**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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|---|---|---|
| **PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL 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 (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.** | ) | **CAUSE NO. 45772** |

## SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; United States Steel Corporation; Walmart Inc.; RV Industry User's Group; and the Indiana Office of Utility Consumer Counselor (collectively the "Settling Parties"), respectfully submits the attached Stipulation and Settlement Agreement (the "Settlement Agreement"). The Settlement Agreement resolves all disputes, claims and issues arising from this proceeding as among the Settling Parties, including revenue requirement, cost of service, rate design, and cost allocation issues.

Respectfully submitted,

_______________________________

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## CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

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Dated this 10th day of March, 2023.

Bryan M. Likins

**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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| **PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL 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 (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.** | ) | **CAUSE NO. 45772** |

## STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 10th day of March, 2023, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); NIPSCO Industrial Group ("Industrial Group");[1] NLMK Indiana; United States Steel Corporation;[2] Walmart Inc.; RV Industry User's Group ("RV Group");[3] and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"). The Setting Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth below represent a fair and reasonable resolution of the issues in this Cause subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein. The Settling Parties agree that this Agreement resolves all disputes, claims and issues arising from the electric general rate case proceeding currently pending in Cause No. 45772 as among the Settling Parties, including revenue requirement, cost of service, rate design, and cost allocation

[1] The Industrial Group is comprised of Accurate Castings and Kingsbury Castings, BP Products North America, Inc., Cargill, Cleveland Cliffs Steel LLC, Enbridge, Linde, Marathon, and USG Corporation.

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

[3] The RV Industry User's Group is comprised of LCI Industries, Inc.; Patrick Industries, Inc.; Forest River, Inc.; and Keystone RV Company.

issues. The Settling Parties agree that NIPSCO's requested relief in this Cause should be granted except as expressly modified herein.

**A. Background**

1. NIPSCO's Current Basic Rates and Charges. NIPSCO's current electric basic rates and charges were approved in the Commission's December 4, 2019 Order in Cause No. 45159 (the "45159 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement on Less Than all the Issues resolving revenue requirement and other miscellaneous issues ("45159 Revenue Settlement") between NIPSCO and the majority of the intervenors.[4] The Commission also approved a Stipulation and Settlement Agreement on Rate 831 Implementation (the "Rate 831 Settlement").[5] Those new basic rates and charges went into effect on January 2, 2020 (the first billing cycle for January 2020). The 45159 Order approved, among other items, an increase in NIPSCO's basic rates and charges. The 45159 Order also approved an alternative regulatory plan which implemented a new service structure for certain industrial customer through NIPSCO's new Rate 831.

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4 The 45159 Revenue Settlement was entered into on April 25, 2019, by and between NIPSCO, NIPSCO Industrial Group ("Industrial Group"), NLMK Indiana ("NLMK"), United States Steel Corporation ("US Steel"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Walmart Inc., Northern Indiana Commuter Transportation District, Sierra Club, and the Indiana Office of Utility Consumer Counselor ("OUCC") (collectively the "Revenue Settling Parties"). On May 15, 2019, Indiana Municipal Utility Group joined the 45159 Revenue Settlement.

5 The Rate 831 Settlement was entered into on May 17, 2019, by and between NIPSCO, Industrial Group, NLMK Indiana, and US Steel.

2. NIPSCO's Current Depreciation Accrual Rates: NIPSCO's current common and electric depreciation rates were approved in the Commission's 45159 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings: NIPSCO files a quarterly Fuel Adjustment Clause ("FAC") proceeding in accordance with Ind. Code § 8-1-2-42(d) in Cause No. 38706-FAC- XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs. 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 871 – Adjustment of Charges for Regional Transmission Organization and Appendix C – Regional Transmission Organization Adjustment Factor ("RTO Tracker") approved by the Commission in its 45159 Rate Case Order,[6] and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs

[6] 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 its July 18, 2016, Order in Cause No. 44688, 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

through its Rider 874 – Adjustment of Charges for Resource Adequacy and Appendix F – Resource Adequacy Adjustment Factor ("RA Tracker") approved by the Commission in its 45159 Rate Case Order.[7]

NIPSCO files an annual proceeding in Cause No. 43618-DSM-XX to recover program costs, lost revenues, and financial incentives associated with approved demand side management and energy efficiency programs through its Rider 883 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G - Demand Side Management Adjustment Mechanism (DSMA) Factor.[8]

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the test year for recovery through the RTO tracker. In its 45159 Rate Case Order, the Commission approved NIPSCO's request 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. In its April 27, 2022 Order in Cause No. 44156-RTO-21, the Commission approved, among other things, a modification of Rider 871 – Adjustment of Charges for Regional Transmission Organization to include recovery of net non-fuel PJM Interconnect LLC costs and revenues.

7 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. The 45159 Rate Case Order approved, among other items, the removal of all embedded capacity costs and/or credits from base rates; tracking of 100% of all capacity costs and/or credits as a charge/credit to customers through the RA Adjustment; and demand allocators for the RA Adjustment.

8 The initial tracking mechanism was approved in the Commission's 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 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) to move from a semi-annual timeline to an annual filing. In its 45159 Rate Case Order, the Commission approved Rider 883 – Demand Side Management Adjustment Mechanism and Appendix G – DSMA Factor, to become effective January 1, 2020.

NIPSCO files an annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 886 – Green Power Rider and Appendix H – Green Power Rider Rate.[9]

NIPSCO has a semi-annual tracking mechanism to recover federally mandated costs through its Rider 787 – Adjustment of Charges for Federally Mandated Costs and Appendix I – Federally Mandated Cost Adjustment Factor.[10] NIPSCO has requests for a Certificate of Public Convenience and Necessity for federally mandated projects pending in Cause Nos. 45700 and 45797 for recovery through NIPSCO's FMCA tracking mechanism.

NIPSCO files a semi-annual proceeding in Cause No. 45557-TDSIC- XX to recover 80% of eligible and approved capital expenditures and transmission, distribution, and storage system improvement charge ("TDSIC") costs through Rider 888 - Adjustment of Charges for Transmission, Distribution and Storage System

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9 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 – Green Power Rider to move from a semi-annual timeline to an annual filing. In its June 24, 2020 Order in Cause No. 44198 GPR 12, the Commission approved modifying the GPR to separate NIPSCO's recovery of certification costs from marketing costs.

10 The initial tracking mechanism was approved in the Commission's January 29, 2014 Order in Cause No. 44340. Although NIPSCO has two pending requests to utilize the FMCA tracking mechanism, NIPSCO does not currently recover any costs through the FMCA tracking mechanism.

Improvement Charge and Appendix J - Transmission, Distribution and Storage System Improvement Charge.[11]

5. This Proceeding: On September 19, 2022, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to modify its retail rates and charges for electric utility service through a phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders (both existing and new); (3) approval of a new rider for variable non-labor O&M expenses associated with coal-fired generation ("Variable Cost Tracker"); (4) modification of the fuel cost adjustment to pass back 100% of off-system sales revenues net of expenses; (5) approving revised common and electric depreciation rates applicable to its electric plant in service; (6) approving necessary and appropriate accounting relief, including but not limited to approval of (a) certain deferral mechanisms for pension and other post-retirement benefits ("OPEB") expenses, (b) regulatory accounting for actual costs of removal associated with coal units following the retirement of the last coal unit (Michigan City Generating Station ("Michigan City") Unit 12), and (c) a modification of Joint Venture accounting authority to consolidate the reserves for purposes of passing back Joint Venture cash; (7) approving alternative regulatory plans for the (a) modification of NIPSCO's industrial rate service structure, and (b) implementation of a new low income program; (8) reviewing and determining

[11] The initial tracking mechanism was approved in the Commission's February 17, 2014 Order in Cause No. 44371.

