 and 733 back-up and maintenance revenues based on the proposed new service structure that gives Rate 831 customers alternatives for Back-Up and Maintenance Services. Any Back-Up and Maintenance margins generated by Rider 876 and within Rate 830 will be passed back in the RTO tracker.

Adjustment Rev 7-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 7. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $10,822,388 for DSM lost revenues that will continue to be recovered through NIPSCO's DSM tracker filing after Step 1 base rates are implemented.

Mr. Westerhausen explained the proposed increase in the Trip Charge. NIPSCO is proposing to increase the revenue collected in the Forward Test Year by $18,780. If a Customer schedules an appointment in association with a service request, and NIPSCO's serviceman is not able to gain access to the Customer's facilities due to the absence of the Customer, the Customer shall be charged a Trip Charge when the appointment is rescheduled by the Customer. NIPSCO is proposing a $15 increase in this charge, raising it from $40 to $55. In the Historic Base Period, there were 1,252 trips made. Applying this same number of trips to the Forward Test Year, multiplied by the $15 increase in the Trip Charge results in an $18,780 increase.

Mr. Westerhausen explained the proposed increase in the Reconnection Charge. NIPSCO is proposing to increase the revenue collected in the Forward Test Year by $164,280. A Customer incurs a Reconnection Charge whenever the service has been turned off by NIPSCO in accordance with Rule 12 (shut off for non-payment). NIPSCO is proposing a $20 increase in the charge for normal working hours, raising it from $70 to $90. In the Historic Base Period, 8,214 disconnect/reconnect trips were made. Applying this same number of trips to the Forward Test Year, multiplied by the $20 increase in the Reconnection Charge results in a $164,280 increase.

Mr. Westerhausen described how the Rate 830 Billing Determinants were derived. Customers taking service on the proposed Rate 830 are coming from both Rates 732 and 733. The starting point for the Rate 830 demands, energy and reactive kV Amps is the 2019 forecast. Proposed Rate 830 has different contract requirements than the current Rates 732 and 733. The 2019 demand forecast is based on the current rates and ratchets. NIPSCO reviewed the 12 months ending September 2018 demand billing components and recalculated these billing demands based on the customer's on-peak and off-peak demands and eliminated any influents of current contract demands. The forecasted billing demands were reduced to these recalculated billing demands.

Mr. Westerhausen described how the Rate 831 Billing Determinants were derived. He explained that customers taking service on the proposed Rate 831 are coming from Rates 732, 733, and 734. The starting point for the Rate 831 demands, energy, and reactive kV Amps is the 2019 forecast. Proposed Rate 831 has three tiers of service and allows customers with multiple premises to aggregate their load on an hourly basis. The customers can select a Tier 1 contract demand, which when multiplied by 12 becomes their annual billing demand. NIPSCO took the customers

2017 actual hourly demands, aggregated them for the two customers where aggregation applies, and then calculated the hourly Tier 1 and Tiers 2 and 3 energy. These were them summed to calculate the customer's annual 2017 energy for Tier 1 and Tiers 2 and 3. The 2017 energy was compared to the 2019 forecast energy. For customers with a Tier 1 energy with a 99% or higher load factor, Tier 2 and 3 energy was adjusted. For Customers with a Tier 1 load factor below 99%, the adjustment was made at the same proportion as their 2017 Tier 1, Tier 2, and Tier 3 energy. Transmission flow studies were performed for two customers who have multiple Premises held under common ownership or by affiliates (as defined in Ind. Code § 23-1-43-1) and having the same qualifying service voltage, IDR meters with five-minute interval telemetry capability at those Premises. Transmission volumes were calculated for the gross energy consumption (not netted with potential outputs from other qualifying meters) of each individual IDR meter. Their Tier 2 and 3 energy was adjusted based on these studies. No adjustments were made to the forecasted reactive kV Amps.

Mr. Westerhausen described NIPSCO's proposed updates to the tracker allocators. He explained that Rate 831 contains three tiers of service with the current trackers applicable to Tier 1 firm service. The energy only revenue requirement of the RTO would also apply to Tier 2. Currently, it is assumed that no transmission-related costs will remain in the FMCA, but if that changes in the future, transmission-related charges would apply to both Tier 2 and Tier 3 transmission portion of Rate 831. The demand allocators are based on the mitigated allocation of the ACOSS revenue. The Rate 831 allocation was adjusted to reduce the ACOSS revenue down to the revenue associated with Tier 1. The energy allocators are based on the sales allocator from the ACOSS. The Rate 831 sales are strictly Tier 1 sales so no adjustment is required. He explained that Rate 831 Tier 2 transmission volumes are not known at this time, so a placeholder has been included in the allocation. The TDSIC transmission allocators are based on the transmission and sub-transmission allocation of the revenues in the ACOSS. Rate 831 has been adjusted to the transmission volumes for Tier 1. The TDSIC distribution allocators are derived from the primary and secondary distribution revenue from the ACOSS. No adjustments were made for Rate 831. The tracker allocations are provided in Attachment 19-F.

7. <u>OUCC Case-in-Chief.</u>

A. <u>Michael D. Eckert</u>. Mr. Eckert recommended that NIPSCO's Phase 1 revenues should be decreased by $30,630,526 or 2.14% based on a WACC of 6.25%, and NIPSCO's Phase 2 revenues should be decreased by $10,233,307 or 0.71% based on a WACC of 6.27%. He reviewed NIPSCO's test-year operating expenses and related pro forma operating expense adjustments and accepted several of NIPSCO's adjustments, modified a few of NIPSCO's adjustments and proposed additional adjustments. He also sponsored the following adjustments: Billing Determinants – Revenues, Billing Determinants – Fuel Production, Labor Adjustment, Corporate Incentive Plan Expense, Pension Expense, OPEB Expense, medical Benefits Expense, Other Benefits Expense, Other Employee Benefits, Long-Term Incentive Compensation and Profit Sharing ("LTIP") Expense, Benefits Administration Expense, Uncollectible Expense, Vegetation Management Expense, Bad Debts Expense, and Interest Synchronization.

Mr. Eckert stated Mr. Novak's billing determinant adjustment increases the amount of kWh sales for NIPSCO, which in turn increases the total fuel production expense. He calculated the increase to fuel production expense by subtracting NIPSCO's proposed billing kWh billing determinants from the OUCC's proposed kWh billing determinants and multiplying it by NIPSCO's proposed fuel cost rate resulting in a $1,686,881 increase in fuel production expense.

Mr. Eckert stated Mr. Blakley made recommendations and proposed changes to NIPSCO's ADIT, which he incorporated into the OUCC's revenue requirement calculation.

Mr. Eckert calculated total labor expense as $130,478,191 using NIPSCO's method for calculating labor expense in making his calculation; however he used the actual average headcount for calendar year 2018, which is the same actual average headcount for calendar year 2017, rather than NIPSCO's budgeted headcount for calendar year 2019, resulting in a reduction in labor expense of $6,707,894. He also changed Corporate Incentive Plan, Pension Expense, OPEB, Medical Benefits, Other Benefits, Other Employee Benefits, Long Term Incentive Plan, Benefits Administration Expense, and payroll tax to reflect the reduction to labor expense. Mr. Eckert calculated these adjustments by taking the projected amounts for each of these expenses as reflected in NIPSCO's pro forma number and reduced them by the 4.89% reduction in labor expense, resulting in a combined total downward adjustment of $2,459,206.

Mr. Eckert did not oppose NIPSCO's adjustment to rate case expense, but he recommended NIPSCO reduce base rates for the amortization of rate case expense once the amortization period expires. He supported the continuation of the purchased power over the benchmark calculation.

Mr. Eckert did not oppose NIPSCO's proposal to defer unrecovered ECR expenses and amortize them over two years; however the OUCC recommended that NIPSCO reduce base rates for the amortization of expenses once those amortization periods have expired.

Mr. Eckert did not oppose NIPSCO's proposal that the FAC Rider be modified to reflect the updated cost of fuel that will be established in this base rate case. The OUCC recommended the Commission allow the continuation of the agreement with NIPSCO that allows the OUCC and intervenors to file their testimony and report 35 days after NIPSCO files its petition and testimony.

Mr. Eckert had no concerns with NIPSCO's proposed changes to its RTO Tracker. He stated that since NIPSCO will not know what customers will partake in NIPSCO's requested Rate 831, Tier 2 and 3, until the time of Phase 2 rates, or until and if approved by the Commission, the OUCC does not oppose NIPSCO's proposal to not embed an amount for MISO non-fuel costs and revenues in base rates; however, if Rate 831 is denied by the Commission, and similar to other Indiana investor-owned utilities, there may be a reason to embed an amount of MISO non-fuel costs and revenues in base rates, as there may not be any unknowns and embedding an amount in base rates may reduce the volatility of costs through the rider. The OUCC also did not oppose NIPSCO's proposal to reset OSS margin credit in base rates to zero dollars and track 100% of all OSS margins above zero dollars as a credit to customers through the RTO Rider. The OUCC also did not have any concerns with NIPSCO's proposal to pass back 100% of any demand margins resulting from back-up and maintenance services as a credit to customers through the RTO Rider.

Mr. Eckert testified the OUCC does not oppose NIPSCO's proposal to remove the interruptible credit from the RA Tracker. The OUCC also does not oppose NIPSCO's proposal to remove all embedded costs and/or credits associated with capacity from base rates and track 100% of all capacity costs and/or credits as a charge/credit to customers through the RA Tracker because such treatment of capacity purchase costs and sales credits: as (1) NIPSCO relies on the MISO PRA to sell excess capacity; (2) NIPSCO does not control the MISO PRA clearing prices associated with capacity; and (3) the auction process can vary.

With regard to the cost allocation factors for NIPSCO's TDSIC, Mr. Eckert recommended that the Commission require that NIPSCO use the customer class revenue allocation factors recommended by Mr. Watkins.

Mr. Eckert testified that the OUCC does not oppose NIPSCO's proposal to treat Indiana URT as a separate line item on customer bills, resulting in removal of URT from all of its riders.

B. Neha Medhekar. Ms. Medhekar testified that NIPSCO's filing includes ratepayer benefits resulting from the TCJA because the TCJA resulted in a federal tax decrease from 35% to 21%, resulting in excess deferred taxes that are being returned to the customer over the remaining life of the assets.

Ms. Medhekar stated NIPSCO's forecasted property tax expenses for 2018 and 2019 are reasonable noting that NIPSCO made an adjustment to remove MVP property taxes. She recommended NIPSCO's proposed payroll tax expense amount should be reduced based on Mr. Eckert's adjustment to O&M labor expense. She testified NIPSCO's calculation of public utility fee is consistent with the Commission's 2018 Annual Report providing the 2018-2019 public utility fee billing rate as 0.001202040.

Ms. Medhekar testified NIPSCO's customers will benefit from removing URT from basic rates, and the OUCC does not object to NIPSCO's proposal. She noted that if not approved, URT would need to be included in total cost related to taxes other than income resulting in an increase in gross retail electric revenue of $32,994,983.

Ms. Medhekar did not oppose NIPSCO's calculated state income tax rate. She explained that any adjustment to income results in an adjustment to income tax expense. As a result of the OUCC's proposed adjustment to NIPSCO's revenue requirement, there is a reduction of $573,729 for state income tax expense and a reduction of $2,021,439 for federal income tax expenses.

Mr. Medhekar has no objection to NIPSCO's calculation of state excess deferred taxes.

C. Wes R. Blakley. Mr. Blakley clarified the actual total company percentage increase in revenue requirement NIPSCO is requesting is 7.77% to arrive at its total company pro forma proposed revenues. He noted that at 1,000 kWh, if NIPSCO's requested increase were approved in its entirety, a typical residential customers would experience an 11.54% rate increase or $15.11 per month increase.

Mr. Blakley calculated NIPSCO's annual accrual depreciation using the 2019 forecasted future accruals in the depreciation study, and applied the results to the composite remaining life of the coal assets from its depreciation study in Cause No. 44688, resulting in an increase to NIPSCO's annual depreciation accruals of approximately $42 million. He stated the accelerated depreciation proposed by NIPSCO provides additional annual cash flow of approximately $42 million that will last through 2030, which is a benefit to NIPSCO, as is the special ratemaking treatment proposed for Schahfer and the ongoing "return on" it seeks to earn on these retired coal assets. He indicated that any increased rates due to the accelerated retirements should be mitigated. Mr. Blakley proposed a mitigation mechanism in which ratepayers are credited with the effect of the annual depreciation of Schahfer and Michigan City. He explained the credit mechanism would function similarly to a Construction Work in Progress ("CWIP")/Plant Investment tracker, in which plant investment is reduced by associated depreciation over a period, and the return "on" is calculated on the new, lower net plant balance. He explained that while the plant investment is decreasing each year due to depreciation of the investment, NIPSCO would still receive a return "on" the investment with the credit reflecting the difference between the amount authorized in rates and the actual investment amount adjusted for depreciation. He noted that the credit would be repeated annually until the physical asset or regulatory asset is fully depreciated or amortized.

Mr. Blakley disagreed with NIPSCO's proposal to return unprotected excess ADIT over the same period as the protected excess ADIT. He stated that the public interest would not be served by allowing NIPSCO to amortize unprotected excess ADIT over 26 years. He instead proposed NIPSCO amortize unprotected excess ADIT over the expected life of the rates set in this Cause for five years, resulting in an annual amortization of $36,680,662 for unprotected excess ADIT.

D. J. Randall Woolridge. Dr. Woolridge recommended a 9.25% return on common equity, an overall rate of return of 7.41% from investor-supplied capital, and a 6.27% overall fair rate of return from capital. He primarily disagreed with Mr. Rea in measuring NIPSCO's rate of return or cost of capital as follows: (1) significantly different views regarding the state of the markets and the outlook for capital costs; (2) Mr. Rea's DCF equity cost rate estimates are excess because he has (a) asymmetrically eliminated low-end DCF results, (b) relied excessively on the earnings per share growth rates of Wall Street analysists and *Value Line*, made an inappropriate adjustment for leverage, (c) made an inappropriate adjustment for flotation costs, and (d) included the DCF results of a non-utility group of companies; (3) Mr. Rea's CAPM equity cost rates are overstated because he has (a) used economists' forecasts of future interest rates, (b) made a market value – book value leverage adjustment to his betas, (c) employed inflated historical and projected MRPs that do not reflect current market fundaments, (d) included unjustified size and flotation cost adjustments, (e) used the CAPM results of a non-utility group of companies, and (f) employed a variance of the CAPM; (4) Mr. Rea's risk premium approach produces inflated equity cost rates for NIPSCO because he has (a) used economists' forecasts of future interest rates, (b) employed inflated historical and projected risk premiums that do not reflect current market fundamentals, (c) made a market value – book value leverage adjustment to his betas, (d) included an unjustified flotation cost adjustment, and (e) included the risk premium results of a non-regulated group of companies; and (5) Mr. Rea used a non-traditional equity cost rate approach.

E. William H. Novak. Mr. Novak stated the primary differences between NIPSCO's and the OUCC's calculations of forecasted period billing determinants are due to different forecasts for normal weather and customer growth and recommended the appropriate: (1) number of customer bills to set rates upon should be 6,761,663, an increase of 212,483; (2) billing demand should be 14,160,249, a decrease of 20,012; and (3) kWh usage should be 12,101,489,114, an increase of 65,507,561. He explained how his test period billing determinants were adjusted for weather and added customers and explained his analysis for consideration of usage for NIPSCO's industrial customers stating that he adopted NIPSCO's proposed billing determinants and revenues associated with Rates 830 and 831. Mr. Novak stated that he adopted NIPSCO's proposed test period values for the remaining billing determinants primarily consisting of certain minimum bills related to three-phase charges, horsepower charges, and charges based on residential or commercial pumps as well as the test-period billing determinants for reconnection charges, turn-on charges, returned check charges, and automatic meter opt-out charges, which have remained relatively consistent since 2012. He stated the forward-looking billing determinants were multiplied by the current base tariff rates giving $1,412,394,583 in revenues.

F. Peter M. Boerger. Dr. Boerger testified regarding NIPSCO's proposal for a new rate design (i.e., Rate 831) that would allow certain large industrial customers to pay MISO wholesale market prices for service under Tiers 2 and 3 (non-firm) service under NIPSCO's proposed Rate 831. He indicated that the OUCC expects that access to the wholesale market will allow these customers to lower their cost of electric service compared to NIPSCO's current rates. He highlighted the significance of this issue for regulatory policy across all Indiana electric utilities in that it is a first-of-its-kind request.

Dr. Boerger presented NIPSCO's estimate, obtained through discovery, of a $40.2 million cost shift from industrial customers to other rate classes through the implementation of Rate 831. He referred to OUCC witness Watkins' testimony that this $40.2 million cost shift serves as a minimum value for the cost shift and that the shift may be higher. He explained that this cost shift would allow this class of customers to avoid a significant share of NIPSCO's legacy costs that would otherwise be allocated to these customers under a cost-based rate. He presented the OUCC position that because of this cost shift, NIPSCO's proposal is not reasonable without a payment from Rate 831 customers, which he called a "transition charge" to be recovered over the period through which NIPSCO recovers accelerated depreciation on its coal-fired plants. Under this OUCC proposal, the exact size of the annual transition charge would be determined in the Phase 2 rate proceeding in this Cause, which would also be used to adjudicate the effects of Rate 831 customers not subscribing to the amount of firm service that NIPSCO envisioned in designing Rate 831 charges. The revenues from the transition charge would be allocated to other rate classes based upon the production cost allocation methodology approved in this Cause.

Dr. Boerger also presented concerns about Rate 831 tariff provisions. Specifically, he identified the early termination of Rate 831 contract provisions under Section 5.8 of its proposed tariff, which otherwise requires a five-year contract provision before customer commitments to firm service can be reduced and a five-year notice provision before a customer's firm service can be increased. He stated that these notice provisions are important to the reasonableness of the tariff and should not be allowed to end prematurely. In response to that concern, he presented the OUCC recommendation that Section 5.8 provisions not apply to Rate 831 contracts. Another Rate 831 provision with which Dr. Boerger takes issue pertains to the allowed 12-month notice provision for reducing firm service in the event of "aggregation" or "partially closing a Premise." He finds these provisions to be vague and not reasonably justified and that their inclusion in the Rate 831 tariff provisions is unreasonable.

Dr. Boerger took issue with the design of NIPSCO's proposed transmission charge under Rate 831 and the related Rider 876. He stated that this transmission charge was intended by NIPSCO to recover the Rate 831 share of transmission revenue requirement, and identified that the OUCC does not object to the inclusion of a transmission charge in NIPSCO's tariff. However, he explained that the proposed charge would not adequately recover the cost of providing service for back-up of self-generation facilities, in that it only charges those facilities for the service of wheeling electricity at the time of unexpected generation outages to the exclusion of the cost of providing service for "standing ready" to move power, which is a 365 day per year service. He explained that the charge as proposed by NIPSCO would under-recover revenue requirement for the back-up transmission service and provide inappropriate economic signals for the building of self-generation facilities. He recommended that NIPSCO's transmission charge be designed to recover transmission revenue requirement on the basis of demand, including the amount of demand needed to back-up self-generation facilities. This approach would require establishing a contract level of back-up service for self-generation facilities, which would be reflected in the potential peak load from Rate 831 customers' non-firm transmission needs. He further recommended that NIPSCO rerun its cost of service and rate design analysis to include such non-firm demand, including back-up of self-generation, which should be presented in the Phase 2 rate proceeding in this Cause. Finally, he recommended that such a transmission charge be included as part of any successor to NIPSCO's 700 series of rates if NIPSCO's Rate 831 proposal is not approved.

G. Glenn A. Watkins. Mr. Watkins testified regarding Cost of Service, which addresses the reasonable allocation of NIPSCO's revenue requirement to the various customer classes. He testified that NIPSCO filed this case in part due to its proposed rate restructuring plan for large industrial customers that would allow these customers to purchase the majority of their energy requirements in the wholesale market and would collectively save on average approximately $47.1 million annually on their total electric bills based on their 2017 and 2018 actual usages and load profiles. As a result of NIPSCO's proposed industrial ratemaking plan, all remaining customers would be responsible for NIPSCO's total investment in generation plant. He stated that even though NIPSCO's generation plant was planned and built in large part to meet the load and energy requirements of large industrial customers, these large customers would be able to walk away from any cost responsibility associated with NIPSCO's legacy fixed generation costs wherein all remaining customers would be responsible for the entire cost of NIPSCO's generation plant. Mr. Watkins estimated the impact on all other customers' rates and revenues of NIPSCO's proposed industrial rate restructuring plan is in the range of $40.2 million to $80.2 million.

Mr. Watkins discussed NIPSCO's rate restructuring plan and how the largest industrial customers would qualify for Rate 831 in which these customers will contract for a specified amount of firm capacity during each hour of the year and any additional load would be purchased at the prevailing day ahead wholesale LMP. NIPSCO projected only a small portion of these large industrial customers' loads will be provided from NIPSCO's own generation resources. The vast majority of these large industrial customers' loads and energy requirements will bypass NIPSCO's generation resources wherein these load and energy requirements will be purchased directly from the wholesale market. Mr. Watkins testified that under NIPSCO's proposed restructuring plan, the majority of large industrial loads will bypass NIPSCO's generation system such that the remaining residential, commercial, municipal, and small industrial customers must then pick up a much larger percentage of NIPSCO's fixed, or sunk, generation plant-related costs. As a result of these large industrials bypassing NIPSCO's generation system, a significant portion of NIPSCO's fixed generation costs would be stranded absent an alternative ratemaking plan. He discussed how he has not been able to quantify the impact on all other customers with any level of precision because NIPSCO has presented its case as if the plan will be accepted by the Commission. He stated that NIPSCO has not presented its evidence based on the actual current rate structure but rather, only after all of the numerous large industrial adjustments are made as proposed under its rate restructuring plan. Through discovery, Mr. Watkins was able to determine a range for the impact on all other customers in the range of $40.2 million to $80.2 million.

To support his position that Rate 831 would reduce large industrial customers' total electric bills, Mr. Watkins used 2017 and 2018 data from multiple data request responses (total electric bills, total kWh consumption, hourly loads, and hourly MISO day-ahead LMPs), along with each customer's projected contract demands from Dr. Gaske's Attachment 18-H. Mr. Watkins then compared each customer's proposed Rate 831 total electric bill with actual total bills for 2017 and 2018. He concluded Rate 831 customers would have saved $69.5 million during 2017 and $24.8 million during 2018 for a two-year average annual savings of $47.1 million.

Mr. Watkins addressed the allocation of generation and transmission costs to the customer classes. With regard to generation plant, Mr. Watkins testified that utilities design and build generation facilities to meet both the energy (kWh) requirements and the demand (kW) requirements of their customers on a collective basis. He explained because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated. Mr. Watkins discussed how utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity kW and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year, there is an optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Mr. Watkins explained that methods focused solely on seasonal peaks, such as 1CP and 4CP, are inconsistent with the way utilities plan their systems to meet both peak requirements and their customers' energy requirements throughout the year. He stated that NIPSCO's portfolio of generating assets is comprised predominately of large baseload units that serve the energy needs of NIPSCO throughout the entire year. Furthermore, the total dollar amount of generation investment for utilities such as NIPSCO that have coal generation facilities includes a majority of its net investment to comply with environmental or pollution control requirements. These environmental or pollution control investments are related to the burning of fuel, which is energy-related. As a result of the energy/capacity cost trade-off and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes. Mr. Watkins demonstrated that a majority of NIPSCO's generation investment is related to baseload units that serve all customers throughout the year, which the Commission has previously recognized. Mr. Watkins cited to NIPSCO's last litigated rate case (Cause No. 43526), where the Commission found (at p. 85):

> Much of the capital investment costs at issue were, in fact, incurred to meet NIPSCO's energy requirements at lower costs thereby minimizing the total cost of service. This is consistent with the evidence that NIPSCO's system was designed, planned, and built in material part to serve the loads of its energy intensive

industrial customers. Moreover, we note that the most recent capacity addition to the NIPSCO system was the intermediate/baseload combined cycle Sugar Creek facility, and not a "peaker" generating plant.

Mr. Watkins discussed how Dr. Gaske conducted his COSS utilizing the 4CP method to allocate generation costs. Under Dr. Gaske's 4CP method, the entire amount of NIPSCO's generation plant investment is allocated based on four hours of peak demand. Dr. Gaske assumed that the cost per kW is the same for baseload units as for peaker units, and he has also assumed that the utilization of NIPSCO's baseload units are the same as its peaker units; i.e., peaker units are dispatched and run at the same level throughout the year as baseload units. Mr. Watkins testified that Dr. Gaske indicated either the 4CP or 12CP methodology would be appropriate for NIPSCO's production function, but he chose to only use the 4CP allocation method for NIPSCO's fixed production costs in this case. Mr. Watkins testified that the Commission has previously approved the 12CP methodology for NIPSCO and in fact, directed NIPSCO to utilize a 12CP study as the initial basis on which to determine class revenue responsibilities (43526 Final Order, p. 85). Mr. Watkins testified that Dr. Gaske's 4CP COSS results in several classes receiving a free ride and assign no generation cost. Even though these customers require generation service, they are not assigned a single dollar of rate base associated with generation capacity costs.

Mr. Watkins explained that neither NIPSCO nor Dr. Gaske conducted a cost allocation study based on the current configuration of customer classes, the current usage and load profiles of its various customer classes, nor the current revenues associated with NIPSCO's retail customers. Rather, NIPSCO and Dr. Gaske have presented their case under the assumption that the Commission will approve NIPSCO's proposed Rates 830 and 831 restructuring. As such, Dr. Gaske's COSS only reflects NIPSCO's proposal that a significant amount of large industrial load will leave the NIPSCO system for generation purposes. He stated that this has a profound impact on COSS results. Under NIPSCO's proposals and Dr. Gaske's COSS analysis, all other customers are then allocated the full amount of NIPSCO's capacity-related generation costs wherein the large industrial classes' loads are expressed at significantly reduced levels due to Rates 830 and 831. Mr. Watkins explained this choice by NIPSCO as problematic, and due to the massive number of adjustments that are interrelated to NIPSCO's proposed rate restructuring for Rates 830 and 831, he was not able to create or depict NIPSCO's total costs and revenues under the actual current rate configuration and customer profiles. Additionally, Dr. Gaske only utilized the results of his COSS to assign revenue responsibility to, and design rates for, the proposed Rate 831 rate schedule. With regard to all other rate classes, Dr. Gaske assigned any remaining overall increase in the revenue requirement to classes on an equal percentage basis.

Mr. Watkins explained that to show the relative shift in cost responsibility as a result of NIPSCO's proposal to present its case based on the assumption that its Rate 831 restructuring proposal will be accepted, he had to use Dr. Gaske's 4CP COSS from NIPSCO's last rate case. Mr. Watkins then compared Dr. Gaske's 4CP allocators in that case to his 4CP allocators in this case to show the relative shifts in generation costs. NIPSCO's proposed large industrial rate restructuring plan greatly reduces the large industrials' allocation of generation-related costs from 29.80% in the last case to 11.88% in this case. Mr. Watkins explained that Dr. Gaske must then allocate more costs to the remaining classes. For example, the residential class' generation allocation factor increases from 30.28% to 42.07%.

Mr. Watkins conducted three alternative COSS using the Base-Intermediate-Peak ("BIP"), Peak and Average ("P&A"), and 12CP allocation methodologies. He stated that based on NIPCSO's configuration of generation resources and its load profile, the BIP and P&A methods better reflect the capacity/energy tradeoffs that exist within NIPSCO's generation-related costs. Additionally based on the Commission's prior acceptance of the 12CP method to allocate NIPSCO's generation-related costs, he conducted COSS using each of these three allocation methodologies. Mr. Watkins discussed how BIP and P&A methods more closely reflect the manner in which NIPSCO has planned, built, and utilizes its generation resources and more closely correlates to cost causation; however, the 12CP method is not an unreasonable approach that this Commission has used for allocating NIPSCO's generation costs for several rate cases. Mr. Watkins demonstrated the proposed Rate 831 revenue requirement (using NIPSCO's requested increase) under the alternative allocation methods is: (1) 4CP: $149,068,200; (2) BIP: $172,911,300; (3) P&A: $169,096,200; and (4) 12CP: $162,158,600. He concluded that the difference between Rate 831 revenue requirement from Dr. Gaske's 4CP to the more reasonable Commission-approved 12CP methodology allocates $13,090,400 more to large industrial customers.

Mr. Watkins testified that NIPSCO's proposed class revenue distribution is reasonable with one major caveat. He stated that if the Commission adopts NIPSCO's Rate 831 proposal for large industrial customers, NIPSCO's proposal to develop Rate 831 rates based only on his allocated revenue requirement for this class is unfair and unreasonable to all other customer classes. He stated that this is because Dr. Gaske's allocated revenue requirement for Rate 831 is based upon these customers bypassing NIPSCO's generation system for the majority of their load and energy requirements. Under NIPSCO's proposal, all other customers would be responsible for the level of fixed generation investment that large industrial customers would walk away from. To help alleviate this cost shift, he recommended if the Commission authorizes some form of Rate 831, it should use a more appropriate cost allocation method and implement a transition charge.

Mr. Watkins testified that due to the manner in which NIPSCO presented its case, cost responsibility across classes cannot be determined. Based on this, Mr. Watkins agreed the most reasonable method to assign the remaining increase is across classes on an equal percentage basis.

Mr. Watkins discussed how NIPSCO has requested to increase fixed customer charges for residential and small commercial rate classes even though these customer charges were recently increased by a significant percentage in Cause No. 44688. Mr. Watkins conducted a residential direct customer analyses, which showed at most residential direct customer cost is $5.31 per month, and a small commercial direct customer cost is at most $9.15 per month. Mr. Watkins recommended that even though his direct customer cost analyses indicates that significant reductions to current fixed monthly customer charges applicable to residential and small commercial customers are appropriate, in the interest of rate continuity, gradualism, and impacts on individual customer bills that the current monthly customer charge of $14.00 for residential and $24.00 for small commercial (Rates 720, 721, and 722) be maintained.

8. <u>CAC Case-in-Chief</u>.

A. <u>Jonathan Wallach</u>. Mr. Wallach addressed NIPSCO's proposals to: (1) restructure service for large industrial customers; (2) allocate among the various rate classes the forecasted revenue deficiency for the 2019 test year; and (3) increase the monthly customer charge for residential customers based on the results of NIPSCO's ACOSS.

Mr. Wallach provided an overview of NIPSCO's proposal for a new industrial service structure, described how NIPSCO determined the amount of demand-related embedded production costs to be recovered through the proposed Tier 1 demand charge, and explained how test-year demand-related production costs would be allocated to large industrial customers if industrial service is not restructured. Mr. Wallach stated that NIPSCO has always faced the risk of loss of industrial load – with the associated loss of contribution to NIPSCO's fixed costs – and has attempted to mitigate such risk with special contracts and interruptible rates. However, NIPSCO believes there is now a heightened risk due to changing economic landscape that has reduced the cost to industrial customers of alternatives to NIPSCO firm service. He stated that the proposed restructuring will result in a near-term shifting of some firm costs currently being recovered from the industrial customers to other customers.

Mr. Wallach testified that NIPSCO's Rate 831 proposal would unduly subsidize large industrial customers by shifting recovery of $67-$80 million of embedded production costs to other rate classes by allowing large industrial customers to take fixed rate service at contract demand levels well below total customer demand. He stated NIPSCO proposes to allocate embedded production costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand not contract demand. Consequently, he maintains that the proposed industrial rate structure would recover from large industrial customers less than their fair share of embedded production costs and instead shift recovery of such costs to other rate classes.

Mr. Wallach recommended that Rate 831 revenues be maintained at test-year levels under current rates and that revenues for all other classes be increased by an equal percentage to recover the requested revenue increase. He stated this would thereby reduce the industrial subsidy and provide a fair allocation of the requested revenue increase.

Mr. Wallach provided an overview of NIPSCO's proposal to increase the monthly fixed customer charge for residential customers from $14 to $17 and disagreed with NIPSCO's argument that demand-related costs are fixed for rate-design purposes. He stated that while such costs may appear fixed from a short-run accounting perspective since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load, from the long-run perspective of cost-causation and price efficiency, plant investments are variable with respect to customer usage. He stated that shifting recovery of load-related costs from the volumetric energy rate to the fixed customer charge would drive the energy rate from long-run to short-run marginal costs and thereby dampen price signals for efficient customer behavior.

Mr. Wallach recommended that the Commission approve a residential fixed customer charge at a cost-based rate of $12.55 per residential customer per month.

B. John Howat. Mr. Howat described the need for and recommended that the Commission direct NIPSCO to implement a comprehensive low-income bill payment assistance program that targets current bill benefits to customers eligible to participate in the federal Low-Income Home Energy Assistance Program ("LIHEAP") with an arrearage management design component. According to Mr. Howat, the estimated cost of the recommended program represents just over $9 million per year—or 0.547% of NIPSCO's revenues from sales to residential, commercial, and industrial customers, which could be collected through a uniform volumetric charge. He also recommended that NIPSCO report data monthly to the Commission and stakeholders 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. Mr. Howat presented evidence to demonstrate that shifting utility cost recovery from the volumetric to fixed monthly customer charge portion of bills disproportionately harms low-volume consumers within a rate class and recommended the Commission reject NIPSCO's proposal to increase the monthly fixed customer charge and instead, lower it to CAC's recommended figure of $12.55.

9. ICC Case-in-Chief.

A. Emily S. Medine. Ms. Medine testified that NIPSCO's proposal to allow its largest industrial customers to opt into retail wheeling and reduce or eliminate paying for generation assets built to serve their firm and interruptible loads should be rejected for the following reasons: (1) it will have significant adverse impacts on NIPSCO's other customers; (2) the proposal was not modeled in NIPSCO's 2018 IRP; (3) NIPSCO has invested heavily in generation assets to serve the firm and interruptible loads of those large industrial customers and to the extent those customers are allocated less of the cost of those assets, NIPSCO will seek to recover those stranded costs from other customers; and (4) NIPSCO's proposal for retail wheeling for large industrials customers raises statewide policy issues that are inappropriate for resolution in a rate case. She recommended that NIPSCO's request to allow its largest industrial customers to opt for retail wheeling should be denied without prejudice so that: (1) NIPSCO can perform truly integrated resource planning in its next IRP and include the migration of large industrial firm and interruptible load to retail wheeling; (2) the Commission can include in its Statewide Analysis and annual reporting to the legislature the issues surrounding potential migration of load to market resources in lieu of local utility resources; (3) the issue of stranded cost allocation can be considered from a policy perspective on a statewide basis.

Ms. Medine concluded that NIPSCO's proposed acceleration of depreciation for coal generation units and proposed accounting authority to defer remaining net book value of coal generation assets as regulatory assets after early retirement should be rejected for the following reasons: (1) these proposals are premature because they rely upon an IRP that is still under review and comment; (2) NIPSCO's 2018 IRP modeling suffers from the same fatal flaw as its 2016 modeling – NIPSCO's resource planning is not integrated because it separates (a) the modeling of retirement decisions (using hardwired retirement dates selected by NIPSCO rather than optimized by the model), from (b) replacement portfolio decisions; (3) NIPSCO did not adequately address customer rate impacts that will result from the premature retirements of its remaining coal fleet, accelerated depreciation of the remaining costs and the creation of a regulatory asset; and (4) NIPSCO expended no effort in seeking to minimize the costs of the early retirement of the Schahfer units, including but not limited to, actively marketing the units for sale to third parties. She recommended that in connection with doing a truly integrated resource plan in its next IRP, NIPSCO should, as part of its retirement planning, solicit and meaningfully consider offers from third parties to purchase those assets in order to properly assess the costs of retirement. NIPSCO should not reject without due economic analysis purchase offers that may include proposals for NIPSCO to purchase capacity or energy from those units.

Ms. Medine concluded that if NIPSCO's ECRM Tracker is discontinued, NIPSCO should be prohibited from including such variable operating costs associated with said environmental projects in the calculation of its offer prices when bidding its units into the MISO market.

10. ICC / ICARE Case-in-Chief.

A. Charles S. Griffey. Mr. Griffey testified regarding NIPSCO's 2018 IRP. He stated that the IRP fails to demonstrate that NIPSCO's planned retirements of Schahfer and Bailly are reasonable because NIPSCO created an IRP process using flawed methodology and assumptions, which lead to the conclusion that the coal plants should be retired in the years NIPSCO predetermined.

Mr. Griffey testified against NIPSCO's requests to accelerate depreciation and create a regulatory asset upon retirement of each coal unit. He indicated it is premature for the Commission to determine whether NIPSCO should receive a return on the regulatory asset if it is approved, or what the level of return should be. He testified he takes no position on whether the new market structure and associated cost shift is in the public interest, but he noted that there is no tie between the proposed new structure and the results of the IRP. He stated that because the IRP analysis is significantly flawed, the Commission should postpone any determination regarding rate recovery for the associated plant retirement decisions until after NIPSCO's next IRP.

11. IMUG Case-in-Chief.

A. Theodore Sommer. Mr. Sommer addressed opportunities to collaboratively launch a Municipal Solar Program ("MSP") that would benefit municipalities, their residents, residents in NIPSCO's service area, and NIPSCO and would foster new employment opportunities. He stated the MSP would be designed to maximize benefits for northern Indiana utility regulatory stakeholders. He noted that solar panels could be placed on vacant municipal land, vacant municipal rooftops, blighted land, and brownfields. He explained that participating municipalities would select the available qualifying sites for possible installation of solar panels based upon total value and would have the opportunity to offer solar sites for consideration with NIPSCO. He stated that funding for the MSP panels and installation would be obtained from NIPSCO, a private lender, a private partner, or the municipalities themselves. He indicated there currently is a 30% ITC on the purchase of solar panels suggesting that private financing may be a viable path to capitalization. Mr. Sommer detailed MSP benefits including: (1) new employment opportunities; (2) job training opportunities; (3) Hoosier Homegrown Energy Economic Stimulus; (4) lower purchased power costs for participating municipalities; (5) enhancing public convenience and necessity; (6) environmental benefits and public awareness; and (7) consistency with and promotion of NIPSCO's customer efforts and vision. He testified IMUG is willing to collaboratively work with NIPSCO and others to detail the proposed MSP.

Mr. Sommer had concerns with NIPSCO's proposed streetlight rates with increases of approximately 33% to 49% reflecting NIPSCO's proposed termination of the 50% TDSIC socialization of capital conversion costs for NIPSCO-owned streetlights that have already been converted to LED. He said that ending the 50% LED retrofit socialization created in the approved seven-year TDSIC plan at this time would result in a shocking LED rate increase to IMUG members. He stated that NIPSCO intends to roll the TDSIC LED street light rate base tracker impacts into rate base as of December 31, 2019. He explained that any streetlight fixtures changed out after the time of that cutoff will be afforded a discounted rate similar to the rate those will have previously experienced. He stated that IMUG municipalities first suggested the LED conversion program, worked to maximize the technical characteristics and economic value of the LED conversion program, and worked to have the LED program approved. However, those municipalities who first converted to LEDs would only receive seven-year TDSIC plan 50% savings for a brief two years and would suffer huge rate increases while those who did not invest the time, effort, and money in the LED program will be converted to LED in the future and will continue to receive the TDSIC socialization or discounted rate on LED converted streetlights for a much longer time period. Mr. Sommer proposed that those with the discounted rate for LED rates continue to be charged the discounted rate following December 31, 2019.

Mr. Sommer proposed that 50% socialization of the converted LED streetlight rate responsibility be allocated to the other customer classes because all people in NIPSCO's service area who travel the roads and sidewalks after dark are the primary beneficiaries of streetlights.

12. <u>Industrial Group Case-in-Chief</u>.

A. <u>Michael P. Gorman</u>. Mr. Gorman testified regarding a number of specific adjustments to NIPSCO's claimed revenue deficiency and supported his recommended return on equity ("ROE") of 9.35%, the midpoint of his recommended range of 9.0%-9.7%.

Mr. Gorman first addressed NIPSCO's proposed treatment of unprotected excess ADIT. He noted that NIPSCO had adjusted its cost of service to reflect the new 21% corporate tax rate implemented by the TCJA and that NIPSCO was proposing to return protected excess ADIT using the average rate assumption method ("ARAM") consistent with IRS normalization rules. Mr. Gorman noted that NIPSCO also proposed using approximately a 15-year ARAM amortization period to return unprotected excess ADIT but a ten-year amortization period for other assets. He recommended using a ten-year amortization period for unprotected excess ADIT. Mr. Gorman explained why he considered NIPSCO's decision to use the ARAM amortization period for unprotected excess ADIT unreasonable and why use of a ten-year amortization period was more appropriate. Based on his recommendation, Mr. Gorman reduced NIPSCO's claimed revenue deficiency by approximately $5.15 million.

Mr. Gorman next recommended reducing NIPSCO's revenue deficiency by approximately $3.32 million to reflect a downward adjustment to its labor expense. He made this adjustment by removing costs associated with unfilled positions from NIPSCO's budgeted headcount.

Mr. Gorman also proposed an adjustment to NIPSCO's proposal to recover a regulatory asset related to the deferral of unrecovered ECR expenses incurred prior to the expected implementation date of new rates. He did not oppose NIPSCO's calculation of the value of the deferred asset at approximately $19.0 million; however, he did oppose NIPSCO's proposal to amortize the expense over a two-year period. Instead, Mr. Gorman proposed to match the amortization period with the expected life of the rates set in this case, which reduced the annual amortization expense by approximately $4.75 million.

Mr. Gorman proposed removal of contingency costs from NIPSCO's demolition cost estimates for four of its generation stations. Mr. Gorman explained how the inclusion of contingency costs were inappropriate and inflated the demolition cost estimates which, in turn, increased the depreciation rates. Mr. Gorman, therefore, proposed adjusting the depreciation rates on certain accounts, which resulted in a reduction of $2.5 million in depreciation expense. Offsetting this decrease by an increase in operating income and income taxes, Mr. Gorman proposed a net reduction of approximately $2.3 million to NIPSCO's revenue requirement.

Mr. Gorman testified regarding NIPSCO's proposed rate of return and requested ROE. Mr. Gorman began his analysis with a review of general market conditions. He then presented evidence related to the authorized ROEs for electric and gas utilities, the ability of utilities to maintain credit ratings during periods of declining ROEs, and their ability to access external capital to support infrastructure investment under reasonable terms. Mr. Gorman also testified regarding the market's assessment of the investment risk of NIPSCO and its parent company, NiSource.

Mr. Gorman described NIPSCO's proposed capital structure, which reflected approximately 43%:57% debt to equity ratio. He stated this was unreasonable for purposes of setting rates for several reasons. He further testified that using a 50%:50% ratio would, without other adjustments, reduce NIPSCO's requested revenue requirement by approximately $23.4 million. Mr. Gorman noted that a similar reduction would be achieved by reducing the requested ROE from 10.8% to 9.90%.