the correct amount to include in NIPSCO's "earnings bank" for purposes of Ind. Code § 8-1-2-42.3; (9) authorizing NIPSCO to implement temporary rates; and (10) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on September 19, 2022. On January 20, 2023, the OUCC and intervenors filed their respective cases-in-chief and on February 16, 2023, 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, since the 45159 Rate Case Order, there are a few compounding drivers causing NIPSCO to request a change in rates at this time. NIPSCO is in the midst of substantial generation transition, whereby its generation fleet will be converted from one dominated by coal-fired steam generation to a modern fleet consisting predominantly of renewables, storage and natural gas. By the close of the test year, NIPSCO will have placed in service substantial investments in new utility plant, including several new renewable generating assets. NIPSCO has experienced delays, which are driven by factors outside of NIPSCO's control, in bringing all of its Commission-approved renewable energy projects online. This in turn has caused NIPSCO to continue operations of R.M. Schahfer Generating Station ("Schahfer") Units 17 and 18 longer than anticipated. The delays associated with these renewable energy projects have also required NIPSCO to take additional actions to ensure it continues to provide safe, reliable, and adequate service to its customers. Rates need to be changed to properly reflect the effects of these drivers as soon as possible.

**B. Settlement Terms**

1. Revenue Requirement and Net Operating Income:

(a) Revenue Requirement: As explained further herein, the Settling Parties agree to withdraw NIPSCO's proposed Variable Cost Tracker ("VCT") and instead agree to establish a new Environmental Cost Tracker ("ECT"). The ECT will recover fewer categories of costs than the proposed VCT, and the forecasted annual costs to be recovered through the ECT are $29,880,196. The costs NIPSCO initially proposed to recover through the VCT are now being excluded from the ECT and will instead be recovered through base rates. The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount originally requested by NIPSCO in its case-in-chief. The Settling Parties agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below. Joint Exhibit A attached hereto represents the schedules supporting the calculation of the agreed upon revenue requirement based on the 12-month period ending December 31, 2023.

(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 $402,900,940.

2. Original Cost Rate Base, Capital Structure, and Fair Return:

(a) Original Cost 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 upon this Agreement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.80%, yielding an overall return for earnings test purposes of $402,900,940, based upon:

(i) An original cost rate base of $5,925,013,822, inclusive of materials, supplies, production fuel, and regulatory assets. This amount reflects that forecasted additions to Renewable Energy Joint Venture Investments will be reduced to reflect the additional Investment Tax Credit NIPSCO will receive for Dunn's Bridge I, as reflected in NIPSCO's rebuttal alternative revenue requirement filed position. NIPSCO's current *estimate* is a reduction in additions to forecasted Joint Venture Regulatory Assets of $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660.

However, the *actual* reductions will be based on final project cost, which could be slightly more or less.

(ii) NIPSCO's forecasted capital structure; and

(iii) An authorized return on equity ("ROE") of 9.80%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.80% 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 | $4,564,821,051 | 9.80% | 5.06% |
| Long-Term Debt | $3,233,952,976 | 4.66%% | 1.70% |
| Customer Deposits | $59,541,950 | 5.63% | 0.04% |
| Deferred Income Taxes | $1,393,665,855 | 0.00% | 0.00% |
| Post-Retirement Liability | $13,945,116 | 0.00% | 0.00% |
| Prepaid Pension Asset | $(424,946,780) | 0.00% | 0.00% |
| Post-1970 ITC | $640,278 | 7.67% | 0.00% |
| **Totals** | **$8,841,620,445** | | **6.80%** |

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 and the regulatory assets resulting from regulatory accounting authorized by the 45159 Rate Case Order shall conclude June 30, 2034. This produces a reduction of approximately $26.6 Million in depreciation expense and a reduction of an additional approximate $8.8 Million for the amortization of the regulatory asset resulting from the retirement of Schahfer Units 14 and 15.

(ii) Pro forma depreciation expense will be increased approximately $9.8 Million to reflect additional demolition costs for Schahfer and Michigan City.

(iii) NIPSCO will move to stay Cause No. 45700, and upon Commission approval of all terms of this Agreement, NIPSCO shall move to dismiss Cause No. 45700 with prejudice. NIPSCO will move to stay Cause No. 45797, including staying all post-hearing briefing, and upon Commission approval of all terms of this Agreement, NIPSCO shall move to dismiss Cause No. 45797. In the event this Agreement is not approved in its entirety and with respect to NIPSCO's recovery of costs in relation to the projects proposed in Cause No. 45797, the non-NIPSCO parties in Cause No. 45797[12] agree to not object on the basis of the timeliness of the Petition in that Cause or issuance of a Commission order in that Cause, to recovery of costs incurred by NIPSCO after June 1, 2023, in relation to the projects proposed in that Cause. In the event the Commission rejects this Agreement, NIPSCO will move to lift the stay in those

12 This includes the OUCC, NIPSCO Industrial Group, and CAC.

proceedings, and except as otherwise agreed to above with respect to Cause No. 45797, litigation will resume in both Causes, with all parties able to take any position in the Causes as may be justified by the law and the facts and that are not inconsistent with the terms of this Agreement.

(iv) Depreciation rates for non-coal-fired generation assets shall be reduced, to produce an additional $9.5 Million reduction.

(v) Depreciation rates will be calculated by NIPSCO to produce these changes and will be included in the testimony supporting this Agreement, to be filed on March 17, 2023.

(b) <u>Amortization Expense:</u> The Settling Parties agree that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding with the following exceptions:

(i) The Cause No. 45159 regulatory asset amortization expense will be adjusted by an $8.22 Million annual reduction.

(ii) There will be a $1.7 Million annual reduction from moving the amortization periods for COVID and Rate Case Expense regulatory asset balances from two to four years.

(iii) There will be a $3.1 Million annual reduction from moving the amortization period for FMCA and TDSIC regulatory asset balances from four to seven years.

(iv) NIPSCO will make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement, and rates will be adjusted accordingly.

(c) <u>Future Cost of Removal and Regulatory Accounting:</u>

(i) NIPSCO will not file federal mandate cases pursuant to Ind. Code ch. 8-1-8.4 to recover costs to satisfy any asset retirement obligations associated with coal-fired generation. Instead, NIPSCO will debit FERC Account 108 for reasonable and prudent costs incurred for removal cost associated with coal-fired generation per the FERC Uniform System of Accounts, which entry will be reflected in future depreciation studies. NIPSCO will seek to adjust its future depreciation studies to reflect reasonable and prudent retirement costs.

(ii) The Settling Parties agree regulatory accounting for cost of removal (COR) for its coal-fired generation related assets should be approved as outlined in NIPSCO Witness Shikany's direct testimony (pp. 117-119) in this Cause and agree to the creation of a regulatory liability or asset, as applicable, to be included in future base rates upon the elimination of the appropriate FERC

Plant-in-Service account, subject to any challenge permitted by law, including the reasonableness and prudence of the cost.

4. Pro Forma Net Operating Income at Present Rates:

(a) Revenues: The Settling Parties accept a portion of the proposed increase in the residential sales forecast proposed by Industrial Group, which increases revenues by approximately $2.0 Million.

(b) Labor: The Settling Parties agree NIPSCO's proposed adjustment for vacant positions will be reduced by $2.2 Million.

(c) Pension and OPEB Expense: The Settling Parties accept NIPSCO's proposed adjustment to increase Pension and OPEB Expense by a combined $15.2 Million based upon the most recent actuarial report available prior to the filing of NIPSCO's case-in-chief. NIPSCO withdraws its request for a pension/OPEB balancing account.

(d) Vegetation Management: The Settling Parties agree NIPSCO's proposed vegetation management expense will be reduced by $5.8 Million, resulting in a total annual vegetation management expense of $25.1 Million (NIPSCO's 2022 budgeted expense escalated by a 5.20% inflation factor).