Mr. Gorman then testified regarding his recommendation for NIPSCO's cost of common equity in light of the Hope and Bluefield standard. He explained the methods used to estimate NIPSCO's cost of common equity, including several variations on the DCF model, the Risk Premium Model, and the CAPM and the inputs he used in applying those models. Based on his analyses, Mr. Gorman recommended a range of 9.0% to 9.7% for NIPSCO's ROE, and he recommended return on common equity of 9.35%. Mr. Gorman testified the 9.35% ROE would support an investment-grade bond rating for NIPSCO.

Finally, Mr. Gorman testified regarding his disagreements with Mr. Rea's approach to calculating NIPSCO's ROE, including the use of a flotation cost adjustment, some of the methods used by Mr. Rea, and various inputs used in conducting his analyses.

B. Nicholas Phillips, Jr. Mr. Phillips agreed with NIPSCO's proposal to use a 4CP method for the allocation of generation investment and 12CP for the allocation of transmission investment in its filed COSS. Mr. Phillips testified that NIPSCO's proposed cost of service method is appropriate and produces fair and reasonable results. He said NIPSCO's COSS is consistent with the cost of service method presented by NIPSCO in its last base rate proceeding. He analyzed NIPSCO's historic monthly peaks in the summer period. He stated the 4CP method properly reflects NIPSCO's historic peaks as well as the forecasts used by NIPSCO for capacity planning. Mr. Phillips also testified that NIPSCO's proposed mitigation plan, which basically sets large industrial loads subject to global competition at cost and increases rates for all other classes on an "across-the-board" basis, maintaining the current subsidy received by residential customers, has merit, given the circumstances in this case.

Mr. Phillips described NIPSCO's plan to establish Rate 831 for its largest industrial customers as a well thought out solution for the retention of the global manufacturing operations of its largest customers and mitigates NIPSCO's risk of investing in significant amounts of capacity and energy associated with the replacement of its aging generating fleet. He stated that the proposed Rate 831 is a logical extension of the interruptible service option implemented and expanded by the Commission in NIPSCO's last two rate case orders. He added the Rate 831 approach will help retain the large industrial customers, including jobs and tax base, while shielding NIPSCO and its other customers of the obligation to provide firm service to a significant amount of load associated with the Rate 831 customers. He added that NIPSCO's COSS incorporates its proposed rate structure and correctly eliminates the loads for which it will no longer be required to provide generating service.

Mr. Phillips also testified that NIPSCO's proposal to combine the current low load factor Rate 732 and current high load factor Rate 733 into a new Rate 830 for smaller industrial customers results in apparent unintended increases for some customers. Consequently, he recommended the retention of both a low load factor rate and high load factor rate for those current customers receiving service on Rate 732 and Rate 733 that are not opting, or are not eligible, for Rate 831 service. He noted NIPSCO has offered a low load factor rate and a high load factor rate to its customers for decades and those offerings should not be discontinued. Mr. Phillips also recommended that NIPSCO implement a voltage adjusted fuel factor to more accurately reflect the cost to serve customers at varying voltage levels.

C. James R. Dauphinais. Mr. Dauphinais testified in support of the proposed Rate 831 rate structure. He supported NIPSCO's decision as a prudent judgment in light of the risk that large industrial load will continue to leave the NIPSCO system through self-generation, closures, or shifting production to other locations. He stated NIPSCO's largest customers use energy-intensive processes and are subject to intense competition, and Rate 831 would allow those customers greater ability to manage power costs and risks. He described Rate 831 as a logical evolution of existing options. He also stated that Rate 831 would be beneficial to other rate classes by addressing the risk of continued reductions in large industrial load, while better allowing NIPSCO to "right size" its generation resources and avoid excess capacity.

Mr. Dauphinais explained the structure of Rate 831 and the distinct features of Tiers 1, 2, and 3 as well as Rider 876. He proposed an amendment to tariff language to address a proposed MISO change, and a revision to the proposed definition of an industrial "Premise" in light of a then-pending dispute with a large customer.

13. NLMK Case-in-Chief.

A. James A. Lahtinen. Mr. Lahtinen testified in support of the proposed new industrial rate structure. Mr. Lahtinen explained that NIPSCO correctly discerned that basic changes in energy market place fundamentals including that sustainable supplies of domestically sourced natural gas have enhanced the attractiveness of self-supply alternatives for NIPSCO's largest industrial customers. Given NIPSCO's dependence on industrial customers and energy intensive, competitively at-risk manufacturing facilities for a very large component of its retail electric sales, NIPSCO was compelled to respond constructively to the potential loss of industrial load to on-site generation bypass or production relocation. Based on his previous experience with industrial load loss in Pennsylvania in the 1980s, Mr. Lahtinen commended NIPSCO for proactively developing constructive solutions to retain its largest industrial loads.

Mr. Lahtinen explained that under Rate 831, it was essential that the firm, Tier 1 rates be reasonable for the rate structure to be feasible. He emphasized that the proposed Tier 1 demand charges will be significantly higher than current rates, especially for customers served on current Rate 732, and that it was imperative that Rate 831 rates be designed to provide a rate of return that did not exceed the system average return. Mr. Lahtinen found that NIPSCO's proposed use of a 4CP allocation method for its production plant was reasonable and consistent with cost causation principles given the strong summer peaking nature of NIPSCO's system. Mr. Lahtinen acknowledged that there was substantial uncertainty regarding the amount of Rate 831 load that would be enrolled as firm, Tier 1 service for the first five-year contract term, and that a shortfall in Tier 1 enrollment could have material rate consequences for other customers. Mr. Lahtinen recommended that this uncertainty be resolved in part by increasing the required minimum level of Tier 1 service to the lesser of a customer's historic level of firm service or 30,000 kW.

Noting that under prevailing Rider 775, existing interruptible industrial loads that elect to "buy-through" economic interruptions are charged spot wholesale energy prices, Mr. Lahtinen concluded that the proposal in Rate 831 to expand that buy-through concept to all large industrial non-firm load, which would remain LMRs, was a reasonable approach. He further concluded that the mechanisms that NIPSCO proposed for Tiers 2 and 3 of Rate 831 non-firm service provided the tools reasonably necessary for Rate 831 customers to manage their energy price risk exposure.

Mr. Lahtinen concluded that NIPSCO's proposal to set the Rate 831 revenue requirement based on the cost of service while applying an across the board equal percentage increase to all other rate classes was a balanced and thoughtful approach for re-aligning industrial rates at cost while mitigating the rate impacts on other customers, particularly the residential class. If the Commission determined not to adopt the proposed industrial rate structure, Mr. Lahtinen maintained that the existing industrial rate structure and interruptible Rider 775 should be retained.

14. Peabody Case-in-Chief.

A. Michael J. Nasi. Mr. Nasi testified that NIPSCO's assumed regulatory timelines for compliance with the EPA's CCR Rule and the ELG Rule were too short because of available extension options and EPA's plans to reform both rules. He stated that NIPSCO's estimated capital expenditure and O&M costs were either not backed up by specifics or simply too high. This includes costs for compliance with the CCR Rule, ELG Rule, the CSAPR, and the MATS Rule. He also challenged NIPSCO's retirement decisions based on: (1) inclusion and accuracy of capital and O&M costs for continuing operations and compliance with environmental regulations to justify retirement decisions; and (2) NIPSCO's assumption that both ELG and CCR costs will be incurred regardless of whether the units continue to operate.

Regarding the ELG Rule, Mr. Nasi stated that NIPSCO overestimated the cost of compliance based on the current postponement of certain compliance dates and EPA's intent to revise the ELG Rule by December 2019. He further claimed there were "discrepancies" in NIPSCO's cost estimates and "uncertainties" in the status of the ELG Rule that suggest NIPSCO's request to be unreasonable and imprudent. He stated that there was an unexplained mismatch between certain ELG compliance costs and that NIPSCO should have advocated for broader ELG Rule changes because further ELG Rule changes could potentially be taken up by EPA.

Regarding the CCR Rule, Mr. Nasi testified that NIPSCO overestimated compliance costs, which are estimated to be $226 million, as provided in discovery by NIPSCO. After discussing the background and status of the CCR Rule, including a recent court decision, he opined that he did not agree that NIPSCO's estimated CCR costs within its IRP are reasonable and prudent. He also discussed the AROs and asserted this information was included in Mr. Carmichael's testimony to establish additional justification for NIPSCO's proposed retirement decisions.

As related to MATS Rule compliance, Mr. Nasi stated that it is inappropriate for NIPSCO to continue assuming it will incur long-term MATS O&M costs for its generating units because there is a significant likelihood that EPA will withdraw MATS entirely or drastically alter the rule thereby reducing the ongoing O&M cost burden. He testified that incorporation of "high O&M costs into [NIPSCO's 2018] IRP" is unreasonable because the EPA announced reconsideration of the MATS rule in August 2018 and proposed a revised supplemental cost finding in December.

Mr. Nasi also raised criticism of NIPSCO's proposed compliance path for CSAPR. His primary criticism was that NIPSCO failed to provide adequate justification for selecting SCR technology over the less costly, alternative selective non-catalytic reduction ("SNCR") technology. He stated that there is no reasonable set of assumptions that could justify NIPSCO's assumed SCR expenditure. He also took issue with the responses NIPSCO provided to Peabody Requests 1-010 and 1-011 (included as Attachment Nos. MJN-5 and MJN-6), wherein NIPSCO explained why it had assumed SCR technology for compliance with CSAPR.

15. <u>Sierra Club Case-in-Chief</u>.

A. <u>Avi Allison</u>. Mr. Allison's primary findings can be summarized as follows: (1) NIPSCO's proposal to increase the residential customer charge is based on a flawed theoretical construct that, if following to its logical conclusion, would ultimately result in a residential customer charger greater than $100 per month; (2) NIPSCO's residential customer charge proposal is inconsistent with sound ratemaking principles and would negatively impact energy conservation efforts and low-income customers and that a reasonable residential customer charge would be lower, not higher, than the current NIPSCO customer charge; (3) NIPSCO has failed to provide sufficient justification for its proposed new industrial service structure that would shift at least $40 million in annual costs from industrial customers to other customer classes; (4) the proposed industrial service structure change is not aligned with NIPSCO's IRP load assumptions; and (5) NIPSCO's proposal to depreciate its remaining coal plants through 2030 strikes a reasonable balance between aligning asset recovery with asset life and minimizing near-term rate shock.

Mr. Allison recommended: (1) the Commission should reject NIPSCO's proposed increase in the residential customer charge and instead lower the residential customer charge to no greater than $12.77 per month and reject the use of a "straight-fixed variable" ("SFV") rate design as a reasonable basis for determining an appropriate residential customer charge; (2) the Commission should reject the proposed allocation of costs under the new industrial service structure and that given the massive rate impacts on other customer classes, the Commission should not approve the proposal without concrete evidence of substantial, imminent defections by industrial load; (3) if the Commission approves of the general framework of the new service structure, it should still require that NIPSCO allocate a larger portion of its historical fixed costs to industrial customers, as those costs were incurred to serve industrial customers' historical load; (4) if the Commission approves the proposed industrial service structure change, it should require that all future NIPSCO IRP load forecasts account for any reductions in the reduced industrial demand associated with the new service structure; and (5) the Commission should approve NIPSCO's plan to recover the remaining depreciation expenses associated with Schahfer and Michigan City through 2030; however, this approval should not imply pre-approval of specific investments at those plants and should be contingent on NIPSCO following through with its planned coal plant retirement dates.

16. Walmart Case-in-Chief.

A. Steve W. Chriss. Mr. Chriss testified on cost of service issues, revenue allocation, and rate design, including NIPSCO's proposed Rate 831 structure. Specifically, Mr. Chriss advocated that rates be set based on the utility's cost of service for each rate class and that regulatory policies should be set that support the fair-cost-apportionment objective of rate-making, ensuring that rates reflect cost causation. As Mr. Chriss noted, this sends proper price signals to customers and minimizes price distortions.

Mr. Chriss discussed Walmart's concerns with discrepancies in NIPSCO's COSS that impacted the accuracy of assigning overall costs to the customer classes and establishing the cost-basis for the proposed rates, particularly for NIPSCO's Off-Peak Service class on Rate 726, when evaluated in comparison with NIPSCO's COSS filed in the last base rate case. These discrepancies indicated errors with the load characteristics and billing determinants for the Off-Peak Service class. Mr. Chriss explained these errors produced a misinformed revenue allocation in NIPSCO's COSS that understated revenues associated with the Off-Peak Service class and misrepresented the class's contribution to its cost to serve, as depicted by the Index Rate of Return. However, he stated these errors also impacted NIPSCO's representation of the system's overall "subsidy" position between the various classes. Mr. Chriss further noted that the errors contained in the COSS impact the proper rate design for the Off-Peak Service class by producing overstated prices, which would then lead to excess revenues being collected from the class. As such, Mr. Chriss recommended that the Commission reject NIPSCO's COSS because it would lead to rates that are not just and reasonable and would impact the Commission's assessment of the interests of all NIPSCO customers when reviewing the Rate 831 structure proposed for the industrial class.

Mr. Chriss provided his assessment of NIPSCO's proposed allocation of revenues. He stated that by designing Rate 831 at cost and then assigning an equal percentage increase to all other classes, rates were produced that moved all classes further from their actual cost to serve, which is counter to the goal of eliminating or establishing a targeted reduction of subsidies for all classes. As such, Mr. Chriss recommended that the Commission reject NIPSCO's proposed revenue allocation and instead allocate the authorized revenue in a manner that targets and reduces the subsidy burden for all subsidizing classes. Mr. Chriss noted that this could be done by ordering an increase to subsidizing classes that is lower than the system average increase coupled with an increase to subsidized classes that is above the system average without causing an unduly burdensome rate increase on any class.

Regarding the Rate 831 proposal, Mr. Chriss noted Walmart's concerns that the proposed alternative regulation for this limited class of industrial customers would result in: (1) an unjust shift in cost responsibility from NIPSCO's largest industrial customers to the remaining customers by assigning capacity obligations that are not related to non-Rate 831 customers' actual capacity requirements; (2) the establishment of customer access to the wholesale market, which fails to properly assign transition costs to the departing load; and (3) eligibility requirements that appear to be unduly discriminatory insofar as they exclude other large, sophisticated customers that might also benefit from market access rates. Mr. Chriss recommended that the Commission reject the Rate 831 proposal. However, if the Commission determines that the threat of reduced industrial load warrants immediate action, Mr. Chriss recommended that the Commission establish a solution that addresses the immediate concerns while also addressing the proposed burden on the remaining customers. Mr. Chriss cited to a California state law that requires customers who take service through third-party energy providers to pay a power charge indifference adjustment or an exit fee to ensure that remaining customers are not left with the responsibility to pay transition costs that should be the responsibility of the departing customers.

On July 17, 2019, as requested by the Commission in its July 16, 2019 Docket Entry, Mr. Chriss updated Exhibit SWC-3, an attachment to his prefiled direct testimony. As updated, Exhibit SWC-3 (REVISED) contains a listing and various averages of authorized ROEs in electric utility rate cases ranging from 2016 through July 10, 2019. In particular, the document indicates that the average ROE for vertically integrated electric utilities for the entire period is 9.73% and the average ROE for vertically integrated electric utilities solely for 2019 is also 9.73%.

17. US Steel Case-in-Chief.

A. Brown D. Thornton. Mr. Thornton testified on behalf of US Steel's support of the Rate 831 structure. He identified several aspects of the Rate 831 structure that need to be clarified or resolved prior to its implementation. First, Mr. Thornton recommended that Rate 831 have a phase-in period for customers between the final order in this Cause and May 31, 2020, to coincide with MISO's planning year. Second, he testified that Rate 831 customers should only be financially obligated to either NIPSCO or a third party for the same energy and capacity. Third, Mr. Thornton stated that the Rate 831 tariff should better define NIPSCO's role in the event a Rate 831 customer disputes any MISO charge. Fourth, Mr. Thornton recommended that between the final order and May 31, 2020, NIPSCO and the Rate 831 customers develop a model third-party agreement to govern when a Rate 831 customer remains a retail customer of NIPSCO while contracting for part of its power supply with a third party. Finally, Mr. Thornton recommended that the Rate 831 tariff allow capacity purchases outside of MISO Zone 6 so long as firm capacity is deliverable into Zone 6 to meet MISO's Module E requirements. Ultimately, Mr. Thornton recommended approval of Rate 831 because it provides long-term benefits to NIPSCO's customers by reducing risks for NIPSCO and its customers and ensuring that NIPSCO's largest customers continue to contribute to NIPSCO's fixed costs.

B. Tony M. Georgis. Mr. Georgis testified that US Steel operates three large steel manufacturing and finishing plants in NIPSCO's territory. US Steel is estimated to have a

$55.9 billion total impact on the Indiana economy and is one of NIPSCO's largest customers. Mr. Georgis explained that US Steel is very sensitive to NIPSCO's power prices due largely to international price competition for steel. He testified that in the absence of Rate 831, US Steel may explore other power supply options to significantly reduce US Steel's reliance on NIPSCO through self-built cogeneration that US Steel could certify to FERC as a QF. Mr. Georgis stated that if US Steel leaves the NIPSCO system entirely, the remaining NIPSCO customers would pay the fixed costs currently paid by US Steel, which he estimated at between $17 to $20 million annually, which include labor, depreciation, and other capital costs that do not vary with energy sales.

Mr. Georgis testified that Rate 831 is a natural evolution from NIPSCO's current interruptible service offerings. He recommended that the Commission approve Rate 831 and noted that it benefits other customer classes by simultaneously addressing the needs of NIPSCO's largest industrial customers while ensuring that NIPSCO's remaining customers will not be responsible for replacement generation costs to serve industrial load that is more volatile and able to leave the system with stranded cost. Mr. Georgis recommended adjustments to NIPSCO's over-allocation of transmission costs to the 831 rate class and recommended that NIPSCO subfunctionalize transmission rates for 831 customers to accurately reflect the service voltage levels at which 831 customers receive service. Mr. Georgis also recommended that NIPSCO clarify the firm demand rate calculation and true-up process to be used to ensure that the Rate 831 customers' Tier 1 firm capacity elections meet or exceed the 184,556 kW that NIPSCO proposed to allocate to Tier 1.

18. <u>Cross-Answering Testimony</u>.

A. <u>CAC</u>. Dr. Stanton recommended that the Commission not credit the critiques of NIPSCO's 2018 IRP advanced by ICC witness Medine, ICARE witness Griffey, and Peabody witness Nasi. She found that NIPSCO made significant improvements between its 2016 and 2018 IRPs by conducting an all-source RFP reviewed and improved upon by stakeholders, increasing transparency of modeling data and commodity price forecasts, removing arbitrary limits and unsupported cost additions on renewable resource choices, and addressing other criticisms of its 2016 IRP.

Dr. Stanton stated that although NIPSCO should have modeled a specific representation of Rate 831 industrial load reduction in the IRP as Ms. Medine stressed, the IRP results demonstrate that this modeling very likely would not have changed the order of preference of NIPSCO's portfolios. If anything, an industrial load reduction would have favored earlier retirement of all NIPSCO's coal units (Retirement Portfolio 8) even more strongly. Dr. Stanton explained that Ms. Medine failed to explain or quantify her implied suggestion that NIPSCO should take measures to improve forced outage rates and lower O&M costs at NIPSCO's coal plants or otherwise justify continued use of these coal units. Dr. Stanton also stated that Ms. Medine highlighted the alternative scenarios produced at ICC's request, which included several assumptions favoring delayed coal unit retirements. However, these alternative scenarios were still more expensive than Portfolio 6 and Portfolio 8 and therefore, support NIPSCO's decision to retire all of these units.

Dr. Stanton testified that Mr. Griffey's claims of a solar capital cost bias very likely would not have changed the rank of the eight portfolios by cost or changed the IRP modeling conclusion to retire all coal units. She stated that Mr. Griffey claimed that NIPSCO should have included projected degradation of wind generation into the model. This projected degradation would only affect wind resources owned by NIPSCO, not resources where NIPSCO has a PPA with the resource owner, who has the onus to maintain the facility. She explained that projected degradation is irrelevant in this case because NIPSCO has or will have a PPA for most of the wind resources currently owned by NIPSCO and offered in response to NIPSCO's RFP.

Dr. Stanton stated that Mr. Griffey argued that NIPSCO should have conducted retirement optimization modeling with NIPSCO's actual replacement portfolios. However, she explained that this very likely would not have changed the selection of Retirement Portfolio 6 as the preferred retirement portfolio. She also stated that Mr. Griffey incorrectly contrasted intermittent renewable generation with dispatchable resources in MISO. She then addressed Mr. Griffey claim that Indiana's wind effective load carrying capability ("ELCC") is lower than other states. NIPSCO's current wind generation does not originate in Indiana, and given the wind bids from multiple states responding to NIPSCO's 2018 RFP, NIPSCO's wind additions cannot be assumed to come entirely from Indiana. She explained that NIPSCO's use of the MISO average ELCC in its modeling, rather than the Indiana wind ELCC, was reasonable.

Finally, Dr. Stanton stated that Mr. Nasi provided no reason for NIPSCO to assume that the MATS rule would be delayed or discontinued.

B. ICC. Mr. Graeter responded to Sierra Club witness Allison's agreement with NIPSCO's underlying decision to accelerate the retirement of Michigan City and Schahfer due to the likely savings shown in NIPSCO's IRP retirement analysis because the calculation of savings Mr. Allison references does not take into account the cost of lost jobs that accelerated retirements could cause. Mr. Graeter performed a Job Impact Study of the Accelerated Retirements of NIPSCO's R.M. Schahfer and Michigan City Power Plants showing that the accelerated retirements will have serious negative impacts on the local communities, while NIPSCO's plan to replace these power plants will do little to soften these impacts.

C. ICARE. Mr. Griffey disagreed with Sierra Club witness Allison's conclusion that any potential loss of industrial firm load (due to the proposed industrial service structure or other causes) would likely render NIPSCO's coal units even less viable than they were found to be in the IRP retirement analysis because maintaining flexibility about when to retire the coal plants and deferring burdensome new PPAs or renewables ownership is likely to have great value. He also disagreed with Mr. Allison's agreement with NIPSCO that retiring Schahfer in 2023 and Michigan City in 2028 will likely save NIPSCO's customers more than $4 billion in NPV terms relative to continuing to operate the units because the savings are illusory as NIPSCO only made assumptions and ran the Aurora model for 20 years, yet made 30-year NPV calculations.

Mr. Griffey concluded that if his critique of wind resources is proven correct as to such items as unforced capacity ("UCAP") and congestion costs, it means that NIPSCO's failure to accurately model wind resources in its IRP renders the IRP results useless for decision making.

D. Industrial Group. Mr. Dauphinais disagreed with testimony suggesting that Rate 831 inappropriately shifted costs to other customers and with the proposal for transition charges or exit fees for Rate 831 customers. He stated that Rate 831 is a cost-based rate, and the costs incurred by NIPSCO to provide that service are less only because less system resources are being used. He indicated the proposed transition charges would force Rate 831 customers to cover costs for system resources no longer being used to provide them with service, while also leaving them with cost responsibility for market resources actually used to meet their power needs and the associated market risk.

Mr. Dauphinais disputed the computation of $40.2 million in shifted costs from Rate 831 customers to other customers. He stated that figure does not account for additional OSS margins that NIPSCO will earn and pass through to customers as a result of not serving Tiers 2 and 3 load at average fuel cost, which he calculated as $9.9 million annually. He identified further reductions in price volatility to other customers. He emphasized that, without Rate 831, NIPSCO is at great risk of losing large industrial load due to self-generation, shutdown of facilities, or reduced production. Consequently, lost revenue from those customers could greatly exceed the computation of shifted costs.

Mr. Dauphinais testified the proposed transition charges or exit fees were inappropriate. He stated such charges have not been imposed on customers exercising their right to self-generate or shut down facilities, and it would be misguided to apply such charges here to customers that use self-generation, may use self-generation, or reduce production but for Rate 831. Describing Rate 831 as an initiative to retain at-risk load, he stated the proposed transition charges would undermine that objective and exacerbate the risk. He cited a FERC regulation that permitted recovery of stranded costs only where there was "a reasonable expectation that the utility would continue to serve the customer," an essential predicate absent here. He stated Rate 831 is not retail wheeling, differs in multiple respects from an open access structure, and is supported by the provisions and legislative policy of the Alternative Utility Regulation Act ("ARP Statute"), Ind. Code ch. 8-1-2.5.

Mr. Dauphinais disagreed with the suggestion that NIPSCO's proposed transmission charge should be revised in connection with backing up the self-generation facilities of Rate 831 customers. He stated the transmission rate for back-up service as proposed by NIPSCO was consistent with cost-causation, traditional cost allocation, FERC and Commission rules, and NIPSCO's existing back-up rate. The suggested increase through added demand charges would erect barriers to highly efficient self-generation, contrary to Indiana and Federal policy. He noted NIPSCO allocated transmission costs based on monthly coincident peak demand, not energy, and therefore use of an energy charge will affect only collections from individual customers within the Rate 831 class, with no impact on other classes. He further stated that NIPSCO's allocation of transmission costs is consistent with MISO's current and expected future practices. He cited FERC and Commission rules providing that back-up rates should not be based on an assumption that outages for self-generation facilities on a utility's system will all occur simultaneously, or at system peak, or both, and the addition of demand charges would be inconsistent with those rules.

Mr. Dauphinais also took issue with a proposal that Rate 831 contracts should be exempt from NIPSCO's general rule terminating contracts in the event of a rate case, stating it would be unreasonable to bind a customer to a contract even if a rate case changes the terms and conditions of Rate 831. He further addressed a challenge to a provision in Rate 831 allowing for a reduction in firm demand for closure or partial closure of a customer facility, stating it would be unreasonable to require continued contractual service at the same level when the load being served has significantly changed. Finally, Mr. Dauphinais responded to alternative approaches suggested in the event that actual subscriptions for Tier 1 service end up falling significantly below the projections assumed by NIPSCO, stating the better alternative would be to establish a process to determine Tier 1 demand if and when any shortfall occurs.

Mr. Phillips testified that the concept of legacy costs and a transition charge is fraught with problems, constitutes unreasonable ratemaking, and should be rejected. He explained that the concept assumes industrial customers have not already paid a fair portion of the costs associated with the generation costs and have not saved other customers the avoided costs associated with new generation through self-supply or by accepting the risk of interruptible load.

Mr. Phillips testified that NIPSCO's current coal fleet was constructed between 33 and 45 years ago and that no customer is obligated to support costs for that duration. He said NIPSCO has not planned or constructed a baseload coal-fired generating facility in approximately 50 years and that NIPSCO has already closed two generating stations (Mitchell and Bailly) for various reasons, and NIPSCO plans on closing the remaining facilities in the near future. Mr. Phillips added that industrial customers have mitigated NIPSCO's need to add generation by taking interruptible service and investing in self-generation. He said the U.S. Department of Energy's list of combined heat and power installations in Indiana shows more than 1,300 MW of installed capacity at industrial plants in NIPSCO's territory. Mr. Phillips testified that all of NIPSCO's customers have benefitted historically due to the large industrials' acceptance of interruptible risk and private investment in self-generation, which resulted in less system resources NIPSCO had to build and maintain. He said it would be unbalanced and unreasonable to require those same customers to bear legacy costs. Mr. Phillips testified that customers of all classes are free to lower load, self-generate, or leave a service territory and said it is not appropriate to claim legacy costs from previous decades through a transition charge associated with load reduction.

In response to claims that the Rate 831 customers would be getting a subsidy, Mr. Phillips first noted that under NIPSCO's COSS, production costs are allocated to the Rate 831 customers based on the amount of capacity NIPSCO estimated they would use, which is cost-based ratemaking, not a subsidy. He also provided a history of the subsidies industrial customers have provided to other customer classes since NIPSCO's 1981 rate case. He calculated the subsidies the industrial customers have provided to other customer classes totaled $2.85 billion over the 20-year period from 1987 to NIPSCO's 2008 rate case. Conservatively, Mr. Phillips noted if the calculated subsidies were cut in half, $1.4 billion would still greatly exceed the alleged legacy costs. Consequently, due to the subsidies, large industrials have been paying revenue far in excess of their cost-based share and that excess revenue is much greater than the alleged legacy costs that the other witnesses propose to impose as a transition charge on Rate 831 customers.

Mr. Phillips also took issue with NIPSCO's response to CAC's DR 5-1, upon which Mr. Wallach relied. Mr. Phillips stated that the response inappropriately allocated fixed generation costs to interruptible load. He provided a correction that removed interruptible load from the four highest peaks to recalculate a normalized 4CP allocator. He stated the 2017 load data associated with interruptions used in the response is not normalized or indicative of the 2019 test year.

Mr. Phillips also responded to Mr. Watkins' comparison of the 4CP allocation percentages used in NIPSCO's last rate case to the allocation percentages used in this case. According to Mr. Phillips, there are two significant problems with the comparison. First, the loads in the current case are reduced because of the lost BP load. Second, the loads used in the last rate case included interruptible load, whereas the current case only uses firm load for allocating production costs.

Mr. Phillips also addressed Mr. Watkins' alternative cost allocation methods, noting that to his knowledge, the Commission has never approved an allocation method that classifies and allocates production investment costs on an energy basis. Mr. Phillips described the problems with the various methodologies that Mr. Watkins discussed and noted that not only is the 12CP method not reflective of the cost causation on NIPSCO's system, but that many of the 12 monthly peaks contain buy-through loads by customers on Rider 775. He explained those buy-through loads should not be used to allocate production costs because NIPSCO does not plan for or build generation for interruptible load, and the interruptible customers have obtained the power from the market. He then recommend use of the 4CP method because it is most reflective of cost causation.

E. NLMK. Mr. Lahtinen reiterated that the 4CP allocation method proposed by NIPSCO was reasonable and appropriate considering the NIPSCO system load profile, and that the more energy-oriented alternative methods described by OUCC witness Watkins would undercut the basic purpose of the proposed industrial rate restructuring by unnecessarily shifting costs to large industrial loads. Mr. Lahtinen urged the Commission not to adopt such a counter-productive approach. Similarly, he urged the Commission to reject the "transition cost" proposals advanced by the OUCC and CAC. He observed that industrial rates have historically subsidized the rates of smaller consumers, and that setting Rate 831 to recover the system average return (i.e., to set the rate at "parity") is an essential element to combatting uneconomic industrial customer bypass. Mr. Lahtinen explained that, by proposing the imposition of a Rate 831 transition fee, those parties were espousing an extension of the inter-class subsidies that would produce rates for large industrial customers that might accelerate rather than deter bypass actions.

Mr. Lahtinen explained why the US Steel proposal to create voltage differentiated transmission charges within Rate 831 was problematic, insufficiently supported, and should not be adopted. He also explained that the provisions of the Rate 831 tariff that would extinguish Rate 831 contracts under certain circumstances were reasonable and necessary, and the concerns expressed by the OUCC in that regard were unwarranted.

F. Sierra Club. Mr. Allison responded to ICC witness Medine, ICARE witness Griffey, and Peabody witness Nasi, who argued that NIPSCO should not move forward with its plans to retire its coal units. Mr. Allison showed that the arguments of these witnesses are rooted in a series of inaccurate assumptions, mischaracterizations, and misleading statements.

He stated that NIPSCO's remaining coal units have been uneconomic (i.e., more expensive than available alternatives) for many years now. Contrary to the implication of the coal industry witnesses, these are not currently well performing units that will only become uneconomic if faced with substantial environmental compliance obligations. Rather, are units are already and continue to be a consistent economic burden for NIPSCO's ratepayers. He estimated that each remaining NIPSCO coal unit lost more than $100 million relative to the market from 2014 through 2018.

Mr. Allison explained that NIPSCO's coal units are likely to remain uneconomic irrespective of any environmental capital expenditures. Even if these units do not need to incur any expenses to comply with CCR regulations, ELG, or other federal environmental regulations, near-term retirement would still be in the best interest of NIPSCO's customers because NIPSCO's coal units are already more costly than available alternatives. NIPSCO data indicates that, even in the absence of any environmental capital expenditures, continuing to operate its coal units would result in billions of dollars in NPV losses relative to alternative resources.

Mr. Allison stated Mr. Griffey's claim that NIPSCO's IRP analysis supports the continued operation of Michigan City Unit 12 is false and is rooted in a plainly misleading comparison. He explained that NIPSCO's analysis clearly indicates that retiring Michigan City in the near term would save ratepayers hundreds of millions of dollars. He also stated that Mr. Griffey's claim that it is not in the interest of ratepayers to retire Schahfer Units 14 and 15 in the near term is refuted by his own analysis. Mr. Griffey's analysis indicates that, even under a host of assumptions that are favorable to NIPSCO's coal units, retiring Schahfer Units 14 and 15 in 2023 rather than 2028 would save ratepayers more than $200 million. Mr. Allison testified that Mr. Griffey misstated the potential retirement dates considered by NIPSCO. He explained that the actual retirement dates evaluated by NIPSCO consistently show that retiring NIPSCO's coal units as early as possible is always the lower-cost choice, even in the absence of environmental expenditures.

Mr. Allison stated that Ms. Medine's suggestion that it was unreasonable for NIPSCO to include a carbon price in its base scenario is unpersuasive and is inconsistent with the practices of other Indiana utilities. He also stated that Ms. Medine's suggestion that keeping NIPSCO's coal units online longer will minimize rate shock is unsupported.

Mr. Allison testified that Mr. Nasi's claims that NIPSCO's retirement decisions improperly rely on CCR-related costs that will be incurred regardless of future retirement decisions are unsupported and baseless. He explained that uncertainty does not constitute a valid reason to delay a decision to retire the NIPSCO coal units. While uncertainty is inevitable in any major resource planning decision, the available evidence strongly supports the near-term retirement of NIPSCO's coal units. He added that NIPSCO's proposed industrial service structure change does not justify delaying coal unit retirement decisions.

Mr. Allison testified that fundamentally, the available evidence clearly indicates that NIPSCO's coal units are currently uneconomic and are very likely to remain that way. He concluded that NIPSCO should retire its remaining coal units as soon as is practicable and recommended that the Commission approve reasonable ratemaking treatment that will enable these retirements and their attendant ratepayer benefits.

G. US Steel. Mr. Georgis refuted claims that Rate 831 creates a cost shift to non-Rate 831 customer classes, explaining that presently a subsidy is built into the existing rate structure whereby Rate 831 customers pay disproportionately to the benefit of the remaining customer classes. Mr. Georgis explained that if Rate 831 customers were required to pay an annual $40.2 million transition charge as recommended by other parties, Rate 831 customers would be paying for infrastructure and services they do not use or receive any benefit. Mr. Georgis testified that a $40.2 million subsidization is not cost based, does not follow cost of service principles, and is inconsistent with NIPSCO's treatment of similar customers who reduce demand or generate all or a portion of their power. Mr. Georgis also refuted the OUCC's recommended transmission charge adjustment, noting that the Rate 831 customers should not be forced to purchase back-up and maintenance transmission service embedded in the Rate 831 transmission charges if the customer accepts the risks and consequences associated with their self-generation, especially since customers desiring back-up and maintenance service can obtain it through Rider 876.

Mr. Georgis agreed with NIPSCO's 4CP allocation of production costs since the system is consistently a summer peaking system, which drives NIPSCO's production capacity investments. He reiterated that US Steel continues to actively evaluate additional cogeneration potential and although it withdrew its IDEM permit application pending the outcome of this proceeding, it has not foreclosed building cogeneration in the future. Mr. Georgis disagreed with Dr. Boerger's recommendation for a full adjudicated process for Phase 2 of the proceeding since the Phase 2 issues are limited in scope. Finally, Mr. Georgis recommended that the Rate 831 customers should decide amongst themselves how the $53.9 million of Tier 1 firm contract demand costs should be recovered, which eliminates the unintended consequence that penalizes one or more customers.

19. <u>NIPSCO Rebuttal Evidence</u>.

A. <u>Mr. Hooper</u>. Mr. Hooper addressed the other parties' testimony related to Rate 831, the OUCC's proposed credit mechanism to address return on and of unrecovered balances upon the retirement of Schahfer and Michigan City generating units, CAC's proposal for a comprehensive low-income program and various monthly reporting requirements, and IMUG's proposal to implement an MSP. He testified that NIPSCO believes a migration of load to either self-generation or other jurisdictions for much of its largest industrial load is imminent without a modification to a more competitive service structure as evidenced by discussions with and filings made by those customers supporting the intent to add or increase self-generation. He stated that a combination of these customer's scale, generation experience, and energy market sophistication make them uniquely positioned to take advantage of a proposal such as Rate 831. Likewise, those same traits are sufficient to motivate these customers to either shift operations or invest in additional generation assets when faced with inferior economics from NIPSCO's fleet.

Mr. Hooper disagreed with Mr. Blakley's proposed mechanism in which ratepayers are credited with the effect of annual depreciation expense associated with these extraordinary retirements beginning when new rates go into effect and prior to the units actual retirement dates. He stated that the OUCC and other parties consistently make the mistake of calling NIPSCO's extended recovery period for its retiring coal units as "accelerated" deprecation – which is not true. He noted that were NIPSCO to recover its remaining investments over the remaining useful life of these units, NIPSCO's depreciation rates would be much higher, resulting in a much higher revenue requirement. Instead, NIPSCO is proposing to extend its recovery period to ten years to reduce the rate impact. He also disagreed with OUCC suggestion that its "tracker mechanism" be put in place prior to the retirement date of the Schahfer units. He explained that if a capital tracker was approved, it should not be utilized solely for a one line item, but should allow for the recovery of all additional capital deployed during the recovery period.

In response to CAC's proposal for a comprehensive low-income program, Mr. Hooper testified that NIPSCO wants to implement a proposal that is easily and economically administered that can provide assistance to the most in need. He stated NIPSCO recognizes the demographics of its service territory and recognizes that while it offers a low-income program to its LIHEAP-qualified customers that heat with gas, it offers no additional programs for its LIHEAP electric heating customers. He stated NIPSCO is continuing a stakeholder collaborative to reach agreement regarding additional assistance that can be offered to NIPSCO's low-income customers.

Mr. Hooper disagreed with CAC's recommendation for various monthly reporting requirements. He stated that NIPSCO already participates in an annual Performance Metric Collaborative where it reports on and discusses a host of key performance indicators. He indicated that in the Performance Metric Collaborative report filed by July 1 each year in Cause No. 44688, NIPSCO already provides monthly data for some of the items recommended by Mr. Howat and that additional items recommended by Mr. Howat could possibly be incorporated into the annual report without the added administrative burden that would be required if a separate monthly reporting process were implemented here.

Mr. Hooper agreed that IMUG's proposal to implement an MSP is worth further investigation. He stated, however, this is a program that would need substantial discussion amongst NIPSCO and interested parties. He explained that NIPSCO is willing to work collaboratively with IMUG to discuss the MSP and determine if such a program may fit into its existing generation portfolio. He stated that while he agrees with Mr. Sommer that an MSP could prove beneficial to many stakeholders, it is simply an idea that needs further vetting to ensure the appropriate parties are engaged and all aspects are thoroughly understood.

B. Mr. Kelly. Mr. Kelly stated that while Rate 830 is designed to provide service for NIPSCO's next largest group of industrial customers after Rate 831, the proposed rate is structured for a higher load factor profile. For the lower load factor customers within the rate design, it is likely that their increases would be higher than if the original designs of Rate 732 and 733 had been preserved. Mr. Kelly agreed with Mr. Phillips' recommendation that Rate 830 should be redesigned into two rates similar to the existing Rates 732 and 733. He testified NIPSCO is offering proposed Rates 832 and 833, which are designed as low load factor and high load factor rates similar to Rates 732 and 733. He explained that like the original Rate 830 proposed design, these proposed rates also include provisions for Back-Up, Maintenance, and Temporary Service.

Mr. Kelly testified Rate 831 retains retail service and is therefore not a retail wheeling or retail open access proposal and should not be rejected as incongruent with Indiana law or for failing to meet the requirement that NIPSCO provide retail utility service to its customers, as suggested by Ms. Medine. He stated Rate 831 preserves the bundled retail electric service these customers are served under today's Rates 732, 733, and 734 as well as the ability to purchase power at the MISO LMP during Rider 775 economic interruptions. He explained that Rate 831 only adds two additional features to NIPSCO's existing large industrial service structure: (1) the ability to firm up the customer's LMR obligation registered at MISO through the MISO capacity auction or a third party; and (2) the ability to bid a portion of the customer's load in the MISO portal (granted by NIPSCO) or purchase that portion of its energy from a third-party supplier. To accomplish these new options, NIPSCO still needs to facilitate the transactions as the MISO Market Participant whether by making the necessary registrations or by entering multiparty agreements for the benefit of the customer for capacity or energy. Mr. Kelly said that in retail open access markets, NIPSCO would not be involved at that level in those types of transactions but instead, NIPSCO would simply be wheeling the power and much of the activity would occur between the customer and third parties under MISO's tariff rather than with NIPSCO's involvement under NIPSCO's retail tariff. Said differently, NIPSCO is, by design, too involved in facilitating Tiers 2 and 3 (in addition to the basic bundled firm service of Tier 1) to consider Rate 831 as retail wheeling or retail open access. Finally, he stated that if this was akin to deregulated retail wheeling, NIPSCO would remain the provider of last resort, which is not the case with Rate 831. He explained that Rate 831 requires a five-year notice for a customer to increase its Tier 1 firm contract amount, which protects NIPSCO's other customers from industrial customers "swinging" on its system.

Mr. Kelly testified Rate 831 is designed at parity in the ACOSS and is therefore not being proposed as a discounted service. Further, the identified cost shift to other customer classes for the reduced firm requirements of Rate 831 customers is just and reasonable because Rate 831 is not being subsidized by other classes since the rate is designed at parity. Finally, because the rate is fully costed, no "exit fee" should be assessed against the class to pay for "legacy costs" of the system as suggested by Dr. Boerger and Mr. Wallach. He explained that while the anticipated 184.556 MW of firm demand in Tier 1 (for the "original" five customers measured at the customers' meters) is lower than the amount of firm demand for which these customers have contracted with NIPSCO historically, the rate proposed for that 184.556 MW is at full cost without a discount. He said that still holds true now that an additional customer has been added to the proposed design after expressing interest in joining the rate rather than the originally proposed Rate 830. Mr. Kelly testified the transmission service is also not discounted under Rate 831. He stated that Rate 831 includes a fully costed charge for typical retail transmission service. He explained that for customers that have generating facilities (i.e., QFs) adjacent to their industrial premise, Rate 831 allows any outflows from the generator to be utilized at the industrial premise at a discounted charge for using NIPSCO's transmission system, but all other usage of NIPSCO's transmission system by those same qualifying customers and other Rate 831 customers will be charged at the fully costed transmission rate. Further, the discounted charge is only anticipated to apply to two of the six customers that would take retail service under the rate.

In response to the various challenges to Rate 831 proposing that Rate 831 should only be approved if something akin to an "exit fee" is charged to the participating customers, he understood the rationale offered in many of the arguments that NIPSCO's generation fleet was built to serve all customers including these Rate 831 customers. He stated, however, that these arguments are misplaced for three reasons. First, the idea of an exit fee borrows from policies in other states that have deregulated the generation function from traditional vertically integrated structures. He explained that in those states, the benefit of the bargain was that customers could enjoy the risks and opportunities of retail open access in exchange for buying their way out of the stranded costs of the utility that they would be leaving behind. He explained that the scenario NIPSCO and its other customers are facing is very different because here, large, globally competitive industrial customers with the financial and operational capability of building and operating their own internal generation are pursuing additional cogeneration solutions to avoid NIPSCO's vertically integrated cost to serve. When other states were deregulating, those customers seeking retail open access were not constructing their own cogeneration but were instead seeking access to other third-party generation capacity that already existed in the marketplace. Second, an exit fee would further exacerbate the situation that led NIPSCO to propose Rate 831 in the first place – NIPSCO's cost to serve exceeds these customers' cost to construct and own additional cogeneration facilities or otherwise significantly reduce their loads. Mr. Kelly testified that NIPSCO's proposed Rate 831 structure is a balanced proposal that seeks to preserve some fixed cost contribution from these largest industrial customers into the future. However, to the extent that these customers are faced with an exit fee that would completely offset (or worse) any savings they might achieve in the

MISO markets under Tiers 2 and 3, NIPSCO fully expects that they will continue to rationalize their internal loads with self-funded incremental generation capacity and other measures. He indicated that in that circumstance, the effort to charge a $40 million exit fee is going to lead to stranding the fixed costs associated with the 184.556 MW of firm service these customers would have otherwise paid under the Rate 831 proposal resulting in shifting even more costs to those classes in the long run as NIPSCO's largest industrial customers leave the system. Third, the industrial customers have already abandoned fully firm service from NIPSCO's generation resources years ago. Mr. Kelly noted that in the 1980s, the Commission recognized that it was appropriate for these industrial customers to receive something less than firm service from NIPSCO in exchange for a reduced rate. Because of that interruptible level of service, they have not been responsible for much of the need for additional generation for more than two decades. Mr. Kelly stated that for these reasons, proposals for an exit fee on Rate 831 should be rejected. He testified that if Rate 831 were approved but included a cost of service allocation that increased the fixed cost allocation (i.e., an exit fee), NIPSCO would need to withdraw its ARP proposal rather than implement the rate, and NIPSCO would propose a 90-day procedural schedule to address any rate structure alternatives for its large industrial customers currently served under Rates 732, 733, and 734 and the effects of those alternatives on the other issues in this case.

Mr. Kelly disagreed with Mr. Lahtinen's proposal for addressing the Phase 2 True Up by requiring a minimum of 30,000 kW of Tier 1 service under Rate 831 except in circumstances when a customer's historical firm amount was less than 30,000 kW. Instead, NIPSCO proposed that if the five largest industrial customers are unable or unwilling to subscribe to the 184,556 kW in total under the proposed design, a 90-day procedural schedule be established to address the proper allocation of the 184,556 kW among the five largest customers or any rate structure alternatives that parties may offer for its large industrial customers currently served under Rates 732, 733, and 734. He indicated that to the extent other classes outside of Rate 831 are affected, NIPSCO's pro forma revenue requirement and ACOSS may also need to be revisited.

Mr. Kelly testified that NIPSCO only had four other qualifying customers under Rates 732 and 733 and had assumed that none of those customers would take service under Rate 831 because their firm load was not significantly higher than ten MW. However, now one of the four remaining qualifying customers intends to take service under Rate 831. He explained that NIPSCO's testimony was written to isolate the Phase 2 True Up to specifically manage the uncertainty of the subscription for NIPSCO's five largest customers. He said that in order to avoid an insurmountable level of cost shift to other classes, the industrial service structure was proposed at that 184,556 kW of Tier 1 service for those five largest customers. Mr. Kelly testified that although another customer has expressed intent to participate in Rate 831, the incremental impact between its participation in Rate 831 versus the prior Rate 830 is minimal in the final proposed design of Rate 831 because most of the load that would be available to participate in the non-firm Tiers 2 or 3 is minimal and is partially served on NIPSCO's interruptible (and curtailable) Rider 775 today. He testified that based on the revised Phase 2 True Up proposed here, this sixth customer is likely to sign up for the minimum 10,000 kW of Tier 1 firm service which would be very close to the customer's historical level of firm service.

Mr. Kelly agreed with US Steel witness Thornton that additional information regarding the contractual requirements of Rate 831 would be helpful to customers and third parties seeking the ability to transact under Rate 831. He noted that Mr. Westerhausen is sponsoring a contract that can be used between NIPSCO and Rate 831 customers, and Mr. Campbell is providing additional detail on the required terms of the multiple-party contract among NIPSCO, its Rate 831 customer, and a third-party capacity or energy supplier. Mr. Kelly disagreed with Mr. Thornton's assessment that additional time will be needed for customers to implement Rate 831 assuming an order is received by the end of August 2019. He stated that NIPSCO is proposing that any qualifying customer that is unable to take service under Rate 831 be placed on either proposed Rate 832 or 833 as a temporary "sub"-rate within Rate 831 with the requirement that the customer also maintain any historical curtailable service (MISO LMR registration) under prior Rider 775 through the end of the current MISO 2019/2020 Planning Year. He explained that NIPSCO is not proposing that Rider 775 or its monthly bill credit would continue as a service structure once the 800 series rates go into effect, but any customer unable to take service under Rate 831's Tiers 1, 2, and/or 3 that also had a Rider 775 LMR registration be required to maintain it through the current 2019/2020 MISO Planning Year. He said that while the customers will be required to subscribe to their portion of Tier 1 service in the Phase 2 True Up once the rate takes effect, this approach will provide the necessary bridge for any customer that is not able take service immediately under Tiers 1, 2, and or 3 of Rate 831. Mr. Kelly testified NIPSCO has identified a process for assisting customers in addressing their MISO LMR exposure when activating their Rate 831 service. He explained that after discussions with customers, NIPSCO is proposing that customers be able to purchase any MISO Zone 6 ZRCs associated with the customer's existing firm load that is transferring to Rate 831 above their Tier 1 firm election. Further, to assist customers with procuring additional ZRCs from third-party suppliers during the 2019/2020 planning year, NIPSCO is also offering to conduct a RFP in the coming months for the benefit of its Rate 831 customers, allowing them as many tools as possible in firming up their LMR obligations should they so desire when activating their Rate 831 service. NIPSCO believes this approach will address the concerns raised by Mr. Thornton.

Mr. Kelly agreed with Mr. Thornton that additional information would help clarify how proposed Rate 831 will be implemented. He stated that after discussions with customers expected to take service under proposed Rate 831, NIPSCO is proposing that the five-year contract requirement be adjusted so that it can synchronize with the completion of the last MISO capacity planning year that would be in effect. He indicated that failing to align the contract terms with the closure of the planning year could result in a scenario where a customer's firm and non-firm capacity requirements are changing intra-year without the ability to address that change easily and seamlessly through the annual auction process. Therefore, NIPSCO is proposing that the contract would expire the later of five years from the contract's signing date or the completion date of the last MISO Planning Year in effect during the five years that the contract would otherwise cover.

Mr. Kelly testified that to clarify confusion with curtailment of LMRs under Rate 831 and interaction with Rider 876, LMRs under Rate 831 Tiers 2 and 3 will be registered along with a firm service level including both Tier 1 and any additional capacity procured for Tiers 2 and 3. This firm service level will set a clear floor that customers curtail to in the event MISO exercises the curtailment of the entire LMR capacity registered. He explained that like today under Rider 776, additional services granted under Rider 876 for back-up and maintenance service will not alter this firm service level. As such, NIPSCO proposed language to clarify that service under Rider 876 cannot be used to nullify some or all of a MISO LMR obligation to curtail. Mr. Kelly noted that in instances where MISO does not ask for the entire LMR capacity, customers will only need to drop the requested relief sought by MISO. He clarified that in instances where a customer can be entirely firm under Rate 831 and is taking service under Rider 876, during times of curtailment, Rider 876 is subject to curtailment when curtailments under Rate 831 are insufficient.

Mr. Kelly testified that if the Commission does not approve the proposed industrial service structure or makes material modifications to which NIPSCO does not agree, NIPSCO is proposing that a 90-day procedural schedule be established to address any alternatives that parties may offer for its large industrial customers currently served under Rates 732, 733, and 734 and the effects of those alternatives on this case's other issues. He explained that Rate 831 directly affects the revenue requirement, specifically the fuel and related expenses. Accordingly, if NIPSCO doesn't have a final determination on the rate structure for these large industrial customers, then NIPSCO doesn't have a final revenue requirement or ACOSS and cannot implement new rates for any customer class.

C. Ms. Shikany. Ms. Shikany addressed various revenue requirement issues and pro forma adjustments raised by the parties, discussed normal retirement accounting, provided actual utility plant in service, associated depreciation, and capital structure at December 31, 2018 (removing two TDSIC projects from the Seven-Year Electric TDSIC Plan Regulatory Asset included in rate base in RB 11-R and AMTZ 5-R), provided updated projections for utility plant in service, associated depreciation, and capital structure at June 30, 2019, and December 31, 2019 (based on actual amounts recorded through December 31, 2018, with the addition of forecasted 2019 activity obtained from or based upon assumptions in NIPSCO's 2018 AFP, and updated Electric Rate Case Amortization Expense based on the most current rate case expense estimates), and presented revised schedules supporting NIPSCO's revenue requirements reflecting its rebuttal positions, including: (1) Operating Revenues / Fuel & Purchased Power to (a) eliminate an inconsistency between Mr. Chriss' analysis of load profile and that utilized in NIPSCO's COSS and (b) to reflect an additional migration for one large industrial customer from current Rate 730 to Rate 831; (2) Rate Base, Depreciation Expense, and Amortization Expense to reflect rate base amounts concurrent with current projections of utility plant in service at both June 30, 2019, and December 31, 2019, updating the accumulated depreciation, depreciation expense, and amortization expense associated with these amounts, and updating electric rate case amortization expense based on the most current rate case expense estimates; and (3) WACC to reflect capital structures concurrent with current projections at both June 30, 2019, and December 31, 2019.

Ms. Shikany disagreed with Mr. Eckert's proposal that Uncollectible Expense be based on a two-year average because he removed 2015 in NIPSCO's proposed three-year (2015-2017) average because he believes 2015 was significantly higher than 2016 and 2017. She explained the write off as a percentage of revenues was 0.59% in 2015, 0.31% in 2016, and 0.35% in 2017 and noted that write-offs as a percentage of revenues ranges from 0.31% to 1.08% during the last ten years (2008-2017) with two years in which write-offs as a percentage of revenues exceeded that in 2015. She testified the OUCC's calculation is not reasonable because it produces the lowest level of write-offs as a percentage of revenues in each of the ten scenarios.

Ms. Shikany disagreed with Mr. Eckert's proposed reduction to Vegetation Management Expense based on a five-year historical average budget growth rate. She explained that NIPSCO's proposed rates are based on a forward-looking test year (January 1, 2019 – December 31, 2019) and that NIPSCO's 2018 AFP is the underlying basis for its rate request, which is consistent with Ind. Code § 8-1-2-42.7. She testified that unlike Mr. Eckert's calculation based on rolling forward the 2018 budget amount by the average five-year (2014 – 2018) historical growth in budget, the amount that NIPSCO included is projected data for the forward-looking test year, which is consistent with NIPSCO's budget methodology and based on price times a quantity calculation.

Ms. Shikany disagreed with Mr. Eckert's proposed decrease in depreciation expense because NIPSCO was unable to validate the mathematical accuracy of his proposed adjustment. She testified that NIPSCO's proposed level of depreciation expense was calculated by multiplying NIPSCO's forecasted original cost of utility plant in service by the proposed depreciation accrual rates. She noted that Mr. Eckert did not oppose NIPSCO's proposed rate base but that when NIPSCO multiplied its projected original cost rate base by the OUCC's proposed depreciation accrual rates, it could not reproduce the OUCC's calculation.

Ms. Shikany disagreed with Mr. Lahtinen's characterization of early accelerated recovery. She testified that NIPSCO has not proposed to "accelerate" depreciation but instead conducted a depreciation study and presented depreciation rates that match the expected life of the units – that is not "acceleration" but simply the proper function of depreciation. She described that NIPSCO has offered to defer the recovery over a longer period of time than the units' estimated useful lives. She explained that depreciation studies are prospective and any future accruals of the depreciable property should be amortized over the remaining service life of the property. She stated that when NIPSCO made capital investments that increased the average service lives of certain electric plant accounts, thereby extending the return of its capital investments, no parties objected.

In response to Mr. Gorman's proposal that ECRM Tracker Deferred Expenses be amortized over four years instead of two years as proposed by NIPSCO, and his concern that if NIPSCO amortizes over a two-year period but the base rates remain in effect for four years, then NIPSCO will recover more than double the estimated ECRM deferred costs, Ms. Shikany explained that NIPSCO proposed to amortize these amounts over a two-year period, which is the approximate length of time it would take to recover these costs through the currently approved ECRM Tracker. She stated that consistent with past practice and as recommended by Mr. Eckert in this proceeding, NIPSCO would make a compliance filing to reduce base rates when the amortization of each regulatory asset is complete, which eliminates this risk.

Ms. Shikany disagreed with Mr. Blakley's proposed decrease in income tax expense due to a five-year amortization period for unprotected excess ADIT. She indicated that if Mr. Blakley's proposal is accepted, NIPSCO should be authorized to make a compliance filing at the end of the amortization period to increase its rates accordingly. In response to Mr. Eckert's proposal for a different adjustment to synchronized interest expense, she explained that synchronized interest expense is calculated by multiplying rate base by the cost of long-term debt. As noted by OUCC witness Eckert, the OUCC did not oppose NIPSCO's proposed rate base or cost of debt. She stated that the difference in NIPSCO's and the OUCC's calculation appears to be due to rounding.

Ms. Shikany explained NIPSCO's basis of accounting required by the Commission, including the level of detail the Uniform System of Accounts requires of NIPSCO to maintain its plant records, guidance on the level of detail required when recording additions and retirements, and guidance on how to account for retirements. She testified that in accordance with Uniform System of Accounts guidance, NIPSCO credited Utility Plant in Service and debited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant in amounts equal to the original cost of the asset, which results in no change in the net book value of rate base. She stated that this resulted in a debit balance in accumulated depreciation of $102,923,994 and $142,329,364, for Unit 7 and 8 respectively, which represents the estimated remaining net book value at the date of the physical retirement. Ms. Shikany noted that the Uniform System of Accounts does not offer any alternatives to this methodology. She stated that the Uniform System of Accounts provides further instructions on Depreciation Accounting and that NIPSCO utilized the composite method referenced in those instructions. She testified that consistent with past requests and Commission rulings, NIPSCO is seeking approval of depreciation rates on a FERC account-by-account basis, not by a FERC account-by-account-by-generating station basis.

Ms. Shikany stated that an extraordinary retirement occurs only if the Commission, by order, directs that upon retirement the remaining net book value be recorded as a regulatory asset. She explained that NIPSCO is seeking Commission approval to treat the retirements of Schahfer and Michigan City generating stations as extraordinary and that NIPSCO is seeking approval well in advance of these retirements to: (1) establish a regulatory asset in an amount equal to the remaining future accruals at the date of retirement; (2) defer regulatory recovery of these amounts through 2030; and (3) include this regulatory asset in NIPSCO's calculation of rate base in subsequent base rate proceedings.

D. Mr. Scott. Mr. Scott responded to opposition to the pro forma labor and benefits that NIPSCO presented in its case-in-chief by Mr. Eckert and Mr. Gorman. He noted that in the event that vacancies are not filled, or these vacancies are filled, but other vacancies arise, there will not necessarily be a corresponding decrease in labor cost because the work must still be done and is often filled by overtime or outside contractors.

In response to the proposed adjustment to benefits expense, Mr. Scott testified that NIPSCO's budget in actuality understates the total benefits expense. He stated that in theory, NIPSCO should have built the budget based upon a benefits-per-employee calculation, but instead, it is based upon the actual headcount as reported in the actuarial reports. As such, adjusting labor benefits for vacancies has already been factored into the budget numbers.

E. Mr. Augustine. Mr. Augustine addressed the perceived issues with NIPSCO's 2018 IRP raised by Mr. Griffey, Ms. Medine, and Mr. Nasi. In response to Ms. Medine's claim that the IRP has not been approved and thus cannot be used to support elements associated with this rate case, he stated that the IRP is a planning document and is not subject to a ruling or formal approval by the Commission. He testified that as part of its transparent IRP process, NIPSCO conducted six public advisory meetings over the course of 2018, along with many other individual meetings with stakeholders to provide information and receive feedback on the methodologies and assumptions used in the IRP. He noted that as part of this process, NIPSCO performed several stakeholder-requested analyses prior to submission of the IRP, including some requested by Ms. Medine and the ICC.

Mr. Augustine summarized the general process NIPSCO undertook to evaluate retirement and replacement decisions in its IRP. In response to Ms. Medine's suggestion that NIPSCO should have performed a single optimization analysis to identify the preferred retirement plan for the coal units, Mr. Augustine testified that if NIPSCO would have performed a single, least cost optimization analysis, the IRP models would have determined that the optimal portfolio would be to retire all coal units as soon as possible.

In response to Mr. Griffey's claims that NIPSCO only applied flexibility to its future selection of resources after making an inflexible choice on early plant retirement dates, Mr. Augustine testified that NIPSCO actually concluded that retiring coal earlier than the dates outlined in the preferred portfolio would be the least cost portfolio outcome. He explained that NIPSCO found that retirement of units at Schahfer as early as 2021 would provide savings for customers, but concluded that early retirement was not executable by 2021, given the required transmission upgrades that must be made to ensure system reliability. He also explained that NIPSCO found that retiring Michigan City in 2023 provided the greatest cost savings to customers, but concluded that a change of over 75% of NIPSCO's physical generation at one time in 2023 would create potential reliability and execution risk for customers. Thus, NIPSCO concluded that a 2028 retirement date for Michigan City would allow for a more orderly portfolio transition and provide an ability to gain access to better information regarding technology change and future customer demand. He stated that if NIPSCO had not applied flexibility in its retirement decision, the preferred portfolio would have called for retirement of the units as early as possible.

In response to Mr. Griffey's criticism of the number of scenario/portfolio combinations that were evaluated and his statement that NIPSCO should have constructed evaluations of different retirement dates that changed by scenario, Mr. Augustine testified that NIPSCO's analysis evaluated a very broad range of retirement dates across a range of scenarios and stochastics. He explained that the primary point of evaluating eight different retirement date combinations for the coal fleet across all scenarios and stochastics was to provide a highly transparent analysis of different retirement strategies against different potential market outcomes. He stated that instead of limiting the evaluation of flexibility, as Mr. Griffey suggests, this approach actually allowed NIPSCO to evaluate the performance of different portfolios against changing market assumptions over time.

Mr. Augustine disagreed with Mr. Griffey's claim that by using a two-step approach and never comparing the results across steps, NIPSCO arrives at an inappropriate conclusion in its IRP. Mr. Augustine noted that Mr. Griffey's claim fails to acknowledge the rationale behind the two-step process and the multiple objectives NIPSCO evaluated in its review of retirements and replacement options. He testified that NIPSCO performed retirement analysis in multiple phases against different resource alternatives and concluded that early retirement of coal units was cost effective for customers. He explained that NIPSCO then performed a replacement analysis to evaluate the replacement alternatives through a more comprehensive set of parameters and scoring mechanisms, including a portfolio diversity component to test natural gas and renewable replacements and a commitment duration component, where a mix of PPA and ownership options were evaluated. He testified that resource planning decisions were made based on an integrated scorecard approach and not purely on least cost, which is why certain retirement dates are staggered and why a mix of replacement alternatives was proposed in the preferred portfolio.

Mr. Augustine testified that Mr. Griffey's comparison to show that an alternative retirement plan would have been more cost effective than NIPSCO's preferred portfolio is an apples-to-oranges comparison and ignores the other objectives evaluated by NIPSCO in the replacement analysis. He explained that NIPSCO found that a wide range of resource alternatives were lower cost than operating and maintaining the existing coal fleet. He concluded that Mr. Griffey did not conduct any dispatch or portfolio analysis that would demonstrate a different outcome under his proposed alternative approach.

In response to Ms. Medine's contention that NIPSCO did not properly account for recent changes in delivered coal price expectations for 2019 in the IRP and that NIPSCO did not fully consider all realistic commodity price combinations, Mr. Augustine stated that the difference in assumed coal price raised by Ms. Medine for the fleet averages about \$0.13/MMBtu, which represents around a little more than \$1/MWh, less than 5% of the total variable costs for the units, which is not a significant difference in the context of other drivers of the IRP analysis, including natural gas prices, which dropped even further since the development of the IRP assumptions. He also stated that NIPSCO's 2018 IRP assessed portfolio performance across a wide range of coal and natural gas prices precisely because future market conditions are uncertain and will inevitably be different than any single point forecast. In response to Ms. Medine's critique that NIPSCO did not appropriately consider a scenario without a carbon price and with high gas prices, Mr. Augustine testified that as part of its 2018 IRP stakeholder process, NIPSCO evaluated a scenario developed by the ICC and Ms. Medine that had the same assumptions she claims NIPSCO ignored. He stated that this scenario had no CO_2 price, flat coal prices, and high natural gas prices. He noted that the results from this scenario were consistent with the other four scenarios, concluding that retiring coal capacity early provided substantial cost savings to customers.

Regarding Mr. Griffey's assertion that NIPSCO did not properly account for expected solar cost declines over the long term, Mr. Augustine testified that as Mr. Griffey recommended, NIPSCO directly calibrated its generic solar cost projections to results from the RFP and assumed a \$1,006/kW (real 2017\$) cost for 2023 additions, which is a cost *lower* than Mr. Griffey's recommendation. Mr. Augustine further explained that Mr. Griffey's claim that inaccurate solar cost assumptions were used in the IRP analysis was false due to his failure to account for ongoing coal maintenance capital expenditures, accelerated tax depreciation benefits for solar, and differences in generic solar additions in his calculations.

In response to Mr. Griffey's belief that NIPSCO underestimated the capacity value associated with wind resources, Mr. Augustine noted that historical data for wind plants operating in Indiana is not a reasonable way to project future capacity credit values for new assets. Regarding Mr. Griffey's belief that NIPSCO underestimated the potential of future wind output degradation, Mr. Augustine testified that ongoing maintenance will limit the amount of degradation seen at the future wind facilities and that the IRP analysis included these costs. He explained that while solar bidders to the RFP provided specific information regarding degradation curves, wind bidders did not offer such information, so NIPSCO did not include any assumptions for this factor in the IRP analysis. He noted that Mr. Griffey did not attempt to quantify the potential impact of any degradation, nor did he present any data regarding wind degradation that would suggest he has better information than the RFP bidders, all experienced wind developers. Furthermore, Mr. Augustine noted that NIPSCO does not view this factor as having a meaningful impact on cost outcomes, especially given the large cost savings associated with wind additions to the portfolio.

In response to Mr. Griffey's concerns with the maintenance capital expenditure projections used in the 2018 IRP, Mr. Augustine testified that NIPSCO's capital expenditure projections are consistent with expectations of future operations. He explained that retiring a plant early reduces the expected maintenance capital that is required, due to a reduced need to continue investing in the asset for long-term use, which is an important reality that must be incorporated in an IRP analysis. He stated that Mr. Griffey neglects this reality and seems to think that maintenance capital plans should be the same regardless of when a plant is expected to retire. He said that Mr. Griffey's proposed approach ignores significant cost savings that are associated with retirements.

Regarding cost assumptions relating to ELG and CCR compliance and treatment of potential CO2 costs, Mr. Augustine testified that NIPSCO evaluated different means of ELG compliance and conservatively developed its final set of portfolios around the assumption that plants could achieve compliance through a non-ZLD approach. He noted that NIPSCO evaluated a retirement portfolio that extended the retirement date of Schahfer Units 14 and 15 to 2028 under the assumption that ELG compliance could be achieved through a retirement in that year as opposed to a specific control mechanism by an earlier date. He stated that although NIPSCO's four *scenarios* do not envision compliance obligation changes associated with ELG and CCR Rules, NIPSCO evaluated potential changes in compliance obligations in the *portfolio* development process. He noted that in its 2018 IRP stakeholder process, NIPSCO performed an analysis of the coal retirement economics requested by Ms. Medine and the ICC with *no* new environmental capital incurred at the coal plants – effectively a scenario where no environmental compliance is required over the entire planning period – in which NIPSCO found that retiring coal early still provided significant savings to customers. With regard to treatment of potential CO2 costs, Mr. Augustine stated that NIPSCO evaluated a range of potential CO2 price futures, including a customized scenario requested by the ICC. He explained that while the two CO2 price trajectories developed in the 2018 IRP include a CO2 price starting in 2026, NIPSCO also analyzed scenarios without any CO2 price for the *entire* IRP forecast horizon. He testified that the results of this scenario concluded that retiring coal capacity early would lead to significant savings for customers and that NIPSCO also performed an analysis of the coal retirement economics requested by the ICC with no CO2 price, high natural gas prices, flat coal prices, and no incremental capital, and still found that retiring coal early provided significant savings to customers.

Mr. Augustine responded to general concerns regarding NIPSCO's IRP analysis identified by Mr. Griffey and Ms. Medine, including concerns regarding NIPSCO's incorporation of potential congestion risk, ancillary services costs, and the new proposed industrial rate structure; a claim that NIPSCO has not performed its revenue requirement calculation properly; and a claim that certain retirement portfolios cannot be properly compared due to inconsistent assumptions. He stated that NIPSCO acknowledged the existence of congestion and nodal price risk for certain resources in its 2018 IRP and noted that this would be evaluated in further resource selection processes associated with the RFP, as was done in NIPSCO's analysis for its recently pursued wind resource additions. He stated that while it is possible that MISO-wide ancillary services costs will increase in the future, Mr. Griffey did not provide any actual evidence or analysis to support his implication that NIPSCO's preferred portfolio would face higher net costs than a portfolio that retains coal. With regard to future industrial load uncertainty, Mr. Augustine testified that NIPSCO did evaluate a low-load scenario, which was based on substantial industrial load leaving the system. He noted that although it was combined with other factors that differed from the Base Case and although it was not based on specific assumptions regarding lower industrial firm demand that may materialize from a new rate structure, it found that retiring coal units provided savings to customers. He stated that any loss of firm load can be managed through NIPSCO's procurement of replacement resources, while investing in and maintaining the high-cost coal units could result in more high-cost capacity than necessary if load obligations were to fall significantly.

Mr. Augustine testified that Ms. Medine's statement that NIPSCO's NPV approach assumes levelized recovery of capital investment is a false assertion. He explained that Ms. Medine's claim shows a lack of understanding of how NIPSCO conducted its IRP analysis, since NIPSCO did not levelize capital expenditures but instead performed a revenue requirement calculation that puts new capital into rate base as units enter into servicing, resulting in NIPSCO earning a return of and on that new capital over time. As a result, the recovery of new capital is front-loaded in NIPSCO's analysis, meaning that customers pay more in the first year than in subsequent years, contrary to Ms. Medine's claims. In response to Mr. Griffey's suggestion that he was unable to compare the economics of retiring Schahfer Units 17 and 18 versus the alternatives because the portfolio that holds all coal through end-of-life does not include new DSM and EE measures beyond what is currently in NIPSCO's approved plans, Mr. Augustine testified that the purpose of the IRP is to compare current resources with alternatives, whether they be demand- or supply-side options, as NIPSCO has done. He explained that in evaluating different portfolio options within similar reserve margin constraints, alternatives such as DSM and other supply-side resources are only needed when coal units retire.

Mr. Augustine concluded that while the 2018 IRP involved a complex set of portfolio analyses, including hourly dispatch analysis and detailed revenue requirement projections, the simplest explanation for NIPSCO's preferred portfolio is that the *all-in* costs of acquiring and operating new renewable resources are far lower than the expected costs of continuing to maintain and operate NIPSCO's coal units. He testified that in the IRP, the all-in costs for PPA or NIPSCO-owned renewables over their expected operating horizons ranged between approximately \$25/MWh and \$51/MWh (nominal \$) and that over the same period, the *variable-only* costs for the coal fleet associated with coal expenses and variable operations and maintenance costs are close to or even higher than the *all-in* costs of many of the renewables options. Therefore, any additional costs for the coal plants associated with fixed operations and maintenance activities, new capital investments, or future carbon regulations all raise the costs substantially higher than new renewables. He stated that even in scenarios where these other costs are eliminated or dramatically reduced, retiring the coal plants and replacing the energy and capacity with renewables is a lower cost outcome.

F. Mr. Hooper. Mr. Hooper responded to the OUCC's proposal to limit the adjustment of Forward Test Year Vegetation Management expense to a five-year average value. He testified that NIPSCO's clearance distances are designed to provide adequate clearance at time of trimming to allow for vegetation growth with minimal impact to system reliability until the next trim cycle. He explained that while Mr. Eckert's analysis is mathematically correct, it fails to consider the benefits of maintaining a 1,500 mile clearance goal and fails to account for the fact that the costs of vegetation management continue to climb. He noted that the OUCC did not challenge the underlying facts supporting the rationale for the proposed increase in Vegetation Management expense and contended that reducing the requested amount by \$1.3 million would not be representative of the ongoing cost of those activities.

G. Mr. Carmichael. Mr. Carmichael responded to criticisms from Mr. Nasi that regulatory timelines NIPSCO assumed for compliance with the EPA's CCR and ELG Rules were too short because of available extension options and EPA's plans to reform those rules and that assumed capital and O&M expenditures were too high or not properly supported. Mr. Carmichael explained the overall process NIPSCO utilized to determine the anticipated compliance timelines and environmental cost estimates that were utilized in NIPSCO's 2018 IRP, including how NIPSCO determined compliance timelines based on a plain reading of the rules and regulatory agency guidance and how available extensions were considered and applied. He discussed how NIPSCO utilized expert third-party consultants with extensive industry experience, internal expertise, and available industry data to determine the capital environmental cost estimates used in the IRP and reviewed the potential options for meeting compliance these experts provided to assist in selecting technical solutions/projects. NIPSCO also balanced current and future compliance obligations with operational needs and overall cost to choose a compliance option; the estimates were then adjusted to align with the estimated annual spend to complete a project; and dollars were applied to the estimates for owner's costs, indirect costs, and escalation. In each instance, NIPSCO utilized the most reasonable compliance alternative and estimated cost and used its best judgment. However, Mr. Carmichael noted that, when predicting the future state of environmental regulatory compliance, there will necessarily be some uncertainty.

Mr. Carmichael also explained why it is important for NIPSCO to include its best estimate for environmental compliance costs in its long-term planning, including in its 2018 IRP. While there is uncertainty around practically all major environmental rules, he stated that NIPSCO must make judgments about many things, including environmental rules, when making important decisions like what generation will best position NIPSCO to serve its customers in the future. NIPSCO also cannot assume no compliance costs for a rule that is subject to challenge or reconsideration. He noted that Mr. Nasi criticized NIPSCO's environmental compliance cost estimates used for the 2018 IRP but nowhere provided his own cost estimates. Because NIPSCO conducted detailed cost estimation using proven methodologies and in coordination with its expert consultants, Mr. Carmichael stated that Mr. Nasi's criticisms are unwarranted.

With respect to compliance with the ELG Rule, Mr. Carmichael summarized Mr. Nasi's criticism that NIPSCO has overstated the compliance costs. Mr. Carmichael reviewed the current status of the ELG Rule and noted that NIPSCO incorporated lower ELG costs and adjusted timing assumptions in the 2018 IRP as a result of EPA's yet-to-be-finalized reconsideration of the ELG Rule. He explained that Michigan City Unit 12 is already compliant with the ELG Rule and why the "Postponement Rule" discussed by Mr. Nasi has no bearing on the NIPSCO ELG compliance timing for the Schahfer Generating Station assumed in the IRP for 2023. He also testified that there is no indication the ELG Rule and related requirements will go away completely and how NIPSCO changed assumptions in the 2018 IRP to: (1) lower ELG costs with the assumption that EPA would relax the 2023 ZLD requirement; and (2) assume that a non-ZLD option would be allowed at Schahfer for FGD wastewater. For bottom ash transport water, Mr. Carmichael explained that Schahfer Units 14 and 15 are already retrofitted for compliance with the CCR Rule; thus, there are no additional cost or timing issues related to ELG. Regarding Schahfer Units 17 and 18 bottom ash transport water, he explained that it would be likely that bottom ash transport projects (like those for Units 14 and 15) would be required and that NIPSCO's assumed cost estimates were similar to those projects it has already installed at Units 14 and 15. He clarified that the settlement in Cause No. 44872, which addressed CCR compliance projects but not ELG compliance projects, does not in any way invalidate cost estimates or timing assumptions in the 2018 IRP, nor does it demonstrate that NIPSCO will not be required to comply with the ELG Rule in the future.

Regarding the CCR Rule, Mr. Carmichael noted Mr. Nasi's criticism of NIPSCO's cost estimates. Mr. Carmichael explained that NIPSCO considered all options available under the CCR Rule regarding compliance timelines and costs. He stated that NIPSCO must make decisions and implement compliance plans to meet currently existing requirements even though the rule is undergoing reconsideration. If NIPSCO did not do this and instead waited for a final EPA decision, generating facilities may be forced to shut down early (October 2020 or earlier) to avoid non-compliance with the regulations. Mr. Carmichael testified that this risky approach would be inconsistent with NIPSCO's commitment to provide reliable service to its customers. He also testified about the CCR compliance options that were prepared by third-party consultants and those agreed to in the 44872 Settlement, which have been executed on budget by NIPSCO. He stated that this demonstrates NIPSCO's cost estimates for Schahfer Units 14, 15, 17, and 18 and Michigan City Unit 12 are reasonable. Mr. Carmichael also clarified that his discussion of certain CCR ARO costs, which NIPSCO is not seeking to recover here, was not related to the 2018 IRP. Based on a recent court decision, he also stated that NIPSCO disagrees with Mr. Nasi and does not anticipate that CCR Surface Impoundments will be allowed to continue to receive CCR and non-CCR wastewater in the future.

Mr. Carmichael next addressed criticisms about NIPSCO's compliance plan for the MATS Rule. He specifically disagreed with Mr. Nasi's assertion that NIPSCO's inclusion of MATS-related O&M costs in the 2018 IRP was unreasonable. Mr. Carmichael explained that the MATS Rule's requirements are still in effect, and NIPSCO must continue to comply with them. Because the MATS Rule remains effective and it is unlikely that EPA will withdraw MATS entirely or drastically alter the rule, NIPSCO has assumed it will continue to incur compliance costs for the time in which the impacted generating units operate and, thus, made no changes in its MATS compliance plans. He also noted that the majority of the O&M costs to comply with MATS come from operation of the FGD systems; thus, even if EPA were to repeal MATS, the FGDs would be required to continue to operate for purposes of compliance with other EPA rules, and the FGD-related O&M costs would continue to be incurred. More broadly, Mr. Carmichael criticized Mr. Nasi's advocacy for a "wait-and-see approach" to compliance, providing examples of how this previously would have resulted in coal-fired generation that would not have had control equipment installed in time for compliance and thus would have been non-operational for years. This is why it would not be prudent for NIPSCO to utilize this wait-and-see approach and assume that CCR, ELG, MATS, or other EPA rules will result in no future cost.

Regarding NIPSCO's path to compliance with CSAPR, Mr. Carmichael responded to Mr. Nasi's critique that NIPSCO failed to adequately justify the selection of SCR technology over the less expensive SNCR technology. After discussing NIPSCO's response to Peabody Request 1-010, included as Attachment No. MJN-5 to Mr. Nasi's testimony, Mr. Carmichael further explained the operational characteristics of Schahfer Units 17 and 18. He testified that installation of SNCR technology would not reduce NOx emissions below the current allocation. On the other hand, SCR technology can achieve a NOx rate that would bring Schahfer Units 17 and 18 in-line with the current NOx allocation rate. While SCR is a more capital-intensive technology, if the EPA continues the historical trend and lowers the ozone standard below 70 ppb, as expected during the IRP planning horizon, or if additional environmental regulations are promulgated that impact the relevant emission requirements, it is likely that SNCR technology would not be able to achieve compliance without a significant curtailment of coal-fired generation to achieve compliance or significant reliance on allowances in future NOx markets, assuming that the markets exist at a price that justifies running coal-fired units. He added that if NIPSCO implemented SNCR technology and incurred the associated capital costs and later needed to comply with more stringent standards, SCR technology would likely need to be implemented at a significantly higher cost than implementing SCR technology in the first instance. Mr. Carmichael summarized that without SCR, NIPSCO's operational flexibility—its ability to run Schahfer Units 17 and 18, if at all—would become increasingly constrained as EPA implements the 70 ppb ozone standard and future standards. Regarding "operational flexibility" that SCR technology would allow, he explained that NIPSCO was speaking about the ability to continue to ramp output of the relevant units to meet system needs while also complying with current and future regulations because SCR allows units to operate over a wider range of output at lower emission rates than SNCR allows. Based on the operational characteristics of NIPSCO's generation fleet, existing and expected regulations, and as advised by internal and external subject-matter experts, NIPSCO believes SCR technology is the most appropriate technological assumption for long-term CASPR compliance.

Mr. Carmichael testified that NIPSCO has a proven track record of navigating compliance and assuring that associated timing and costs were ultimately warranted to achieve compliance. With regards to consideration of other scenarios in the 2018 IRP, he also briefly explained that the ICC requested NIPSCO to perform an analysis with its own set of assumptions—scenarios that included no carbon costs, reduced future environmental capital costs, flat coal pricing, and a high natural gas price curve. The output presented at IRP stakeholder meetings showed that, even under the ICC's market scenario with no new environmental capital for the coal plants, retirement of coal as early as possible still remained the lowest cost option. Mr. Carmichael also noted that NIPSCO is required to submit another IRP within the next three years (i.e., prior to the proposed 2023 retirement of the Schahfer coal-fired units) and that this IRP will incorporate the most current information and projections on environmental costs and timing.

Mr. Carmichael also responded to three issues that Mr. Nasi seemed to misunderstand in Mr. Carmichael's direct testimony. First, regarding the alleged mismatch for ELG Rule compliance costs, he clarified that the $170 million estimate from page 13 of his direct testimony is NIPSCO's initial ELG Rule compliance estimate for Schahfer Units 14 and 15. He explained that, looking at page 12 of that testimony, it stated that Michigan City Unit 12 would not need to incur ELG Rule compliance costs, because it has a dry FGD system installed, and this was also addressing Schahfer Units 14 and 15. The $440 million estimate provided in response to discovery, which was included in Nasi's Attachment No. MJN-2, was an estimate for Schahfer Units 14 and 15, as well as Schahfer Units 17 and 18. Second, Mr. Carmichael stated that Mr. Nasi's criticism of NIPSCO not advocating for ELG Rule changes that go beyond bottom ash transport water and FGD wastewater shows that he misunderstands NIPSCO operations and/or the ELG Rule. Mr. Carmichael outlined why it would be nonsensical for NIPSCO to waste time and resources advocating for additional ELG Rule changes when such changes would have no potential benefit for NIPSCO and its customers. Third, regarding Mr. Nasi's criticism of NIPSCO's inclusion and accuracy of capital and O&M costs and inclusion of costs that will be incurred regardless of whether the units continue to operate to justify retirement decisions, Mr. Carmichael pointed to Mr. Augustine's rebuttal testimony, which explained that NIPSCO evaluated a portfolio with no new environmental capital for all coal units and found that retiring coal early provided significant savings to customers even in this scenario.

H. Mr. Campbell. Mr. Campbell responded to Industrial Group witness Dauphinais' testimony about the Rate 831 tariff language regarding curtailment notification and US Steel witness Thornton's testimony related to Rate 831 customer qualification for Auction Revenue Rights ("ARRs")/ Financial Transmission Rights ("FTRs"), recommended phase in period for Rate 831 implementation, and MISO billing disputes.

Mr. Campbell testified that while NIPSCO does not oppose the recommendation by Mr. Dauphinais for a two-hour curtailment notice for Rate 831 customers, consistent with current practices, NIPSCO will add 30 minutes to the LMR notification time to allow for the communication of any MISO curtailment event.

In response to Mr. Thornton, Mr. Campbell testified that Rate 831 customers will not qualify for ARRs/FTRs. He explained that because MISO requires that an entity be registered as a Market Participant to hold FTRs or ARRs, NIPSCO, acting as the MISO Market Participant, will register Rate 831 customers electing Tier 3 service as Asset Owners. He explained that the MISO Tariff and Business Practices Manuals explain what actions Asset Owners are qualified to perform. He stated that MISO Market Participants are the only entities allowed to procure FTRs with MISO because of the additional credit requirements to participate in the FTR market but that MISO Market Participants may act as agents and procure FTRs on behalf of other parties. He stated that under Rate 831, NIPSCO will not act as an agent to procure FTRs on behalf of the Rate 831 Tier 3 Customer but that customers are free to contract with other third-party MISO Market Participants to obtain FTRs. He indicated that any settlements will be handled outside of the MISO settlement process between Rate 831 customers and the third-party MISO Market Participant. He stated that Mr. Thornton characterized allocated ARRs/FTRs as a benefit, but they can also represent a cost and that if Rate 831 customers are allocated ARRs/FTRs, they should also be allocated their portion of any charges associated with the ongoing investment in the transmission system.

Mr. Campbell disagreed with Mr. Thornton's proposal for a phase-in period for Rate 831 implementation. He explained that NIPSCO is proposing that any qualifying customer that is unable to take service under Rate 831 be placed on either proposed Rate 832 or Rate 833 with the requirement that the customer also maintain any historical curtailable service (MISO LMR registration) under prior Rider 775 through the end of the current MISO 2019/2020 Planning Year. He stated that, alternatively, for customers that are intending to take Tier 3 service under Rate 831, customers can choose to take service under Tier 2 until they are ready to transition to Tier 3 service. He noted that this optionality is already present in Rate 831 where customers can change their elections between Tier 2 and Tier 3 quarterly (commensurate with MISO model update cycle).

Mr. Campbell testified that NIPSCO has identified a process for assisting customers in addressing their MISO LMR exposure when activating their Rate 831 service. He explained that NIPSCO is proposing that customers be able to purchase any ZRCs associated with the customer's existing firm load that is transferring to Rate 831 above their Tier 1 firm election to afford customers the benefit of existing firm load that has already cleared the MISO PRA.

In addition, to assist customers with procuring MISO Zone 6 ZRCs from third-party suppliers during the 2019/2020 planning year, NIPSCO is offering to conduct a one-time RFP for intra-year MISO Zone 6 ZRCs prior to the implementation date for the benefit of Rate 831 customers to assist them in firming up their LMR obligations should they so desire when activating their Rate 831 service.