(e) Fuel Costs: The Settling Parties agree the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $25.0 Million.

(f) Schahfer Fire: The Settling Parties agree a $1.06 million annual O&M reduction will be made in this case and through June 30, 2034 to resolve all known and/or disclosed issues related to the fire at Schahfer in July of 2020. NIPSCO will propose this same O&M reduction of $1.06 million per year in future general rate cases. This term shall survive the termination of this Agreement and expire on June 30, 2034. NIPSCO represents that it is unaware of any facts that would support a claim for disallowance of any expenses or costs that could be attributable to the fire that has not already been presented to the Commission. The Settling Parties reserve all rights to pursue further adjustments should previously unknown or undisclosed facts support further disallowance.

(g) Other O&M: The Settling Parties agree a further reduction to O&M in this case shall be made, to reduce O&M by a total of $4.7 Million. This reduction addresses, among other issues, CAC's proposed disallowance of Edison Electric Institute expenses.

5. Environmental Cost Tracker: NIPSCO's proposed Variable Cost Tracker shall be renamed the Environmental Cost Tracker ("ECT") and shall be approved, using the filing methodology and frequency described by NIPSCO Witness Blissmer, except as modified herein. The only costs to be recovered through the ECT are NOx emissions allowances and variable chemical costs (estimated to be $30 Million per year). The ECT will be allocated among rate classes on the basis of energy. For Rate 526, the Settling

Parties agree to a demand-based rate design, with recovery through demand charges. NIPSCO will make good faith efforts to monetize unused NOx allowances, with 100% of benefits passed to NIPSCO customers through the ECT, to re-evaluate procurement practices, and to report on monetization in each ECT tracker filing. The costs associated with generation maintenance and outages originally proposed by NIPSCO as part of the VCT will be embedded in base rates in the amount estimated by NIPSCO in its case-in-chief of approximately $72 Million. For the costs that will be included in base rates, the Settling Parties agree that these costs will be allocated in the same manner that these costs were allocated in Cause No. 45159 to maintain the "status quo" regarding allocation, which includes both a demand- and energy-based allocation component.

6. Phased Rate Implementation:

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. The Settling Parties agree that Step 1 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 June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023 and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "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 June 30, 2023. NIPSCO will provide all Parties to this proceeding 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. All Parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on or about March 1, 2024 and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The 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, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "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, 2023. 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. The 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.

(c) Additional Interim Phases: In the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully in service by June 30, 2023 (meaning the portion that is not certified as partially in service as described in Mr. Campbell's rebuttal testimony) but come into service on or before December 31, 2023, then an additional interim step will be implemented after Step 1 and before Step 2. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

7. Cost of Service, Rate Design and Rate 831/531 Settlement:

(a) Rate 831/531 Settlement. All Settling Parties agree to support or not oppose adoption of the Rate 831/531 Settlement. All Parties not signatories to the Rate 831/531 Settlement retain all rights in future proceedings to take any position with respect to cost of service and Rate 531 issues.

(b) Mitigation. The Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, residential rates under Rate 511 are being subsidized by several other rate classes, including, but not limited to, Rate 520 through Rate 533. For this reason, the Settling Parties have agreed to mitigating a portion of the subsidy in this Agreement consistent with the Commission's policy of gradualism. The reduction in annual revenue (*i.e.*, the annual revenue below NIPSCO's as-filed case) will be allocated: 1st to maintain Rate 531 at cost of service based on 180 megawatts ("MW") of allocated demand as reflected in Rate 831/531 Settlement; 2nd 25% of the remaining amount for subsidy reduction; and 3rd with the 75% remaining amount allocated on an across-the-board basis. Because Rate 831 is being brought to parity at 180 MW of allocated demand, it will not receive either a reduction to reduce subsidies (the 25% portion) or a reduction on an across-the-board basis (the 75% portion). Rate 811 rates will participate in the across-the-board reduction (the 75% portion). Rates will be designed so that no rate class that is currently being subsidized will move to subsidizing other rates, and no rate that is currently subsidizing other rate classes will move to being subsidized by other rates. The provisions of this paragraph will be implemented in the cost of service and rates included with NIPSCO's settlement testimony, which will be submitted to the Commission by March 17, 2023.

(c) Industrial Group-Specific Issues. The Industrial Group agrees not to pursue its proposal for voltage-adjusted FAC and revised allocation for renewable resources in this case. All Settling Parties retain all rights in future proceedings to litigate these issues.

(d) Production Demand Allocation in Future Cases. In its next electric base rate case, NIPSCO will prepare a 4 coincident peak ("CP") and 12 CP cost of service analysis for purposes of allocating production-related demand costs and make each analysis available to all parties in the case. NIPSCO will determine which cost of service analysis to propose in its case-in-chief, and all other parties will have the right to take any position with regard to cost of service in that case.

(e) Increases in Load by Rate 531 Customers. The Settling Parties will discuss concerns relating to protections for other classes in the event of future increases in firm load by new or existing Rate 531 customers, including any appropriate clarifications.

(f) Future Reductions in Tier 1 Load and Cost Allocations. Future reductions to Tier 1 load and cost allocations to Rate 531 as contemplated in the Rate

831/531 Settlement will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates, pursuant to the following provisions. The process for determining future reductions in Tier 1 load and cost allocations to Rate 531 shall be as follows: (a) the relevant comparison is between end of test year in prior rate case and end of test year in subsequent rate case; (b) the measure of costs for legacy coal assets includes capital balances for coal assets, as well as fixed O&M, coal inventory, and other base rate inclusions; (c) the starting point is the proposed Rate 531 tariff terms and conditions, 180 MW of Rate 531 class demand, and 170 MWs of Rate 531 contract demand commitments per the Rate 831/531 Settlement, and the eventual end point, based on the current composition of the class, is 70 MW of both Rate 531 Tier 1 class demand and actual contract demand, with future proportional adjustments reducing the prevailing 110 MW differential between the current Rate 531 class demand and the end point; (d) consistent with the Rate 831/531 Settlement, successive future adjustments will involve both reductions in Tier 1 Rate 531 class allocations and contract demand commitments to progressively narrow the spread between allocated Rate 531 class demand and actual contract demand for the class; and (e) the above methodology assumes existing class composition throughout legacy coal asset recovery period, subject to an agreed process to address any material changes in circumstance. Nothing in this Agreement shall obligate a class member to increase its Tier 1 contract demand commitments in the future.

(g) Material Changes in Circumstances. The signatories to the Rate 831/531 Settlement and OUCC will meet and confer in the event of any material change of circumstances affecting the composition of the class or the class load, with the following clarifications: (a) no class member is prohibited from exiting the rate upon expiration of the contractual term; (b) existing tariff provisions on modifying commitments in the event of a facility closure remain in force; (c) in the event a class member exits the rate, the allocated demand and total contracted demand for the class will be reduced correspondingly provided that the exiting customer is migrating to another rate schedule with a like firm demand or the exit from Rate 531 is attributable to a facility closure or material reduction in load; (d) in the event that a class member increases Tier 1 load then other class members not at tariff minimum may decrease Tier 1 commitments correspondingly to maintain class load at agreed levels; (e) in the event a new customer joins the rate class then existing customers with firm demand above the tariff minimum will be permitted to reduce Tier 1 commitments so long as the class load is maintained at the agreed levels; and (f) recognizing that not all contingencies can be anticipated and addressed in advance, any signatory to the Rate 831/531 Settlement or the OUCC may initiate discussions in the event of a material change of circumstances and, absent agreement, may submit the issue for resolution by the Commission.

(h) Rate 526. Considering that significant amounts of demand costs are being recovered through the energy charge, the revenue reduction as a result of this

Agreement that is allocated to Rate 526 will be used to reduce the energy charge until all energy and demand components of Rate 526 match NIPSCO's energy/demand cost of service levels.

(i) Customer Charges. Customer charges proposed by NIPSCO shall be approved, except NIPSCO's existing monthly charge for Rate 511 shall be increased to $14.00 and the existing monthly charge for Rate 521 shall be increased to $32.50.

(j) Multi Family Rate. NIPSCO will collect data on residential customer housing types to identify multi-family customers and analyze cost differentials between single- and multi-family residential customers. NIPSCO will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, NIPSCO will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested stakeholder the results of its analysis.

(k) Rate 532. As part of preparing cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to this rate or the creation of another rate for current customers in Rate 532 is appropriate. This review will include, but will not be limited to, a review of the appropriate minimum demand level for participation in Rate 532 and demand blocks and demand and energy charges. NIPSCO will make this information available to any member of this rate class and/or their consultants who request such information.

(l) Rate 550. The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511.

(m) Survival of Terms of Paragraphs 4(f) and 7(f) and (g). The terms in Paragraphs 4(f) and 7(f) and (g) relating to O&M reduction relating to Schahfer fire, future reductions in Tier 1 load, and cost allocations to Rate 531, shall survive the termination of this Agreement.

8. Low Income Program and Issues. NIPSCO agrees to withdraw its proposed Low Income Program. However, NIPSCO retains the right to seek approval of a low income program in the future. In recognition of concerns expressed by the OUCC and CAC, NIPSCO will contribute below the line (*i.e.*, not to be recovered through rates) a total of $400,000 to Indiana Community Action Association for the Community Action Programs to enable Community Action Program health and safety work for the low income weatherization program. These contributions will be made in $100,000 increments in calendar years 2024, 2025, 2026, and 2027.

9. Distributed Generation. As part of the annual Performance Metrics Report filed pursuant to the Commission's July 18, 2016 Order in Cause No. 44688, NIPSCO agrees to include monthly data that separately provides data on Excess

Distributed Generation tariff and Small Power Production tariff customer participation, broken down by residential and non-residential customers, and including data on both new and total (a) capacity (kW-ac) installed, (b) number of customers, and (c) size of battery storage system (both kW and kWh) if one is part of the customer's system.

10. Demand Response. NIPSCO will continue to work with its Energy Efficiency Oversight Board ("OSB") on appropriate demand response programs. NIPSCO will work with its OSB on how best to model demand response for its next integrated resource plan, including but not limited to inclusion in the demand side management market potential study. NIPSCO will work with its OSB to do a request for proposals for demand response programs, either as part of an all-source request for proposals or as a stand-alone event.

11. Infrastructure Investment and Jobs Act ("IIJA") / Inflation Reduction Act ("IRA"). NIPSCO will meet with CAC and other interested stakeholders to evaluate potential opportunities associated with the IIJA and IRA that could be reasonably pursued by NIPSCO to the benefit of NIPSCO's customers. NIPSCO will provide CAC and other interested stakeholders with the results of its evaluation and provide the parties the opportunity to comment on NIPSCO's evaluation. Meetings will begin within 60 days of execution of this Agreement.

12. Indiana Municipal Utility Group.[13] IMUG is agreeing to not oppose this Agreement for the consideration and commitments contained in Addendum A, which provisions the Settling Parties agree to support or not oppose.

13. RV Users Group. The RV Group is signing this Agreement to receive the benefits contained herein and for the consideration and commitments contained in Addendum B, which NIPSCO agrees to support, but which other Settling Parties will not oppose. With respect to the RV Group TDSIC provisions in Addendum B, the Settling Parties (other than NIPSCO) take no position on and do not endorse such provisions but will not oppose them.

14. Other Relief Requested by NIPSCO. The Settling Parties agree that all other aspects of NIPSCO's case-in-chief, as modified in its rebuttal testimony, should be approved.

**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

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[13] Indiana Municipal Utility Group is comprised of Towns of Schererville, Dyer, and the City of East Chicago.

preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval. All evidence which has been prefiled by the Settling Parties will be admitted into the record. All Settling Parties waive cross-examination on all witnesses of other Settling Parties but reserve the right to ask questions of any witness who may be cross-examined by a non- settling party.

3. 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. If the Agreement is withdrawn, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. 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 acknowledge that this Settlement Agreement addresses all issues in the proceeding, including the appropriate revenue requirement and allocation of costs, and includes compromises upon the part of each Settling Party. The Settling Parties agree that this Agreement and each term, condition, amount,

methodology, and exclusion contained herein (a) reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement; (b) has accounted for the overall level of risk presented to NIPSCO by the Settlement Agreement; and (c) 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 terms set forth in this Agreement are the complete and final agreement among the Settling Parties. 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 10th day of March, 2023.

**[SIGNATURE PAGES FOLLOW]**

**Northern Indiana Public Service Company LLC**

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

**Indiana Office of Utility Consumer Counselor**

William Fine

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William Fine
Utility Consumer Counselor
**Indiana Office of Utility Consumer Counselor**
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204

**NIPSCO Industrial Group**

Todd Richardson

**NLMK Indiana**

3-10-2023

**United States Steel Corporation**

**RV Industry User's Group**

**Walmart Inc.**

**Northern Indiana Public Service Company LLC**
**Statement of Operating Income**
**Actual, Pro forma, and Proposed**
**For the Twelve Month Period Ending December 31, 2023**

| Line No. | Description | Actual | Pro forma Adjustments Increases (Decreases) | Attachment 3-B Reference[1] | Pro forma Results Based on Current Rates | Pro forma Adjustments Increases (Decreases) | Attachment 3-C Reference | Pro forma Results Based on Proposed Rates |
|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | G | H |
| 1 | **Operating Revenue** | | | | | | | |
| 2 | Revenue (Actual / Pro Forma) | $ 1,700,765,620 | | REV, Col A | $ 1,505,336,512 | 261,923,892 | PF - 1- S | $ 1,767,260,404 |
| 3 | Pro forma Adjustments December 31, 2021 | | (19,779,195) | REV, Col B | | | | |
| 4 | Budget Adjustments December 31, 2022 | | (51,640,914) | REV, Col D | | | | |
| 5 | Budget Adjustments December 31, 2023 | | 19,012,369 | REV, Col F | | | | |
| 6 | Ratemaking Adjustments December 31, 2023 | | (143,021,367) | REV-S, Col H | | | | |
| 7 | Total Operating Revenue | $ 1,700,765,620 | $ (195,429,108) | | $ 1,505,336,512 | $ 261,923,892 | | $ 1,767,260,404 |
| 8 | **Fuel & Purchased Power** | | | | | | | |
| 9 | Fuel Cost (Actual / Pro Forma) | $ 416,398,339 | | COGS, Col A | $ 367,509,634 | - | | $ 367,509,634 |
| 10 | Pro forma Adjustments December 31, 2021 | | (3,843,760) | COGS, Col B | | | | |
| 11 | Budget Adjustments December 31, 2022 | | (25,895,162) | COGS, Col D | | | | |
| 12 | Budget Adjustments December 31, 2023 | | (4,860,689) | COGS, Col F | | | | |
| 13 | Ratemaking Adjustments December 31, 2023 | | (14,289,094) | COGS-S, Col H | | | | |
| 14 | Total Fuel and Purchased Power Costs | $ 416,398,339 | $ (48,888,705) | | $ 367,509,634 | | | $ 367,509,634 |
| 15 | **Gross Margin** | $ 1,284,367,281 | $ (146,540,403) | | $ 1,137,826,878 | $ 261,923,892 | | $ 1,399,750,770 |
| 16 | **Operations and Maintenance Expenses** | | | | | | | |
| 17 | Operations and Maintenance Expenses (Actual / Pro Forma) | $ 493,605,075 | | O&M, Col A | $ 488,572,809 | 671,748 | PF - 2 - S | $ 489,244,558 |
| 18 | Pro forma Adjustments December 31, 2021 | | (23,438,011) | O&M, Col B | | | | |
| 19 | Budget Adjustments December 31, 2022 | | 44,307,375 | O&M, Col D | | | | |
| 20 | Budget Adjustments December 31, 2023 | | 42,240,218 | O&M, Col F | | | | |
| 21 | Ratemaking Adjustments December 31, 2023 | | (68,141,848) | O&M-S, Col H | | | | |
| 22 | Total Operations and Maintenance Expense | $ 493,605,075 | $ (5,032,265) | | $ 488,572,809 | $ 671,748 | | $ 489,244,558 |
| 23 | **Depreciation Expense** | | | | | | | |
| 24 | Depreciation Expense (Actual / Pro Forma) | $ 300,041,895 | | DEPR, Col A | $ 286,232,067 | | | $ 286,232,067 |
| 25 | Pro forma Adjustments December 31, 2021 | | (10,408,351) | DEPR, Col B | | | | |
| 26 | Budget Adjustments December 31, 2022 | | 4,307,754 | DEPR, Col D | | | | |
| 27 | Budget Adjustments December 31, 2023 | | 19,336,047 | DEPR, Col F | | | | |
| 28 | Ratemaking Adjustments December 31, 2023 | | (27,045,278) | DEPR-S, Col H | | | | |
| 29 | Total Depreciation Expense | $ 300,041,895 | $ (13,809,828) | | $ 286,232,067 | $ - | | $ 286,232,067 |