Mr. Campbell disagreed with Mr. Thornton's recommendation that during the proposed phase-in period, NIPSCO should work with its Rate 831 eligible customers to develop a model agreement that includes acceptable terms and conditions for customer-procured capacity and/or energy. He stated there are many ways to construct bilateral arrangements. He noted that an ISDA Master Agreement or EEI Master Contract are industry tools that can help form those agreements, especially in instances where there is a potential for multiple reoccurring transactions. He explained that standalone contracts are also employed, but they can have many of the elements referenced in the ISDA or EEI. He stated that based on NIPSCO's understanding, contracts in the broader market, while similarly structured, have certain provisions that are unique per counterparty requirements and additional provisions that are unique because of customer specific requirements. He indicated that recognizing that there is the potential for standard and non-standard agreements for customer-procured capacity and/or energy, NIPSCO is committed to working with the customer and the customer's identified third party in outlining the terms associated with any potential agreement incidental to Rate 831 service. He stated that in general, such agreements between NIPSCO, customer, and third party for capacity and/or energy will need to be a three-party agreement between NIPSCO, customer, and customer's third-party supplier, and at a minimum such agreement will need to contain provisions that: (1) identify NIPSCO as the Market Participant for the retail customer at MISO; (2) reference-NIPSCO's market based rate authority with FERC; (3) clearly state the Rate 831 customer remains a retail customer of NIPSCO; (4) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations); and (5) incorporates relevant provisions from NIPSCO's Rate 831 schedule.

He testified that NIPSCO also understands that certain terms such as, but not limited to, pricing may need to be treated as confidential and may be limited from view from certain NIPSCO personnel and, further, may be subject to a non-disclosure agreement. He stated that while NIPSCO does not believe a model agreement is necessary or prudent given the unique nature of potential capacity and energy transactions, NIPSCO believes the details outlined above are responsive to the concerns outlined by Mr. Thornton.

Mr. Campbell disagreed with Mr. Thornton's request that NIPSCO modify the language on billing disputes by adding specific dispute resolution provisions, which would define the rights and obligations of NIPSCO and the industrial customer, and include specific remedies. He stated that the dispute process is adequately defined in proposed Rate 831. He described that, in general, the hierarchy as defined within Rate 831 allows an Asset Owner to file the dispute with MISO, while keeping NIPSCO informed. If the dispute is denied and the customer wants to pursue it further, the customer needs to request NIPSCO to file an Alternative Dispute Resolution ("ADR") on its behalf with MISO. He noted that if the customer is unsatisfied with MISO's decision in the ADR, it can pursue a complaint with FERC.

I. Mr. Ranalletta. Mr. Ranalletta disagreed with Mr. Gorman that a contingency factor is not a known and measurable cost and therefore not appropriate for including in rates. He testified that use of a contingency factor in any major construction or demolition project is well accepted in the industry, the amount selected here is well supported, and it is sufficiently certain for purposes of including expected demolition costs in Mr. Spanos' calculation of depreciation accrual rates. He stated that estimates of demolition costs of NIPSCO's generation plants are prepared with the intent of accurately representing what contractors would bid to abate, remediate, and demolish the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known decommissioning tasks under ideal conditions. He stated that he included a 20% contingency factor in his estimates. He explained that in addition to the known tasks under ideal conditions, contingency is added to account for unknown, but reasonably expected to be incurred, costs. He indicated that the application of contingency is a common and prudent practice in the construction and demolition industries, and it is included in order to recognize the probability of increases in cost due to these unknown events. Finally, he noted that contingency is a cost that is typically included by owners throughout all stages of planning and execution of the project.

J. Mr. Spanos. Mr. Spanos first responded generally to the criticism by other parties regarding the service lives of generating plant. He testified that other parties are misusing the phrase "accelerated depreciation." He explained that NIPSCO's proposed depreciation rates based upon the current estimated useful lives of the generating plants is not a form of accelerated depreciation. He reiterated the service lives used in his study and pointed out that other parties argued not to update the service lives from prior studies or inherent in existing rates or generally not to retire the plants as planned. He testified that in his experience, it is more common for assets such as power plants to be retired before they have been fully depreciated than such assets becoming depreciated before being removed from service. Given this reality, he explained that depreciation rates should be set as accurately as possible but that erring on the higher side for depreciation rates is preferable to erring on the lower side. The likelihood and the risks of adverse effects on both the utility and customers are greater if depreciation is underestimated.

With respect to Mr. Garrett's proposal to reject the Equal Life Group procedure, Mr. Spanos testified that Equal Life Group has been used in Indiana for many years. He quoted the 43526 Order, where the Commission stated, "We consider the debate between [Equal Life Group] and [Average Life Group] to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the [Equal Life Group] procedure." P. 51. He then summarized the history of the use of the Equal Life Group in Indiana.

Mr. Spanos also responded to Mr. Garrett's proposal to remove escalation from decommissioning costs. He again cited to NIPSCO's most recent litigated case and to a 2004 rate case in Cause No. 42359. He testified that in both cases, it was affirmed that decommissioning costs should be escalated to the future time at which the facilities would be retired.

With respect to contingency, Mr. Spanos testified that the use of contingency is also accepted by this Commission and that, indeed, Mr. Gorman's firm had previously proposed to remove contingency for NIPSCO in Cause No. 43526 and was rejected.

Mr. Spanos also responded to the nine mass property accounts for which Mr. Garrett had proposed service life adjustments. Mr. Spanos noted that his depreciation study recommended an increase to the average service life from both current depreciation rates and the estimate from the previous depreciation study. He explained that Mr. Garrett's proposals are to increase the service lives even further. He testified that Mr. Garrett's adjustments relied too much on mathematical curve fitting and too little on the use of informed judgment. He gave examples where Mr. Garrett's approach resulted in estimated survival years beyond what should be considered reasonable. Finally, he noted that all of Mr. Garrett's adjustments resulted from an error in constructing his charts in Excel, which shifted the smooth survivor curves to the right in each graph.

K. Mr. McCuen. Mr. McCuen responded to the parties' testimony related to excess ADIT. He stated that all witnesses agree that the IRS has mandated that these excess ADIT be passed back to customers using ARAM and that all witnesses understand that the unprotected excess ADIT can be passed back to customers over any reasonable period of time. He testified that he has proposed using ARAM, Mr. Blakley proposed a five-year amortization period, and Mr. Gorman proposed a ten-year amortization period. Mr. McCuen supported his proposal using ARAM based on the Commission's June 1, 1987 Interim Order in Cause No. 38194 and the Report of the Executive Committee filed in that Cause on April 15, 1987, concluding that all excess deferred taxes should be passed back using ARAM, specifically stating that "protected" deferred taxes are those that relate to depreciation method and life of public utility property and the "unprotected" portion includes the remaining balance of excess deferred taxes. The Report found that excess deferred tax reserves existing on the books of utilities at whatever point in time the utility reduces its tax rate in compliance with the Tax Reform Act of 1986, should be returned to the ratepayers utilizing ARAM. Mr. McCuen stated that while the Executive Committee chose not to differentiate, he believes the portion of the unprotected items related to property (repairs, capitalized overheads, and mixed service costs) should appropriately follow the ARAM flow back to customers, and the non-property related excess deferred taxes may have a more appropriate shorter flowback period depending on the underlying cause of the temporary difference giving rise to the deferred tax. Mr. McCuen proposed a ten-year amortization period for these types of items.

Mr. McCuen believes the shorter period offered by Mr. Blakley and Mr. Gorman is not appropriate because: (1) investment decisions have been made taking into account the cash flow for the payment of taxes, whether the payment is to the federal government or a return to the customer, the payments should be made over the same period of time so as not to invalidate the economics underlying those investment decisions which have already been made; (2) the flow-back of excess deferred taxes should be done ratably over the life of the asset giving rise to the deferred taxes to avoid inter-generational inequity between customers today and those customers in the future that will continue to pay for the asset; and (3) a rapid flowback of excess deferred taxes will negatively impact NIPSCO's cost of capital that raises the cost to customers, the WACC will increase at a faster rate with a rapid flowback of the excess ADIT, and the negative cash flow implications for NIPSCO may result in degradation of credit ratings, which will increase financing costs of investments and ultimately the WACC.

Mr. McCuen explained what the pass back would look like had the TCJA not been enacted. He stated that when looking at the unprotected property related items, such as repairs and mixed service deduction, the deferred taxes reverse over the life of the assets as they are depreciated. The assets that these deductions relate to are typically long-lived utility assets with book lives over 40 years. He stated that the deferred taxes are purely the result of timing differences as the tax deduction has been taken more quickly than the expense is incurred for regulatory purposes. He explained that assuming a capital asset was installed at the beginning of Year 1 with a 40-year life but which qualified for the repairs deduction, at the end of Year 1, the entire investment would be deducted for tax purposes, but for regulatory purposes only one year of depreciation expense would be recorded. He stated that the deferred tax this situation creates will reverse over the remaining 39 years, as depreciation expense is recorded for regulatory purposes. For these reasons, NIPSCO believes amortization of the excess deferred taxes over the remaining life of the assets is the most prudent approach for its customers.

Mr. McCuen testified ARAM provides tax benefits to ratepayers smoothly over the life of the investment. In contrast, flowing it through over a five-year period front loads the benefit. Returning to his example of the single repairs deduction, under Mr. Blakley's proposal, for the next five years rates would be held artificially low as the excess deferred taxes are amortized over his abbreviated timeframe. Then there would be an immediate spike as the abbreviated amortization ends, and the spike would be exacerbated by an increase in the WACC caused by the deferred taxes having been flowed back entirely. He explained using the five-year amortization period means ratepayers will be charged more after that period because the deferred taxes will not be an offset to tax expense and the WACC will be higher. He testified that NIPSCO believes that using ARAM and providing the tax benefits to ratepayers smoothly over the life of the investment is the most prudent alternative.

Mr. McCuen explained how the pass back of excess deferred taxes impacts inter-generational equality. He stated that the normalization concept prevents the inter-generational inequity that can occur when the flow-through method is used. If NIPSCO uses an immediate or faster flow-through method, current customers receive the entire refund and disproportionally benefit. Returning to his example of the single repairs deduction, under Mr. Blakley's proposal, customers during the first five years see 100% of the benefit from the TCJA, whereas the customers over the remainder of asset's life see none of the benefit although the asset giving rise to the benefit will serve all of them. The WACC is also inequitable for those later customers. He stated that the entirety of the zero-cost excess deferred taxes will have already been returned over the first five years, meaning a higher WACC for the remainder of the life of the asset giving rise to the benefit. Mr. Blakley's and Mr. Gorman's approach is the equivalent of paying the lowest interest loans in the capital structure first rather than the higher interest loans. In this scenario, future customers are unfairly penalized because they may not receive any refund, yet pay for the cost of the utility asset over its remaining useful life. He testified that normalization ensures that tax benefits are spread to all customers who benefit from NIPSCO's long-life assets, not just current customers. He testified that NIPSCO believes that the normalization concept should be applied to unprotected property, and the pass back of these excess deferred taxes should use ARAM.

Mr. McCuen explained how a normalization approach to the return of unprotected property related items impacts the originally anticipated payment to the government. He testified that under a policy of normalization for the return of excess deferred taxes, NIPSCO would be required to pay the money no longer owed to the government to its ratepayers instead, but in approximately the same time pattern as NIPSCO originally expected to pay it to the government.

Mr. McCuen disagreed with Mr. Blakley that ADIT represents a "loan" from ratepayers to the utility because although Mr. Blakely correctly identifies how ADIT is created, ADIT is really an interest-free loan from the U.S. Government. Mr. McCuen cited to a FERC Order finding no reasonable basis for concluding that customers actually provide a loan to their utility. He added that the ARM methodology used by NIPSCO is required by the IRS.

Mr. McCuen testified NIPSCO is currently amortizing the regulatory liability associated with excess deferred taxes using ARAM. He stated this regulatory liability includes excess from pre-TCJA and amounts generated from TCJA. Mr. McCuen reiterated that NIPSCO has continued to follow the guidance provided by the Commission in its June 1, 1987 Interim Order. He explained that the Commission has always approved this approach, most recently in its 44688 Rate Case Order, and this is the proper accounting and regulatory treatment until a new order is issued. He also noted that the filed rate doctrine and prohibition against retroactive ratemaking bar NIPSCO from charging a rate other than the rate properly filed with the Commission, and similarly bar the retroactive imposition of a rate change for service already provided.

L. Mr. Rea. Mr. Rea testified that the ROE recommendations of OUCC witness Woolridge and Industrial Group witness Gorman should be rejected by the Commission. Specifically, Dr. Woolridge recommended that NIPSCO's ROE be set at 8.75% but further proposed that in recognition of the practice of gradualism, a 9.25% ROE would be more appropriate. Mr. Gorman recommended an ROE of 9.35%. In his rebuttal testimony, Mr. Rea demonstrated that the ROE recommendations of Dr. Woolridge and Mr. Gorman would not allow NIPSCO the opportunity to earn a fair return as compared to other electric utility companies. He stated that if these ROE recommendations were adopted, it would send a message to the financial community that Indiana's regulatory climate was not fully supportive of maintaining financially sound utilities, which could have negative implications from a capital attraction standpoint.

Mr. Rea testified that by ignoring the authorized returns of other electric utility companies of comparable risk, Dr. Woolridge and Mr. Gorman have failed to recognize the fair return standards established in the Hope and Bluefield cases. Mr. Rea further stated Dr. Woolridge and Mr. Gorman failed to adequately recognize that U.S. capital market conditions have recently been anomalous and that the Federal Reserve's recent monetary policy interventions have played a contributory role in driving interest rates to all-time lows and the stock market to its all-time high.

Mr. Rea testified that the failure of Dr. Woolridge and Mr. Gorman to evaluate a broader group of non-rate-regulated companies with comparable risks, and which provides useful perspective on the competitive market result, ultimately causes their cost of equity recommendations to be unreliable. He stated that the manner in which they have applied the DCF, CAPM, and Risk Premium models suffer from a number of infirmities. He also stated that their failure to evaluate the expected earned returns of companies with comparable risks results in ROE recommendations that do not adequately recognize the Comparable Earnings standard established in Hope and Bluefield.

Mr. Rea further testified that the recommendations of Dr. Woolridge and Mr. Gorman to: (1) reduce NIPSCO's authorized ROE on the basis of NIPSCO's equity capitalization layer; (2) reduce NIPSCO's authorized ROE due to the implementation of NIPSCO's TDSIC program and other regulatory mechanisms; and (3) deny a return on NiSource's stock issuance flotation costs, should all be unequivocally rejected. He summarized that after reviewing the testimony and analyses of Dr. Woolridge and Mr. Gorman and revisiting his original cost of equity evaluation, he concluded that NIPSCO's cost of equity remains in the range of 10.55% to 11.05%, and that the Commission should adopt a cost of equity at the midpoint of this range, or 10.80%.

Mr. Rea sponsored Attachment 15-R-B, Schedule 2 – Updated, presenting NIPSCO's capital structure as of December 31, 2019, as follows:

Projected Capital Structure as of December 31, 2019

	Balance (000)	% of Total	Cost	WACC
Common Equity	$2,864,884,714	47.85%	10.80%	5.17%
Long-Term Debt	2,151,351,378	35.93%	4.97%	1.79%
Customer Deposits	71,453,491	1.19%	5.15%	0.06%
Deferred Income Taxes	1,266,429,454	21.15%	0.00%	0.00%
Post-Retirement Liability	66,142,914	1.11%	0.00%	0.00%
Prepaid Pension Asset	(435,272,223)	-7.27%	0.00%	0.00%
Post-1970 ITC	2,014,831	0.03%	8.30%	0.00%
Totals	$5,987,004,559	100.00%		7.02%

M. Ms. Strauss. Ms. Strauss addressed proposed bill counts and kWh usage for residential customers, including weather normalization, sponsored by OUCC witness Novak and that clarified the support used as the basis for the derivation of proposed billing determinants sponsored by NIPSCO witness Westerhausen. Ms. Strauss was critical of Mr. Novak's proposed bill counts, contending that they had employed unreasonably high growth rates and as a result producing a residential customer bill count that was excessive. She explained that NIPSCO recommends considering other factors in addition to historic growth levels when forecasting customer counts and reiterated that NIPSCO's method for forecasting residential bill counts relies on market intelligence from the New Business Team and is cross checked by running a regression analysis, which shows that local housing starts are a strong predictor of new residential customers.

Ms. Strauss testified that the only similarity between the weather normalization she sponsored and that discussed by OUCC witness Novak was his proposal to adjust only residential and commercial customer classes for weather due to the correlation between their energy usage and weather. She explained that Mr. Novak's proposed weather normalization adjustment had been developed outside of the regression modeling used to produce NIPSCO's forecasted usage, and thus could not be applied to NIPSCO's forecast. She testified that the OUCC recommendation of 3,616,043,140 kWh for the residential customer class for 2019 included a weather normalization adjustment of 158,919,910 kWh (almost 4.4% of the total) and a growth adjustment of 172,942,640 kWh (more than 4.7% of the total) and that the forecast was unreasonably high. She noted that Mr. Novak's projected Forward Test Year residential usage per customer was above NIPSCO's historic annual usage per customer even when that annual usage per customer is calculated using the OUCC excessive bill count. She testified that NIPSCO's forecasted 2019 residential usage of 8,286 kWh per year is below the actual 2016 usage and consistent with the trend of decreasing usage per customer observed from 2012 through 2016. She concluded that NIPSCO's demand forecast is based upon econometric analyses and statistically significant regression results, is more reasonable and reflective of actual experience on NIPSCO's system, and should be approved.

N. Mr. Rimal. In rebuttal, Mr. Rimal discussed the changes to some of the special studies used for cost allocation that he had conducted for his direct testimony. He stated these changes are driven by three primary factors: (1) the migration of a sixth customer into Rate 831; (2) the assumption that customers that would have been moved to the new Rate 830 will remain with their original rate schedules (now Rates 832 and 833); and (3) revisions to the test year projected billing units associated with Rates 721, 723, 724, and 726 to reflect customers that have migrated between rate schedules.

O. Dr. Gaske. In rebuttal, Dr. Gaske responded to issues raised by OUCC witness Watkins, NLMK witness Lahtinen, Industrial Group witness Phillips, US Steel witness Georgis, CAC witness Wallach, Sierra Club witness Allison, and Walmart witness Chriss. He also updated the ACOSS and addressed associated rate design and bill impacts for changes in NIPSCO's revenue requirement.

Dr. Gaske noted that Mr. Phillips and Mr. Lahtinen agreed with the 4CP method for the allocation of production costs because NIPSCO is a strong summer-peaking utility and Mr. Lahtinen asserted that this approach will help combat bypass by the large customers. In response to Mr. Watkins recommendation that either the BIP, P&A, or 12CP methods would result in a reasonable allocation of NIPSCO's demand-related production costs, Dr. Gaske testified that these methods would allocate greater costs to the new Rate 831 industrial class that will consist of customers who will purchase only a minor portion of their power from NIPSCO. He testified that he used the 4CP method for NIPSCO because in recent years, the system peaks in 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. He disagreed with Mr. Watkins that the 4CP does not recognize the investment or operational characteristics of NIPSCO's generation portfolio as it allocates the total generation plant investment based on a few peak hours of the year. He also showed that Mr. Watkins incorrectly assumed that NIPSCO's baseload facilities have higher capacity costs than intermediate or peaking facilities. This incorrect assumption that baseload plant achieves lower energy costs by incurring higher capacity costs led Mr. Watkins to conclude that the BIP or P&A methods are more appropriate because he assumed that they recognize the fact that the baseload generation resources are utilized at a very high capacity factor to meet the energy needs throughout the year. Dr. Gaske explained that once installed, any generation asset may be available for dispatch at any time. He stated that while Mr. Watkins is correct that utilities typically consider a tradeoff between capacity costs and energy costs when they first construct a plant, circumstances change and the relative costs of fuel and the efficiencies of different types of capacity can change significantly over time. He stated that the assumption that NIPSCO incurred higher capacity costs in order to achieve lower energy costs for its baseload units is not correct.

Dr. Gaske also disagreed with Mr. Watkins' criticism of the FERC tests to determine the reasonableness of 4CP allocator noting that his criticism is based solely on the fact that the tests were developed by FERC. He stated that the FERC tests are a commonly used method for analyzing system load characteristics and determining whether a utility has monthly peak periods that can be distinguished from off-peak periods and that establishing the extent to which such a distinction exists provides a basis for determining the time periods which are most relevant for production and transmission capacity cost incurrence.

Dr. Gaske also responded to Mr. Watkins testimony that the 4CP peak hours occurred during mid-afternoon summer hours when certain commercial heating (Rates 720 and 722) and the lighting (Rates 750 and 760) services are not using any electricity and his criticism of the 4CP method because it does not allocate any generation capacity costs to those services. He stated that to the extent that these heating and lighting services are off-peak and do not cause or contribute to the need to construct additional generating plant, it is not unreasonable that they should receive little or no allocation of generating plant costs. He noted that the commercial heating services are small, ancillary services that are used by customers who take their primary electric service under other rates that do have an allocation of generating plant costs and that the total bills paid by these customers are designed to cover the costs of providing their services.

Dr. Gaske testified that Mr. Watkins concluded that the 12CP method is reasonable for allocating transmission costs. He testified that although Mr. Georgis' proposal to sub-functionalize the transmission facilities might be more accurate, all ratemaking involves some degree of averaging of costs of different facilities and customer characteristics. Thus, this issue basically reduces to a question of how far to go in de-averaging rates and recognizing individual differences. In Dr. Gaske's opinion, the method proposed by NIPSCO is reasonable, and he did not propose to change that method in his updated, rebuttal calculations.

In response to Mr. Allison's argument that minimum system distribution costs are not clearly a function of the number of customers because if a customer has zero demand, then there is no need to build any distribution infrastructure, Dr. Gaske testified that the minimum system analyses used by Mr. Rimal are based on the assumption that there is a minimum-sized distribution system required to be capable of serving minimum requirements of customers. He stated that this minimum system cost is dependent primarily on the number and location of customers, not on the peak demand the customers place on the system. He responded that the zero-demand assumption that Mr. Allison invokes is relevant under the "zero-intercept" or the "minimum-intercept" method, which seeks to identify the portion of the plant that is related to a hypothetical no load situation, but it is not relevant for the minimum system method that is used in Mr. Rimal's study.

In response to Mr. Allison's argument that if a new customer is added to an already populated area, there are no additional secondary distribution costs unless that customer increases the peak demand on the distribution system and, therefore, the cost is driven by demand and not the number of customers, Dr. Gaske testified that does not mean that the entire distribution system cost should be classified as being demand-driven. He stated that a portion of the distribution system that was existing before a customer is added is required to serve the minimum requirements of the customers and their geographic dispersion. He explained that the whole point of conducting a minimum system analysis is to calculate the portion of the distribution system that does not vary by demand because a portion of the distribution costs are incurred regardless of the peak demand of the customers. He noted that increases or decreases in demand do not result in proportionate increases or decreases in the number of poles and miles of conductors required to distribute electricity. He explained that a portion of the distribution system costs are classified as customer-related because the distribution system exists to deliver electricity to hundreds of thousands of customers who are widely dispersed. He said that a significant portion of those costs are totally unrelated to the peak demand and, thus, should not be allocated based on demand. He noted that Mr. Allison appears to agree that minimum system costs could reasonably be allocated to classes based on the number of customers, but Mr. Allison more strongly objects to inclusion of those costs in the customer charge for rate design purposes.

Dr. Gaske disagreed with Mr. Wallach's assertion that the minimum secondary distribution cost per customer is overstated by a minimum system study. He stated that distribution system costs are incurred to move electricity from generation and transmission facilities to individual customers that are distributed geographically throughout the NIPSCO service territory. He noted that Mr. Wallach is correct that some portion of the distribution system costs vary with demand, which is why the ACOSS classifies a portion of the costs as demand-related, but it is incorrect to assume that all distribution system costs are demand-related.

In response to Mr. Wallach's statement that distribution equipment that carries zero load can serve an infinite number of customers with zero load, Dr. Gaske agreed that an infinite number of customers could be served by the NIPSCO distribution system if each customer has a demand approaching zero. However, NIPSCO is allocating the costs to the customers that are actually served by its distribution system. He stated again that the minimum system method is based on the premise that a minimum size distribution system is required to deliver electricity to the geographically dispersed customers that are actually on the NIPSCO system, and the costs of this minimum system is unrelated to either peak demands or total energy usage. He noted that although the minimum system costs per customer would be lower for a utility that serves a more densely populated territory, it is still reasonable for the customers to share those costs equally because a large portion of distribution system costs are related to reaching the numerous, geographically dispersed customers, and those minimum system costs are unrelated to peak demand.

Dr. Gaske disagreed with Mr. Wallach's claim that all line transformer costs had been classified as customer-related and his argument that a portion of these costs should be classified as demand-related. Dr. Gaske stated that line transformers are at the intersection of the distribution system and the customer premises and, like meters and services, are designed for the specific customer or customers at a location. For that reason, these costs are largely related to the number of customers. He stated that, more importantly, the line transformer costs (Account 368) are not allocated based on a simple allocation by number of customers but instead, a weighted customer allocation was developed based on the types of transformers and costs used to serve each class. This weighted approach allocates 4.5 times as much per customer to commercial customers than residential customers, which implicitly reflects the greater demand and more accurately reflects the higher cost of transformers for commercial customers. He testified that approximately 96% of these line transformer costs are allocated to the residential and small commercial classes, which do not have demand meters. Thus, once allocated to the classes based on their different weighted costs per customer, it is most appropriate to recover these costs in the customer charge because the costs are fixed regardless of a customer's energy use.

Dr. Gaske disagreed with Mr. Georgis' recommendation that transmission-related revenue in Account 456 should be allocated to the various rate classes in the same manner that transmission costs are allocated (i.e., the 12CP method). He testified that he used the amount of revenue margin (i.e., revenue excluding fuel costs) for each class as an allocator to allocate and credit Account 456 transmission-related revenues to the various classes. He explained that these revenue credits are used to offset the fixed costs incurred by all classes on an equal basis relative to their contributions to the revenue margin. He stated that although the approach proposed by Mr. Georgis is not unreasonable, it is also reasonable to continue to treat the transmission revenues as a general source of funds available to offset the overall costs of serving all classes on a pro rata basis.

Dr. Gaske disagreed with the rate mitigation strategies proposed by Mr. Wallach, Mr. Watkins, and Mr. Chriss. He testified that with the possible exception of Mr. Chriss, each of these witnesses appears to agree that increasing all rate classes except Rate 831 by an equal percentage is reasonable. He noted that, as discussed by NIPSCO witness Kelly, the proposals to allocate either more or less costs to Rate 831 would not be consistent with the balance between competing interests and competitive pressures that NIPSCO is trying to achieve in its proposed industrial service restructuring, cost allocation, and mitigation. Importantly, he noted that the proposed Rate 831 revenue requirement is not a discounted rate but instead, the Rate 831 revenue requirement is set equal to the fully allocated cost of service.

In response to the objections of Mr. Wallach, Mr. Watkins, and Mr. Allison to the implementation of an SFV rate design concept, Dr. Gaske testified that although an SFV rate design would provide better price signals for efficient usage, he is not proposing an SFV price structure for NIPSCO's residential and commercial customers at this time. Instead, a substantial amount of fixed costs would continue to be recovered in the energy charge and the marginal price of consumption generally will exceed the marginal cost of production by a large amount. He testified that while he disagrees with their assertions and interpretations concerning the theory of efficient pricing, in reality NIPSCO's proposed rate structure would recover only a small fraction of residential and small general service fixed costs in the customer charge and as a result, many of their theoretical arguments are misdirected.

Dr. Gaske disagreed with the arguments that the energy rate should be based on long-run marginal costs and as a result, it is appropriate to recover demand-related costs from residential customers in the variable energy rate in proportion to their energy use. He testified that fixed, demand-related production and transmission costs are typically driven by the coincident peak demand while demand-related distribution costs are generally driven by the non-coincident peak demand on different parts of the system. He stated NIPSCO incurs these costs to meet peak load; therefore, they are not based on the total amount of kWh a given customer consumes. He noted that customer coincident and non-coincident peak loads are a significant driver of the costs of NIPSCO's distribution system.

Dr. Gaske also disagreed with claims that recovering a small portion of demand-related costs in the customer charge and less than 100% of such costs in the energy rate would result in cost subsidization within the residential class and would dampen energy price signals to consumers for controlling bills through conservation, EE investments, or distributed renewable generation. He testified that the production and delivery of electricity consists of both fixed costs and variable costs. He explained that when a rate structure recovers fixed costs in variable energy charges, as Mr. Wallach, Mr. Watkins, and Mr. Allison recommend, the rate structure overstates the marginal cost of electricity and discourages consumption that would be efficient because the marginal benefit of consuming additional units of electricity exceeds the marginal cost of the energy required to produce that electricity. He stated these witnesses' concepts of conservation and efficiency appear to be narrowly focused on attempting to discourage electricity use and encourage consumption of alternative resources, but electricity use provides enormous benefits to consumers and the community, and consumers require proper price signals as to the marginal cost of electricity to make decisions that improve the welfare of themselves and the community.

In response to Mr. Watkins' claims that the price signal that results from SFV pricing is meant to promote additional consumption, Dr. Gaske testified that it is more accurate to say that this type of rate design is meant to promote efficient consumption by allowing alternative energy sources to compete on the basis of their marginal fuel cost without the distortion of trying to collect fixed costs through a variable energy charge. Regarding FERC Order No. 636, Dr. Gaske indicated that FERC placed all of the fixed costs in a demand charge so that recovery of fixed costs in the volumetric charge would not distort the price signals in the commodity cost of energy and thereby improve competitive efficiency in the market. He stated that for customers with demand meters, NIPSCO is generally proposing to recover the demand-related fixed costs in a demand charge, and the customer-related fixed costs in a customer charge so that the energy charge is close to the utility's variable cost of fuel and energy thus promoting efficiency because it charges customers based on the costs they cause the utility to incur. Dr. Gaske disagreed with Mr. Watkins' discussion on theoretical pricing in competitive markets noting that Mr. Watkins neglects the fact that many competitive industries use multi-part rates to properly reflect costs and dimensions of service.

Dr. Gaske presented updated cost of service and rate design schedules assuming separate small industrial rates are retained for low load factor and high load factor service. He stated that in these schedules, proposed Rate 832 comprises those industrial customers currently taking service under Rate 732 that will not be moving to the proposed large industrial Rate 831, and proposed Rate 833 is comprised of customers currently taking service under Rate 733 that will not be moving to proposed Rate 831. He listed all the changes that were incorporated into the updated ACOSS and rate design as: (1) an update to the revenue requirements; (2) the assumption that customers that would have been moved to the new Rate 830 will remain with their original rate schedules (832 and 833); (3) the migration of a sixth customer into Rate 831 with a reduction in that customer's expected 4CP demand and billing unit; and (4) revisions to the test year projected billing units associated with Rates 721, 723, 724, and 726 to correctly reflect customers that have migrated between rate schedules. He concluded that in general, these changes had a *de minimis* effect on the rates that NIPSCO is proposing for the various classes.

P. Mr. Westerhausen. In response to Industrial Group witness Phillips' concerns with NIPSCO's proposed Rate 830, Mr. Westerhausen testified that NIPSCO is willing to develop two separate rates, both a load factor rate and a high load factor rate for those current customers receiving service on Rate 732 and Rate 733 not opting, or eligible, for Rate 831 service. He stated that to prevent an unintended adverse impact on NIPSCO's low load factor customers, NIPSCO is willing to continue a Rate 732 low load factor service (now proposed Rate 832) and a Rate 733 high load factor service (now proposed Rate 833). He explained that these new rates will include the Back-Up, Maintenance, and Temporary Service that was proposed in Rate 830. He stated that Appendix A has been revised to reflect new Rates 832 and 833. He testified that in its compliance filing to implement Step 1 rates, NIPSCO will update its Series 800 Tariff to address the removal of Rate 830 and the addition of Rates 832 and 833.

Mr. Westerhausen also testified that a transition service that expires on May 31, 2020, has been added to both Rate 832 and Rate 833 for customers that intend to move to proposed Rate 831 but will not be ready when the new rate schedules go into effect. He explained that these customers will be required to maintain their historical interruptible capacity through the current MISO Planning Year and that the maximum capacity contract limit of 25,000 kW will not go into effect until June 1, 2020. He stated that language from NIPSCO's current Rider 775 for Character of Service, Curtailment, and Interruption limits, Interruptions, Energy Charges and Customer's Failure to Comply with Requested Interruptions or Curtailment has also been added to both rates.

Mr. Westerhausen responded to US Steel witness Thornton's concerns that: (1) although most of the riders are straightforward with respect to calculation and application, there are concerns about possible cost shifting depending on customers' Tier 1, Tier 2, and Tier 3 firm capacity elections; (2) it is not clear whether the energy and demand tracker allocators will be trued up once the large industrial customers have made final firm capacity elections; and (3) truing up tracker allocators is necessary to avoid possible inter-class subsidies and over-collection of costs. Mr. Westerhausen testified that: (1) NIPSCO will true up the energy and demand tracker allocators with the final Tier 1, 2, and 3 contracts; and (2) there were no changes to NIPSCO's proposal for the allocation of its various trackers to the different tiers of service within Rate 831 – the methodology is the same as what NIPSCO presented in its case-in-chief, but the proposed tracker allocations were updated to reflect the rebuttal ACOSS, which includes the rebuttal revenue requirement and the migration of one additional customer to proposed Rate 831.

Mr. Westerhausen addressed an update to the Rate 831 billing determinants. He stated one additional large customer is being migrated from proposed Rate 830 to proposed Rate 831, resulting in an additional ten MW of Rate 831 Firm Demand, 86,597,913 kWh Tier 1 energy, and 63,271,988 kWh Tier 2/3 energy. He explained that Tier 1 energy was calculated by using 2017 actual 30 minute kW meter readings and by allocating the lessor of ten MW or their actual demand into Tier 1 energy, and the remaining if their actual demand was greater than ten MW into Tier 2/3 energy. He said the 2017 monthly total energy was then compared to the 2019 forecasted monthly energies and since the 2017 Tier 1 energy was at a 99.9% load factor, the monthly energy difference from 2017 actuals to the 2019 forecast was added to Tier 2/3. He stated that because the additional 63,271,988 Tier 2/3 energy will no longer be sourced from NIPSCO generation, a reduction to the Forward Test Year electric operating revenues was made for an additional $1,629,317 of fuel expense reduction (Adjustments REV 1-R and FP 1-R). He stated the total adjustment reflected in REV 1A-R-19SS and FP 1A-R-19SS of $85,260,118 reflects all changes in industrial fuel based on the proposed new service structure. He noted that if this adjustment is not included, Forward Test Year electric operating revenues would be overstated and that if NIPSCO's service structure is not approved, this balance will need to be updated.

Mr. Westerhausen described two revisions to Rate 831. The first revision allows customers who are not ready to take service under Rate 831 on its effective date to take service under Rate 832 or Rate 833 through May 31, 2020. The second revision is related to the MISO Curtailment and Firm Capacity Options to provide at least two hours advance notice of MISO curtailments.

Mr. Westerhausen testified there is one revision to Rider 876 to clarify that service under Rider 876 cannot be used to nullify some or all of a MISO LMR obligation to curtail. Mr. Westerhausen supported Adjustment REV 1J-R-19R to increase Forward Test Year electric operating revenues in the amount of $2,187,672 to reflect the reallocation of commercial and small industrial customer revenues resulting from reallocation of the demand forecast utilizing 2018 actual billing determinants.

In response to Mr. Chriss' concerns with the Rate 726 class load profile data and 2019 billing determinants, Mr. Westerhausen testified that although the forecasted Billing Determinants in Total for Commercial and Small Industrial Customer Classes vary by less than 2%, there are material differences in the allocation between Rates 721, 723, 724, and 726. He stated that this misallocation was partially driven by a significant amount of customer migrations to Rate 726 between 2016 and 2018. Therefore, an adjustment was necessary to reallocate those billing determinants between those four rates based on 2018 allocation factors. He stated that the same methodology used by Financial Planning to allocate forecasted energy billing determinants by customer class to individual rates and blocks was utilized. He explained that billing determinants are planned for customer count, Demand (kW), and Energy (kWh) by rate. He described that this is completed within six rate classes – Residential, Commercial, Small Industrial, Large Industrial, Lighting, and Other. Forecasted customer count and kWh are provided by customer class by Demand Forecasting. He stated the Demand Forecast customer count and kWh are then passed to Financial Planning, where they are allocated to the individual rates and blocks, except for the Large Industrial Forecast, which is provided separately by customer. The allocation methodology uses billing data from a historical test period and their relationships to allocate the forecasted kWh and customer count to the rates and blocks. For the 2018 and 2019 budgets, the 12 months ended December 2016 was used as the historical test period, which was the last year end prior to the planning process. Mr. Westerhausen explained that demand is forecasted based on the percent change in kWh forecast as compared to the kWh in the test period. He noted that same percentage is applied to the kW in the test period to get forecasted kW for the budget. He explained that Adjustment REV 1J-R-19R kept the forecasted billing determinants for Rates 721, 723, 724, and 726 the same in total, but reallocated them between the four rates based on the 12 months ended December 31, 2018 actuals. He noted that the same allocation methodology was used to reallocate the forecasted kW between these four rates rather than using the growth factor performed by Financial Planning. He stated that the reason for this deviation from the planning process is that they already had established a reasonable amount of kW in total, and reallocating the forecasted kW resulted in reasonable results compared to 2018 actuals. He noted that these allocations were performed for the Commercial Class and Small Industrial Class, but did not change the Large Industrial or Other Customer Classes.

Mr. Westerhausen described Adjustment Rev 1E-R-19R and FP 1E-R-19R. He stated that NIPSCO proposed an adjustment for small migrations in its case-in-chief to annualize small customer migration that occurred in 2017 and the first half of 2018, which was necessary in the case-in-chief because the billing determinants for test year 2019 were based on the AFP, which used calendar year 2016 to allocate forecasted billing determinants by customer class to rates. He stated that an adjustment was made to the 2019 AFP to reallocate forecasted billing determinants based on 2018 actuals (see Adjustment Rev 1J-R-19R for further detail). He stated that since 2018 actual allocation of billing determinants was used to restate individual rate billing determinants, that process accounted for any 2017 and 2018 customer migrations that had occurred through December 31, 2018. As such, the small customer migration adjustment is no longer applicable and is being removed from rebuttal adjustments for billing determinants, revenues, and fuel.

Mr. Westerhausen testified the average system fuel was calculated by using the total fuel and purchase power of $321,765,239 divided by total fuel kWh of 12,034,825,315, resulting in an average fuel cost of .02674/kWh.

Mr. Westerhausen sponsored Attachment 19-R-L, an update to Attachment 19-C (Revised), which shows 2017, 2018, and 2019 billing determinants. He stated that Attachment 19-R-L was also updated for the additional migration of a large industrial customer currently served under Rate 833 to Rate 831, Plan Allocation in Adjustment REV 1J-R-19R, and reversal of Small Migration in Adjustment REV 1E-R-19R, and also included a correction to Rate 721 2019 kWh billing determinants. He noted that the 2,123,333 kWh for the 2019 Weather Normalization adjustment shown in Column K was not included in the 2019 Projected Billing Determinants Column M and that this correction results in the 2019 revised billing determinants decreasing by 2,123,333 kWh. He indicated that Attachment 19-R-L also included six insignificant corrections to 2017, 2018, and the starting kWh in Column I of 2019 Budget Billing Determinants that did not affect the 2019 billing determinants.

Mr. Westerhausen sponsored Attachment 19-R-M, NIPSCO's proposed standard contract for service. He stated the agreement has been revised from the proposed standard contract for the removal of Rate 830 and Rate 831 and added references to Rates 832 and 833. He also sponsored Attachment 19-R-O, NIPSCO's proposed standard contract for service for Rate 831 incorporating Tier 1, 2, and 3 contract demands and aggregation information specifically for this rate.

20. <u>Overview of the Revenue Settlement</u>. The Revenue Settlement entered into by and among NIPSCO, Industrial Group, NLMK, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC resolves revenue requirements issues and other miscellaneous issues. The key terms of the Revenue Settlement are summarized as follows:

- NIPSCO's base rates will be designed to produce $1,482,166,740 prior to application of surviving Riders, which represents a decrease of approximately $63.648 million from the amount originally requested by NIPSCO. The revenue requirement reflects the depreciation study and accrual rates and amortization and a $2,000,000 decrease to NIPSCO's proposed O&M Expense. The agreed revenue requirement does not include:
    - All MISO related costs not included in FAC charges which had been recovered through base rates. Those costs shall be recovered instead through the RTO tracker; and
    - Costs related to the URT are removed from base rates. The URT shall be calculated and recovered as a separate line item on customer bills.
- NIPSCO's authorized NOI will be $271,211,585.
- The Revenue Settling Parties agreed that the WACC times NIPSCO's original cost rate base yields a fair return for purposes of this case, and agree that NIPSCO should be authorized a fair return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets as proposed in NIPSCO's case-in-chief (unless corrected in this proceeding); (2) NIPSCO's proposed capital structure as set forth below; and (3) NIPSCO's authorized ROE of 9.90%.

- NIPSCO's overall WACC is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$2,864,884,714	9.90%	4.74%
Long-Term Debt	$2,151,351,378	4.97%	1.79%
Customer Deposits	$71,453,491	4.91%	0.06%
Deferred Income Taxes	$1,266,429,454	0.00%	0.00%
Post-Retirement Liability	$66,142,914	0.00%	0.00%
Prepaid Pension Asset	$(435,272,223)	0.00%	0.00%
Post-1970 ITC	$2,014,831	8.30%	0.00%
Totals	**$5,987,004,559**		**6.59%**

- The depreciation accrual rates recommended by NIPSCO witness Spanos and presented in the Depreciation Study should be approved except that: (1) the amortization period for retired coal-fired generating units described in NIPSCO's case-in-chief shall conclude in 2032, which presumes the retirement of Schahfer in 2023 and the Michigan City in 2028; and (2) annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency expense included in demolition costs, as proposed by Industrial Group witness Gorman.

- NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding except that the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years. If not already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

- NIPSCO agrees to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base at the time a final order is issued in this proceeding and the actual investment amount adjusted for depreciation as outlined in OUCC witness Blakely's direct testimony. NIPSCO agrees to implement the credit upon the retirement of the generating units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. The credit will be limited to the net plant investment value of the Schahfer and Michigan City generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in paragraph B.1(a); and (2) the NOI established in paragraph B.1(b) for purposes of its earnings test. NIPSCO agrees to hold annual pre-filing meetings preceding the 30-day compliance filing with interested stakeholders.

- The Revenue Settling Parties agree that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in

NIPSCO's revenue requirement at the ARAM, estimated at the time of this Agreement to be 26 years.

- The Revenue Settling Parties agree that NIPSCO's Unprotected and Other Excess ADIT balance, totaled approximately $137,789,071 as of December 31, 2017. NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. If not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization.

- Step 2 Rates shall be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agrees it shall not be permitted to include in rate base for Step 2 Rates plant in excess of the amount or value of plant projected in this Cause. The Revenue Settling Parties agree that Step 2 Rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Step 2 Rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019, and calculate the Step 2 Rates using those certified figures. NIPSCO will provide all Revenue Settling Parties with its certification. The Revenue Settling Parties and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Revenue Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 Rates were put into place.

- The Revenue Settling Parties agreed to the following issues related to rate design:

  - Rates should be designed with the Residential Customer Charge set at $13.50/month;

  - as proposed in Industrial Group witness Phillips' direct testimony and NIPSCO witness Westerhausen's rebuttal testimony, Rate 830 shall be split into Rates 832 and 833 which shall reflect the current structure of Rates 732 and 733, and provide for back-up and maintenance provisions reflected in current Rider 776; and

  - Rate 844 shall see no increase in its base rates resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago.

- The Revenue Settling Parties agreed to the following tracker and rider issues:

- NIPSCO agrees to flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero.
- NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years.
- NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief.

- NIPSCO commits to seek approval of a voluntary low-income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process NIPSCO has already established with interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

- The lamp charge for TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. The resulting revenue deficiency (estimated at NIPSCO's proposed COSS to equal approximately $52,500) will be allocated to other customer and NIPSCO-owned lamp types in Rate 850.

21. <u>Revenue Settlement Supporting Testimony</u>.[35]

A. <u>NIPSCO Witness Sistovaris</u>. Ms. Sistovaris and the other Revenue Settling Parties sponsored Joint Exhibit 1, which is a copy of the Revenue Settlement in this Cause, including the Formal Notice of Indiana Municipal Utility Group Joinder in Amended Partial Settlement Agreement filed May 15, 2019. She testified the specific objectives addressed in the Revenue Settlement include: (1) resolution of the revenue requirements issues; (2) resolution of issues related to the Residential Customer Charge; (3) resolution of issues relating to proposed Rate 830; (4) resolution of issues related to the impact on proposed Rate 844 customers; (5) resolution of issues relating to proposed Rate 850; (6) resolution of issues related to NIPSCO's proposals relating to proposed Riders 871, 872, and 877; and (7) resolution of issues relating to creation of a low-income program.

Ms. Sistovaris summarized the differences in the proposed revenue requirements among the parties. She testified that NIPSCO filed this case to: (1) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure; (2) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (3) revise its depreciation rates; and (4) align its rates and charges required to maintain safe and reliable service. She stated the majority of

[35] Sierra Club filed a notice of support for the Revenue Settlement stating that the direct and cross-answering testimonies of Ms. Allison to support the overall reasonableness of the fixed charge for residential service and the acceleration of depreciation for NIPSCO's coal-burning units.

the differences in the proposed revenue requirements among the parties can be reduced to three issues: (1) NIPSCO's authorized ROE; (2) NIPSCO's need to address unresolved impacts related to the TCJA, particularly the return of excess ADIT; and (3) NIPSCO's efforts to mitigate the effects of the requested change in depreciation rates. Additionally, there were other proposed differences to the revenue requirement related to proposed amortization periods for various regulatory assets and differences in pro forma operating costs.

In support of the agreed-upon ROE and the resulting authorized NOI, Ms. Sistovaris stated there was a balancing of interests among NIPSCO's stakeholders. She noted 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 to provide reasonably adequate service and facilities. However, NIPSCO recognizes that returns have trended downward since its last rate case order. She stated that balancing the interest of all stakeholders, the Revenue Settling Parties agreed upon an ROE of 9.90%, which is lower than NIPSCO's requested ROE but higher than the ROE proposed by the OUCC, the Industrial Group, and Walmart.

In support of the agreed-upon treatment of the return of excess ADIT, Ms. Sistovaris stated the Revenue Settling Parties agreed that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460), shall be passed back in NIPSCO's revenue requirement at the ARAM, estimated at the time of the Revenue Settlement to be 26 years. She stated that the Revenue Settling Parties also agreed that NIPSCO's Unprotected and Other Excess ADIT balance (totaled approximately $137,789,071 as of December 31, 2017) shall be amortized $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. The Revenue Settling Parties agreed that at the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. Finally, NIPSCO agreed that if not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO will make a tariff filing that will reflect the ending of the amortization.

In support of the agreed-upon resolution of NIPSCO's request to modify its depreciation rates and cost recovery in rates, Ms. Sistovaris stated that the Revenue Settling Parties agreed to the depreciation accrual rates recommended by Mr. Spanos and presented in the Depreciation Study with two exceptions. First, those proposed depreciation rates are expected to result in a regulatory asset to be included in rate base and amortized over a period of years as described in NIPSCO witness Shikany's direct testimony. The Revenue Settlement provides that the amortization period of that regulatory asset shall conclude in 2032. Second, annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency expense included in demolition costs, as proposed by Industrial Group witness Gorman.

Ms. Sistovaris testified the Revenue Settling Parties agreed that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding, except that the amount of annual amortization expense shall be modified to reflect an amortization period for the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years. She stated that NIPSCO agreed that if not already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO will make a tariff filing that will reflect the reduction in amortization expense.

Ms. Sistovaris stated the Revenue Settling Parties agreed that NIPSCO would implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base and rates resulting from the final order in this proceeding and the actual investment amount adjusted for depreciation as outlined in Mr. Blakely's direct testimony and also agreed to implement the credit upon the retirement of the generating units. She described the credit will be limited to the net plant investment value of the Schahfer and Michigan City generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. She explained that NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in the Revenue Settlement (paragraph B.1(a)); and (2) the NOI established in the Revenue Settlement (paragraph B.1(b)) for purposes of its earnings test. NIPSCO also agreed to hold annual pre-filing meetings preceding the 30-day compliance filing with interested stakeholders.

Ms. Sistovaris testified NIPSCO agrees that a NOI of $271,211,585 is an acceptable return on the fair value of its assets. With regard to the proposed changes to Rate 811, Ms. Sistovaris testified the Revenue Settling Parties agreed that the customer charge for Rate 811 will be $13.50 per month. She explained that for purposes of this proceeding, NIPSCO is willing to reduce its customer charge based on the result of a compromise between NIPSCO, CAC, and the OUCC.

With regard to the proposed changes to Rate 830, Ms. Sistovaris testified the Revenue Settling Parties agreed that as proposed in Mr. Phillips' direct testimony and Mr. Westerhausen's rebuttal testimony, Rate 830 will be split into Rates 832 and 833 which will reflect the current structure of Rates 732 and 733, and provide for back-up and maintenance provisions reflected in current Rider 776.

With regard to the proposed changes to Rate 844, Ms. Sistovaris testified the Revenue Settling Parties agreed that Rate 844 will see no increase in its base rates resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. She explained that NICTD, a regional commuter rail authority uniquely situated among NIPSCO's customers, is NIPSCO's only customer taking service under proposed Rate 844. She stated that NIPSCO believes that any unnecessary financial burden on NICTD will have a direct impact on economic development in the region. She noted that NICTD provides a vital transportation function within northwest Indiana directly adjacent to Chicago allowing for thousands of commuters from this region to travel to and from work in Chicago, funneling hundreds of millions of dollars of earned wages into the area each year.

Regarding proposed changes to Rate 850, Ms. Sistovaris testified the Revenue Settling Parties agreed that the lamp charge for TDSIC Light-Emitting Diode ("LED") NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. She explained the resulting revenue deficiency will be allocated to other customer and NIPSCO-owned lamp types in Rate 850 and that NIPSCO recognizes the important public service benefits that municipal street lighting provides and the individual efforts of IMUG in initiating and supporting the LED modernization of NIPSCO street lights. She testified the Rate 850 outcome is reasonable.

Ms. Sistovaris addressed proposed changes to NIPSCO's Tariff resulting from the Revenue Settlement by stating the Revenue Settling Parties agreed that: (1) NIPSCO will flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; (2) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years; and (3) NIPSCO's proposal for treatment of economic development rider contracts in Rider 877 shall be approved, including the deferral mechanism described in NIPSCO's case-in-chief.

Ms. Sistovaris testified the Revenue Settling Parties agreed that NIPSCO will seek approval of a voluntary low-income program within six months of a final order in this proceeding. She explained that other program details will be established in good faith through the collaborative process NIPSCO has already established with NIPSCO and interested stakeholders. She stated NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. She said funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

Ms. Sistovaris explained that NIPSCO initiated this proceeding to address three main drivers: (1) to change depreciation rates; (2) NIPSCO needed to address the impact of the TCJA, and; (3) NIPSCO is proposing a change in its large industrial service structure to address the changing economic landscape. She commended the efforts of all Revenue Settling Parties that led to the Revenue Settlement in the abbreviated time permitted by General Administrative Order 2013-5 and Ind. Code § 8-1-2-42.7 and stated the Revenue Settlement was only possible because of the collaborative and open efforts of all Revenue Settling Parties. She stated the Revenue Settlement represents a diligent effort by all Revenue Settling Parties to reach a comprehensive result. She explained that the complexity of the issues and the diversity of the Revenue Settling Parties dictated the need for compromise on the part of everyone involved, and the Revenue Settlement reflects a delicate balance that accommodates the interests of all Revenue Settling Parties in a reasonable way.

Ms. Sistovaris testified approval of the Revenue Settlement as it is written is consistent with the public interest. She stated that as the evidence reflects, the Revenue Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement and a few other issues. Moreover, the Revenue Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost.

B. <u>NIPSCO Witness Shikany</u>. Ms. Shikany supported the Revenue Settling Parties agreement that NIPSCO should be authorized to implement its basic rates and charges for electric utility service in two steps: (1) the first change in rates will be based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation and amortization expense as of June 30, 2019 ("Step 1"); and (2) the second change in rates will be based on the agreed revenue requirement as of December 31, 2019, as adjusted, if necessary, to reflect the lesser of (a) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($4,115,502,071), or (b) NIPSCO's certified test-year-end net plant in service as of December 31, 2019 ("Step 2") and includes the amortization of $12,170,384 per year in the revenue requirement related to the pass back of the unprotected property and other unprotected excess ADIT to customers.

She stated that the Step 1 revenue requirement reflects NIPSCO's projected net utility plant in service, projected capital structure and the associated depreciation and amortization expense as of June 30, 2019, and maintains the amortization of the protected property excess ADIT using ARAM and unprotected property and other unprotected excess ADIT using ARAM and ten years, respectively. She explained that the Revenue Settlement provides for amortization to increase at Step 2 to reflect the pass back of $12,170,384 per year, and that Step 1 rates will go into effect on the next billing cycle following NIPSCO's submission of its Step 1 compliance filing.

She stated that the Step 2 revenue requirement reflects NIPSCO's projected net utility plant in service, projected capital structure and the associated depreciation and amortization expense as of December 31, 2019 and contains the additional pass back of the unprotected property and other unprotected excess ADIT and that Step 2 rates will be certified and go into effect, subject to refund, on March 1, 2020.

Ms. Shikany described the settlement adjustments agreed to by the Revenue Settling Parties. She testified that NIPSCO also updated the Costs of Customer Deposits and the Post-1970 ITC to correct clerical errors made during settlement negotiations, both of which had no impact on the overall WACC agreed to by the Revenue Settling Parties.

In summarizing the Step 2 revenue requirement, Ms. Shikany testified that NIPSCO proposes to recover the gross revenue amount of $1,482,166,740, which reflects a revenue increase of $46,608,036 as compared to test year pro forma results based on new service structure or a revenue decrease of $45,035,606 compared to test year pro forma results based on current rates, providing NIPSCO the opportunity to earn NOI of $271,211,585. She stated the agreed revenue requirement of $1,482,166,740 reflects a reduction of $63,648,449 from NIPSCO's case-in-chief proposal of $1,545,815,189 and a reduction of $62,891,513 from NIPSCO's rebuttal proposal of $1,545,058,253.

In summarizing the Step 1 revenue requirement, Ms. Shikany testified the Step 1 revenue requirement maintains the amortization of the unprotected property and other unprotected excess ADIT using ARAM and ten years, respectively and is based on the 12-month period ending June 30, 2019. Step 1 proposes to recover the gross revenue amount of $1,456,884,344, which reflects a revenue increase of $21,325,640 as compared to test year pro forma results based on new service structure or a revenue decrease of $70,318,002 compared to test year pro forma results based on current rates, providing NIPSCO the opportunity to earn NOI of $259,146,998.

Ms. Shikany explained the Revenue Settlement adjustments for Step 1. She testified that Settlement Adjustments OM 24-S2-S-19R, AMTZ 10-S2-S-19R, and AMTZ 11-S2-S-19R discussed above for Step 2 are applicable to Step 1. She testified the Step 1 revenue requirement is based on NIPSCO's current projections of utility plant in service, accumulated depreciation, and capital structure at June 30, 2019; therefore, the depreciation and some amortization expense adjustments, and the federal and state income taxes adjustment have been updated to include the pass back of the unprotected property and other unprotected excess ADIT at ARAM and ten years, respectively (the pass back of unprotected property and other unprotected excess ADIT at $12,170,384 per year, which will occur as of Step 2).

Ms. Shikany described the changes to NIPSCO's Tariffs as a result of the Revenue Settlement. She testified the Revenue Settling Parties agreed that: (1) NIPSCO will flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; and (2) NIPSCO shall discontinue its ECR Mechanism and shall recover the remaining regulatory asset over two years.

Ms. Shikany described the prospective annual credit mechanism agreed to in the Revenue Settlement. She stated the Revenue Settling Parties agreed that NIPSCO will implement an annual credit mechanism to reflect the difference between the net book value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base and rates resulting from the final order in this proceeding and the net book value at the date of the retirement as outlined in OUCC witness Blakely's direct testimony. She stated NIPSCO agreed to implement the credit upon the retirement of the generating units. She explained that the credit will be limited to the net book value of the Schahfer and Michigan City generating units embedded in base rates established in this Cause. She noted that NIPSCO will utilize a standardized form and will adjust: (1) the revenue requirement established in this proceeding; and (2) the NOI established in this revenue requirement for the purposes of its earnings test, and that NIPSCO agreed to hold annual pre-filing meetings preceding the 30-day filing with interested stakeholders.

Ms. Shikany testified that NIPSCO is seeking approval of depreciation accrual rates on an account by account basis. She stated that the depreciation study sponsored by Mr. Spanos in NIPSCO's case-in-chief, proposed specific depreciation rates by FERC account. She stated that the Revenue Settling Parties agreed that the depreciation accrual rates would be modified as described above to remove $26 million in contingency expense included in demolition costs and reflect the 2032 conclusion of the amortization period for the regulatory assets. Ms. Shikany stated that NIPSCO is requesting approval of these modified depreciation rates by FERC account.

Ms. Shikany explained that: (1) NIPSCO is seeking accounting authority to continue to defer, as a regulatory asset; discounts offered to certain customers under its Economic Development Rider for recovery in a future rate case in a manner consistent with the 44688 Rate Case Order; (2) NIPSCO is seeking authority to defer, as a regulatory liability, an amount equal to 100% of annual OSS margins net of expenses and back-up and maintenance demand margins, both for pass back through the RTO Tracker; and (3) NIPSCO is seeking authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. She testified that NIPSCO is requesting Commission approval of the deferrals.

C. NIPSCO Witness Westerhausen. Mr. Westerhausen explained how the Revenue Settlement rate-specific revenue requirement is calculated for proposed Rate 844 – Railroad Power Service, and he sponsored the proposed mitigation updated for the settlement revenue requirement and the adjustment for Rate 844. He also described and supported the Revenue Settling Parties' agreement that TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase.

Mr. Westerhausen testified that the Revenue Settling Parties agreed that Rate 844 shall see no increase in its base rates given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. He explained that keeping the demand rate at $16.85 and the two block energy rates at $0.041718 and $0.039468, resulted in the Rate 844 proposed mitigated revenue requirement excluding other revenue being $2,119,429 and that adding $26,855 in other revenue credits results in the proposed mitigated revenue for Rate 844 being $2,146,284. He explained that although the current Rate 744 two block energy rates are $0.041731 and $0.039481, these rates have been updated to reflect the forecasted rates to go into effect with the first billing cycle of October 2019 to adjust for the amortization roll off of the three-year amortization of electric vehicle expenses that was approved in the 44688 Rate Case Order.

Mr. Westerhausen testified that the Revenue Settling Parties agreed that TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. He stated this agreement is responsive to IMUG's testimony that the proposed Rate 850 rate increases to those municipalities that were the most prepared and first had their NIPSCO-owned street lights converted to LED would receive a disproportionate rate increase. He explained that NIPSCO recognizes and appreciates IMUG's concerns, and this agreement is responsive to those concerns. He testified that the Rate 850 settlement provision was very important to IMUG and necessary for their participation in the Revenue Settlement and that this adjustment only affects other customers within Rate 850. In Joint Exhibit 8, which was admitted in lieu of cross examination of Mr. Westerhausen, NIPSCO stated that the calculation of the cost of the Rate 850 agreement had been calculated on a monthly basis, but reported as an annual number. This resulted in an annual shortfall of revenue of $632,110. NIPSCO agreed with the OUCC to allocate only one-half of the revenue shortfall to NIPSCO's other Rate 850 customers and that NIPSCO would not seek recovery of the remainder from its other customers.

Mr. Westerhausen sponsored NIPSCO's proposed mitigation based on the Revenue Settlement's revenue requirement and the adjusted Rate 844 revenue requirement. He testified the total revenues proposed are based on an ACOSS that utilized a 4CP production allocation. He explained that with Rate 831 held at parity, the revised rate increase for all the rate classes except Rates 831 and 844 is 6.66%. Mr. Westerhausen also updated Attachment 19-R-F to his rebuttal testimony for the Revenue Settlement's revenue requirement and for the adjustment of Rate 844 in order to establish the allocation factors for NIPSCO's surviving tracking mechanisms.

D. <u>OUCC Witness Blakley</u>. Mr. Blakley's Revenue Settlement testimony addressed two items. He detailed the Revenue Settling Parties' agreement regarding the revenue credit mechanism related to the Schahfer and Michigan City Generating Stations. The revenue credit mechanism recognizes the net rate base value of the stations at the time the rates are approved in this Cause, then reduces the plant investment for annual depreciation at the time the first annual revenue credit mechanism is implemented. The mechanism will then recalculate NIPSCO's return on the reduced plant investment of Schahfer and Michigan City. He explained the difference between the return embedded in NIPSCO's base rates for Schahfer and Michigan City and the annual recalculated return based on the reduced plant value will be credited back to customers annually through a revenue credit mechanism filing.

Mr. Blakley also described the Revenue Settling Parties' agreement on excess ADIT to be returned to ratepayers. He described how the agreement will pass back approximately $203,164,460 of protected excess ADIT using ARAM over an estimated period of 26 years. Mr. Blakley also explained how the refund of unprotected and other excess ADIT of approximately $137,789,071 will start at $12,170,384 annually to begin after Phase 2 rate implementation on or around March 1, 2020. At the time of NIPSCO's next rate case, the total amount of unprotected excess ADIT to be passed back will be determined and the agreed amortization may be adjusted.

Mr. Blakley testified these two portions of the Revenue Settlement generate customer benefits that were achieved only in settlement, as there was not consensus on either item in the parties' prefiled testimonies. He concluded that in context with the other terms, the entire Revenue Settlement serves the public interest and should be approved, in its entirety, without modification.

E. OUCC Witness Eckert. Mr. Eckert testified that if approved, the Revenue Settlement will provide certainty regarding critical issues, including revenue requirements, authorized return, and other miscellaneous issues. He testified that the Revenue Settlement was a result of intense negotiations with each party offering compromise to challenging issues, including assessing the litigation risk that the tribunal will find the other side's case more compelling. He stated that while the Revenue Settlement represents a balance of all interests, given the number of benefits provided to ratepayers, the OUCC believes the Revenue Settlement is a fair resolution, supported by evidence, and should be approved.

Mr. Eckert testified that as a result of the Revenue Settlement, NIPSCO's base rates reflect a lower revenue requirement than NIPSCO's initial proposal with the system-wide revenue increase of approximately 3.25%, thereby reducing the revenue increase impact for all NIPSCO's customers relative to NIPSCO's original proposal. He testified the Revenue Settlement resolves the TCJA issues and accounts for the changes to NIPSCO's revenue requirement necessary to address the TCJA and the Commission's order in Cause No. 45032-S5.

Mr. Eckert testified the ratepayer benefits in the Revenue Settlement include: (1) a $13.50 monthly residential customer charge – a $0.50 decrease from the current $14 charge and $3.50 less than NIPSCO's initial request of $17.00; (2) a 9.90% authorized ROE compared to NIPSCO's proposed increase to 10.80%; (3) resolving all issues regarding the TCJA; (4) NIPSCO's commitment to seek approval of a voluntary low-income program and establish a collaborative process to work out the program details (the cost of which is not reflected in the agreed revenue deficiency in this case); (5) certain exceptions to the depreciation accrual rates recommended by NIPSCO, resulting in a reduction to the revenue requirement; (6) adjustments to NIPSCO's proposed annual amortization expense; (7) an annual revenue credit mechanism reflecting the difference between the value of Schahfer and Michigan City units in NIPSCO's rate base at the time a final order is issued and the actual investment amount adjusted for depreciation; (8) changes to Rates and Tariffs; and (9) additional benefits negotiated by the Revenue Settlement.

Mr. Eckert explained that NIPSCO proposed a 10.80% ROE and the OUCC, Industrial Group, and other intervenors advocated for a considerably lower ROE applied to NIPSCO's original cost rate base. He testified that as a result of the negotiations, a compromise was reached, resulting in a 9.90% ROE and elimination of the fair value increment. Mr. Eckert testified a lower ROE benefits ratepayers by reducing the return on the rate base ultimately reducing the revenue requirement by approximately $23.8 million. He stated the Revenue Settlement establishes a balanced plan that is in the interest of both ratepayers and shareholders.

Mr. Eckert testified that the impacts of the TCJA lowered NIPSCO's annual revenue requirement by approximately $20.0 million as addressed in the Revenue Settlement. Mr. Eckert also testified that the Revenue Settlement reduced test year O&M expense by $2 million, a reduction to amortization expense in the amount of $7,789,765, and a reduction in depreciation expense of $29 million.

With regard to treatment for OSS margins in the RTO Tracker, Mr. Eckert testified that flowing through 100% of OSS margins is an offset to ratepayers who are paying NIPSCO's retail rates to support the O&M expenses and provide a return of and a return on the assets that support OSS. He stated that ratepayers pay rates that reflect the MISO administrative fees, which provide for MISO to administer OSS of NIPSCO's excess generation. Additionally, 100% tracking of OSS margins will simplify the calculation of the OSS margin component of NIPSCO's proposed RTO Tracker and will provide transparency in the flow through of OSS margins. He testified that the Settling Parties agreement to continue NIPSCO's EDR proposal, including the deferral mechanism, will continue to bring economic benefits to NIPSCO, its ratepayers, and the region.

Mr. Eckert testified NIPSCO's commitment to seek approval of a voluntary low-income program within six months of an order in this proceeding. He stated that the program funding will be voluntary for all customers will not impact NIPSCO's revenue requirement.

Mr. Eckert concluded that the OUCC recommends that the Commission find the Revenue Settlement to be in the public interest and approve it in its entirety.

F. Industrial Group Witness Gorman. Mr. Gorman provided testimony in support of the Revenue Settlement and recommended that the Commission approve the settlement as reasonable and in the public interest.

Mr. Gorman testified that the Revenue Settlement reasonably resolved the parties' contested revenue issues. Specifically, he testified the Revenue Settlement reduced the proposed revenue increase by 57%, decreasing the proposed $111.4 million increase by $63.648 million. He testified that each of the revenue compromises, relative to the range of issues in the case, provide a reasonable outcome as they impact the total revenue requirement. He testified that the Revenue Settlement reflected a 9.90% ROE, which is in line with the ROE authorized by the Commission in NIPSCO's last base rate case. He added that the lack of change in capital market costs since that time supported finding a ROE reasonably comparable to the last case. Mr. Gorman also noted that NIPSCO had adjusted its proposed amortization of excess unprotected ADIT to ten years, and that the overall adjustment to operating expenses is appropriate and consistent with the compromise resolution of issues in the case.

22. Revenue Settlement Opposing Testimony.

A. ICC Witness Medine. Ms. Medine addressed three aspects of the Revenue Settlement: (1) approval years in advance of the accounting treatment and amortized recovery of undepreciated costs that NIPSCO will receive when it decides to retire any existing coal generation resource; and (2) any aspect of the settlement that locks-in specific retirement dates for any existing coal generation resource. In addition, she addressed why NIPSCO should only be allowed to include costs that are regularly adjusted outside base rates in the MISO bid prices for the coal units and should not be allowed to include costs that are recovered through base rates.

Mr. Medine recommended that the Commission deny approval of accounting treatment and amortized recovery that NIPSCO would receive if and when it retires any existing coal generation resources, and require NIPSCO to seek that relief at or near the time of actual retirement. She also recommended that the Commission avoid giving explicit or implicit approval to any specific date for retirement of any specific existing coal generation resource at this time. She recommended that the Commission limit NIPSCO from including variable operating costs in its offer price to MISO that are being recovered in base rates. Finally, she recommended that the Commission give guidance to NIPSCO for its 2021 IRP.

B. ICC/ICARE Witness Griffey. Mr. Griffey testified he does not oppose the Revenue Settling Parties' decision to set depreciation accrual rates for the coal units based on assumed lives ending in 2032. However, he recommended the Commission reject the aspect of the Revenue Settlement that would have it pre-approve now, years in advance of when NIPSCO may actually retire the units, regulatory asset treatment for sunk costs and pre-ordained amortization based on an assumption that the Schahfer units will all retire in 2023 and Michigan City in 2028.

Mr. Griffey noted a legislative Task Force will present findings in 2020 concerning the impacts of changing electric generation portfolios. He stated the Commission cannot know today what the statewide policies and regulatory statutes will be in 2023 and beyond thus making it premature to preordain in 2019 what accounting treatment and/or amortization treatment NIPSCO should receive if and when it actually retires existing generation resources in or after 2023.

Mr. Griffey stated that given the flaws in NIPSCO's IRP retirement and replacement analysis and the Task Force's mandate, he recommended the Commission: (1) decline to adopt any aspect of the settlement that forecloses flexibility; and (2) decline to approve explicitly or implicitly NIPSCO's professed retirement intentions based on its flawed IRP. He further recommended the Commission direct NIPSCO to: (1) perform an integrated retirement and replacement analysis in its 2021 IRP; and (2) seek regulatory and accounting treatment for any retiring coal plants at or near the time of actual retirement.

C. LaPorte Witness Cearley. Mr. Cearley took issue with the Revenue Settlement proposed cost of equity of 9.90% as being reasonable based on below average customer satisfaction results. He made two recommendations: (1) the Commission should adopt a return toward the bottom of the proposed range to reflect NIPSCO's lack of customer focus and poor customer satisfaction performance levels; and (2) NIPSCO's proposals to address its environmental and disproportionate level of large industrial load should have the effect of mitigating NIPSCO's risk. In response to the Commission's docket entry question, LaPorte stated that Mr. Cearley believes that a 25 to 50 basis point downward ROE adjustment for the elimination of each of these significant risk factors is appropriate and reasonable. LaPorte's docket entry response stated that this recommendation is further supported by Mr. Cearley's recognition in his direct testimony of the compounding effect of NIPSCO's repetitive risk adjustments to its return calculations based on environmental risks and its requests for upward risk adjustments due to a disproportionate level of large industrial load in its last three to four rate case proceedings.

23. Revenue Settlement Reply Testimony.

A. NIPSCO Witness Sistovaris. In response to LaPorte witness Cearley's criticism of NIPSCO's J.D. Power results and recommendation that the ROE in the Revenue Settlement be rejected, Ms. Sistovaris first noted that the J.D. Power surveys attached to his testimony do not support his claims. She explained that those surveys show on both the residential- and business- customer satisfaction side, NIPSCO's scores have been improving and that NIPSCO has been improving relative to its peers. Notably, NIPSCO is moving closer to the average survey result. She stated that on the residential side, NIPSCO has grown from a score of 645 in 2016 to a score of 706 in 2018 and that over that period, its distance from the average score has been cut in half. On the business side, NIPSCO's score has grown from 671 to 760, and it is almost at the average score. Additionally, J.D. Power has listed NIPSCO among the nation's most improved electric utilities in 2010, 2012, and 2015. She testified that these results show improvement, including improvement compared to NIPSCO's peers.

B. NIPSCO Witness Shikany. Ms. Shikany testified that Ms. Medine and Mr. Griffey seem to misunderstand the relief requested in this case. She explained this case is not about NIPSCO's preferred portfolio in its 2018 IRP, generation transition, or selecting a portfolio of resources. In fact, the preferred portfolio in the 2018 IRP is irrelevant to the issues in this case. She stated that this case is not about locking in retirement dates for NIPSCO's coal-fired generation. Rather, this is a general rate case, and as part of that general rate case, NIPSCO has sought approval of new depreciation accrual rates and has submitted a depreciation study. Ms. Shikany said that neither Ms. Medine nor Mr. Griffey took issue with the depreciation study or the depreciation rates that come out of the depreciation study. In fact, Ms. Medine specifically acknowledged that she takes no issue with the depreciation rate for NIPSCO's steam production plant, which underlies the Revenue Settlement. She stated that because the ICC and ICARE do not represent customers in this proceeding, the Revenue Settlement has no effect on them, and the only issue that may concern them (depreciation lives for coal plants), they explicitly accept.

Ms. Shikany testified that much of ICC and ICARE testimony is posturing for some future case that has not been filed rather than having anything to do with the relief NIPSCO seeks in this Cause. She noted that the ICC has intervened in four NIPSCO cases: this one, two PPA cases (Cause Nos. 45195 and 45196), and one joint venture case (Cause No. 45194). She explained that in all four cases, they have opposed NIPSCO's relief, yet none of those cases has any impact on the ICC, a fact that Ms. Medine admits when she notes that the "wind projects [in Cause Nos. 45195 and 45196] contribute very little UCAP and therefore have less relevance to the IRP which is focused on resources." Ms. Shikany stated that if those cases are irrelevant and have "very little impact" on the ICC's core issue (the IRP), then it is troublesome that the ICC chose to intervene and take up valuable resources to oppose relief "having very little impact." Instead, the ICC could have simply stated its issues with the IRP (which it has already done in the IRP process) and taken no issue on the ultimate relief sought – relief which every other party (all of whom represented actual customers who pay NIPSCO utility rates) agreed should be granted. She testified that this case contributes zero UCAP and therefore has even "less relevance to the IRP," and therefore less effect on the ICC and ICARE.

Ms. Shikany noted that both Ms. Medine and Mr. Griffey testified that NIPSCO's regulatory asset treatment resulting from the Revenue Settlement is unnecessary at this time and should be deferred until the coal plants are actually retired. She stated the Revenue Settling Parties would not have reached a settlement that delayed the return on and of its investment in coal-fired generation until 2032 without granting the proposed regulatory asset treatment.

Ms. Shikany testified that deferring a decision on the regulatory asset treatment until the coal plants are actually retired would not be wise and is inconsistent with proper ratemaking. She described that this case is about establishing electric rates and, as part of that determination, setting new depreciation accrual rates. She explained that in the normal course, depreciation accrual rates would be set to recover the remaining book value over the remaining estimated useful life of the assets. She stated that the only evidence that has been introduced concerning the proper estimated useful life of the Schahfer units is 2023 and of the Michigan City unit is 2028. She testified that the ICC and ICARE have not proposed a different estimated useful life of these generating stations for depreciation purposes than that proposed by NIPSCO. She explained that under this scenario, NIPSCO would recover the remaining investment of Schahfer over the next four years and Michigan City over the next nine years at which point NIPSCO would fully recover its remaining investment in these units and would recover a return on that remaining investment. Ms. Shikany testified that from the outset of this case, NIPSCO has recognized that such a result would produce significant rate increases and has, accordingly, proposed to delay the recovery of the remaining investment over a longer period on the condition that the resulting regulatory asset would be included in rate base. She noted that every group representing customer interests in this case has either agreed to that condition or has not opposed it. She indicated that absent this condition, NIPSCO would recover the entire investment by the physical retirement date, which would result in significantly higher customer rates that would not be agreed to by the Revenue Settling Parties in the Revenue Settlement. She stated that the only parties opposing that condition are coal interests that will have absolutely no interest in whether NIPSCO earns a return of and on its investment.

Ms. Shikany stated that the only evidence that has been introduced of the estimated useful lives of NIPSCO's coal plants is 2023 and 2028. She explained that if NIPSCO were to come out of this case without either: (1) depreciation rates which would match recovery to those useful lives; or (2) assurance that it will recover both a return of and on any costs that would not have been recovered at the time of retirement, NIPSCO faces a risk of immediate write-off under GAAP, which would have a negative impact on the financial statements and the investor community. She also explained that a delay in the cash recovery beyond the useful life of the related assets without assurance that the remaining net book value of the coal generation assets as a regulatory asset in rate base could result in a negative impact on NIPSCO's credit ratings resulting in an increase in NIPSCO's cost of capital. She stated that not facing the depreciation issue today when it should be addressed would result in needless harm to an Indiana utility and its customers. Ms. Shikany testified there is a very real need to either set appropriate depreciation rates based upon the estimated useful life today or, if that result needs to be mitigated, assure NIPSCO that it will recover a return of and on its investment.

Ms. Shikany testified the deferral mechanism to which the parties have agreed provides that NIPSCO will recover a return of and on the investment through 2032. She explained that so long as those coal plants are retired between now and 2032, there would be absolutely no difference to the relief that is set forth in the Revenue Settlement. She explained that if Schahfer were to remain in service until 2028, the remaining net book value at the time of the retirement would be smaller (due to five years of additional depreciation expense) and NIPSCO would simply amortize that remainder over a period shortened by five years. She noted that under either scenario, NIPSCO is recovering a return of and on the same investment and, therefore, there is no harm to customers from granting the regulatory asset treatment today.

In response to Ms. Medine's and Mr. Griffey's testimony that the Commission should wait to grant the regulatory asset treatment until after the legislative Task Force completes its work, Ms. Shikany stated that the legislative Task Force is not going to have an effect on the relief NIPSCO seeks in this proceeding and certainly no effect that could not be revisited at that time. Ms. Shikany stated that any number of changes could be implemented after they are adopted and would have no effect on this case. She said that as it is, there are no retirements planned until three years after the Task Force meets affording plenty of time to reflect legislative changes should they occur. She testified that the issue in this case is how much customers today should pay in rates so that NIPSCO can be assured recovery of a return of and on its investment in coal-fired generation that has served its customers very well for many years.

In response to Mr. Griffey's recommendation that the Commission should decline any aspect of the Revenue Settlement that forecloses flexibility and decline to approve explicitly or implicitly NIPSCO's retirement dates, Ms. Shikany testified that no aspect of the Revenue Settlement does either. She noted that there continues to be great flexibility for NIPSCO to adapt to the changing environment. She reiterated that this case is purely about cost recovery today, and the Commission is not approving explicitly or implicitly retirement dates; rather, it is setting depreciation accrual rates. She stated that the actual lives of these generating facilities may be different than the lives that are estimated today, which is not uncommon. She testified that if estimated lives change, the differences will be addressed through prospective changes in depreciation accrual rates that would be proposed in a subsequent base rate proceeding.

C. NIPSCO Witness Augustine. Mr. Augustine responded to Mr. Griffey and Ms. Medine's claims that NIPSCO's 2018 IRP contained multiple flaws. Mr. Augustine sponsored his rebuttal testimonies in Cause No. 45194 (Attachment 6-S1-R-A), 45195 (Attachment 6-S1-R-B), 45196 (Attachment 6-S1-R-C), and NIPSCO's response to stakeholder comments on the 2018 IRP (Attachment 6-S1-R-D) and testified that within his rebuttal testimony in this Cause and in these other responses and testimonies, he addressed concerns related to industrial load uncertainty, end effects calculations, and the 20-year versus 30-year analysis time horizon, retirement, and replacement analysis modeling and associated portfolio development assumptions, future coal plant capital and maintenance costs, environmental regulation assumptions, scenario development and the IRP's stochastic risk analysis, the flexibility of NIPSCO's preferred portfolio, wind and solar cost and operational assumptions, congestion and transmission cost assumptions, and ancillary services cost assumptions. He noted that many of the concerns raised by witnesses Griffey and Medine related to NIPSCO's 2018 IRP in their responses to the Revenue Settlement were litigated in significant detail in Cause Nos. 45195 and 45196, wherein the Commission concluded that "[w]hile ICC criticized various aspects of NIPSCO's modeling, witness Augustine, in rebuttal, adequately addressed those criticisms."[36]

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[36] Order in Cause No. 45195 (IURC 06/05/2019) (the "45195 Order"), p. 9, and Order in Cause No. 45196 (IURC 06/05/2019) (the "45196 Order"), p. 10.

Mr. Augustine responded further to Mr. Griffey's claims that NIPSCO's two-step retirement and replacement analysis is inherently flawed and, Ms. Medine's suggestion that the Commission should direct NIPSCO to perform integrated planning that does not separate retirement and replacement decisions. He testified that the IRP analysis approach allowed NIPSCO to first fully evaluate a wide range of retirement concepts and then to secondly evaluate replacement portfolios across a range of objectives and a range of commitment duration and diversity outcomes. He testified that in its 45195 and 45196 Orders, the Commission affirmed its understanding of this process, and in response to the ICC's claims that the approach was biased, stated that the "ICC fails to recognize that the two analyses have distinct purposes."[37] He noted that the first purpose of evaluating the range of retirement options is most relevant because the issue at hand is the economic useful life of the current coal fleet and the depreciation rates for NIPSCO's existing assets, and not a specific replacement decision. He explained that throughout its 2018 IRP, NIPSCO found that the early retirement of coal capacity is cost effective for customers whether the existing coal units are replaced with the least cost renewable options from the RFPs conducted as part of the 2018 IRP or with higher-cost MISO market energy purchases and capacity costs based on cost of new entry. He stated Mr. Griffey has not refuted this, and his efforts to compare retirement portfolios from this first step of the analysis with replacement portfolios that were constructed based on different objectives in the second step should not distract from the clear finding that retaining coal is higher cost than any number of alternatives. He stated again that NIPSCO incorporated other decision metrics in its analysis, including cost risk, reliability risk, environmental stewardship, and the impact on employees and the local economy in arriving at its preferred portfolio. He stated that if NIPSCO followed Mr. Griffey's guidance to select the lowest cost portfolio over the next 20 years, then a portfolio that retires all coal in 2023 would have been chosen. He testified that instead, a plan that staggers the retirements and replaces capacity with a mix of different renewables with different commitment durations was selected.

Mr. Augustine responded to Mr. Griffey and Ms. Medine's suggestion that industrial load uncertainty, particularly related to proposed Rate 831, was not sufficiently addressed in the 2018 IRP. He testified that: (1) NIPSCO's 2018 IRP evaluated a low load scenario with substantial industrial load leaving the system; (2) the competitiveness of the existing coal fleet and alternative replacement renewable resources is driven primarily by the cost structure of such resources and their position in the MISO market and not NIPSCO's internal load; and (3) future loss of firm load can be managed through the flexibility inherent in NIPSCO's preferred portfolio. He added that he is now aware that the partial settlement with five large industrial customers in this Cause is based on subscription of approximately 194 MW of firm load to Rate 831. He stated that when offset by the loss of industrial interruptible capacity that NIPSCO currently considers a supply resource, the impact of this rate design change on NIPSCO's load obligations is approximately 60 MW, a level that is far less than the load uncertainty ranges evaluated in the IRP and represents a small fraction of total demand.

Mr. Augustine responded to Mr. Griffey's testimony that the commitment of less than 200 MW for Tier 1 service is only for five years, which should support a decision to maintain flexibility about when to retire the coal plants, and Ms. Medine's suggestion that in the future NIPSCO should use a load forecast that accounts for any possible resulting change in load both in the initial five years of Rate 831 contracts and in later years. He agreed that load uncertainty should continue to

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[37] 45195 Order, p. 9, 45196 Order, p. 10.

be evaluated and that the industrial load uncertainty in NIPSCO's service territory is one reason to ensure flexibility in the supply portfolio; however, he testified that NIPSCO's preferred portfolio accomplishes this far better than Mr. Griffey's preference to continue operating the coal plants. He demonstrated that continued operation of the coal fleet is immediately higher cost than the alternatives, while NIPSCO's replacement plan allows for flexible procurement of new resources with different commitment durations over time, all at a lower cost. He stated that Mr. Griffey falsely attempts to claim that lower industrial load in the Challenged Economy scenario was the reason why coal units looked more economic, when the real driver of this result was the lack of a carbon price in that scenario. He stated that all of the scenarios evaluated by NIPSCO in the 2018 IRP, including the one designed by the ICC, showed that early retirement of the coal plants results in lower customer costs.

Finally, Mr. Augustine testified that he does not believe that Mr. Griffey's attempts to compare NIPSCO's process and situation to Vectren's are valid. In response to his claims that like Vectren, "NIPSCO plans to put most of its eggs in [one] basket," Mr. Augustine asserted that this is not true at all. NIPSCO plans to phase out coal plants over a ten-year period, NIPSCO owns an approximately 500 MW existing natural gas combined cycle plant that is part of its long-term preferred portfolio, along with other smaller natural gas peaking units, and NIPSCO plans to procure a mix of owned and contracted wind, solar, and storage resources, allowing for significant diversity and flexibility in resource procurement as technology and markets evolve. He noted that the Commission recently acknowledged the distinction between Vectren's plan and NIPSCO's and affirmed that "NIPSCO's 2018 IRP was explicitly developed to maintain optionality to enable making adjustments and modifications as circumstances warrant."[38]

Mr. Augustine also testified that Mr. Griffey's claim that "NIPSCO's IRP ignored options that could allow the coal units to remain in service" is false, as NIPSCO explicitly developed a range of portfolios that keep coal plants on longer, including with less stringent environmental regulations. He explained that NIPSCO also evaluated a scenario developed by the ICC that assumed *no* additional environmental capital expenditures would be required for the coal fleet and still found that early retirements were lower cost. Additionally, NIPSCO evaluated coal-to-gas conversion options and found that renewable replacements were lower cost than conversion. He stated that Mr. Griffey's claims that NIPSCO "failed to consider the possibility of higher gas and energy prices without CO2 taxes" and failed to update assumptions related to load uncertainty and wind operational parameters are false. He testified that NIPSCO evaluated a scenario with higher gas and energy prices and no CO2 price, designed specifically by the ICC to test the possibility Mr. Griffey claims was ignored, and found that early coal retirement and replacement with renewables was lower cost. In addition, NIPSCO also addressed load uncertainty sufficiently and confirmed that the overall cost and performance of the specific wind resources currently being added to the portfolio are consistent with the IRP's assumptions for wind resources.

D. <u>NIPSCO Witness Campbell</u>. Mr. Campbell responded to Ms. Medine's request that NIPSCO exclude non-FAC costs for purposes of MISO offer prices for NIPSCO's coal units. He testified that this issue was raised and rejected by the Commission in its April 29, 2019 Order in Cause No. 38706 FAC 122. He stated that in that Order, the Commission found that

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[38] Order in Cause No. 45195 (IURC 06/05/2019) (the "45195 Order"), p. 10, and Order in Cause No. 45196 (IURC 06/05/2019) (the "45196 Order"), p. 11.