**Northern Indiana Public Service Company LLC**
**Statement of Operating Income**
**Actual, Pro forma, and Proposed**
**For the Twelve Month Period Ending December 31, 2023**

| Line No. | Description | Actual | Pro forma Adjustments Increases (Decreases) | Attachment 3-B Reference[1] | Pro forma Results Based on Current Rates | Pro forma Adjustments Increases (Decreases) | Attachment 3-C Reference | Pro forma Results Based on Proposed Rates |
|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | G | H |
| **30** | **Amortization Expense** | | | | | | | |
| **31** | Amortization Expense (Actual / Pro Forma) | $ 28,049,666 | | AMTZ, Col A | $ 118,760,693 | | | $ 118,760,693 |
| **32** | Pro forma Adjustments December 31, 2021 | | 33,681,838 | AMTZ, Col B | | | | |
| **33** | Budget Adjustments December 31, 2022 | | 35,261,815 | AMTZ, Col D | | | | |
| **34** | Budget Adjustments December 31, 2023 | | 20,002,648 | AMTZ, Col F | | | | |
| **35** | Ratemaking Adjustments December 31, 2023 | | 1,764,724 | AMTZ-S, Col H | | | | |
| **36** | Total Amortization Expense | $ 28,049,666 | $ 90,711,026 | | $ 118,760,693 | $ - | | $ 118,760,693 |
| **37** | **Taxes** | | | | | | | |
| **38** | **Taxes Other than Income** | | | | | | | |
| **39** | Taxes Other than Income (Actual / Pro Forma) | $ 56,893,980 | | OTX, Col A | $ 35,531,910 | | | $ 35,531,910 |
| **40** | Pro forma Adjustments December 31, 2021 | | (608,134) | OTX, Col B | | | | |
| **41** | Budget Adjustments December 31, 2022 | | 11,539,562 | OTX, Col D | | | | |
| **42** | Budget Adjustments December 31, 2023 | | (609,441) | OTX, Col F | | | | $ - |
| **43** | Ratemaking Adjustments December 31, 2023 | | (31,684,057) | OTX, Col H | | 334,236 | PF - 3 - S | $ 334,236 |
| **44** | Total Taxes Other Than Income | $ 56,893,980 | $ (21,362,070) | | $ 35,531,910 | $ 334,236 | | $ 35,866,145 |
| **45** | **Operating Income Before Income Taxes** | $ 405,776,664 | $ (197,047,265) | | $ 208,729,399 | $ 260,917,908 | | $ 469,647,307 |
| **46** | **Income Taxes** | | | | | | | |
| **47** | Federal and State Taxes (Actual / Pro Forma) | $ 55,596,061 | (53,742,587) | Attachment 3-C-S, ITX 1-S | $ 1,853,474 | 64,892,893 | PF - 4 - S | $ 66,746,367 |
| **48** | Total Taxes | $ 112,490,040 | $ (75,104,657) | | $ 37,385,384 | $ 65,227,129 | | $ 102,612,512 |
| **49** | **Total Operating Expenses including Income Taxes** | $ 934,186,677 | $ (3,235,724) | | $ 930,950,953 | $ 65,898,877 | | $ 996,849,830 |
| **50** | **Required Net Operating Income** | $ 350,180,604 | $ (143,304,679) | | $ 206,875,925 | $ 196,025,015 | | $ 402,900,940 |

Footnote 1 - Unless otherwise noted

**Northern Indiana Public Service Company LLC**
**Calculation of Proposed Revenue Increase**
**Based on Pro forma Operating Results**
**Original Cost Rate Base Estimated at December 31, 2023**

| Line No. | Description | | | | | Revenue Deficiency |
|---|---|---|---|---|---|---|
| 1 | Net Original Cost Rate Base | | | | | $ 5,925,013,822 |
| 2 | Rate of Return | | | | | 6.80% |
| 3 | Net Operating Income | | | | | $ 402,900,940 |
| 4 | Pro forma Net Operating Income | | | | | $ 206,875,925 |
| 5 | Increase in Net Operating Income (NOI Shortfall) | | | | | $ 196,025,015 |
| 6 | Effective Incremental Revenuel NOI Conversion Factor | | | | | 74.84% |
| 7 | Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6) | | | | | $ 261,923,892 |
| 8 | One | | 1.000000 | | | |
| 9 | Less: Public Utility Fee | | 0.001276 | | | |
| 10 | Less: Bad Debt | | 0.002565 | | | |
| 11 | State Taxable Income | | | 0.996159 | | |
| 12 | One | 1.000000 | | | | |
| 13 | Less: IN Utilities Receipts Tax | - | | | | |
| 14 | Taxable Adjusted Gross Income Tax | | 0.996159 | | | |
| 15 | Adjusted Gross Income Tax Rate | | 0.049000 | | | |
| 16 | Adjusted Gross Income Tax | | | 0.048812 | | |
| 17 | Line 11 less line 13 less line 16 | | | | 0.947347 | |
| 18 | One | | | 1.000000 | | |
| 19 | Less: Federal Income Tax Rate | | | 0.210000 | | |
| 20 | One Less Federal Income Tax Rate | | | | 0.790000 | |
| 21 | Effective Incremental Revenue / NOI Conversion Factor | | | | | 74.840% |

**Northern Indiana Public Service Company LLC**
**Summary of Rate Base**
**As Of December 31, 2023**

| Line No. | Description | | Pro forma As Of December 31, 2023 | Attachment 3-B-S2-S Reference |
|---|---|---|---|---|
| | **Rate Base** | | | |
| 1 | Utility Plant | $ | 8,252,008,653 | RB, Col I |
| 2 | Common Allocated | | 384,894,416 | RB, Col I |
| 3 | **Total Utility Plant** | **$** | **8,636,903,069** | RB, Col I |
| 4 | Accumulated Depreciation and Amortization | | (4,069,667,383) | RB, Col I |
| 5 | Common Allocated | | (245,419,231) | RB, Col I |
| 6 | **Total Accumulated Depreciation and Amortization** | **$** | **(4,315,086,614)** | RB, Col I |
| 7 | **Net Utility Plant** | **$** | **4,321,816,455** | RB, Col I |
| 8 | RMS Unit 14/15 Retirement | $ | 593,022,393 | RB, Col I |
| 9 | Joint Venture Reg Assets | | 817,299,925 | RB, Col I |
| 10 | Reg Assets - Cause 44688 & 45159 | | 23,510,338 | RB, Col I |
| 11 | Electric 2021-2026 TDSIC Plan Cause #45557 | | 24,558,486 | RB, Col I |
| 12 | FMCA - Post 45159 & CCR Remediation | | 545,389 | RB, Col I |
| 13 | Materials & Supplies | | 98,989,010 | RB, Col I |
| 14 | Production Fuel | | 45,271,825 | RB, Col I |
| 15 | **Total Rate Base** | **$** | **5,925,013,822** | RB, Col I |

**Northern Indiana Public Service Company LLC**
**Capital Structure - S2**
**As Of December 31, 2023**

| Line No. | Description | Total Company Capitalization | Percent of Total | Cost | Weighted Average Cost |
|---|---|---|---|---|---|
| | A | B | C | D | E |
| 1 | Common Equity | $ 4,564,821,051 | 51.63% | 9.80% | 5.06% |
| 2 | Long-Term Debt | 3,233,952,976 | 36.58% | 4.66% | 1.70% |
| 3 | Customer Deposits | 59,541,950 | 0.67% | 5.63% | 0.04% |
| 4 | Deferred Income Taxes | 1,393,665,855 | 15.76% | 0.00% | 0.00% |
| 5 | Post-Retirement Liability | 13,945,116 | 0.16% | 0.00% | 0.00% |
| 6 | Prepaid Pension Asset | (424,946,780) | -4.81% | 0.00% | 0.00% |
| 7 | Post-1970 ITC | 640,278 | 0.01% | 7.67% | 0.00% |
| 8 | Totals | **$ 8,841,620,445** | **100.00%** | | **6.80%** |

**Cost of Investor Supplied Capital**

| | Description | Total Company Capitalization | Percent of Total | Cost | Weighted Average Cost |
|---|---|---|---|---|---|
| | A | B | C | D | E |
| 9 | Common Equity | $ 4,564,821,051 | 58.53% | 9.80% | 5.74% |
| 10 | Long-Term Debt | 3,233,952,976 | 41.47% | 4.66% | 1.93% |
| 11 | **Totals** | **$ 7,798,774,027** | **100.00%** | | **7.67%** |

**Northern Indiana Public Service Company LLC**
**Statement of Operating Income**
**Actual, Pro forma, and Proposed**
**For the Twelve Month Period Ending December 31, 2023**

| Line No. | Description | Actual | Pro forma Adjustments Increases (Decreases) | Attachment 3-B Reference[1] | Pro forma Results Based on Current Rates | Pro forma Adjustments Increases (Decreases) | Attachment 3-C Reference | Pro forma Results Based on Proposed Rates |
|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | G | H |
| 1 | **Operating Revenue** | | | | | | | |
| 2 | Revenue (Actual / Pro Forma) | $ 1,700,765,620 | | REV, Col A | $ 1,505,336,512 | 291,804,089 | PF - 1- S-ALT | $ 1,797,140,601 |
| 3 | Pro forma Adjustments December 31, 2021 | | (19,779,195) | REV, Col B | | | | |
| 4 | Budget Adjustments December 31, 2022 | | (51,640,914) | REV, Col D | | | | |
| 5 | Budget Adjustments December 31, 2023 | | 19,012,369 | REV, Col F | | | | |
| 6 | Ratemaking Adjustments December 31, 2023 | | (143,021,367) | REV-S, Col H | | | | |
| 7 | Total Operating Revenue | $ 1,700,765,620 | $ (195,429,108) | | $ 1,505,336,512 | $ 291,804,089 | | $ 1,797,140,601 |
| 8 | **Fuel & Purchased Power** | | | | | | | |
| 9 | Fuel Cost (Actual / Pro Forma) | $ 416,398,339 | | COGS, Col A | $ 367,509,634 | - | | $ 367,509,634 |
| 10 | Pro forma Adjustments December 31, 2021 | | (3,843,760) | COGS, Col B | | | | |
| 11 | Budget Adjustments December 31, 2022 | | (25,895,162) | COGS, Col D | | | | |
| 12 | Budget Adjustments December 31, 2023 | | (4,860,689) | COGS, Col F | | | | |
| 13 | Ratemaking Adjustments December 31, 2023 | | (14,289,094) | COGS-S, Col H | | | | |
| 14 | Total Fuel and Purchased Power Costs | $ 416,398,339 | $ (48,888,705) | | $ 367,509,634 | | | $ 367,509,634 |
| 15 | **Gross Margin** | $ 1,284,367,281 | $ (146,540,403) | | $ 1,137,826,878 | $ 291,804,089 | | $ 1,429,630,966 |
| 16 | **Operations and Maintenance Expenses** | | | | | | | |
| 17 | Operations and Maintenance Expenses (Actual / Pro Forma) | $ 493,605,075 | | O&M, Col A | $ 518,338,243 | 748,381 | PF - 2 - S-ALT | $ 519,086,625 |
| 18 | Pro forma Adjustments December 31, 2021 | | (23,438,011) | O&M, Col B | | | | |
| 19 | Budget Adjustments December 31, 2022 | | 44,307,375 | O&M, Col D | | | | |
| 20 | Budget Adjustments December 31, 2023 | | 42,240,218 | O&M, Col F | | | | |
| 21 | Ratemaking Adjustments December 31, 2023 | | (38,376,414) | O&M-S, Col H | | | | |
| 22 | Total Operations and Maintenance Expense | $ 493,605,075 | $ 24,733,169 | | $ 518,338,243 | $ 748,381 | | $ 519,086,625 |
| 23 | **Depreciation Expense** | | | | | | | |
| 24 | Depreciation Expense (Actual / Pro Forma) | $ 300,041,895 | | DEPR, Col A | $ 286,232,067 | | | $ 286,232,067 |
| 25 | Pro forma Adjustments December 31, 2021 | | (10,408,351) | DEPR, Col B | | | | |
| 26 | Budget Adjustments December 31, 2022 | | 4,307,754 | DEPR, Col D | | | | |
| 27 | Budget Adjustments December 31, 2023 | | 19,336,047 | DEPR, Col F | | | | |
| 28 | Ratemaking Adjustments December 31, 2023 | | (27,045,278) | DEPR-S, Col H | | | | |
| 29 | Total Depreciation Expense | $ 300,041,895 | $ (13,809,828) | | $ 286,232,067 | $ - | | $ 286,232,067 |

**Northern Indiana Public Service Company LLC**
**Statement of Operating Income**
**Actual, Pro forma, and Proposed**
**For the Twelve Month Period Ending December 31, 2023**