NIPSCO demonstrated that its current offer strategy of its generation units into the MISO energy market was reasonable.[39] In addition, NIPSCO did not include inappropriate components of its offers to MISO, nor were they imprudent with respect to its generation decision-making. As such, the Commission should reach the same conclusion in this case. Mr. Campbell testified that Ms. Medine's view that including costs that are not tracked in NIPSCO's FAC would result in the possibility of over recovery of costs would actually result in an under recovery of costs related to the sale of energy into the MISO market. He explained that the variable costs of production that are built into the agreed revenue requirement are based upon production cost modeling, which is based upon NIPSCO's variable costs of production in relation to other sources of power offered into the MISO market. He stated that if NIPSCO were not to include all of the variable costs of production in its actual bids, all else being equal, NIPSCO's units would dispatch more energy than is assumed in the rate case. In other words, NIPSCO would incur variable costs of production that are not tracked and that would be in excess of the amount assumed in this case.

Mr. Campbell testified that even if the Commission allowed NIPSCO to recover its higher projected variable costs in base rates, NIPSCO's retail customers would be harmed. He explained that MISO maximizes the efficient use of the energy grid by utilizing its Security Constrained Economic Dispatch software that matches energy needs with resources based upon capability and price. He stated that were NIPSCO to offer its generation into the MISO market without consideration of its related variable costs, its offer price would not reflect the economic cost of running its generation units, its generating units would be uneconomically dispatched, and its retail customers would likely end up paying higher costs.

24. **Overview of the Rate 831 Settlement.** On May 17, 2019, NIPSCO, Industrial Group, NLMK Indiana, and US Steel filed the Rate 831 Settlement.[40] The Rate 831 Settling Parties stated that the Rate 831 Settlement fairly and reasonably resolves issues related to Rate 831, subject to Commission approval without any modification or condition that is unacceptable to the Rate 831 Settling Parties. The Rate 831 Settlement looks to resolve all issues related to implementation of Rate 831. The key terms of the Rate 831 Settlement are summarized as follows:

- The Rate 831 Settling Parties[41] agree that NIPSCO's COSS should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 MW.[42] The Rate 831 Settling Parties agree that $149.438 million (exclusive of approximately $2.827 million in "other revenues") shall be allocated to Rate 831.

- For purposes of tracker allocations, the Rate 831 Settling Parties agreed:

    - Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO witness Westerhausen's Verified Rebuttal Testimony

[39] The Commission stated (at 9) that "NIPSCO has adequately demonstrated that it 'has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]' Ind. Code § 8-1-2-42."

[40] The Rate 831 Settling Parties filed a revision to the Rate 831 Settlement on June 7, 2019.

[41] US Steel filed testimony only related to Rate 831, and thus supports the settlement COSS as it relates to the rates, charges, and trackers related to Rate 831, and takes no position on the remaining rate design.

[42] As shown in Confidential Exhibit C to the Rate 831 Settlement, Tier 1 subscriptions will be less than the presumed MW level, but this shall not alter the stated revenues assigned to Rate 831.

(updated for the settlement revenue requirement and the adjustment for Rate 844), shall be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms;

- Rate 831 Implementation Agreement Exhibit B, which is Attachment 19-R-E to NIPSCO witness Westerhausen's Verified Rebuttal Testimony (with no changes), sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism; and

- For the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO witness Westerhausen's Verified Rebuttal Testimony (updated with the settlement revenue requirement), reflect the allocation factors for TDSIC purposes.

- For purposes of Rate 831 rate design, the Rate 831 Settling Parties agreed:

  - Except as otherwise provided in the Rate 831 Settlement, the Rate 831 Settling Parties agree that Rate 831 shall be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in Paragraph B.1. of the Rate 831 Settlement.

  - The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the COSS presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in Paragraph B.1. of the Rate 831 Settlement.

  - For purposes of the AAQFPTC, the Rate 831 Settling Parties agree that the provision shall be amended by adding the following language: "If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period."

  - The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial five-year contract is set forth in Rate 831 Implementation Agreement Confidential Exhibit C. The Rate 831 Settling Parties agree that Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C shall be binding upon each customer in the event of the approval of this Agreement without modification.

  - The Rate 831 Settling Parties agree that a transition period, lasting from the date on which Step 1 Rates become effective until June 1, 2020, shall provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs. The Rate 831 Settling Parties agree that the terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

25. Rate 831 Settlement Supporting Testimony.

A. NIPSCO Witness Westerhausen. Mr. Westerhausen summarized the Rate 831 Settlement. He testified that the Rate 831 Settlement reflects the Rate 831 Settling Parties agreement on issues related to Rate 831 between and among themselves, including implementation. He stated the specific objectives addressed in the Rate 831 Settlement include resolution of: (1) the allocation of costs to Rate 831, eliminating the risk for a Phase 2 proceeding provided the Revenue Settlement, revenue allocation, and rate design of Rate 831 as proposed by NIPSCO are accepted; (2) allocation of trackers; and (3) Rate 831 implementation.

Mr. Westerhausen summarized that for purposes of settlement, the Rate 831 Settling Parties agreed that NIPSCO's COSS should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 MW allocating approximately $149.438 million (exclusive of approximately $2.827 million in "other revenues") to Rate 831.

Mr. Westerhausen stated that for purposes of settlement, the Rate 831 Settling Parties agree: (1) that Rate 831 Implementation Agreement Exhibit A (which is Attachment 19-R-F to his rebuttal testimony updated for the settlement revenue requirement and the adjustment for Rate 844) will be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms; (2) that Rate 831 Implementation Agreement Exhibit B (which is Attachment 19-R-E to his rebuttal testimony with no changes) sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism; and (3) for the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load," and TDSIC revenue allocation will only be applied to revenue associated with Rate 831 customers' Tier 1 load. He stated the Rate 831 Settling Parties agreed that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A reflect the allocation factors for TDSIC purposes.

Mr. Westerhausen summarized that for purposes of settlement, the Rate 831 Settling Parties agree that: (1) except as otherwise provided in the Rate 831 Settlement, Rate 831 will be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in the Rate 831 Settlement; (2) the design of Rate 831 will be based on the COSS presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in the Rate 831 Settlement; (3) the "Adjacent Affiliate Qualified Facility Premise Transmission Charge" provision will be amended to be clear that if the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period; (4) the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial five-year contract is as set forth in Rate 831 Implementation Agreement Confidential Exhibit C and agree that Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C will be binding upon each customer in the event of the approval of the Rate 831 Settlement without modification; and (5) a transition period (lasting from the date on which Phase I rates become effective until June 1, 2020) will provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs and agree that applicable terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

Mr. Westerhausen testified that Rate 831 Implementation Agreement Exhibit D sets forth the: (1) Tier 2 and/or Tier 3 contract terms; (2) rate implementation dates; (3) firm capacity transactions under Tiers 2 and 3; and (4) dispute resolution provisions, applicable to the transition period. He stated that the Rate 831 Settling Parties agree that any contract for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions: (1) identify NIPSCO as the Market Participant for the retail customer at MISO; (2) reference NIPSCO's market-based rate authority with FERC; (3) clearly state the Rate 831 customer remains a retail customer of NIPSCO; (4) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations); (5) incorporate relevant provisions of the Rate 831 tariff; (6) all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and (7) any information shared with NIPSCO shall be subject to a confidentiality agreement applicable to all terms of said agreements.

Mr. Westerhausen testified that the Rate 831 Settling Parties agree that the customer's elections under Rate 831 Tiers 2 and/or Tier 3 will occur in a window between the day after NIPSCO's compliance filing in this Cause to 30 days thereafter. He explained that in discussions with NIPSCO, customers recognize that in order to implement Tier 3, customers may need to install software including a security certificate provided by NIPSCO. He noted that the parties agree to work together during the 30-day period to achieve implementation.

Mr. Westerhausen testified that NIPSCO agrees that under either Tier 2 or Tier 3, a customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges.

Mr. Westerhausen testified that NIPSCO agrees that the third-party energy and capacity supplier may represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the Commission. He indicated that at a minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

Mr. Westerhausen sponsored a redlined tariff that incorporates changes necessary to implement the Rate 831 Settlement as Attachment 19-S2-A.

Mr. Westerhausen testified that if approved, the Rate 831 Settlement assures that if the agreed-upon revenue requirement (as reflected in the Revenue Settlement) and NIPSCO's proposed Rate 831 and cost allocation are approved, there will be no need for a Phase 2 proceeding to establish revised rates. Additionally, Rate 831 Implementation Agreement Exhibit D specifically addresses implementation concerns previously raised by some industrial customers.

B. Industrial Group Witness Phillips. Mr. Phillips presented testimony in support of the 831 Settlement among NIPSCO, the Industrial Group, NLMK, and US Steel. Mr.

Phillips explained that members of the Industrial Group, particularly ArcelorMittal, BP, Cargill, and Praxair, are among the largest of NIPSCO's industrial customers and not only qualify for, but are willing to accept the risk associated with using the proposed service structure under Rate 831.

Mr. Phillips reiterated the importance of establishing appropriate industrial rates as these energy intensive industries continue to face intense domestic and international competition. He stated because of the energy intensive nature of their businesses, energy costs are a major component of the companies' production cost and materially impact economic viability of their operations in NIPSCO's service territory. He stated that approval of the Rate 831 service structure in a form that effectively addresses the issues the rate was intended to address is of significant importance to the Industrial Group. He noted that given the importance of keeping and attracting industrial customers to the overall economic benefit of northwest Indiana, approval of Rate 831 should be of significant importance to all participants in the rate proceeding.

Mr. Phillips testified that the Industrial Group shares the interest in mitigating the rate increases for all customers and therefore was an active and aggressive participant in the negotiations that led to the Revenue Settlement. He noted that settlement reduced NIPSCO's proposed revenue requirement by approximately $63.6 million, which significantly reduced the overall rate increase for all customers.

Mr. Phillips explained that the Rate 831 issues covered in the Implementation Agreement reflect changes in the revenue requirement established by the Revenue Settlement. He added that the Implementation Agreement resolved contested issues regarding the design of Rate 831 and includes the commitment of each Rate 831 customer to take an agreed level of firm service under Tier 1. He added that although the actual level of Tier 1 demand subscribed to by the Rate 831 customers is less than the 194.556 MW that NIPSCO used to allocate cost to Rate 831, the Implementation Agreement provides that the allocation of cost will continue to be based on 194.556 MW. He noted the result of that provision means that the actual rates for Rate 831 will be above cost of service for those customers. Mr. Phillips said that the Implementation Agreement also provides tariff revisions to reflect modifications NIPSCO made on rebuttal or to resolve other issues raised by Rate 831 customers, such as a dispute resolution process, implementation of aggregated metering for adjacent premises, and formulating requirements for third-party contracts.

Mr. Phillips concluded that he recommends approval of the Implementation Agreement because, in his opinion, it significantly reduces the range of issues that would need to be resolved regarding Rate 831, which reduces the need for further litigation on those issues and eliminates the need for a Step 2 true-up process. He concluded the Implementation Agreement establishes Rate 831 in a manner that is workable and fulfills the goals that it was introduced to address.

C. US Steel Witness Georgis. Mr. Georgis testified in support of both the Revenue Requirement and Rate 831 Settlements, noting specifically that the Rate 831 Settlement is premised on the 4CP allocation of production costs because it is appropriate for NIPSCO's summer peaking system and because a 12CP methodology will shift costs into the Rate 831 industrial class, thereby creating even stronger economic signals that make customer self-generation more attractive. Mr. Georgis stated that US Steel's decision to enter into the Rate 831 Settlement is driven by US Steel's analyses of its least cost power options and is an acceptable alternative to NIPSCO's status quo rate structure, which is no longer an economically viable option for US Steel. Mr. Georgis provided specific details on US Steel's plans to self-build new cogeneration if an economic solution is not achieved.

Mr. Georgis observed that if Rate 831 is not approved or is modified to include additional cost shifts or transition fees, it will be uneconomic for US Steel compared to its cogeneration self-build option. Mr. Georgis testified that in the Rate 831 Settlement, the large industrial customers proactively agreed to commit to a set amount of Tier 1 firm contract demand that fully recovers the required settled revenue requirement for Rate 831 and without such a commitment, the Revenue Settlement as it relates to Rate 831 is meaningless because no customer can be forced to take a set level of firm demand. Mr. Georgis concluded that in addition to being the most economic option for US Steel, the Rate 831 Settlement guarantees that US Steel will remain a customer taking service with a firm contract demand, thereby improving the certainty and future stability of NIPSCO's revenues and rates while US Steel continues to contribute to NIPSCO's fixed cost recovery to the benefit of all customers.

26. Rate 831 Settlement Opposing Testimony.

A. OUCC Witness Boerger. Dr. Boerger filed testimony is response to the Rate 831 Settlement. He supported the OUCC's position that the Rate 831 Settlement should be rejected because it does not address the problems with NIPSCO's original Rate 831 proposal. Dr. Boerger stated that the Rate 831 Settlement does not address, even in part, the cost shift from Rate 831 customers to other rate classes that he identified in his direct testimony. Dr. Boerger addressed the supposed historical "sizable subsidy" argument presented in the Rate 831 Settlement, which appeared to be the basis for not addressing the cost shift to other rate classes. He noted that these large customers cost more to serve than is reflected in traditional cost of service studies, calling into question the existence of such historical subsidies.

Additionally, Dr. Boerger identified other issues of fairness that the Rate 831 Settlement does not adequately address, including the use of a 4CP cost allocation methodology that the Commission has not previously approved for NIPSCO that would further shift costs away from Rate 831 customers. Further, the Rate 831 Settlement, according to Dr. Boerger, would have the Commission accept changes to the AAQFPTC which would cause it to no longer reflect the cost of providing this service, providing further reason to reject the Rate 831 Settlement. Dr. Boerger also stated that the Rate 831 Settlement would not allow the Commission to redesign NIPSCO's proposed transmission charge in a way that would provide correct economic signals for the building of self-generation facilities, as discussed in his direct testimony.

Finally, Dr. Boerger identified an issue discovered in reviewing Rate 831 Settlement documents that carries over from NIPSCO's original proposal for calculating its demand-related cost allocation tracker factors (shown originally in NIPSCO witness Westerhausen's Attachment 19-E). NIPSCO and other settling parties would have a TDSIC-like reduction in cost responsibility applied to non-firm load in spite of a lack of evidence or statutory requirement for making this change, as is the case with TDSIC trackers. Dr. Boerger concluded that this proposed allocation methodology would result in Rate 831 customers being allocated too little revenue requirement and other rate classes too much revenue requirement, and he recommended that NIPSCO be required to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1

Adjustment shown in Implementation Agreement Exhibit A and in Attachment 19-E of Mr. Westerhausen's prefiled direct testimony.

B. CAC Witness Olson. Mr. Olson offered testimony in response to the Rate 831 Settlement. He sponsored transcripts from the public field hearing, highlighting testimony from many of the speakers, including the Michigan City Council President, local business owners, and residential customers. He spoke about several local ordinances and resolutions passed by municipal governments located in NIPSCO's service territory, which reference the initial request for an approximate 12% increase for residential customers. Mr. Olson stated that all members of the rate-paying public have an interest in achieving a fair and balanced outcome, but the parties to the 831 Settlement are its only beneficiaries. Mr. Olson concluded that the Commission should reject NIPSCO's proposal for industrial restructuring and reject the proposed Rate 831 Settlement.

C. CAC Witness Wallach. Mr. Wallach testified the Rate 831 Settlement would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes and would allocate those costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand, not contract demand. He stated that the proposed allocation of revenues to the Rate 831 class would recover from large industrial customers less than their fair share of embedded production costs and would instead unfairly and unreasonably shift recovery of such costs to other rate classes. Specifically, he estimated that the Rate 831 Settlement's revenue allocation would shift recovery of about $66 million of annual non-fuel revenue requirements from industrial customers to other customers, assuming a 4CP allocator is used. If demand-related production costs were allocated using a 12CP allocator, as the OUCC recommends, then Mr. Wallach estimated the proposed Rate 831 Settlement would shift recovery of about $94 million of annual non-fuel revenue requirements from industrial customers to other customers.

Mr. Wallach recommended the Commission reject the Rate 831 Settlement and deny NIPSCO's request for an ARP as not in the public interest. Instead, he recommended that the current industrial service structure be retained and that a procedural schedule be established to determine the appropriate revenue allocation and rate design for all rate classes.

Mr. Wallach testified there is a risk of a loss of industrial load, with its attendant cost-shifting, if the Commission decides to retain the current industrial service structure; however, neither NIPSCO nor any of the other Rate 831 Settling Parties provided any evidence that the potential load loss under the current service structure would exceed the current load loss under the proposed Rate 831 structure. Thus, he said, the Rate 831 Settling Parties failed to show that other customers would be worse off under the current service structure than under the Rate 831 structure. Instead, the Rate 831 Settling Parties would have the Commission approve a radical change in the industrial service structure based on speculation that the potential margin loss with the current structure could be even greater than the demonstrated loss under the Rate 831 structure.

27. Rate 831 Settlement Reply Testimony.

A. NIPSCO Witness Kelly. Mr. Kelly made clear that in the event the Commission rejects the Rate 831 Settlement, as suggested by both OUCC witness Boerger and CAC witness Wallach, the revenue requirement would need to be changed to remove adjustments that were made to effectuate the ARP, including updating load research for historical demand to reflect firm demand for Rate 831 customers under existing Rates 732, 733, and 734; addressing the treatment of MISO charges and revenues that have been proposed to be removed from base rates; making adjustments to reflect aggregation that would migrate customer premises among Rates 724, 732, and 733; and addressing Rider 776 Back-up, Maintenance, and Temporary Service revenues and OSS activities.

Mr. Kelly also noted that the assumption that US Steel's demand under Rates 732 and 733 would be similar to that projected under Rate 831 is incorrect because no additional interruptible service is available under Rider 775. As such, the firm amount would need to remain at a level consistent with today's 700 Series rate structure, under Rate 831, except for the adjustment for aggregating multiple premises currently served under Rates 732 and 733.

Mr. Kelly pointed out that no evidence has been provided to show that an across-the-board rate increase as suggested by OUCC witness Boerger utilizing existing Rates 732, 733, and 734, would result in rates that were just and reasonable.

Mr. Kelly raised concern that the testimony of witnesses Boerger, Wallach, and Olson (and others) attacks the prudence of Rate 831 by fixating on the near-term impacts to other rate classes without recognizing the substantial long-term risks that are in play with this decision. He testified that what is being characterized as an industrial subsidy for Rate 831 customers is a misnomer and ignores the fact that Rate 831 is a fully costed rate designed at parity. He emphasized that NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers as it addresses its aging coal generation fleet and navigates a dynamic economic environment. Mr. Kelly opined that it is undeniable that the Rate 831 proposal will assign more of NIPSCO's production costs to other customer classes, which will produce higher rates in the near term than they would otherwise pay absent the restructuring of large industrial rates. He asserted that the long-term risk is garnering little attention and that these large industrial customers already have options for significantly reducing their firm requirements and are poising themselves to implement those options if Rate 831 is not approved.

Mr. Kelly testified that if Rate 831 is not approved according to the terms of the Rate 831 Settlement, he is convinced that at least some of these customers are going to make the incremental investments to leave the NIPSCO system, or worse, will shift industrial production away from NIPSCO's service territory. He stated that when that occurs, NIPSCO will need to file multiple rate cases as chunks of firm load leave its system, and those rate cases are going to propose to reallocate the unrecovered fixed costs left behind by these customers from the remaining customer classes. He testified that while witnesses in this case are focusing on the fairness of a cost shift within this rate case of approximately $40 million to $66 million between Rate 831 and other classes, if NIPSCO does not move to the Rate 831 structure now, it will be talking about another $100 million to $150 million of unrecovered costs that would have been collected under Rate 831 but will be left behind as these customers further bypass NIPSCO's service. That is not to say that $40 to $66 million dollars is an insignificant issue or that NIPSCO does not care about the near-term impact to its other customers classes, but when NIPSCO considered the full range of impacts in play rather than just the near-term cost shift, it was apparent that Rate 831 is the right solution now rather than later. Mr. Kelly restated that attempting to retain the current service structure is only going to increase the risk that these customers will exercise their options to cogenerate additional power or relocate production to avoid an increasing NIPSCO electric price.

Mr. Kelly stated that he is concerned because the arguments being raised attempt to mute NIPSCO's interest in representing its other customer classes in the Rate 831 proposal. He noted that it is atypical for a vertically integrated utility to propose allowing a significant portion of its load to have the ability to procure capacity and energy from wholesale market suppliers; in fact, that cuts directly against the profit motive of an investor-owned utility. He asserted that NIPSCO is considering the interest of all of its customers and stakeholders as it moves through this transitional time.

Mr. Kelly testified that the Rate 831 proposal would reduce NIPSCO's long-term business opportunity as an investor-owned utility because it is downsizing the amount of firm load that NIPSCO is obligated to serve for at least five years thereby reducing the amount of MW that NIPSCO has the right under Indiana law to serve under its monopoly charter. He stated that the reason NIPSCO is making this proposal, however, is because it is the best outcome that could be identified for all of its customers, employees, investors, and stakeholders given the parameters that NIPSCO faces at this time of sustained low natural gas prices, historically lower cost of capital, aged coal-fired generation, aging boiler systems within customer plants creating a cogeneration opportunity when replacing, large sophisticated energy users, strong economic conditions, etc. Mr. Kelly testified that this decision was not reached lightly, and NIPSCO did not craft it alone for its benefit. His ultimate concern is that NIPSCO is going to miss out on reaching a sustainable path forward where these customers keep paying a sizeable portion of their costs because there is a lot of volume on the near-term portion of the analysis without considering the substantially larger risk around the long-term portions.

In response to CAC witness Olson's testimony objecting to a 12% rate increase for those other rate classes, Mr. Kelly pointed out that the 12% figure is the result from NIPSCO's original proposal as filed. He pointed out that if the Commission approves both the Rate 831 Settlement and the Revenue Settlement, the resulting change in rates for all other customers (other than Rate 831) would be 6.66%.

Finally, Mr. Kelly pointed out the consequences of rejecting the Rate 831 Settlement. He explained that as NIPSCO begins to implement the results of its IRP and procure replacement capacity that will live on for decades, NIPSCO needs to ensure some stability in what its obligation to serve will be for its largest industrial loads. He stated that retaining the current industrial service structure will only increase the risk that NIPSCO's industrial load will further decline over time and create unrecovered costs on the way down. Mr. Kelly testified that without approval of the Rate 831 industrial service structure, NIPSCO would be put into a position of modifying its existing Rate 732, 733, and 734 service structure to re-integrate the Rate 831 customers, which is no small task. He explained that as part of that process, to retain some of the assurances of stability in the near term, NIPSCO would likely seek to modify parts of the existing Rate 732, 733, and 734 industrial service structure such as changing contract terms, altering Rider 775 registrations, and restructuring NIPSCO's back-up and maintenance service. He noted that these steps do not actually reduce the risk industrial customers will exercise their options in the future, and may in fact increase that chance.

B. Industrial Group Witness Phillips. Mr. Phillips presented settlement reply testimony in response to the OUCC witness Boerger and CAC witness Wallach. In response to the OUCC and CAC witnesses' assertion that the Implementation Agreement unfairly shifts rate recovery of NIPSCO's legacy production costs to other customer classes, Mr. Phillips testified that for many decades the industrial classes have paid above-cost rates in order to subsidize residential customers. Mr. Phillips discussed the Commission orders describing the inter-class subsidies that industrial classes have provided to other customers. Mr. Phillips also stated that over the last two rate cases, industrial rate increases have totaled more than 22%. Mr. Phillips quantified the magnitude of the rate subsidies paid over the years by the industrial classes as being in the range of $1.4 billion to $2.85 billion, which are substantially greater than the legacy cost that Dr. Boerger and Mr. Wallace contend the large industrials would avoid under the Implementation Agreement. He stated that it is clear that the industrial classes have already provided rate revenue far in excess of their cost-based share of NIPSCO's legacy production cost and that essentially the OUCC and CAC are advocating for continuing and increasing the subsidies paid by industrial customers.

Mr. Phillips took issue with Dr. Boerger's theory that a need for rate mitigation does not necessarily imply the presence of a subsidy and that industrial customers should have paid higher returns in the past. Mr. Phillips first noted that it is clear residential customers have been subsidized for a number of years as detailed in Commission orders as far back as 1981. Mr. Phillips also noted that in the current case, even under the OUCC's preferred cost methodologies, the residential class would still be receiving a subsidy. He added that if all subsidies were eliminated and a 12CP allocation method were used, the residential class would see a rate increase of 17.4% rather than the 6.66% provided for in the Revenue Settlement agreement and the Implementation Agreement. He stated that questioning the residential rate subsidy amounts to disagreeing with both a consistent line of Commission orders and the OUCC's own cost of service proposal.

Mr. Phillips also testified that Dr. Boerger's theory that industrial customers should have been paying a higher rate of return had never been addressed in NIPSCO's past rate cases or in any of the cost allocation methodologies the OUCC has proposed. He added that the alleged risk suggests volatility in the industrial load in contrast to what Dr. Boerger described as the more stable residential service, but in fact the residential load is much more volatile due to seasonal swings than the high load factor industrial customers Dr. Boerger referenced. Therefore, Mr. Phillips stated it is misguided to attempt to reinterpret past orders based on a nonstandard theory that was not raised previously and rests on a faulty rationale.

Mr. Phillips testified that the Implementation Agreement locks in cost recovery from Rate 831 customers based on 194.556 MW of firm demand under five-year contracts, which allows NIPSCO to retain firm load in the face of the risk that industrial usage on the system would continue to decline. In response to the OUCC and CAC witnesses' contention that the risk of the loss of industrial load does not justify the approval of the Implementation Agreement, Mr. Phillips testified that the risk of additional loss of load is immediate and substantial. He pointed to BP's self-supply arrangement and US Steel's potential additional cogeneration project if Rate 831 is not approved. He added that ArcelorMittal has already reduced load served by NIPSCO by 50% since 2011 due to closing facilities and generating more power internally in response to NIPSCO's rates. He stated there is continuing pressure to cut NIPSCO's load by shifting production to other locations or increasing internal generation because costs are consistently higher in locations served by NIPSCO than in other ArcelorMittal facilities. He added that Praxair is evaluating significant self-generation projects. Mr. Phillips testified that absent the revenue stability provided by Rate 831, NIPSCO faces continued loss of industrial load, which would lead to a cycle of rate cases that would result in further increases making NIPSCO's service less viable for industrial customers.

Mr. Phillips explained that the Implementation Agreement would provide full cost recovery of system costs for the firm load being served under Tier 1, including the cost associated with legacy production assets and depreciation expenses relating to planned retirements. He added NIPSCO will continue to collect transmission revenue from Rate 831 customers on their non-firm load under Tier 2 and 3 as well as under Tier 1. Mr. Phillips also noted that the contractual commitments under the Implementation Agreement will provide NIPSCO with a more reliable projection of capacity needs and facilitate a more orderly transition to a new resource portfolio.

Mr. Phillips stated that the alleged cost shift and Rate 831 subsidy are both inaccurately described and incorrectly computed. He noted that the OUCC and CAC witnesses treat Rate 831 as if it were a rate decrease instead of a revenue reduction aligned with the decreased use of NIPSCO's assets. He added that Mr. Wallach's computation improperly allocates production cost to interruptible load, which is contrary to cost of service principles. Mr. Phillips referred to his cross-answering testimony relating to the flaws in Mr. Wallach's computation and also explained that the studies provided in response to CAC data request 11-001(b) and (c) are flawed for the same reasons. Mr. Phillips explained that allocating generation investment to interruptible load and then subtracting revenue credits does not fix the erroneous allocation of production cost. He stated that subtracting revenue credits reduces the rate of return of those particular rate classes, which creates the opposite effect of fixing the erroneous allocation of costs. He added that the revenue credits do not equal the generation cost erroneously being allocated to interruptible load because the revenue credits are less than the generation cost being allocated. Mr. Phillips also stated that Mr. Wallach only used $42.6M in revenue credits, which was less than the credits actually paid. He added there are other issues with the Rates 732, 733, and 734 COSS Mr. Wallach relied upon because it includes different riders than the 800 series would have under NIPSCO's proposal. The revenue requirements and fuel costs used were larger than used for settlement, the removal of the BP load may be inconsistent with NIPSCO's treatment of the removal in the COSS in this case, and the study fails to normalize the 2017 loads for allocation.

Mr. Phillips also disagreed with Mr. Wallach's assertion that the aggregation of metering for BP and WCE would result in a cost shift and provide a subsidy to industrial customers. He noted that self-supply arrangements are expressly encouraged as a matter of public policy under Indiana and federal law and that BP's use of privately owned generation assets to supply power to itself results in a decrease in the electric service from NIPSCO. Consequently, NIPSCO will collect less revenue from BP because it will sell less power to BP. Mr. Phillips stated that is no more of a cost shift than any change in demand between rate cases and does not establish any subsidy that industrial customers will enjoy at the expense of other rate classes.

In response to the OUCC and CAC witnesses' arguments that the industrial customers should be required to provide a higher level of cost recovery for NIPSCO's legacy production assets, Mr. Phillips explained that the Commission has consistently recognized that interruptible service enables NIPSCO to avoid building generation capacity to serve that load to the benefit of all ratepayers. In addition, NIPSCO's largest industrial customers have invested in private generation assets, which reduces the incremental load that NIPSCO had to build and maintain generation capacity to serve. He said that if NIPSCO had been required to build additional capacity to serve the interruptible load and the self-supplied load as firm demand, the magnitude of unrecovered cost for legacy production assets would be much greater than it is currently. Consequently, Mr. Phillips stated that the large industrial customers have mitigated the magnitude of the legacy costs through their interruptible service and self-supply arrangements and have also paid their allocated share for the bulk of NIPSCO's historical investments in coal-fired generating units, while providing massive rate subsidies to residential customers over that same period.

Mr. Phillips also noted that the large industrial load serviced by NIPSCO today is a very different set of customers from those on the system when the legacy production investments were made. He testified there is no expectation that the prior customers would be obligated to continue providing cost recovery 40-50 years into the future and that subsequent customers would take on that obligation.

In response to the OUCC's and CAC's criticism of the Implementation Agreement providing for a 4CP allocation, Mr. Phillips said that NIPSCO had proposed the 4CP method in its original filing, that the industrial parties had filed testimony supporting that allocation, that the 4CP method is consistent with how NIPSCO designs and operates its system and represents sound ratemaking. He also explained that the Implementation Agreement, by locking in firm Tier 1 demand commitments, eliminates the need for a second phase.

In response to Dr. Boerger's suggestion that Tier 1 commitments could be filed as a standalone without predetermining other issues, Mr. Phillips explained that Rate 831 customers cannot commit to a level of firm demand without knowing what the rates would be. Mr. Phillips testified that the Implementation Agreement provides significant value that had not previously been established. He noted that the possibility material changes to Rate 831 could lead to withdrawal of the proposal has been present throughout the case and not introduced for the first time by the Implementation Agreement.

Mr. Phillips also addressed Dr. Boerger's arguments regarding NIPSCO's tracker allocations. Mr. Phillips testified NIPSCO has not changed the proposed allocation from its case-in-chief; all the Implementation Agreement does is update the agreed reduction in revenue requirements. He noted that Dr. Boerger did not raise any objection to the proposed allocation in his direct testimony. Mr. Phillips added that allocating the demand allocators on firm demand is appropriate for the same reasons allocating base rate costs only on firm load is appropriate. The Rate 831 customers' Tier 2 and 3 loads will not be served using NIPSCO's production resources and therefore should not have trackers allocated on that load.

As to Dr. Boerger's objection to the revision of the adjacent customer facilities, Mr. Phillips explained that the proposed change was to resolve a longstanding dispute between NIPSCO and one of its large customers. He said the change maintains the status quo for the facilities at issue in Cause No. 45078 by determining the amount of energy subject to the transmission charge on a monthly basis.

C. <u>US Steel Witness Georgis</u>. Mr. Georgis addressed the OUCC's and CAC's Rate 831 Settlement opposition. Mr. Georgis testified that the Rate 831 Settlement preserves the fundamental rate and structure of Rate 831 and fully recovers the settled revenue requirement associated with the large industrial class. Mr. Georgis observed that under the Rate 831 Settlement, large industrial customers proactively agreed to commit to a set amount of Tier 1 Firm Contract Demand elections and a demand rate that fully recovers the required settled revenue requirement for the 831 rate class. He noted that without such a commitment, the Revenue Settlement as it relates to Rate 831 is meaningless because no customer can be forced, either by NIPSCO or the Commission, to take a set level of firm demand. He testified that the Rate 831 firm Tier 1 service offering is similar to the status quo, in that NIPSCO and its large industrial customers currently have contracts under the existing Commission-approved interruptible rate structure that commits those customers to a certain level of firm service.

Mr. Georgis disagreed with Dr. Boerger's distinction between mitigation and subsidy, noting that the terms go hand in hand. He observed that if there is no subsidy in the rate structure, there is no need for mitigation, but as the Rate 831 Settlement notes, there is a sizable subsidy in NIPSCO's residential rates. Mr. Georgis concluded that if Rate 811 is not paying its cost of service, it is being subsidized. He stated that in addition to the subsidy in the settled revenue requirement, Rate 831 is further subsidizing other customer classes based on the transmission portion of the ACOSS. He noted that five of the large industrial customers are paying $17 million more than their cost of service for transmission and subsidizing the transmission costs of other customer classes. He noted that a sixth customer will only increase this level of transmission subsidy, which was ignored by the OUCC. Mr. Georgis testified that the Commission should not look at Rate 831 in isolation and ignore years of subsidization by large industrial customers to the benefit of other customer classes. He stated that without the approval of Rate 831, upward movement in NIPSCO's rates and sustained subsidization will cause the continued bypass of NIPSCO's system by large industrial customers.

Mr. Georgis refuted Dr. Boerger's claim that industrial customers are more risky and presumably should be allocated additional costs. He noted that for years, Rate 831 customers have paid a subsidy and premium. He testified that NIPSCO's rates are already too high and are not competitive, which is why US Steel's existing cogeneration is beneficial and future cogeneration is still a possibility if Rate 831 is not approved. He also stated that increased rates for large industrial customers will exacerbate the departure of industrial load, which increases rate volatility and risk for other customer classes. Mr. Georgis testified that the OUCC's proposal amplifies the existing uncompetitive rate environment rather than creating the competitive, cost-based solution that Rate 831 provides while helping to ensure that large industrial customers commit to staying on NIPSCO's system and pay a cost-based share of system costs.

Mr. Georgis also refuted Dr. Boerger's claims that the loss of additional US Steel load if Rate 831 is not approved would be modest. He noted that it is important to look at the financial impact of the US Steel load within the context of the position that the OUCC is taking on Rate 831. Under Rate 831, he explained that large industrial customers have a combined firm revenue allocation of $149.438 million. While not indicative of any one particular customer's share, he testified that on average, there is a $24.9 million contribution to the revenue requirement for each of the six large industrial customers, which is more than the $20 million lower end of the OUCC's alleged Rate 831 "cost shift" range. Mr. Georgis testified that these demand costs would shift to other customers if US Steel installed additional cogeneration and took additional firm load off of NIPSCO's system. Mr. Georgis concluded that the financial impact of just one large industrial customer leaving NIPSCO's system is well within the range of the $20 million to $40 million in "cost shifting" that the OUCC argues exists under Rate 831.

Mr. Georgis also refuted Dr. Boerger's claim that the Rate 831 AAQFPTC is unreasonable. He noted that Rate 831 already overpays on transmission relative to NIPSCO's cost of service, so increasing the AAQFPTC exacerbates that problem. He testified that while NIPSCO refined the inputs, the methodology for calculating the AAQFPTC remains the same as originally proposed and accurately reflects the impacts of both settlements.

In response to Dr. Boerger's recommendation that NIPSCO recalculate its demand allocation tracker allocators to eliminate the Rate 831 Tier 1 adjustment, Mr. Georgis testified that these tracker costs are only applicable to NIPSCO full requirements customers or portions of customers' loads that are full requirements service. He explained that Rate 831 Tier 1 service is full requirements service, while Tier 2 and 3 are not. Mr. Georgis stated that the Demand Allocation referenced by Dr. Boerger is used for the RTO and FMCA riders, but these riders are not applicable to Tiers 2 and 3 because Rate 831 customers are buying energy in the wholesale market. Mr. Georgis testified that large industrial customers should not pay NIPSCO's system costs covered by these riders because they are not using NIPSCO's system under the market-based rate concept. He stated that the only part of NIPSCO's system that US Steel will use is bulk transmission, and those transmission costs are appropriately recovered under the Rate 831 tariff.

Mr. Georgis noted several practical problems with Dr. Boerger's suggestion that if Rate 831 is not approved, the Commission can address large industrial rates in a Phase 2 proceeding setting rates based on the existing 700 series rate design. First, he testified that eliminating the proposed and settled rate design of the largest load on NIPSCO's system that ensures full cost recovery and replacing it at a later date while all other elements of NIPSCO's rate structure remain static leads to significant uncertainty and potential volatility. Second, such a result would not allow Rate 831 customers proper time to plan and evaluate customer and bill impacts and implications of the rates. Finally, he stated the current and proposed rate structures are not an "apples to apples" comparison, and the rates should not be delayed and potentially replaced in this way.

Mr. Georgis testified that under the Rate 831 Settlement, US Steel has agreed to accept a rate design that it still believes, at least in part, contains subsidies. He noted that to request those subsidies continue in another form or alternative rates that provide none of the benefits of Rate 831 is neither fair nor equitable. Mr. Georgis observed that none of the large industrial customers qualify under any other of NIPSCO's proposed rate classes, and NIPSCO has not presented any form or pricing of an interruptible credit in this proceeding, which is a key element of the existing 700 series rates. Mr. Georgis concluded that in the event Rate 831 is not approved, customers should be permitted to revisit arguments regarding the full access, functionalization, and allocation of costs so that they have a fair opportunity to present evidence to the Commission regarding proper rate design for all customers.

Mr. Georgis testified that CAC's witnesses mischaracterize Rate 831 as a subsidy to industrial customers. Mr. Georgis emphasized while large industrial customers' rate revenues are decreasing from current levels, this is largely because their rates reflect the true cost of service since they are no longer procuring the vast majority of their power from NIPSCO. Mr. Georgis testified that under Rate 831 large industrial customers still must pay to cover their load, either via the market pass-through rates under Tier 2, or to a third party under Tier 3. He also noted that while Rate 831 customers have the opportunity to benefit from the market, they are also taking on risk. He concluded that Rate 831 is simply not a "guaranteed win" for large industrial customers, nor is it a guaranteed rate savings. Instead, Mr. Georgis testified that Rate 831 is a regulatory solution to the problem of NIPSCO's continued load loss and provides an economic alternative for some of the largest companies in Indiana to remain customers of NIPSCO.

28. <u>Commission Discussion and Findings</u>.

A. <u>Settlement</u>. Settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 664 N.E.2d at 406.

Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Pub. Serv. Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Revenue Settlement or Rate 831 Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Revenue Settlement and Rate 831 Settlement are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such agreements serve the public interest.

Our review of the reasonableness of the Revenue Settlement and Rate 831 Settlement is aided by the comprehensive scope of the Revenue Settling Parties' and Rate 831 Settling Parties' agreements as well as the extensive evidence of record that addresses competing positions on a wide range of issues, including: (1) the cost of common equity; (2) calculation of NIPSCO's capital structure; and (3) the financial basis for results at present, proposed, and settlement rates. Each of these issues was addressed in testimony that considered a range of proposed outcomes. The evidentiary record provides a thorough consideration of the merits of the issues presented, thereby affording the Commission with a detailed record from which to make findings and conclusions.

We first address the Rate 831 Settlement and then the Revenue Settlement, which is impacted by our decision on the Rate 831 Settlement.

B. <u>Rate 831 Settlement</u>. In reviewing NIPSCO's proposed Rate 831 industrial service structure and the Rate 831 Settlement, we first recognize that NIPSCO's system is uniquely situated from other Indiana electric utilities. Industrial customers comprise less than 1% of total NIPSCO customers but account for more than 56% of its energy sales, and NIPSCO's five largest customers reflect 40% of NIPSCO's load. This large concentration of load in a few specific customers presents a distinct business risk for NIPSCO. This risk is heightened by the fact that these customers are mostly large, sophisticated energy users competing in global and domestic markets characterized by sustained low natural gas prices and historically low cost of capital. These factors further incent industrial customers to utilize new or existing self-generation facilities to wholly or partially serve their energy needs.

Over the years, the Commission has found it to be in the public interest for NIPSCO to utilize the interruptible service characteristics of its large industrial customers. In Cause No. 43969, NIPSCO expanded its long-standing use of interruptible service to be integrated into the evolving MISO market. In Cause No. 43969, seven customer premises took service subject to Rider 675, and NIPSCO's capacity requirements in the MISO market were reduced by approximately 377 MW. In Cause No. 44688, we approved NIPSCO's proposed expansion of the availability of the interruptible rate at the request of its industrial customers. This expansion of interruptible load in turn allowed NIPSCO to reduce its capacity requirements by approximately 530 MW to the benefit of all customer classes. Given this context, NIPSCO developed its proposed Rate 831 industrial service structure as an evolution of its current interruptible service option approved by the Commission in NIPSCO's last two rate case orders.

In its Petition, NIPSCO requested that the Commission approve its proposal for a new industrial service structure as an ARP. NIPSCO elected, pursuant to Ind. Code § 8-1-2.5-4, to become subject to the provisions of Ind. Code § 8-1-2.5-6 for this purpose, and requests that the proposed industrial service structure be found to be in the public interest pursuant to Ind. Code § 8-1-2.5-6. The Rate 831 Settlement modifies, and provides the means to implement, the proposed ARP. As such, we assess the Rate 831 Settlement as an ARP under the provisions of the ARP Statute.

The legislative policy set forth in Section 1 of the ARP Statute anticipates the implementation of flexible alternatives to traditional regulatory practices and structures, and recognizes that amidst a changing energy environment, such flexibility is "essential to the well-being of the state, its economy, and its citizens." Moreover, pursuant to Ind. Code § 8-1-2.5-1(6), we are specifically authorized to implement such flexible alternatives.

NIPSCO seeks approval of the Rate 831 industrial service structure under Ind. Code § 8-1-2.5-6, which provides:

> (a) Notwithstanding any other law or rule adopted by the commission, except those cited, or rules adopted that pertain to those cited, in section 11 of this chapter, in approving retail energy services or establishing just and reasonable rates and charges, or both for an energy utility electing to become subject to this section, the commission may do the following:
>
> > (1) Adopt alternative regulatory practices, procedures, and mechanisms, and establish rates and charges that:
> > (A) are in the public interest as determined by consideration of the factors described in section 5 of this chapter; and
> > (B) enhance or maintain the value of the energy utility's retail energy services or property;

including practices, procedures, and mechanisms focusing on the price, quality, reliability, and efficiency of the service provided by the energy utility.

(2) Establish rates and charges based on market or average prices, price caps, index based prices, and prices that:

(A) use performance based rewards or penalties, either related to or unrelated to the energy utility's return or property; and

(B) are designed to promote efficiency in the rendering of retail energy services.

We may approve, reject, or modify the plan; however we may not make material modifications without NIPSCO's consent. Ind. Code § 8-1-2.5-6(d). In evaluating an ARP submitted under Ind. Code § 8-1-2.5-6, we are directed by Ind. Code § 8-1-2.5-6(a)(1)(A) to make a public interest finding "as determined by consideration of the factors described in section 5 of this chapter." Therefore, in determining whether the public interest will be served by this limited declination of jurisdiction, Ind. Code § 8-1-2.5-5(b) requires that we consider the following:

1. Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;

2. Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;

3. Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency; and

4. Whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

It is against these statutory criteria, and in light of the legislative policy set out in Ind. Code § 8-1-2.5-1, that we evaluate NIPSCO's request to approve its ARP seeking to establish the proposed industrial service structure as implemented through the Rate 831 Settlement.

As we consider the first factor, there is ample evidence in the record that changes in the technology, operational conditions, and competitive forces support approval of the Rate 831 Settlement. It is uncontroverted that NIPSCO's large industrial customers utilize energy intensive processes and are sophisticated market participants competing on the basis of price globally. Given this competitive marketplace and the ability of NIPSCO's large industrial customers to reduce their demand on NIPSCO's system through self-generation or relocation, we agree with NIPSCO and find that now is the time to address the risks presented by its large industrial customers as NIPSCO simultaneously addresses its on-going generation needs. Service under Tiers 2 and 3 of Rate 831 will be set by competitive forces administered by MISO under FERC jurisdiction. Furthermore, NIPSCO's proposal requires its largest industrial customers to remain as its retail customers, while at the same time providing more market choices. The Commission has considered the evidence presented and finds that the Rate 831 Settlement meets this first factor.

Regarding the second factor, the evidence supports the conclusion that approval of the Rate 831 Settlement will benefit the energy utility, its customers, and the state. The evidence shows that NIPSCO has already lost a significant amount of its industrial load due to customer self-generation and customers shifting or closing production. Furthermore, the evidence demonstrates that NIPSCO is at risk of losing more industrial load in the absence of a change in service structure to better align industrial rates with cost of service.

Assessing the severity of the risks of large industrial bypass requires informed judgment. The record shows that NIPSCO has closely examined the global trends affecting its steel-making and other largest loads as well as facility-specific actions that are under consideration. Based on this analysis, NIPSCO has proposed Rate 831 to ameliorate the substantial threat posed by potential industrial load loss. The record shows that approval of Rate 831 would reduce NIPSCO's long-term business risk because the amount of firm load it is obligated to serve for at least five years would be more certain. We find the record describing BP's actions to self-serve its load, the testimony detailing the planned or potential actions by US Steel and Praxair, and the significant reduction of ArcelorMittal load to be persuasive evidence warranting a proactive response by NIPSCO.

The Commission understands that the OUCC and CAC opposed approval of the Rate 831 Settlement and considered their arguments that the Rate 831 Settlement: (1) avoids NIPSCO's legacy cost burden by passing it on to other rate classes; (2) implements a cost allocation methodology unfair to other rate classes; (3) eliminates the opportunity to ensure the transmission charge for backing up self-generation reflects the cost of service; and (4) modifies NIPSCO's proposed adjacent facilities transmission charge such that it no longer reflects cost of service. The OUCC also recommended the Commission require NIPSCO to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1 Adjustment in Exhibit A to the Rate 831 Settlement. The CAC argued that the Rate 831 Settlement is not in the public interest because it would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes and by allocating those costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand.

By analyzing the prudence of Rate 831 through a fixation on the near-term impacts to other rate classes, the OUCC, CAC, and other parties fail to recognize the substantial long-term risks addressed by this decision. What these parties qualify as a subsidy for Rate 831 customers is a mischaracterization that ignores the fact that Rate 831 is a fully costed rate designed at parity. NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers while addressing its aging generation and navigating a dynamic economic environment. Although the Rate 831 proposal requires NIPSCO's other customer classes to pay higher rates in the near term than they are currently paying today under the existing service structure, the long-term risk is that these large industrial customers will otherwise exercise their options to significantly shift load off NIPSCO's system. When that occurs, costs might reasonably be reallocated to the remaining customer classes. While the OUCC and CAC focused on the fairness of a cost shift within this rate case between Rate 831 and other classes, the record shows that denying Rate 831 now would likely result in even higher costs, which would otherwise have been collected under Rate 831 if these customers further bypass NIPSCO's service. When considering the full range of impacts in play rather than just the near-term cost shift, Rate 831 is a reasonable solution now rather than later. We find that retaining the current service structure would only increase the risk that these customers will exercise their options to self-generate additional power or relocate production to avoid an increasing NIPSCO electric price.

Given that large industrial customers constitute such a significant portion of NIPSCO's retail electric sales, reducing their load would cause precipitous declines in NIPSCO's revenues and operating margins far faster than could be offset by growth in other sectors. In the long run, we find that such load loss would subject remaining customers and customer classes to increased costs above and beyond the near term costs of the Rate 831 Settlement. Conversely, we find that approval of this new service structure will provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time.

For the foregoing reasons, we find the Rate 831 Settlement is a reasonable proposition to retain industrial load, and its approval is beneficial to NIPSCO and all of its customers. As such, the Rate 831 Settlement satisfies the second factor.

The Commission finds that the Rate 831 Settlement also meets the third factor by promoting utility efficiency. In particular, Rate 831 reduces the amount of replacement capacity NIPSCO must plan for, provides more reliable load projections for planning purposes, and mitigates the risk of building excess capacity.

As NIPSCO begins to implement the results of its IRP and procure replacement capacity, NIPSCO needs to ensure some stability in what its obligation to serve will be for its largest industrial loads. Rejecting Rate 831 and retaining the current industrial service structure would only increase the risk that NIPSCO's industrial load will further decline over time thereby creating unrecovered costs. NIPSCO would simultaneously be forced to modify its existing Rate 732, 733, and 734 service structure to re-integrate the Rate 831 customers. In that alternative, NIPSCO would likely seek to modify the existing Rate 732, 733, and 734 industrial service structure, alter Rider 775 registrations, and restructure NIPSCO's back-up and maintenance service. These hypothetical proposals to attain some near-term load stability would not actually reduce the risk that industrial customers will exercise their options in the future. We find that approval of the Rate 831 Settlement would demonstrably improve NIPSCO's ability to forecast the load it is required to serve and would thereby enhance its accuracy in procuring the appropriate amount of replacement capacity for its aging generation resources. Likewise, approval of the Rate 831 Settlement will also enable NIPSCO to make better resource decisions while maintaining system reliability and resiliency. As such, we find that the Rate 831 Settlement satisfies the third factor by promoting utility efficiency through more accurate load forecasts and corresponding capacity procurement.

Finally, regarding the fourth factor, a review of the evidence shows that, without the approval of the Rate 831 Settlement, NIPSCO will be hindered in its ability to compete with alternative sources of energy supply and risks further migration of load from its largest industrial customers.

Based on the evidence, we find that NIPSCO is facing the prospect of retiring aging generation resources and procuring replacement capacity in the near term. Despite current strong economic conditions, NIPSCO Electric operations continue to face declining industrial usage driven by the development of customer-sited generation and uncertainty in some global industrial markets. We find that the electric industry is in the midst of a transformation, and it is crucial that NIPSCO be in a position to flexibly align with this transformation.

In past orders, NIPSCO has been permitted to allow its large industrial customers to assume more market risk through the use of interruptible service offerings. The new industrial service structure is the next step in this evolutionary process. In exchange for taking a set amount of contract demand for a period of five years, NIPSCO's largest, most sophisticated customers will be allowed to make more decisions regarding their energy procurement. Transitioning much of NIPSCO's industrial load to Rate 831 requires better cost recovery alignment resulting in a near-term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward. We find that if NIPSCO does not respond, there is a high probability that more industrial load will leave the system, and once gone, the chances that it will return are low.

Based on this evidence and the findings made above, the Commission finds that the Rate 831 Settlement meets the fourth factor and that NIPSCO's proposed ARP, as embodied in the Rate 831 Settlement, is in the public interest.

The Commission has considered the Section 5(b) factors and the evidence, and we find that they support approval of NIPSCO's proposed ARP. We find the proposed ARP and Rate 831 Settlement are consistent with the legislative policy set forth in Ind. Code § 8-1-2.5-1. We are mindful of NIPSCO's unique reliance on a small number of very large industrial loads that are subject to intense global competitive pressures. We find that technological conditions and competitive forces are rendering traditional regulation over NIPSCO's industrial service structure less efficient and potentially more costly because, if a change is not made, more industrial load is reasonably expected to leave the system of customers supporting NIPSCO's retail service cost thereby creating future cost-recovery risks. It is not in the public interest to ignore the challenges of NIPSCO's traditional rate structure in the face of demonstrated and probable industrial load loss, and we are not inclined to adopt a purely reactive approach. By declining to exercise our traditional jurisdiction and embracing the alternative structure that is captured in the Rate 831 Settlement, we find that NIPSCO, all of its customers, and the State should benefit by preserving a defined level of firm large industrial load and avoiding the effects of stranded cost that might reasonably otherwise occur. In so doing, we promote energy utility efficiency by allowing NIPSCO to better plan for the firm load it must serve and by allowing NIPSCO to "right size" its generation resources and avoid the future potential inefficiencies of maintaining excess capacity.

The record demonstrates that if the Rate 831 Settlement, the Revenue Requirement as embodied in the Revenue Settlement, and NIPSCO's proposed cost allocation are approved, there will be no need for a Phase 2 proceeding to establish revised rates. Exhibit D to the Rate 831 Settlement specifically addresses implementation concerns previously raised by some industrial customers.

The Rate 831 Settlement also resolves contested issues regarding the design of Rate 831 that would otherwise require litigation or a true-up process. In particular, each Rate 831 customer has agreed to subscribe to a specific level of firm, Tier 1 demand. Additionally, the parties agreed that the design of Rate 831 should be based on NIPSCO's COSS with costs allocated to Rate 831 based on 194.556 MW of firm demand. These agreements confirm the subscription levels of the Rate 831 customers and establish a cost allocation based on that firm demand, which not only eliminates the need for a true-up process but provides certainty to the Commission and the other parties regarding the share of costs being allocated to Rate 831. The actual Tier 1 subscription is also below that used by NIPSCO in setting cost allocation, but through the Rate 831 Settlement, Rate 831 customers will cover the costs of the 194.556 MW used to allocate costs.

The OUCC and Walmart proposed assessing transition charges on Rate 831 customers. We note that the Commission has no direct statutory authority to prohibit any customer from building or utilizing self-generation nor do we have the ability to preclude a large industrial customer from reducing consumption or moving its operations to another location. In these instances, no transition costs are paid. Rather, as in this case, NIPSCO could file another rate case, seeking to recover the lost revenue from its remaining customers. Moreover, the implementation of transition charges would defeat the purpose of the Rate 831 service structure, which is to maintain load by creating a cost-based rate and providing access to market-priced capacity and energy, not to make NIPSCO's industrial rates less competitive. Based upon the evidence presented, we find that the proposed Rate 831 service structure is reasonable and that no transition charges should be assigned to Rate 831 customers.[43]

In conclusion, the record demonstrates that it was appropriate and reasonably necessary for NIPSCO to revise its industrial rate structure in order to mitigate the credible and preventable threat of large industrial load loss. The record also demonstrates that it is important to NIPSCO and all of its customers to retain the Rate 831 customers and for them to continue contributing to NIPSCO's fixed production costs. We now find that NIPSCO's proposed Rate 831 service structure and the Rate 831 Settlement will best position these large industrial customers to remain cost competitive within their global markets while continuing to contribute to NIPSCO's fixed production costs to serve. This balance enables these customers to be more economically competitive and provides certainty to NIPSCO regarding its obligation to serve. We find that NIPSCO's proposed ARP to implement Rate 831 is in the public interest and will enhance or maintain the value of NIPSCO's retail energy services or property. For the foregoing reasons, the Rate 831 Settlement and Implementation Agreement are approved.

C. <u>Revenue Allocation</u>. We next address the allocation of costs to the various customer classes, as proposed by NIPSCO, and embedded in the terms of the Rate 831 Settlement.

Having considered the evidence presented on the issue of cost allocation, we find the 4CP allocation as proposed by NIPSCO and as reflected in the Corrected Rate 831 Implementation Agreement Exhibit A to the Rate 831 Settlement is reasonable and in the public interest, and is,

[43] While no transition charge is assigned to Rate 831 customers, a risk reduction transition adjustment resulting in a revenue requirement decrease of $3,876,748 is allocated to all non-Rate 831 and Rate 844 customers, as discussed in section 28.D.4.

therefore, approved. The 4CP method for NIPSCO is appropriate for cost allocation based on the fact that in recent years the system peaks in 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. The FERC tests utilized by Dr. Gaske are a commonly used method for analyzing system load characteristics and determining whether a utility has monthly peak periods that can be distinguished from off-peak periods. The 4CP allocation is consistent with the design and operation of NIPSCO's system, and it appropriately and reasonably aligns cost allocation with cost causation.

NIPSCO proposed a mitigation plan to keep Rate 831 at parity and provided for an across-the-board percentage rate increase. NIPSCO began with a fully ACOSS and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MW of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement over all customer classes equally. NIPSCO proposed the methodology to avoid rate shock to its Residential customers, and this approach aims to mitigate the rate increases so that no class will see an unusually large increase in its base rates while allowing NIPSCO to retain its large industrial customers on the system. Because of residential class subsidies that were retained in prior rate proceedings and the combination of industrial service restructuring and other cost increases, the residential customers would require a rate increase in excess of 30%. Therefore, to mitigate this impact, it was determined that all classes except Rate 831 should receive the same across-the-board percentage rate increase, and the rates for the large industrial class would then be based on the allocated cost of service.

CAC recommended that Rate 831 revenues be maintained at test-year levels under current rates and that the revenues of all other customer classes be increased by an equal percentage. Other than its proposal for a transition charge, the OUCC agreed that it is reasonable to assign the remaining increase across the customer classes on an equal percentage basis. NLMK argued that NIPSCO's proposal reasonably addresses its concerns about industrial bypass and rate mitigation. The Industrial Group agreed with NIPSCO's proposal. Walmart recommended that, if it is not possible to eliminate inter-class subsidies in this case, the Commission should establish a path to eliminate or reduce subsidies in future cases.

With the exception of Walmart, no party opposed NIPSCO's mitigation proposal after the Revenue Settlement was entered. Based upon the evidence of record, we find NIPSCO's request to keep Rate 831 at parity and to provide for an across-the-board percentage rate increase, except for Rate 844 and Rate 850 as discussed below, is supported by substantial evidence, in the public interest, and approved.

Based upon this conclusion, we find that the relevant allocations should be as follows:

Demand Allocation		
Class	Rate Schedule	Allocation
Residential	Rate 811	35.05%
C&GS Heat Pump	Rate 820	0.06%
GS Small	Rate 821	17.50%
Comml SH	Rate 822	0.08%
GS Medium	Rate 823	11.42%

GS Large	Rate 824	14.33%
Metal Melting	Rate 825	0.50%
Off-Peak Serv.	Rate 826	8.34%
Ind. Pwr Serv. – Large – Tier 1	Rate 831	8.32%
Small Industrial Service – LLF	Rate 832	0.88%
Small Industrial Service – HLF	Rate 833	1.99%
Muni. Power	Rate 841	0.24%
Int WW Pumping	Rate 842	0.01%
Railroad	Rate 844	0.15%
Street Lighting	Rate 850	0.54%
Traffic Lighting	Rate 855	0.06%
Dusk-to-Dawn	Rate 860	0.18%
Interdepartmental	Interdepartmental	0.34%
Energy Allocation		
Class	Rate Schedule	Allocation
Residential	Rate 811	28.86%
C&GS Heat Pump	Rate 820	0.09%
GS Small	Rate 821	13.67%
Comml SH	Rate 822	0.10%
GS Medium	Rate 823	10.69%
GS Large	Rate 824	15.54%
Metal Melting	Rate 825	0.78%
Off-Peak Serv.	Rate 826	10.72%
Ind. Pwr Serv. – Large – Tier 1	Rate 831	13.86%
Ind. Pwr Serv. – Large – Tier 2		0.00%
Small Industrial Service – LLF	Rate 832	1.23%
Small Industrial Service – HLF	Rate 833	3.30%
Muni. Power	Rate 841	0.24%
Int WW Pumping	Rate 842	0.00%
Railroad	Rate 844	0.18%
Street Lighting	Rate 850	0.35%
Traffic Lighting	Rate 855	0.05%
Dusk-to-Dawn	Rate 860	0.12%
Interdepartmental	Interdepartmental	0.21%

TDSIC Allocation (based upon firm load)			
Class	Rate Schedule	Transmission Rev. Req. Allocation	Distribution Rev. Req. Allocation
Residential	Rate 811	36.64%	53.48%
C&GS Heat Pump	Rate 820	0.11%	0.19%
GS Small	Rate 821	15.94%	17.65%
Comml SH	Rate 822	0.12%	0.18%
GS Medium	Rate 823	11.67%	9.90%

GS Large	Rate 824	13.82%	10.77%
Metal Melting	Rate 825	0.48%	0.53%
Off-Peak Serv.	Rate 826	8.49%	5.98%
Ind. Pwr Serv. – Large	Rate 831	8.57%	0.00%
Small Industrial Service – LLF	Rate 832	1.05%	0.00%
Small Industrial Service – HLF	Rate 833	2.25%	0.00%
Muni. Power	Rate 841	0.25%	0.33%
Int WW Pumping	Rate 842	0.00%	0.00%
Railroad	Rate 844	0.14%	0.00%
Street Lighting	Rate 850	0.07%	0.27%
Traffic Lighting	Rate 855	0.04%	0.03%
Dusk-to-Dawn	Rate 860	0.04%	0.20%
Interdepartmental	Interdepartmental	0.31%	0.50%

There also was a dispute among the parties regarding the appropriate allocation of demand costs for trackers other than TDSIC. OUCC witness Boerger recommended that "NIPSCO be required to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1 Adjustment shown on Page .1 of Rate 831 Implementation Agreement Exhibit and in Attachment 19-E of Mr. Westerhausen's prefiled direct testimony in this case . . . ." Industrial Group witness Phillips and US Steel witness Georgis disagreed with that proposed revision and explained why the tracker allocations proposed by NIPSCO are consistent with system utilization and cost causation. Mr. Phillips stated that it is appropriate to allocate production trackers only to Tier 1 firm load because the Rate 831 customers do not use NIPSCO's production resources for their Tier 2 and 3 loads. At the hearing, Dr. Boerger repeatedly acknowledged during cross-examination that production costs should not be allocated to non-firm load. Tr. at D-94 – D-95, D-96 – D-97. Based upon the evidence of record, the Commission finds that the adjustments proposed in Mr. Westerhausen's prefiled direct testimony contained in Attachment 19-E should be approved.

D. Revenue Settlement. We now review and address the Revenue Settlement, which was opposed by the ICC, ICARE, and LaPorte. We note that the ICC and ICARE do not represent customers in this proceeding, and they explicitly did not oppose the Revenue Settling Parties' agreement to set depreciation accrual rates for the Schahfer and Michigan City coal units based on assumed lives ending in 2032. LaPorte's opposition to the Revenue Settlement highlighted NIPSCO's J.D. Power results and recommended that based on those results, the Revenue Settlement's ROE should be rejected.

(1) Rate Base Update Mechanism Process. For Step 1 Rates, NIPSCO proposed to update its requested relief to be effective subsequent to the receipt of the Commission's final order based upon an actual rate base and capital structure cutoff date of June 30, 2019. As part of its compliance filing, in addition to any other changes identified in this Order, NIPSCO will update its basic rates and charges to reflect the actual rate base and related depreciation and amortization expense, as well as the actual capital structure based on the June 30, 2019 cutoff date. NIPSCO proposed that these rates will become effective with the first billing cycle following the issuance of the Order and remain in effect until replaced by Commission-approved rates resulting from NIPSCO's proposed second compliance filing as part of Step 2.

For Step 2 Rates, the Revenue Settling Parties agreed Step 2 Rates will be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agreed not to include in rate base for Step 2 Rates plant in excess of the amount or value of plant projected in this Cause. The Settling Parties agreed that Step 2 Rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Step 2 Rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019, and calculate the Step 2 Rates using those certified figures. For purposes of this section, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2019. The Revenue Settling Parties and other parties to this proceeding will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Revenue Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 Rates took effect.

We find that the proposed rate base update mechanism process is reasonable, supported by evidence of record, and should be approved.

(2) Revenue Requirement and NOI. The Revenue Settling Parties agree that NIPSCO's base rates will be designed to produce a Revenue Requirement of $1,482,166,740 prior to the application of surviving Riders, which represents a decrease of $63,648,449 from the amount originally requested by NIPSCO. The Revenue Settling Parties also agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as agreed to in the Revenue Settlement, and a $2,000,000 decrease to NIPSCO's proposed O&M Expense. The Revenue Settling Parties agree that NIPSCO's Revenue Requirement results in a proposed authorized NOI of $271,211,585.

As discussed below, we find that the Revenue Settlement provisions regarding NIPSCO's revenue requirement, exclusive of the parties' agreed-upon ROE as discussed below, are reasonable, supported by evidence of record, and are approved. Based on our finding below regarding NIPSCO's authorized ROE, we find and authorize a Revenue Requirement of $1,453,163,108 for Step 1 rates and $1,478,289,992 for Step 2 rates.

(3) NIPSCO's Fair Value Rate Base. The Revenue Settling Parties agreed that the WACC times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based on the Revenue Settlement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding; (2) NIPSCO's proposed capital structure; and (3) an authorized ROE of 9.90%. Neither the components nor value of that fair value rate base is disputed by any party. However, given our finding below regarding NIPSCO's authorized ROE, NIPSCO's overall return for earning test purposes shall be 6.52%. Accordingly, we find that

NIPSCO's fair value rate base for purposes of this proceeding is $4,115,502,071, and that this fair value rate base should be used for purposes of Ind. Code § 8-1-2-6.

(4) NIPSCO's ROE. In its case-in-chief, NIPSCO requested an ROE of 10.80%. OUCC witness Woolridge suggested that NIPSCO's ROE could be set at 8.75%, but in recognition of the practice of gradualism, a 9.25% ROE would be more appropriate. NIPSCO Industrial Group witness Gorman recommended an ROE of 9.35%. Walmart witness Chriss suggested an ROE of 9.69%. The Revenue Settling Parties agreed to an authorized ROE of 9.90%.

In considering the Revenue Settling Parties' recommended ROE, we note that the Revenue Settlement was finalized, signed, and filed prior to the Rate 831 Settlement and Implementation Agreement. As such, the fate of NIPSCO's proposed Rate 831 large industrial service structure was still uncertain at that time. Furthermore, at no place in the Revenue Settlement is its approval made explicitly contingent upon approval of Rate 831. The Commission's approval of the Rate 831 Settlement and Implementation Agreement and the new industrial service construct designed in it significantly mitigates the risk of the loss of industrial load to NIPSCO and the associated earnings volatility. Therefore, based on this reduced risk for NIPSCO's shareholders, we find that a decrease in NIPSCO's ROE is warranted.

In response to the Commission's July 16, 2019 docket entry question, LaPorte witness Cearley stated that based on his review of Mr. Rea's testimony and NIPSCO's similar testimony in its last rate case, Mr. Cearley believes that a 25 to 50 basis point downward ROE adjustment is appropriate and reasonable due to NIPSCO's proposals in this case to address its environmental risk elements and its concentration of large industrial load. Mr. Cearley explained that this recommendation is further supported by his recognition in his direct testimony of the compounding effect of NIPSCO's repetitive "...risk adjustments to its return calculations based on environmental risks and its case-after-case request for upward risk adjustments due to a disproportionate level of large industrial load" in each of its last three to four rate case proceedings.

Based upon the totality of evidence presented and the reduced risk to NIPSCO as a result of our approval of the Rate 831 Settlement and Implementation Agreement, we find that the Revenue Settling Parties' agreed-upon ROE of 9.90% should not be approved. Instead, we find that an ROE of 9.75% is within the range of the ROE evidence presented and is approved, as it is reasonable and appropriate in light of the reduced business risk to NIPSCO as a result of approval of the Rate 831 Settlement. In addition, we note that the Rate 831 Settlement and Implementation Agreement explicitly assigns a revenue requirement to the Rate 831 customers. Further, the evidence in this case reflects the transition to the new industrial service has a distinct impact on the non-Rate 831 customers. Accordingly, this 15 basis point reduction and the resulting $3,876,748 revenue requirement decrease shall be applied across the board only to the customer classes experiencing a rate increase as the result of this Order. As such, Rate 831 and Rate 844 customer classes are exempt and are assigned their agreed-to revenue requirements identified in the Rate 831 Settlement. The application of this risk reduction transition adjustment is essentially funded by NIPSCO through a reduction in its ROE and provides a measure of relief to non-Rate 831 customers in light of the reduced risk to NIPSCO and is not inconsistent with the OUCC's transition charge proposal. Furthermore, the approved 9.75% ROE is consistent with Walmart Exhibit No. 2, Exhibit SWC-3 (REVISED) sponsored by Walmart witness Chriss showing that the average ROE for vertically integrated electric utilities in the country from 2016 through July 10, 2019, is 9.73%.

(5) Depreciation and Amortization Expense. NIPSCO witness Spanos recommended depreciation accrual rates for NIPSCO's electric and common plant assets calculated in accordance with the depreciation study he sponsored. The only witnesses proposing changes to the depreciation accrual rates recommended by Mr. Spanos were OUCC witnesses Garrett and Blakley and Industrial Group witness Gorman, and their issues were resolved pursuant to the Revenue Settlement. No other evidence was presented that disputed the results of Mr. Spanos' depreciation study or the resulting accrual rates. Further, no evidence was presented disputing the Revenue Settlement depreciation accrual rates. We find that the Revenue Settling Parties' agreement regarding depreciation accrual rates should be approved. Those are the original depreciation accrual rates recommended by Mr. Spanos with the following exceptions: (1) the amortization period for retired coal-fired generating units as described in NIPSCO's case-in-chief shall conclude in 2032; and (2) annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency included in demolition costs. These are the depreciation accrual rates that should be used for purposes of determining NIPSCO's total revenue requirement and that should be used for purposes of depreciation expense that will accrue between the date of this Order and December 31, 2019, for purposes of NIPSCO's Step 2 rate base. Neither ICC nor ICARE took issue with the depreciation study or the depreciation rates that come out of the depreciation study. In fact, ICC witness Medine specifically acknowledged that she takes no issue with the depreciation rate for NIPSCO's steam production plant, which underlies the Revenue Settlement.

In the Revenue Settlement, NIPSCO agreed to implement a credit mechanism upon the retirement of its coal-fired generating units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. This credit mechanism was recommended by OUCC witness Blakley. Mr. Blakey testified that ratepayers should be credited with the effect of the annual depreciation of Schahfer and Michigan City plant. He explained that the credit mechanism would function similarly to a CWIP plant investment tracker, in which plant investment is reduced by associated depreciation over a period and the return "on" is calculated on the new lower net plant balance. While the plant investment is decreasing each year due to depreciation of the investment, NIPSCO would otherwise still receive a return "on" the investment as determined at the time of this rate case. The credit would reflect the difference between the amount authorized in rates and the actual investment amount adjusted for depreciation. The credit would be repeated annually until the physical asset or regulatory asset is fully depreciated or amortized. The credit will be limited to the net plant investment value of the Schahfer and Michigan City coal-fired generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in the Revenue Settlement Paragraph B.1(a); and (2) the NOI established in the Revenue Settlement Paragraph B.1(b) for purposes of its earnings test. NIPSCO agreed to hold annual meetings preceding the 30-day compliance filing with interested stakeholders. No party opposed the credit mechanism, and we find it is reasonable and should be approved.

ICC and ICARE were the only parties to oppose the provisions of the Revenue Settlement related to depreciation. Ms. Medine specifically stated that she takes no issue with the depreciation rate for NIPSCO's steam production plant underlying the Revenue Settlement. However, both witnesses Medine and Griffey testified that approval of NIPSCO's regulatory asset treatment resulting from the Revenue Settlement is unnecessary at this time and should be deferred until the coal plants are actually retired. Mr. Griffey recommended that the Commission reject any aspect of the Revenue Settlement that forecloses flexibility and decline to approve explicitly or implicitly NIPSCO's retirement dates.

As noted by Ms. Shikany during cross-examination, approval of the Revenue Settlement – and the attendant depreciation/amortization of amounts based upon a 2032 date – results in zero difference in the revenue requirement agreed upon. Tr. at B-28. In fact, NIPSCO's agreement in the Revenue Settlement to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base at the time a final order is issued and the actual investment amount adjusted for depreciation as outlined in OUCC witness Blakely's direct testimony results in customer savings. Based upon all the evidence, the Commission finds that the depreciation rates agreed upon in the Revenue Settlement are reasonable and should be approved. However, in approving the agreed-upon depreciation rates, we do not, either explicitly or implicitly, approve NIPSCO's retirement dates.

During the hearing held in this Cause, NIPSCO witness Shikany explained the need for a determination regarding the treatment of the remaining book value of the Schahfer and Michigan City generating units at the time of their retirement. She explained that the Uniform System of Accounts is very prescriptive of how to treat a normal retirement. Tr. at B-33. She explained that under normal retirement accounting due to the use of composite depreciation, Mr. Spanos could assign sufficient accumulated depreciation to the Bailly assets to reflect a full recovery by reducing the accumulated depreciation. Tr. at B-33. However, she explained that once the Schahfer units are retired, there will not be enough time to collect the remaining book value through depreciation. Therefore, NIPSCO has proposed to treat the retirement as extraordinary, which needs the Commission's approval. Tr. at B-34. Based upon Ms. Shikany's explanation in Revenue Settlement rebuttal testimony and in redirect examination why a determination is needed at this point concerning the regulatory asset and the fact that customers are not adversely affected by such confirmation (as is further confirmed by the fact that no customer parties opposed this aspect of the Revenue Settlement) and that NIPSCO would face financial risk were we not to provide such confirmation, we therefore find that granting authority for the regulatory asset treatment contained in the Revenue Settlement is reasonable and in the public interest. Accordingly, we find that should the Schahfer and/or Michigan City generating units be retired before the end of 2032, the retirement(s) should be deemed extraordinary pursuant to the FERC Uniform System of Accounts. Further, we find that the net book value of the retiring unit(s) at retirement should be recorded as a regulatory asset when the units are actually retired; that the regulatory asset should be amortized over a period expiring at the end of 2032; that the annual amortization expense should be recovered through rates; and that the regulatory asset should be reflected in NIPSCO's net original cost rate base upon which a full return should be authorized for ratemaking purposes.

With respect to the remaining issue related to amortization expense, the evidentiary record includes proposals from NIPSCO and the OUCC proposing competing approaches to the amortization and amount of the regulatory assets for rate case expense, and for the amortization of the TDSIC deferred balance. The Revenue Settling Parties agreed to resolution of these issues providing that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding, with the exception that the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years, and that if it has not been already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO will make a tariff filing to reflect the reduction in amortization expense. We find this resolution to be reasonable and appropriate.

(6) Other Specific Ratemaking Issues. As discussed above, the Revenue Settling Parties agreed to a level of operating expenses to be incorporated in NIPSCO's revenue requirement, which includes the following issues:

a. TCJA. In its June 1, 1987 Interim Order issued in Cause No. 38194 adopting the recommendations of the Report of the Executive Committee on April 15, 1987, the Commission concluded that all excess deferred taxes should be passed back using the ARAM. After the adoption of the TCJA, the Commission opened an investigation in Cause No. 45032 into the impacts of that TCJA and possible rate implications. The first phase was to address immediate rate reductions to remove the difference between: (1) the amount of federal taxes that the given Rate or Charge was designed to recover based on the tax rate in effect at the time the Rate or Charge was approved; and (2) the amount of federal taxes that would have been embedded in the given Rate or Charge had the new tax rate applicable to NIPSCO as a result of the TCJA been in effect at the time of approval. The second phase was to address all remaining issues, including: (1) the amount and amortization of normalized and non-normalized excess ADIT and the regulatory accounting being used for estimated impacts resulting from the TCJA; and (2) the timing and method for how these benefits will be realized by customers, whether directly or indirectly.

In its sub-docket resulting from Cause No. 45032 (Cause No. 45032-S5), NIPSCO did not file a case-in-chief and instead filed an Unopposed Motion to Hold in Abeyance the Procedural Schedule, which was granted by the Commission on August 15, 2018. In its motion, NIPSCO proposed a method by which it would return excess income tax revenue recovered through rates between January 1, 2018 and April 30, 2018, which was at that time reflected as a regulatory liability and stated that the parties will resolve all other Phase 2 issues in a rate case to be filed by December 31, 2018.

In the Revenue Settlement, the Revenue Settling Parties agreed that: (1) NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in NIPSCO's revenue requirement at the ARAM, estimated at the time of the Revenue Settlement to be 26 years; and (2) with regard to NIPSCO's Unprotected and Other Excess ADIT balance, which totaled approximately $137,789,071 as of December 31, 2017, NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Step 2 Rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030, and if not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization. The total amount of unprotected excess ADIT to be passed back to customers will be addressed in NIPSCO's next general rate case.

The resolution proposed for issues associated with the return of excess ADIT balances is supported by the uncontested evidence of record. The utilization of ARAM as the basis for the pass back of ADIT associated with protected assets is consistent with regulations promulgated by the U.S. Department of Treasury. The amortization of unprotected and other excess ADIT is subject to Commission discretion. We note that the amortization of excess ADIT as agreed to in the Revenue Settlement was uncontested by the non-settling parties. We find the proposed treatment of ADIT balances as proposed by the Revenue Settling Parties to be reasonable and in the public interest. This resolves all remaining issues in Cause No. 45032-S5.

b. Rate Design. In its case-in-chief, NIPSCO proposed an increase in the Residential Customer Charge from $14.00 to $17.00 per month. CAC proposed a reduction to $12.55. Sierra Club proposed a reduction to $12.77. The OUCC proposed no change to the Residential Customer charge. We find that the Revenue Settling Parties' agreement that rates should be designed with the Residential Customer Charge set at $13.50 per month is reasonable and should be approved.

In its case-in-chief, NIPSCO proposed to replace Rates 732 and 733 with Rate 830. The Industrial Group proposed low load factor and high load factor rates for Rate 830. We find that the Revenue Settling Parties' agreement that Rate 830 be split into Rates 832 and 833 to reflect the current structure of Rates 732 and 733 (as proposed in Industrial Group witness Phillips' direct testimony and NIPSCO witness Westerhausen's rebuttal testimony) and that those rates provide for back-up and maintenance provisions reflected in current Rider 776, is reasonable and should be approved.

The Revenue Settling Parties agreed that Rate 844 shall see no increase resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. We find this provision is reasonable and should be approved.

c. Tariff Changes – Trackers and Riders. The Revenue Settling Parties agreed: (1) NIPSCO shall flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; (2) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years; and (3) NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief. We find this provision is reasonable and should be approved.

d. Low-Income Program Commitment. The Revenue Settlement includes a provision that NIPSCO commits to seek approval of a voluntary low-income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process that NIPSCO has already established with interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, will not impact NIPSCO's revenue requirement and will be discussed in the collaborative process. We find this provision is reasonable and should be approved.

e. Rate 850 – Street Lighting. The Revenue Settlement includes a provision that the lamp charge for TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. Pursuant to Joint Exhibit 8, the resulting revenue deficiency will be allocated to other customer and NIPSCO-owned lamp types in Rate 850. We note no evidence was presented in opposition to this provision. We find this provision as modified by Joint Exhibit 8 to be reasonable and should be approved.

(7) Operating Income under Present Rates. For the 12 months ending December 31, 2019, NIPSCO's projected jurisdictional operating income from its electric utility operations at current rates was shown by NIPSCO to be as follows:

Total Operating Revenue		$1,527,202,346
Less Total Fuel Costs	$407,025,357	
Gross Margin		$1,120,176,989
Less Total Operations and Maintenance Expense	$495,797,094	
Less Total Depreciation Expense	$269,915,038	
Less Total Amortization Expense	$43,180,556	
Less Total Taxes Other Than Income	$39,273,167	
Less Federal and State Taxes	$35,787,103	
Total Operating Expenses including Income Taxes		$883,952,958
Net Operating Income		$236,224,031

Petitioner's Attachment 4-A-S2-S.[44] The evidence of record supports the conclusion that NIPSCO's current rates and charges are unjust, unreasonable, and inconsistent with the public interest and that NIPSCO should be authorized to adjust its rates so as to permit the provision of reasonably adequate service and facilities at just and reasonable rates.

(8) Rate Level to be Authorized. Based on the Revenue Settlement and the Commission's risk reduction transition adjustment, NIPSCO should be authorized a fair rate of return of no more than $268,330,735 yielding an overall return of 6.52%, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding; (2) NIPSCO's proposed capital structure adjusted for the Commission's risk reduction transition adjustment, which prescribes an authorized ROE of 9.75%.

Based on the foregoing, the Commission finds that NIPSCO should be authorized rates projected to produce operating revenue for Step 1 and Step 2, as follows:

	Step 1	Step 2
Operating Revenues	$1,453,163,108	$1,478,289,992
Operating Expenses and Taxes		
Fuel Costs	$321,765,239	$321,765,239
Operating & Maintenance Expenses	$489,075,656	489,128,103
Depreciation Expense	$261,122,046	$269,915,038

[44] The values shown were provided in support of Petitioner's projected Step 2 rates to be based on plant in service and capital structure as of December 31, 2019, and thereby correspond to the close of Petitioner's 2019 Forward Test Year.

Amortization Expense	$39,292,177	$43,180,556
Taxes Other Than Income Taxes	$39,184,168	$39,214,372
Income Taxes	$46,342,112	$46,755,949
Total Operating Expenses and Taxes	$1,196,781,399	$1,209,959,257
Projected Net Operating Income	$256,381,710	$268,330,735

(9) Conclusion Regarding Revenue Settlement. Based upon the evidence of record, we find and conclude that the Revenue Settlement presents a balanced and comprehensive resolution of the revenue and other miscellaneous issues set out above. Therefore, the Commission approves the Revenue Settlement's terms and conditions, exclusive of the agreed-upon ROE, as reasonable, supported by substantial evidence, and in the public interest.

(10) Effect of Settlement. With regard to future citation of this Order, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC 3/19/1997).

E. Electric Service Tariff and Standard Contract. NIPSCO witness Westerhausen sponsored NIPSCO's Proposed Tariff,[45] Agreement for Electric Service for Rates 824, 825, 832, 833, and 844,[46] and Agreement for Electric Service for Rate 831 and Rider 876.[47] The facts that affect the specific schedule charge amounts have been discussed throughout this Order and shall be incorporated in the compliance filing to this Order. With the exception of: (1) NIPSCO's proposed changes to reflect its proposed industrial service structure; (2) NIPSCO's proposed updates to its FAC Tracker; and (3) NIPSCO's proposal to discontinue its ECR Mechanism, no party objected to NIPSCO's Proposed Tariff and Standard Contract for Electric Service. Based upon the evidence of record, the uncontested proposals for NIPSCO's Proposed Tariff and Standard Contract for Electric Service, are approved as proposed by NIPSCO.

Based upon the evidence of record and consistent with our approval of the Rate 831 Settlement, NIPSCO's proposed Rates 831, 832, and 833, and Riders 881 and 882 reflecting its industrial service structure are approved.

Mr. Westerhausen explained that the FAC Tracker had been revised: (1) to update the average cost of fuel in base rates in this proceeding; (2) due to the elimination of Rider 775, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 will no longer be passed through the FAC Tracker; and (3) to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider. The OUCC recommended that the Commission continue allowing the OUCC and intervenors to file their testimony and report 35 days after NIPSCO files its FAC application and testimony. No party opposed that

[45] Attachment 19-A, as corrected (January 2, 2019, January 22, 2019, and June 7, 2019) and revised in Attachment 19-R-A (Rate 832), Attachment 19-R-B (Rate 833), Attachment 19-R-E (Appendix A), Attachment 19-R-H (Rate 831), and Attachment 19-S2-A (Rate 831 and Riders 881 and 882).
[46] Attachment 19-R-M.
[47] Attachment 19-R-O.

recommendation and the Commission agrees to keep it in place. For purpose of NIPSCO's FAC proceedings, we find NIPSCO's base cost of fuel to be $0.026736.

With regard to NIPSCO's proposal to discontinue its ECR Mechanism, NIPSCO witness Westerhausen explained that since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECR Mechanism. ICC witness Medine recommended that approval to discontinue the ECR Mechanism should only be provided if NIPSCO agrees to exclude all variable costs currently in the ECR Mechanism and in base rates from the calculation of its offer prices when bidding its units into the market. NIPSCO witness Campbell testified that NIPSCO did not include inappropriate components of its offers to MISO, nor were they imprudent with respect to its generation decision-making. He explained that the variable costs of production that are built into the agreed revenue requirement are based upon production cost modeling, which is based upon NIPSCO's variable costs of production in relation to other sources of power that are offered into the MISO market. This precise issue was raised and rejected in our April 29, 2019 Order in Cause No. 38706 FAC 122 ("FAC 122 Order"). In our FAC 122 Order, we found that NIPSCO demonstrated that its current offer strategy of its generation units into the MISO energy market was reasonable. In that order, we also found that "NIPSCO has adequately demonstrated that it 'has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]' Ind. Code § 8-1-2-42." The Commission reaches the same conclusion in this case. Based upon the evidence of record and consistent with our approval of the Revenue Settlement, NIPSCO's proposal to discontinue its ECR Mechanism is approved.

F. Accounting Relief. Besides the accounting relief requested and which we have already approved regarding the depreciation rates and estimated useful lives of generating assets, NIPSCO seeks accounting authority to defer, as a regulatory asset, discounts offered to certain customers under its EDR for recovery in a future rate case; authority to defer, as a regulatory liability, an amount equal to 100% of: (1) annual OSS margins net of expenses; and (2) back-up and maintenance demand margins, both for pass back through the RTO Tracker; and authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. No party objected to NIPSCO's requested accounting authority. Based upon the evidence of record, and consistent with our approval of the Revenue Settlement, we find that NIPSCO's request is reasonable and should be approved.

G. DSM. NIPSCO proposes to reset lost margins in its DSM tracker filing upon new, effective base rates in this proceeding to eliminate lost margins attributable to all EE measures installed prior to December 31, 2017. Ultimately, NIPSCO is seeking a neutral transition to lost margin recovery between the filing of this rate case and the operation of its DSM tracker filing. No party objected to NIPSCO's request. Based upon the evidence of record, we find that NIPSCO's request is reasonable and should be approved.