| Line No. | Description | Actual | Pro forma Adjustments Increases (Decreases) | Attachment 3-B Reference[1] | Pro forma Results Based on Current Rates | Pro forma Adjustments Increases (Decreases) | Attachment 3-C Reference | Pro forma Results Based on Proposed Rates |
|---|---|---|---|---|---|---|---|---|
| 30 | **Amortization Expense** | | | | | | | |
| 31 | Amortization Expense (Actual / Pro Forma) | $ 28,049,666 | | AMTZ, Col A | $ 118,760,693 | | | $ 118,760,693 |
| 32 | Pro forma Adjustments December 31, 2021 | | 33,681,838 | AMTZ, Col B | | | | |
| 33 | Budget Adjustments December 31, 2022 | | 35,261,815 | AMTZ, Col D | | | | |
| 34 | Budget Adjustments December 31, 2023 | | 20,002,648 | AMTZ, Col F | | | | |
| 35 | Ratemaking Adjustments December 31, 2023 | | 1,764,724 | AMTZ-S, Col H | | | | |
| 36 | Total Amortization Expense | $ 28,049,666 | $ 90,711,026 | | $ 118,760,693 | $ - | | $ 118,760,693 |
| 37 | **Taxes** | | | | | | | |
| 38 | **Taxes Other than Income** | | | | | | | |
| 39 | Taxes Other than Income (Actual / Pro Forma) | $ 56,893,980 | | OTX, Col A | $ 35,531,910 | | | $ 35,531,910 |
| 40 | Pro forma Adjustments December 31, 2021 | | (608,134) | OTX, Col B | | | | |
| 41 | Budget Adjustments December 31, 2022 | | 11,539,562 | OTX, Col D | | | | |
| 42 | Budget Adjustments December 31, 2023 | | (609,441) | OTX, Col F | | - | | $ - |
| 43 | Ratemaking Adjustments December 31, 2023 | | (31,684,057) | OTX, Col H | | 372,365 | PF - 3 - S-ALT | $ 372,365 |
| 44 | Total Taxes Other Than Income | $ 56,893,980 | $ (21,362,070) | | $ 35,531,910 | $ 372,365 | | $ 35,904,275 |
| 45 | **Operating Income Before Income Taxes** | $ 405,776,664 | $ (226,812,699) | | $ 178,963,965 | $ 290,683,342 | | $ 469,647,307 |
| 46 | **Income Taxes** | | | | | | | |
| 47 | Federal and State Taxes (Actual / Pro Forma) | $ 55,596,061 | (61,145,548) | Attachment 3-C-S, ITX 1 - S-ALT | $ (5,549,487) | 72,295,854 | PF - 4 - S-ALT | $ 66,746,367 |
| 48 | Total Taxes | $ 112,490,040 | $ (82,507,618) | | $ 29,982,423 | $ 72,668,219 | | $ 102,650,642 |
| 49 | **Total Operating Expenses including Income Taxes** | $ 934,186,677 | $ 19,126,749 | | $ 953,313,426 | $ 73,416,601 | | $ 1,026,730,026 |
| 50 | **Required Net Operating Income** | $ 350,180,604 | $ (165,667,152) | | $ 184,513,452 | $ 218,387,488 | | $ 402,900,940 |

Footnote 1 - Unless otherwise noted

**Northern Indiana Public Service Company LLC**
**Calculation of Proposed Revenue Increase**
**Based on Pro forma Operating Results**
**Original Cost Rate Base Estimated at December 31, 2023**

| Line No. | Description | | | | | Revenue Deficiency |
|---|---|---|---|---|---|---|
| 1 | Net Original Cost Rate Base | | | | | $ 5,925,013,822 |
| 2 | Rate of Return | | | | | 6.80% |
| 3 | Net Operating Income | | | | | $ 402,900,940 |
| 4 | Pro forma Net Operating Income | | | | | $ 184,513,452 |
| 5 | Increase in Net Operating Income (NOI Shortfall) | | | | | $ 218,387,488 |
| 6 | Effective Incremental Revenuel NOI Conversion Factor | | | | | 74.84% |
| 7 | Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6) | | | | | $ 291,804,089 |
| | | | | | | |
| 8 | One | | 1.000000 | | | |
| 9 | Less: Public Utility Fee | | 0.001276 | | | |
| 10 | Less: Bad Debt | | 0.002565 | | | |
| 11 | State Taxable Income | | | 0.996159 | | |
| 12 | One | 1.000000 | | | | |
| 13 | Less: IN Utilities Receipts Tax | - | | | | |
| 14 | Taxable Adjusted Gross Income Tax | | 0.996159 | | | |
| 15 | Adjusted Gross Income Tax Rate | | 0.049000 | | | |
| 16 | Adjusted Gross Income Tax | | | 0.048812 | | |
| 17 | Line 11 less line 13 less line 16 | | | | 0.947347 | |
| 18 | One | | | 1.000000 | | |
| 19 | Less: Federal Income Tax Rate | | | 0.210000 | | |
| 20 | One Less Federal Income Tax Rate | | | | 0.790000 | |
| 21 | Effective Incremental Revenue / NOI Conversion Factor | | | | | 74.840% |

**Northern Indiana Public Service Company LLC**
**Summary of Rate Base**
**As Of December 31, 2023**

| Line No. | Description | | Pro forma As Of December 31, 2023 | Attachment 3-B-S2-S Reference |
|---|---|---|---|---|
| | **Rate Base** | | | |
| 1 | Utility Plant | $ | 8,252,008,653 | RB, Col I |
| 2 | Common Allocated | | 384,894,416 | RB, Col I |
| 3 | **Total Utility Plant** | **$** | **8,636,903,069** | RB, Col I |
| 4 | Accumulated Depreciation and Amortization | | (4,069,667,383) | RB, Col I |
| 5 | Common Allocated | | (245,419,231) | RB, Col I |
| 6 | **Total Accumulated Depreciation and Amortization** | **$** | **(4,315,086,614)** | RB, Col I |
| 7 | **Net Utility Plant** | **$** | **4,321,816,455** | RB, Col I |
| 8 | RMS Unit 14/15 Retirement | $ | 593,022,393 | RB, Col I |
| 9 | Joint Venture Reg Assets | | 817,299,925 | RB, Col I |
| 10 | Reg Assets - Cause 44688 & 45159 | | 23,510,338 | RB, Col I |
| 11 | Electric 2021-2026 TDSIC Plan Cause #45557 | | 24,558,486 | RB, Col I |
| 12 | FMCA - Post 45159 & CCR Remediation | | 545,389 | RB, Col I |
| 13 | Materials & Supplies | | 98,989,010 | RB, Col I |
| 14 | Production Fuel | | 45,271,825 | RB, Col I |
| 15 | **Total Rate Base** | **$** | **5,925,013,822** | RB, Col I |

**Northern Indiana Public Service Company LLC**
**Capital Structure**
**As Of December 31, 2023**

| Line No. | Description | Total Company Capitalization | Percent of Total | Cost | Weighted Average Cost |
|---|---|---|---|---|---|
| | A | B | C | D | E |
| 1 | Common Equity | $ 4,564,821,051 | 51.63% | 9.80% | 5.06% |
| 2 | Long-Term Debt | 3,233,952,976 | 36.58% | 4.66% | 1.70% |
| 3 | Customer Deposits | 59,541,950 | 0.67% | 5.63% | 0.04% |
| 4 | Deferred Income Taxes | 1,393,665,855 | 15.76% | 0.00% | 0.00% |
| 5 | Post-Retirement Liability | 13,945,116 | 0.16% | 0.00% | 0.00% |
| 6 | Prepaid Pension Asset | (424,946,780) | -4.81% | 0.00% | 0.00% |
| 7 | Post-1970 ITC | 640,278 | 0.01% | 7.67% | 0.00% |
| 8 | Totals | **$ 8,841,620,445** | **100.00%** | | **6.80%** |

**Cost of Investor Supplied Capital**

| | Description | Total Company Capitalization | Percent of Total | Cost | Weighted Average Cost |
|---|---|---|---|---|---|
| | A | B | C | D | E |
| 9 | Common Equity | $ 4,564,821,051 | 58.53% | 9.80% | 5.74% |
| 10 | Long-Term Debt | 3,233,952,976 | 41.47% | 4.66% | 1.93% |
| 11 | **Totals** | **$ 7,798,774,027** | **100.00%** | | **7.67%** |

Addendum A

## Settlement Agreement Addendum Responsive to the Indiana Municipal Utility Group ("IMUG") Recommendations[1]

1) IMUG will in writing not oppose the Settlement Agreement in Cause No. 45772. This includes IMUG and all Settling or not opposing Parties waiving cross-examination of all Settling Parties' witnesses, but IMUG reserves the right to ask questions of any witness that does appear and is crossed by a non-settling party, or crossed in a manner contrary to IMUG's benefits from this Settlement.