H. RTO Tracker and OSS Margin Sharing. NIPSCO proposed to update Rider 771 – Adjustment of Charges for Regional Transmission Organization to: (1) remove MISO charges and credits and collect 100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO; (3) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology. No party objected to NIPSCO's request, except to the extent they objected to the allocation methodology proposed for Rate 831. Based upon the evidence of record and our approval of the Rate 831 Settlement, we find that NIPSCO's request is reasonable and should be approved.

I. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with Commission orders. Ms. Shikany described these costs as follows: TDSIC Remand Amount in accordance with the September 23, 2015 Order on Remand in Consolidated Cause Nos. 44370/44371; TDSIC Costs in accordance with the July 12, 2016 Order in Cause No. 44733; Federally Mandated Costs in accordance with the January 29, 2014 order in Cause No. 44340, December 13, 2017 Order in Cause No. 44872, and July 12, 2017 Order in Cause No. 44889; and MATS Expenses in accordance with the October 10, 2013 Order in Cause No. 44311. Based on the evidence of record, and consistent with our approval of the Revenue Settlement, we find that NIPSCO's request is reasonable and should be approved.

29. Confidential Information. NIPSCO filed motions for protective order on October 31, 2018, February 27, 2019, March 13, 2019, and July 17, 2019, all of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued docket entries finding all of the information described in the motions to be preliminarily confidential, after which such information was submitted under seal. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. The Stipulation and Settlement Agreement on Rate 831 Implementation between NIPSCO, Industrial Group, NLMK Indiana, and US Steel attached hereto is approved and adopted by the Commission, in its entirety, without change or modification.

2. The Stipulation and Settlement Agreement on Less than all the Issues between NIPSCO, Industrial Group, NLMK Indiana, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC attached hereto is approved and adopted by the Commission, exclusive of the Revenue Settling Parties' agreed-upon ROE, as set forth in Finding 28.C.(4) above, which impacts the Revenue Settling Parties' agreed-upon Revenue Requirement.

3. NIPSCO is authorized to implement the authorized rate increase in two steps to be implemented as set forth in Ordering Paragraphs 4 and 5 below. Prior to implementing the rates authorized in this Order, NIPSCO shall file the tariff and applicable rate schedules under this Cause with the Commission, and such rates shall be effective subject to the Energy Division's review and agreement with the amount reflected.

4. For Step 1, NIPSCO shall file new schedules of rates and charges with the Energy

Division of the Commission based on the agreed revenue requirement as adjusted to reflect the order-approved ROE, original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation and amortization expense as of June 30, 2019, maintaining the amortization of the protected excess ADIT using ARAM and unprotected property using ARAM and other unprotected excess ADIT using ten years. Step 1 rates will become effective on the next billing cycle following NIPSCO's submission of its Step 1 compliance filing.

5. For Step 2, NIPSCO shall file new schedules of rates and charges with the Energy Division of the Commission based on the agreed revenue requirement, as adjusted to reflect the order-approved ROE, as of December 31, 2019, as adjusted, if necessary, to reflect the lesser of: (1) NIPSCO's forecasted test-year-end rate base as updated in NIPSCO's rebuttal evidence ($4,115,502,071); or (2) NIPSCO's certified test-year-end net plant in service as of December 31, 2019. Step 2 rates shall include the amortization of $12,170,384 per year in the revenue requirement related to the pass back of the unprotected property and other unprotected excess ADIT to customers. Step 2 rates will be certified and go into effect, subject to refund, on March 1, 2020. The OUCC and intervening parties will have 60 days from the date of certification to state any objections to NIPSCO's certified test-year-end net plant in service. If there are objections, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued-up (with carrying charges) retroactive to the date that NIPSCO's Step 2 rates became effective.

6. All schedules of rates and charges submitted under Ordering Paragraphs 4 and 5 shall be developed according to the agreed on rate design as described by the terms of the Revenue Settlement and the allocation among customer classes as described by the terms of the Rate 831 Settlement, as set forth in Finding 28.C. above.

7. The proposed IURC Electric Service Tariff, Original Volume No. 14 is approved consistent with the Rate 831 Settlement and Revenue Settlement and this Order, inclusive of the associated General Rules and Regulations and Standard Contracts.

8. NIPSCO's proposed depreciation rates are approved consistent with the Revenue Settlement and this Order.

9. NIPSCO is authorized to create a regulatory asset equal to the remaining net book value of its R.M. Schahfer Generating Units and Michigan City Generating Unit at the date of each unit's retirement to be amortized through December 31, 2032 consistent with the Revenue Settlement and this Order.

10. NIPSCO is authorized: (1) to defer as a regulatory asset, discounts offered to certain customers under its Economic Development Rider for recovery in a future rate case; and (2) to defer as a regulatory liability, an amount equal to 100% of annual off-system sales margins net of expenses and back-up and maintenance demand margins, both for pass back through the RTO Tracker.

11. The information submitted under seal in this Cause pursuant to motions for protective orders is determined to be confidential and exempt from public access and disclosure

pursuant to Ind. Code § 24-2-3-2 and § 5-14-3-4.

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

<u>HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR</u>:

APPROVED: DEC 4 2019

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

FILED
April 26, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT ON LESS THAN ALL THE ISSUES

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; United States Steel Corporation; the Citizens Action Coalition of Indiana, Inc.; Walmart Inc.; Northern Indiana Commuter Transportation District; Sierra Club; and the Indiana Office of Utility Consumer Counselor (collectively the "Settling Parties"), respectfully submits the attached Stipulation and Settlement Agreement on Less Than all the Issues (the "Settlement Agreement").

The Settlement Agreement resolves the revenue requirements issues and other miscellaneous issues. The Settling Parties are continuing to work to see if any other parties will join the Settlement Agreement. The Settling Parties are also continuing discussions regarding revenue allocation and Rate 831 rate design to attempt to reach resolution. The Settling Parties will provide the Commission with a status report on or before April 30, 2019 regarding the status of settlement negotiations on revenue allocation and Rate 831 rate design and to advise if any additional parties have agreed to join the Settlement Agreement.

Respectfully submitted on behalf of the Settling Parties,

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Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic transmission this 26th day of April, 2019 to:

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

STIPULATION AND SETTLEMENT AGREEMENT ON LESS THAN ALL THE ISSUES

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 25th day of April, 2019, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); the NIPSCO Industrial Group ("Industrial Group");[1] NLMK Indiana; United States Steel Corporation; the Citizens Action Coalition of Indiana, Inc.; Walmart Inc.; Northern Indiana Commuter Transportation District; Sierra Club; and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"), who stipulate and agree for purposes of settling the revenue requirements issues in this Cause that the terms and conditions set forth below represent a fair and reasonable resolution of the revenue requirement issues and other miscellaneous issues subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission

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[1] The Industrial Group is comprised of Accurate Castings, Inc., ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc., Enbridge Energy, Praxair, Inc., and USG Corporation.

("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein.

A. Background

1. NIPSCO's Current Rates and Charges: NIPSCO's current electric basic rates and charges were approved in the Commission's July 18, 2016 Order in Cause No. 44688 (the "44688 Rate Case Order"). The basic rates and charges approved in the 44688 Rate Case Order went into effect on September 29, 2016. Those rates and charges remain in effect today, as modified by various riders approved by the Commission from time to time; and as modified on May 1, 2018 pursuant to the Commission's January 3, 2018 Order in Cause No. 45032 to reflect the reduction in the federal income tax rate from 35 percent to 21 percent in accordance with the Tax Cut and Jobs Act of 2017 ("TCJA").[2]

2. NIPSCO's Current Depreciation and Accrual Rates: NIPSCO's current common and electric depreciation rates were approved in the Commission's 44688 Rate Case Order. The Commission's Orders in Cause Nos. 44012 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 44688 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings: 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 fluctuation in its fuel and purchased energy costs. In accordance with Rider 770 – Adjustment of Charges for Cost of Fuel

[2] The Commission approved NIPSCO's 30-Day Filing No. 50167 on April 25, 2018.

Rider, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 – Interruptible Industrial Service Rider are also recovered in quarterly FAC proceedings. Historically, NIPSCO has agreed that the OUCC and other interested parties should have thirty-five (35) days to review NIPSCO's FAC filings and NIPSCO has agreed to continue that practice.

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 771 – Adjustment of Charges for Regional Transmission Organization ("RTO Tracker") and Appendix C – Regional Transmission Organization Adjustment Factor approved by the Commission in its 44688 Rate Case Order; and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs through its Rider 774 – Adjustment of Charges for Resource Adequacy ("RA Tracker") and Appendix F – Resource Adequacy Adjustment Factor approved by the Commission in its 44688 Rate Case Order.[3] In addition, pursuant to Rider 774, 75% of costs associated with credits paid for interruptible load under Rider 775 are recovered through the RA Tracker.

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[3] In its August 25, 2010 Order 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. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RTO Adjustment approved in Cause No. 43526 by approving Rider 671 and Appendix C. In the 44688 Rate Case Order, the Commission approved NIPSCO's request for 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.

In its August 25, 2010 Order in Cause No. 43526, the Commission found that NIPSCO's prudently incurred capacity should be recovered through the Resource Adequacy or RA Adjustment. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RA Adjustment approved in Cause No. 43526 by approving Rider 674 and Appendix F.

NIPSCO files semi-annual proceedings in Cause No. 42150-ECR-XX to recover costs associated with qualified pollution control property, clean coal technology and clean energy projects to allow NIPSCO to comply with various environmental obligations through its Rider 772 – Adjustment of Charges for Environmental Cost Recovery Mechanism ("ECRM Tracker") and Appendix D — Environmental Cost Recovery Mechanism Factor approved by the Commission in its 44688 Rate Case Order.[4]

NIPSCO files an annual proceeding in Cause No. 43618-DSM-XX to recover program costs and lost revenues associated with approved demand side management and energy efficiency programs through its Rider 783 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor initially approved by the Commission in its May 25, 2011 Order in Cause No. 43618. In its February 27, 2017 Order in Cause No. 43618-DSM-11, the Commission approved a modification to NIPSCO's Rider 783 to move from a semi-annual to annual filing.

NIPSCO files an annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 786 – Green Power Rider and Appendix H – Green Power Rider Rate. The initial tracking mechanism was approved in the Commission's December 19, 2012 Order in Cause No. 44198. In its December 28, 2016 Order in Cause No. 44198-GPR-8 the Commission approved a modification to NIPSCO's Rider 786 to move from a semi-annual to annual filing.

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4 The Commission approved two tracking mechanisms in its November 26, 2002 Order in Cause No. 42150 by approving Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor and Rider 673 □ Adjustment of Charges for Environmental Expense Recovery Mechanism and Appendix E – Environmental Expense Recovery Mechanism Factor. The Commission subsequently approved the consolidation of Riders 672 and 673 in its 44688 Rate Case Order.

NIPSCO files a semi-annual proceeding in Cause No. 44340-FMCA-XX to recover federally mandated costs through its Rider 787 – Adjustment of Charges for Federally Mandated Costs ("FCMA") and Appendix I – Federally Mandated Cost Adjustment Factor. The initial tracking mechanism was approved in the Commission's January 29, 2014 Order in Cause No. 44340.

NIPSCO files a semi-annual proceeding in Cause No. 44733-TDSIC-XX to recover 80% of eligible and approved capital expenditures and transmission, distribution, and storage system improvement charge costs for eligible projects through Rider 788 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix J – Transmission, Distribution and Storage System Improvement Charge. The initial tracking mechanism was approved in the Commission's February 17, 2014 Order in Cause No. 44371.

5. This Proceeding: On October 31, 2018, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to increase its retail rates and charges for electric utility service through the phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders; (3) approving revised common and electric depreciation rates applicable to electric plant in service; (4) approving necessary and appropriate accounting relief; (5) approving a new service structure for industrial rates ("Rate 831"); (6) authorizing NIPSCO to implement temporary rates; and (7) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on October 31, 2018. On February 13, 2019, the OUCC and intervenors filed their

respective cases-in-chief and on March 15, 2019, NIPSCO filed its rebuttal testimony and exhibits and several intervenors filed cross-answering testimony and exhibits.

As discussed within NIPSCO's Verified Petition, and the testimony of various parties including NIPSCO, this rate case filing was driven by several developments subsequent to the 44688 Rate Case Order. First, NIPSCO needed to address unresolved impacts related to the TCJA, particularly the return of excess Accumulated Deferred Income Tax ("ADIT"). Second, NIPSCO sought to modify its depreciation rates and cost recovery in rates for NIPSCO's coal-fired generating assets to reflect the useful life of those assets as reflected in NIPSCO's Integrated Resource Plan. Third, as part of an alternative regulatory plan under Ind. Code §8-1-2.5-6, NIPSCO proposed to modify its industrial service rate structure to respond to a changing energy landscape and economic conditions that directly impact its largest customers.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income:

(a) Revenue Requirement: The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,482,166,740 prior to application of surviving Riders. This Revenue Requirement is a decrease of approximately $63.648 Million from the amount originally requested by NIPSCO. The Settling Parties agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below, and a $2,000,000 decrease to NIPSCO's proposed O&M Expense.

(b) Net Operating Income: The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income ("NOI") of $271,211,585.

2. Fair Value Rate Base, Capital Structure, and Fair Return:

(a) Fair Value Rate Base: The Settling Parties agree that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based on this Agreement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon:

(i) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding;

(ii) NIPSCO's proposed capital structure; and

(iii) an authorized return on equity ("ROE") of 9.90%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.90% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$2,864,884,714	9.90%	4.74%
Long-Term Debt	$2,151,351,378	4.97%	1.79%
Customer Deposits	$71,453,491	4.91%	0.06%
Deferred Income Taxes	$1,266,429,454	0.00%	0.00%
Post-Retirement Liability	$66,142,914	0.00%	0.00%
Prepaid Pension Asset	$(435,272,223)	0.00%	0.00%
Post-1970 ITC	$2,014,831	8.30%	0.00%
Totals	**$5,987,004,559**		**6.59%**

3. Depreciation and Amortization Expense:

(a) Depreciation Expense: The Settling Parties agree that the depreciation accrual rates recommended by NIPSCO in this proceeding should be approved with the following exceptions:

(i) the amortization period for retired coal-fired generating units as described in NIPSCO's case-in-chief shall conclude in 2032, which presumes the retirement of the R.M. Schahfer ("Schahfer") Generating Units in 2023 and the Michigan City Generating Unit in 2028; and

(ii) annual depreciation expense shall be adjusted to reflect the removal of $26 Million in contingency expense included in demolition costs, as proposed by Industrial Group Witness Gorman.

(b) Amortization Expense: The Settling Parties agree that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding with the following exception:

(i) the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC 7 Year Plan, FMCA, MATs, EDR and Electric Rate Case Expense of seven (7) years.

If not already addressed by an intervening base rate case order, after the completion of the seven (7) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(c) Revenue Credit: NIPSCO agrees to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City Generating Units reflected in NIPSCO's rate base at the time a Final Order is issued in this proceeding and the actual investment amount adjusted for depreciation as outlined in OUCC Witness Blakely's direct testimony. NIPSCO agrees to implement the credit upon the retirement of the Generating Units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. The credit will be limited to the net plant investment value of the Schahfer and Michigan City Generating Units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in paragraph B.1(a), and (2) the NOI established in paragraph B.1(b) for purposes of its earnings test. NIPSCO agrees to hold annual pre-filing meetings preceding the 30 day compliance filing with interested stakeholders.

4. Tax Cut and Jobs Act:

(a) Protected and Net Operating Loss Excess ADIT: The Settling Parties agree that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately \$(203,164,460) shall be passed back in NIPSCO's revenue requirement at the average rate assumption method ("ARAM"), estimated at the time of this Agreement to be 26 years.

5. Unprotected and Other Excess ADIT: The Settling Parties agree that NIPSCO's Unprotected and Other Excess ADIT balance, totaled approximately \$137,789,071 as of December 31, 2017. NIPSCO shall amortize \$12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. If not already addressed by an intervening base rate case order, after the completion of the ten (10) year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization.

6. Phase II Rate Implementation:

(a) Phase II Rates Subject to Refund: Phase II rates shall be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agrees it shall not be permitted to include in rate base for Phase II rates plant in excess of the amount or value of plant projected in this Cause. The Settling Parties agree that Phase II rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Phase II rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019 and calculate the Phase II rates using those certified figures. For purposes of this Agreement, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies and that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2019. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Phase II rates were put into place.

7. <u>Revenue Allocation:</u>

(a) The Settling Parties agree to continue discussions regarding revenue allocation and Rate 831 rate design to attempt to reach resolution and also agree to provide the Commission with a status report on or before April 30, 2019 regarding the status of settlement negotiations on revenue allocation and Rate 831 rate design.

8. <u>Rate Design</u>:

(a) The Settling Parties have agreed on the following issues related to rate design.

(i) <u>Residential Customer Charge</u>: The Settling Parties agree that rates should be designed with the Residential Customer Charge set at $13.50/month.

(ii) <u>Rate 830</u>: The Settling Parties agree that as proposed in Industrial Group Witness Phillips' Direct Testimony and NIPSCO Witness Westerhausen's Rebuttal Testimony, Rate 830 shall be split into Rates 832 and 833 which shall reflect the current structure of Rates 732 and 733, and provide for backup and maintenance provisions reflected in current Rider 776.

(iii) Rate 844: The Settling Parties agree that Rate 844 shall see no increase in its base rates resulting from this proceeding given its importance to Northwest Indiana in providing public transportation between South Bend and Chicago.

9. Tariff Changes:

(a) Trackers and Riders:

(i) NIPSCO agrees to flow through the RTO Tracker 100% of all margins, including any net losses, from off-system sales, down to zero.

(ii) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years.

(iii) The Settling Parties agree that NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief.

10. Low Income Program Commitment:

(a) NIPSCO commits to seek approval of a voluntary low income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process NIPSCO has already established with

NIPSCO and interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

C. Procedural Aspects and Presentation of the Agreement

1. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the simplification and minimization of issues to be presented in the proceeding.

2. The Settling Parties agree to jointly present this Agreement to the Commission for 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.

3. 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 cited 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 modification of material condition deemed unacceptable to any Settling 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 contains any unacceptable modifications. In the event the Agreement is withdrawn, the Settling Parties will request an Attorney's Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

4. 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 any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final 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 has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

5. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion 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.

6. 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; and further represent and agree that each Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

7. 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 any portion of the of Final Order by any person not a party to this Agreement.

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

9. 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 25th day of April, 2019.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Michael Hooper
Senior Vice President
Regulatory, Legislative Affairs and Strategy

Indiana Office of Utility Consumer Counselor

Jeffrey M. Reed

NIPSCO Industrial Group

NLMK Indiana

James C. Bier

4-25-2019

United States Steel Corporation

Citizens Action Coalition of Indiana, Inc.

Jennifer Washburn
____

Walmart Inc.

Northern Indiana Commuter Transportation District

By ______________________________

JAMES A. L. BUDDENBAUM

One of Its attorneys

Sierra Club

Tony Mendoza
Staff Attorney, Sierra Club

FILED
May 17, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831 IMPLEMENTATION

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; and United States Steel Corporation (collectively the "Rate 831 Settling Parties"), respectfully submits the attached Stipulation and Settlement Agreement on Rate 831 Implementation (the Rate 831 Implementation Agreement"). The Rate 831 Implementation Agreement resolves the implementation of Rate 831, including the proposed revenue allocation to Rate 831. The Rate 831 Settling Parties would propose that any party wishing to file testimony in response to the Rate 831 Implementation Agreement do so by June 7, 2019, to allow for the remainder of the procedural schedule to remain unchanged.

Respectfully submitted on behalf of the Rate 831 Settling Parties,

Claudia J. Earls

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Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic transmission this 17th day of May, 2019 to:

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Claudia J. Earls

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831 IMPLEMENTATION

This Stipulation and Settlement Agreement on Rate 831 Implementation ("Rate 831 Implementation Agreement") is entered into this 17th day of May, 2019, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); the NIPSCO Industrial Group[1] ("Industrial Group"); NLMK Indiana ("NLMK");[2] and United States Steel Corporation ("US. Steel") (collectively the "Rate 831 Settling Parties"), who stipulate and agree for purposes of settling issues related to Rate 831, presented in this Cause, that the terms and conditions set forth below represent a fair and reasonable resolution subject to incorporation into a Final Order of the Indiana Utility Regulatory

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[1] The Industrial Group is comprised of Accurate Castings, Inc., ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc, Enbridge Energy, Praxair, Inc., and USG Corporation.

[2] NLMK joins in and supports this Rate 831 Implementation Agreement except as to paragraph C.4.

Commission ("Commission") without any modification or condition that is not acceptable to the Rate 831 Settling Parties.

A. Background

WHEREAS, NIPSCO filed a Verified Petition initiating this Cause on October 31, 2018 requesting, among other relief, approval of an Alternative Regulatory Plan pursuant to Indiana Code §8-1-2.5-6 that would facilitate a new service structure for industrial rates ("Rate 831") to address a changing energy landscape;

WHEREAS, the Rate 831 Settling Parties filed testimony explaining the operation of Rate 831 and supporting the need for Rate 831 to preserve NIPSCO's large industrial load, to retain the contribution of such load to fixed production costs, and support NIPSCO's resource planning;

WHEREAS, the Rate 831 Settling Parties filed testimony supporting the allocation methodology proposed by NIPSCO which would have produced cost-of-service rates for customers on Rate 831 while preserving a sizable subsidy for customers on Rate 811;

WHEREAS, the Rate 831 Settling Parties and other parties, including the Indiana Office of Utility Consumer Counselor, entered into and filed a Stipulation and Settlement Agreement On Less than All the Issues ("Revenue Settlement") with the Commission on April 26, 2019 which, among other matters, decreased NIPSCO's proposed revenue requirement by approximately $63.648 Million from the amount originally requested by NIPSCO;

WHEREAS, the Revenue Settlement indicated that parties would continue discussions in an effort to resolve revenue allocation and issues related to Rate 831;

WHEREAS, after negotiations conducted prior to and after the filing of the Revenue Settlement, the parties have been unable to resolve their differences on revenue allocation and issues related to Rate 831;

WHEREAS, the Rate 831 Settling Parties have been able to reach mutual agreement on issues related to Rate 831 implementation between and among themselves including rate design which will obviate the need for additional proceedings on such issues, including the Step 2 True Up, and wish to present the other parties and the Commission with an agreement to be considered as in the public interest for approval without modification;

NOW, THEREFORE, the Rate 831 Settling Parties agree to the following:

B. Settlement Terms

1. Allocation: The Rate 831 Settling Parties[3] agree that NIPSCO's cost of service study should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 megawatts. The Rate 831 Settling Parties agree that $149.438 Million (exclusive of approximately $2.827 Million in "other revenues") shall be allocated to Rate 831.

---

[3] US Steel submitted testimony in this Cause only related to Rate 831, and thus supports the settlement cost of service study as it relates to the rates, charges and trackers related to Rate 831, and takes no position on the remaining rate design.

2. Tracker Allocations:

a. The Rate 831 Settling Parties agree that Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (updated for the settlement revenue requirement and the adjustment for Rate 844), shall be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms.

b. The Rate 831 Settling Parties agree that Rate 831 Implementation Agreement Exhibit B, which is Attachment 19-R-E to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (with no changes), sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism.

c. For the purposes of recovery of any approved capital transmission, distribution, and storage system improvement charge ("TDSIC") expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (updated with the settlement revenue requirement) reflect the allocation factors for TDSIC purposes.

3. <u>Rate 831 Rate Design</u>:

a. Except as otherwise provided herein, the Rate 831 Settling Parties agree that Rate 831 shall be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in B.1., above.

b. The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the cost of service study presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in B.1., above.

c. For purposes of the "Adjacent Affiliate Qualified Facility Premise Transmission Charge" the Rate 831 Settling Parties agree that the provision shall be amended by adding the following language: " If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period."

d. The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial 5-year contract is set forth in <u>Rate 831 Implementation Agreement Confidential Exhibit C</u>. The Rate 831 Settling Parties agree that the Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C shall be binding upon each customer in the event of the approval of this Agreement without modification.

e. The Rate 831 Settling Parties agree that a transition period, lasting from the date on which Phase I rates become effective until June 1, 2020, shall provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs. The Rate 831 Settling Parties agree that the terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

C. Procedural Aspects and Presentation of the Agreement

1. The Rate 831 Settling Parties acknowledge that a significant motivation to enter into this Rate 831 Implementation Agreement is the expectation that, if the Commission finds this Agreement to be reasonable and in the public interest, a Final Order approving the Agreement and authorizing the implementation of the Rate 831 service structure will be effective immediately, without the need for a Stage 2 True Up proceeding. The Rate 831 Settling Parties have spent considerable and valuable time reviewing data and negotiating the Agreement in an effort to eliminate time consuming and costly litigation. The Rate 831 Settling Parties agree to request that the Commission review this Agreement within the existing procedural schedule, and that if the Commission finds the Agreement to be reasonable and in the public interest, to approve the Agreement without any material modification in sufficient time to allow the Rate 831

service structure to be implemented contemporaneously with the all other changes in rates and charges.

2. The Rate 831 Settling Parties agree to jointly present this Agreement to the Commission for 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.

3. If the Agreement is not approved in its entirety by the Commission, the Rate 831 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 Rate 831 Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling 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 contains any unacceptable modifications.

4. In the event the Commission rejects this Settlement Agreement or the Alternative Regulatory Plan for Rate 831, or makes modifications in the Rate 831 allocation or design (collectively "831 Rejection"), which results in the six largest industrial customers being unable or unwilling to subscribe to the total megawatts included on Rate 831 Implementation Agreement Confidential Exhibit C under the proposed design, the Settling Parties agree that further proceedings in this Cause are

appropriate. In the event of 831 Rejection, the Settling Parties propose to notify the Commission so that a procedural schedule may be established to determine the proper rate structure for NIPSCO's largest industrial customers. The Rate 831 Settling Parties agree that the revenue requirement in the Revenue Settlement is calculated based upon NIPSCO's proposed change in its industrial service structure (i.e., establishing Rate 831). 831 Rejection would directly affect the stipulated revenue requirement, specifically the fuel and related expenses such that the revenue requirement will need to be revised and the allocated cost of service study will need to be revised, and that NIPSCO cannot implement new rates for any customer class until the additional proceeding is concluded.

5. The Rate 831 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 any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Rate 831 Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final 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 Rate 831 Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

6. The Rate 831 Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Rate 831 Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

7. 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.

8. 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; and further represent and agree that each Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

9. The Rate 831 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 Rate 831 Settling Parties shall oppose any appeal of any portion of the Final Order approving this Agreement.

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

11. 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 17th day of May, 2019.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

____
Michael Hooper
Senior Vice President
Regulatory, Legislative Affairs and Strategy

NIPSCO Industrial Group

Bette J. Dodd

NLMK Indiana

United States Steel Corporation

Nikki Shoultz

Tracker Allocators
2018 Electric Rate Case
Demand Allocation

Line	Description	Rate Class	Demand Allocators - Total Revenue	Rate 831 Tier 1 Adjustment	Revised Revenue	Resulting % Allocation on Revenue"
1	Residential	Rate 811	$ 508,397,289		$ 508,397,289	35.05%
2	C&GS Heat Pump	Rate 820	$ 914,117		$ 914,117	0.06%
3	GS Small	Rate 821	$ 253,812,406		$ 253,812,406	17.50%
4	Comml SH	Rate 822	$ 1,211,193		$ 1,211,193	0.08%
5	GS Medium	Rate 823	$ 165,705,139		$ 165,705,139	11.42%
6	GS Large	Rate 824	$ 207,833,587		$ 207,833,587	14.33%
7	Metal Melting	Rate 825	$ 7,273,007		$ 7,273,007	0.50%
8	Off-Peak Serv.	Rate 826	$ 121,033,845		$ 121,033,845	8.34%
9	Industrial Power Service - Large	Rate 831	$ -			
10	Tier 1	Tier 1	$ 152,266,583	$ (31,546,292)	$ 120,720,291	8.32%
11	Small Industrial Service - LLF	Rate 832	$ 12,790,750		$ 12,790,750	0.88%
12	Small Industrial Service - HLF	Rate 833	$ 28,801,612		$ 28,801,612	1.99%
13	Muni. Power	Rate 841	$ 3,500,918		$ 3,500,918	0.24%
14	Int WW Pumping	Rate 842	$ 111,123		$ 111,123	0.01%
15	Railroad	Rate 844	$ 2,146,284		$ 2,146,284	0.15%
16	Street Lighting	Rate 850	$ 7,896,064		$ 7,896,064	0.54%
17	Traffic Lighting	Rate 855	$ 910,582		$ 910,582	0.06%
18	Dusk to Dawn Lighting	Rate 860	$ 2,615,562		$ 2,615,562	0.18%
19		Interdepartmental	$ 4,946,681		$ 4,946,681	0.34%
20	System Total		$ 1,482,166,742		$ 1,450,620,450	100.00%

Tracker Allocators
2018 Electric Rate Case
Demand Allocation Support

Rate 831

Line No.	Description	Billing Determinants (kWh, kW)		Proposed Rate		Revenue		Total Revenue		Tier 1 Revenue
	Billed kW									
1	Firm Contract Demand	2,334,672	$	22.97	$	53,617,496	$	53,617,496	$	53,617,496
2										
3	Total kW	2,334,672			$	53,617,496	$	53,617,496		
	Energy Charge									
4	Variable O&M	1,534,532,236	$	0.003435	$	5,270,461	$	5,270,461	$	5,270,461
5	Fuel	1,684,938,526	$	0.026446	$	44,559,646	$	44,559,646	$	44,559,646
6	Transmission Charge	5,031,239,483	$	0.008573	$	43,132,596	$	43,132,596	$	14,444,904
	Adjacent Qualifying Facility Premise									
7	Transmission Charge	1,222,643,106	$	0.002572	$	3,144,500	$	3,144,500	$	-
8	Transmission Charge Subtotal	6,253,882,589				46,277,096				
9	Total Energy Charge				$	96,107,204	$	96,107,204	$	117,892,508
10	Other Revenue								$	2,827,783
	Discounts - Billed kW									
11	Lagging RKVA Discount	(893,436)	$	0.32	$	(285,900)	$	(285,900)		
12	Total Discount	(893,436)			$	(285,900)	$	(285,900)		
13	Industrial Power Service - Large (Rate 831)				$	149,438,800	$	149,438,800	$	149,438,800
14	Other Revenue / Rate 831 Tier 1 Adjustment						$	2,827,783	$	31,546,292
15	Total						$	152,266,583		

			%
Transmission kWh		5,031,239,483	100.00%
Adjacent Qualifying Facility Premise Transmission kWh	1,222,643,106	-	0.00%
Total		5,031,239,483	

Tracker Allocators
2018 Electric Rate Case
Demand Allocation Support

Description	Rates	Demand Allocators - Total Revenue	Rate 831 Tier 1 Adjustment	Revised Revenue	Resulting % Allocation on Revenue"
Residential	Rate 811	$ 508,397,289		$ 508,397,289	35.05%
C&GS Heat Pump	Rate 820	$ 914,117		$ 914,117	0.06%
GS Small	Rate 821	$ 253,812,406		$ 253,812,406	17.50%
Comml SH	Rate 822	$ 1,211,193		$ 1,211,193	0.08%
GS Medium	Rate 823	$ 165,705,139		$ 165,705,139	11.42%
GS Large	Rate 824	$ 207,833,587		$ 207,833,587	14.33%
Metal Melting	Rate 825	$ 7,273,007		$ 7,273,007	0.50%
Off-Peak Serv.	Rate 826	$ 121,033,845		$ 121,033,845	8.34%
Industrial Power Service - Large	Rate 831				
Tier 1	Tier 1	$ 152,266,583	$ (31,546,292)	$ 120,720,291	8.32%
Small Industrial Service - LLF	Rate 832	$ 12,790,750		$ 12,790,750	0.88%
Small Industrial Service - HLF	Rate 833	$ 28,801,612		$ 28,801,612	1.99%
Muni. Power	Rate 841	$ 3,500,918		$ 3,500,918	0.24%
Int WW Pumping	Rate 842	$ 111,123		$ 111,123	0.01%
Railroad	Rate 844	$ 2,146,284		$ 2,146,284	0.15%
Street Lighting	Rate 850	$ 7,896,064		$ 7,896,064	0.54%
Traffic Lighting	Rate 855	$ 910,582		$ 910,582	0.06%
Dusk to Dawn Lighting	Rate 860	$ 2,615,562		$ 2,615,562	0.18%
	Interdepartmental	$ 4,946,681		$ 4,946,681	0.34%
System Total		$ 1,482,166,742		$ 1,450,620,450	100.00%

Tracker Allocators
2018 Electric Rate Case
Energy Allocation

Line	Description	Rate Class	MWH at the Source	% Allocation on Sales
1	Residential	Rate 811	3,574,056	28.86%
2	C&GS Heat Pump	Rate 820	10,918	0.09%
3	GS Small	Rate 821	1,692,423	13.67%
4	Comml SH	Rate 822	12,282	0.10%
5	GS Medium	Rate 823	1,324,381	10.69%
6	GS Large	Rate 824	1,925,038	15.54%
7	Metal Melting	Rate 825	97,218	0.78%
8	Off-Peak Serv.	Rate 826	1,327,574	10.72%
9	Industrial Power Service - Large	Rate 831		
	Tier 1		1,716,774	13.86%
	Tier 2		0	0.00%
10	Small Industrial Service - LLF	Rate 832	152,471	1.23%
11	Small Industrial Service - HLF	Rate 833	408,867	3.30%
12	Muni. Power	Rate 841	29,678	0.24%
13	Int WW Pumping	Rate 842	355	0.00%
14	Railroad	Rate 844	21,905	0.18%
15	Street Lighting	Rate 850	42,843	0.35%
16	Traffic Lighting	Rate 855	6,532	0.05%
17	Dusk to Dawn Lighting	Rate 860	15,291	0.12%
18		Interdepartmental	26,376	0.21%
19	System Total		12,384,981	100%

Tracker Allocators
2018 Electric Rate Case
TDSIC Allocation

Transmission and Distribution
Revenue Requirement Allocation

*For purposes of recovering approved capital TDSIC expenditures and costs pursuant to I.C. 8-1-39-9(a), the following class allocation factor percentages shall be applied to the respective distribution- or transmission-related revenue requirement and then the resulting TDSIC charge factors (per kWh) applied to each customer's firm (or non-interruptible) load within that class:

Line	Description	Rate Class	Transmission Rev. Req. Allocation Factor %	Distribution Rev. Req. Allocation Factor %
1	Residential	Rate 811	36.65%	53.48%
2	C&GS Heat Pump	Rate 820	0.11%	0.19%
3	GS Small	Rate 821	15.95%	17.65%
4	Comml SH	Rate 822	0.12%	0.18%
5	GS Medium	Rate 823	11.67%	9.90%
6	GS Large	Rate 824	13.82%	10.77%
7	Metal Melting	Rate 825	0.48%	0.53%
8	Off-Peak Serv.	Rate 826	8.49%	5.98%
9	Industrial Power Service - Large	Rate 831	8.55%	0.00%
10	Small Industrial Service - LLF	Rate 832	1.05%	0.00%
11	Small Industrial Service - HLF	Rate 833	2.26%	0.00%
12	Muni. Power	Rate 841	0.25%	0.33%
13	Int WW Pumping	Rate 842	0.00%	0.00%
14	Railroad	Rate 844	0.14%	0.00%
15	Street Lighting	Rate 850	0.07%	0.27%
16	Traffic Lighting	Rate 855	0.04%	0.03%
17	Dusk to Dawn Lighting	Rate 860	0.04%	0.20%
		Interdepartmental	0.31%	0.50%
18	System Total		100.00%	100.00%

Tracker Allocators
2018 Electric Rate Case
TDSIC Allocation Support

TDISC Allocators

Rate	Trans	Sub Trans	Total	831 Tier 1 Adj	Adj. Total	Transmission Rev. Req. Allocation Factor
Rate 811	$ 40,202,805	$ 9,738,719	$ 49,941,524		$ 49,941,524	36.65%
Rate 820	$ 106,041	$ 45,896	$ 151,937		$ 151,937	0.11%
Rate 821	$ 17,869,739	$ 3,858,926	$ 21,728,665		$ 21,728,665	15.95%
Rate 822	$ 122,851	$ 43,518	$ 166,369		$ 166,369	0.12%
Rate 823	$ 13,545,126	$ 2,362,188	$ 15,907,314		$ 15,907,314	11.67%
Rate 824	$ 16,052,377	$ 2,778,410	$ 18,830,787		$ 18,830,787	13.82%
Rate 825	$ 471,091	$ 176,362	$ 647,453		$ 647,453	0.48%
Rate 826	$ 9,953,037	$ 1,618,947	$ 11,571,984		$ 11,571,984	8.49%
Rate 831	$ 46,812,162	$ 778,690	$ 47,590,853	24.48%	$ 11,651,965	8.55%
Rate 832	$ 1,295,072	$ 141,359	$ 1,436,432		$ 1,436,432	1.05%
Rate 833	$ 2,954,176	$ 119,153	$ 3,073,328		$ 3,073,328	2.26%
Rate 841	$ 266,805	$ 73,950	$ 340,755		$ 340,755	0.25%
Rate 842	$ 2,535	$ 336	$ 2,871		$ 2,871	0.00%
Rate 844	$ 124,451	$ 62,044	$ 186,495		$ 186,495	0.14%
Rate 850	$ 38,830	$ 61,938	$ 100,767		$ 100,767	0.07%
Rate 855	$ 51,320	$ 7,114	$ 58,433		$ 58,433	0.04%
Rate 860	$ 18,423	$ 31,541	$ 49,964		$ 49,964	0.04%
Interdepartmental	$ 300,492	$ 123,169	$ 423,661		$ 423,661	0.31%
Total	$ 150,187,333	$ 22,022,260	$ 172,209,593		$ 136,270,706	100%

Tier 1 Transmission Volumes	1,534,532,236	24.48%
Total Transmission Volumes'	6,267,586,326	

Rate	Dist Primary	Dist Secondary	Total	Distribution Rev. Req. Allocation Factor
Rate 811	$ 79,507,533	$ 32,262,948	$ 111,770,481	53.48%
Rate 820	$ 374,700	$ 17,911	$ 392,612	0.19%
Rate 821	$ 31,431,404	$ 5,458,155	$ 36,889,559	17.65%
Rate 822	$ 355,284	$ 26,207	$ 381,491	0.18%
Rate 823	$ 19,272,477	$ 1,419,524	$ 20,692,002	9.90%
Rate 824	$ 21,864,911	$ 639,198	$ 22,504,109	10.77%
Rate 825	$ 1,077,024	$ 27,080	$ 1,104,104	0.53%
Rate 826	$ 12,110,993	$ 394,245	$ 12,505,238	5.98%
Rate 831	$ -	$ -	$ -	0.00%
Rate 832	$ 0	$ -		0.00%
Rate 833	$ (0)	$ -	$ (0)	0.00%
Rate 841	$ 603,733	$ 81,096	$ 684,828	0.33%
Rate 842	$ 2,744	$ 763	$ 3,507	0.00%
Rate 844	$ -	$ -	$ -	0.00%
Rate 850	$ 505,664	$ 53,048	$ 558,712	0.27%
Rate 855	$ 58,075	$ 6,859	$ 64,934	0.03%
Rate 860	$ 257,503	$ 159,191	$ 416,694	0.20%
Interdepartmental	$ 1,005,562	$ 31,466	$ 1,037,029	0.50%
Total	$ 168,427,607	$ 40,577,693	$ 209,005,300	100.00%

APPENDIX A
APPLICABLE RIDERS

Sheet No. 1 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 870	FAC	Adjustment of Charges for Cost of Fuel Rider	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 871	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 874	RA	Adjustment of Charges for Resource Adequacy	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 876	BMTIS	Back-Up and Maintenance Industrial Service Rider	831
Rider 877	EDR	Economic Development Rider	824, 826, 832, 833
Rider 878	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	811, 820, 821, 822, 823, 824, 825, 826, 832, 833, 841, 844,
Rider 879	IS	Interconnection Standards	811, 820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, 844, 865
Rider 880	NM	Net Metering	811, 820, 821, 822, 823, 824, 825, 826, 832, 833, 841

APPENDIX A
APPLICABLE RIDERS

Sheet No. 2 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 881	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	823, 824, 825, 826, 831, 832, 833
Rider 882	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	823, 824, 825, 826, 831, 832, 833
Rider 883	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 844, Rider 876
Rider 886	GPR	Green Power Rider	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, and Rider 876
Rider 887	FMCA	Adjustment of Charges for Federally Mandated Costs	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 888	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

Original Sheet No. 201~~187~~

APPENDIX A
APPLICABLE RIDERS

Sheet No. 1 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 870	FAC	Adjustment of Charges for Cost of Fuel Rider	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 871	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 874	RA	Adjustment of Charges for Resource Adequacy	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 876	BMTIS	Back-Up and Maintenance Industrial Service Rider	831
Rider 877	EDR	Economic Development Rider	824, 826, ~~830~~832, 833
Rider 878	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 832, 833, 841, 844,
Rider 879	IS	Interconnection Standards	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831, 832, 833, 841, 844, 865
Rider 880	NM	Net Metering	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 832, 833, 841

Issued Date
__/__/2019

Effective Date
6/30/2019

NIPSCO

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

Original Sheet No. 202~~188~~

APPENDIX A
APPLICABLE RIDERS

Sheet No. 2 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 881	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	823, 824, 825, 826, ~~830,~~ 831, 832, 833
Rider 882	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	823, 824, 825, 826, ~~830,~~ 831, 832, 833
Rider 883	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 844, Rider 876
Rider 886	GPR	Green Power Rider	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, and Rider 876
Rider 887	FMCA	Adjustment of Charges for Federally Mandated Costs	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 888	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876

Rate 831 Implementation Agreement Confidential Exhibit C (Redacted)
Cause No. 45159

1. <u>Tier 2 and/or Tier 3 Contract Terms</u>.

The Rate 831 Settling Parties agree that any contract for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions:

(a) identify NIPSCO as the Market Participant for the retail customer at Midcontinent Independent System Operator, Inc. ("MISO");

(b) reference NIPSCO's market-based rate authority with Federal Energy Regulatory Commission ("FERC");

(c) clearly state the Rate 831 customer remains a retail customer of NIPSCO;

(d) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations);

(e) incorporate relevant provisions of the Rate 831 tariff;

(f) all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and

(g) any information shared with NIPSCO shall be subject to a confidentiality agreement applicable to all other terms of said agreements.

2. <u>Rate Implementation Dates</u>.

The Rate 831 Settling Parties agree that the customer's elections under Rate 831 Tiers 2 and/or Tier 3 shall occur in a window between the day after NIPSCO's compliance filing in this Cause to thirty (30) days thereafter. Customer recognizes that in order to implement Tier 3, customer may need to install software including a security certificate to be provided by NIPSCO. The parties agree to work together during the 30 day period to achieve implementation.

3. Firm Capacity Transactions.

NIPSCO agrees that under either Tier 2 or Tier 3, a customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges.

4. Dispute Resolution.

NIPSCO agrees that the third party energy and capacity supplier may represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the Indiana Utility Regulatory Commission. At a minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.