2) Streetlights provide essential important public service benefits through nighttime public safety and through promotion of nighttime economic development and social activities. Those public service benefits are further enhanced through the superior lighting provided by modern LED streetlights. NIPSCO's municipal electric customers are public services providers who pay for street lighting and an array of other essential public services through limited municipal budgets without profit motivation. Those municipal streetlight public service efforts primarily benefit and protect NIPSCO area residents. As such it is agreed that:

3) NIPSCO will fund energy efficiency audits and new efficiency measures including LEDs for each of the three participating municipality members of IMUG (as of March 3, 2023), at a maximum cost of up to $25,000 per municipality. NIPSCO will work with the IMUG members to choose a mutually agreeable company or consultant to perform these energy efficiency audits. If a program or project qualifies for NIPSCO's energy efficiency program, this will qualify as a "new energy efficiency measure" under this term, and the customer cost (after rebate) would qualify for reimbursement under this term. NIPSCO and the municipalities will work in good faith as to what qualifies as a "new energy efficiency measure."

4) The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511 as stipulated in Section 7 (l) of the Settlement Agreement.

5) NIPSCO will lend its expertise to any IMUG member that seeks to convert customer-owned streetlights to LEDs, e.g., meetings, exchange of info, sharing access to consultants for learning and knowledge, etc.

6) NIPSCO will work with IMUG to seek to improve its record keeping for LED and HPS street lighting so that the records will differentiate between the type of fixture (*e.g.*, LED, MV, HPS) and the type of repair made.

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[1] Indiana Municipal Utility Group is comprised of Towns of Schererville, Dyer, and the City of East Chicago.

Addendum A

ACCEPTED AND AGREED this 10th day of March, 2023.

**[SIGNATURE PAGES FOLLOW]**

Addendum A

**Northern Indiana Public Service Company LLC**

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Addendum A

**Indiana Municipal Utility Group**

Theodore J Sommer
___

Addendum B

# <u>Settlement Terms between NIPSCO and the RV Industry User's Group ("RV Group")</u>[1]

1) NIPSCO has already begun work on necessary steps to update and upgrade the Mingus Ditch substation which is a required precursor step to system redundancies and reliability improvements in the Goshen/Elkhart County service territory. To the extent feasible, NIPSCO will also speed up the construction of the two substation projects that are discussed in Ronald Talbot's rebuttal testimony in this proceeding (2025 and 2026 projects, which are already identified in and are part of NIPSCO's approved electric TDSIC Plan).
2) NIPSCO commits to fund energy efficiency audits of up to $50,000 per customer for each of the four RV Group members. NIPSCO and the RV Group members will work together to select a mutually satisfactory, qualified company or consultant to perform these energy efficiency audits and to coordinate to ensure viable and cost effective energy efficient proposals and opportunities are identified.
3) NIPSCO agrees to include RV Group representatives in discussions with the DSM Oversight Board related to participating in existing or proposing additional demand response program opportunities available to or that could be expanded to provide additional benefits to RV Group Members and lower NIPSCO peak energy needs. NIPSCO is separately committed to issuing an RFI and/or RFI for demand response as part of its next RFP that shall include and allow for RV Group member proposals consistent with these objectives.
4) NIPSCO will, separately from the DSM Oversight Board process, directly work with and assist the RV Group representatives in determining potential savings, programs, and funding opportunities through its DSM program and any other available Commission-approved processes. To the extent savings are identified that are not current DSM or other programs/measures, NIPSCO will make a good faith effort to add such program/measure to its DSM plan(s).
5) As part of preparing its cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of each of the Members of the RV Group to determine if a new or adjusted rate schedule is appropriate for these customers and customers of similar characteristics who

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[1] The RV Industry User's Group is comprised of LCI Industries, Inc.; Patrick Industries, Inc.; Forest River, Inc.; and Keystone RV Company.

would qualify. As part of these efforts, NIPSCO agrees to make any relevant information available to the RV Group and/or their consultants.

6) As part of its next electric base rate case, subject to any necessary non-disclosure protections, NIPSCO agrees to prepare a 4CP cost of service analysis for purposes allocating production-related costs and make this available to the RV Group in advance of such filing, as well as to any other party subsequently participating in the case who requests it. This analysis shall conform to and be consistent with the principles of cost causation identified by NIPSCO in this and NIPSCO's last base rate case in Cause No. 45159. This does not, however, limit NIPSCO in determining which cost of service analysis it chooses to propose in its case-in-chief, nor does it impact any other parties' right to take any position with regards to cost of service or allocations in that next rate case.

7) NIPSCO commits to meeting with RV Group representatives to review and discuss cost of service concerns before NIPSCO files its next electric base rate case is filed.

**RV Group TDSIC Project(s)**

8) NIPSCO and the RV Group agree that the RV Group may propose one or more projects to be included as part of NIPSCO's TDSIC Plan (currently under Cause No. 45557) totaling up to $3.5 million, provided each project meets the applicable requirements of the TDSIC Statute (Ind. Code ch. 8-1-39). This agreed upon commitment and benefit shall be reserved for the benefit of the RV Group Members and any TDSIC Plan request made by an RV Group Member shall be for qualifying infrastructure upgrade needs that improve reliability and/or spur economic development, which include, but are not limited to upgrades to substations, transformers, distribution and transmission facilities, or other necessary electrical system upgrades to provide service to an RV Group member ("RV Group TDSIC Project(s)"). NIPSCO shall seek approval for inclusion of such RV Group TDSIC Projects and the related funding as part of NIPSCO's TDSIC Plan. To manage the allocation of the RV Group TDSIC Project(s), a Fund shall be pursued as part of NIPSCO's existing TDSIC process. The Fund shall not lapse or be transferred to other NIPSCO customers, but any NIPSCO system upgrades or facilities built to support any RV Group TDSIC Project(s) may also be used to serve other customers, provided this does not diminish service reliability for the RV Group TDSIC Project(s), and the Fund shall continue until fully disbursed for RV Group TDSIC Project(s).

9) RV Group TDSIC Project(s) shall include any-and-all projects that qualify under the TDSIC Statute. NIPSCO will file for approval of the RV Group TDSIC Project(s) to allow the RV Group TDSIC Projects to include as many qualifying types of projects as possible, including: (i) RV Group operation or production facility updates or expansions that will result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support of RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. To the extent that a project proposed by an RV Group member does not qualify under the TDSIC Statute but would qualify under NIPSCO's demand side management ("DSM") tracker, NIPSCO will seek inclusion of qualifying projects in the DSM tracker, and these projects would not count against the $3.5 million total RV Group TDSIC Project amount.

10) Each of the RV Group members shall be entitled to request one or more RV Group TDSIC Project(s) subject to the review and support of NIPSCO, which support and approval shall not be unreasonably withheld or delayed. Any requests to support RV Group TDSIC Project(s) from the Fund will be presented in a tracker filing by NIPSCO in Cause No. 45557-TDSIC-X (or successor docket), which will require and provide a sufficient evidentiary showing consistent with the TDSIC Statute for the approval of such amounts.

11) Notwithstanding the provisions of paragraph B.13 of the Stipulation and Settlement Agreement, all other participating parties in the then-pending TDSIC docket shall be provided notice of and reserve the right to timely take any position on such RV Group TDSIC Project(s) funding request when the request is formally presented in the TDSIC tracker filing.

12) NIPSCO and the RV Group shall work together in good faith to establish precise administrative details for applications or requests for RV Group TDSIC Project(s), and such applications or requests can be made any time after approval of the Settlement Agreement, consistent with the language and requirements herein.

ACCEPTED AND AGREED this 10th day of March, 2023.

**[SIGNATURE PAGES FOLLOW]**

Addendum B

**Northern Indiana Public Service Company LLC**

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Addendum B

**RV Industry User's Group**