STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42, 8-1-2-42.7 AND 8-1-2-61 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR GAS 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 SALES RECONCILIATION ADJUSTMENT MECHANISM; (4) APPROVAL OF REVISED GAS DEPRECIATION RATES APPLICABLE TO ITS GAS PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF CERTAIN DEFERRAL MECHANISMS FOR PENSION, OTHER POST-RETIREMENT BENEFITS, AND LINE LOCATE EXPENSES; AND (6) TO THE EXTENT NECESSARY, APPROVAL OF ANY OF THE RELIEF REQUESTED HEREIN PURSUANT TO IND. CODE CH. 8-1-2.5.	)	**CAUSE NO. 45967**

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 20th day of March, 2024, by and among Northern Indiana Public Service Company LLC ("NIPSCO"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Direct Energy Business Marketing ("Direct Energy"), NIPSCO Industrial Group ("Industrial Group"),[1] Steel Dynamics, Inc. ("SDI"), and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"). The Settling Parties, solely for purposes

[1] The customers comprising the Industrial Group are BP Products North America, Inc., Cleveland-Cliffs Inc., General Motors LLC, Linde, United States Steel Corporation, and University of Notre Dame.

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 this Agreement resolves all disputes, claims, and issues arising from the general gas rate case proceeding currently pending in Cause No. 45967 as among the Settling Parties. The Settling Parties agree that matters for which NIPSCO requested relief in this Cause that are not addressed herein, but were expressly supported by testimony, are resolved as NIPSCO proposed, without waiving the right to challenge such resolution prospectively.

A. Background[2]

1. NIPSCO's Current Basic Rates and Charges. The Commission's July 27, 2022 Order in Cause No. 45621 (the "45621 Rate Case Order") approved a Stipulation and Settlement Agreement among NIPSCO, the OUCC, and the majority of intervenors in that proceeding (the "45621 Settlement").[3] The 45621 Rate Case Order approved a two-step change in rates. Step 1 rates took effect on September 1, 2022 based upon rate

---

[2] This "Background" section is included to provide context for the Agreement and does not reflect any term of the Settling Parties' agreement.

[3] The 45621 Settlement was entered into on March 2, 2022, by and among NIPSCO, the Industrial Group, SDI, and the OUCC. The other parties did not oppose the 45621 Settlement.

base as of June 30, 2022. Step 2 rates took effect March 1, 2023, based upon rate base as of December 31, 2022.

2. NIPSCO's Alternative Regulatory Plan. NIPSCO has operated under the terms of an approved alternative regulatory plan ("ARP") pursuant to Ind. Code ch. 8-1-2.5 since the Commission's Order dated October 8, 1997 in Cause No. 40342. The ARP was renewed and modified in Cause No. 41338, consolidated Cause Nos. 42800 and 42884, and Cause No. 43837. The ARP was most recently extended and modified and became a permanent part of NIPSCO's tariff on March 15, 2012 in Cause No. 44081.

3. NIPSCO's Gas Cost Adjustment ("GCA") Proceedings. Pursuant to Ind. Code § 8-1-2-42(g), NIPSCO files a quarterly Gas Cost Adjustment ("GCA") proceeding in Cause No. 43629-GCA-XXX to adjust its rates to account for fluctuation in its gas costs. The cost of bad debt expense associated with the cost of gas is reflected in NIPSCO's GCA. Pursuant to the Commission's November 4, 2010 Order in Cause No. 43894 and through an annual update to Appendix E – Unaccounted for Gas Percentage ("UAFG"), NIPSCO also recovers through its GCA the actual cost of UAFG up to a maximum percentage of 0.90%. NIPSCO proposes to continue both of these recoveries through the GCA as modified by the terms of this Agreement.

4. NIPSCO's Other Tracking Mechanisms.

(a) Pursuant to the Commission's December 7, 2011 Order in Cause No. 44094, NIPSCO files an annual update to Appendix D – Universal Service Program (USP) Factors in a compliance filing in Cause No. 44094 to be applicable starting with the billing month of October.

(b) Pursuant to the Commission's December 28, 2011 Order in Cause No. 44001, NIPSCO files an annual proceeding in Cause No. 44001-GDSM-XX for recovery of program costs associated with approved demand side management and energy efficiency programs through its Rider 272 – Gas Demand Side Management (GDSM) Rider and Appendix C - GDSM Factors (the "GDSM Mechanism").[4]

(c) Pursuant to the Commission's January 28, 2015 Order in Cause No. 44403-TDSIC-1, NIPSCO has filed a semi-annual proceeding in Cause No. 44403-TDSIC-XX to recover 80% of approved capital expenditures and TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution, and storage system improvements ("TDSIC Projects") through its Rider 288 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix F –

---

[4] The Commission's May 9, 2007 Order in Cause No. 43051 initially approved the GDSM Mechanism. The Commission's December 28, 2011 Order in Cause No. 44001 approved NIPSCO's request to change to a semi-annual reconciliation. The Commission's February 22, 2017 Order in Cause No. 44001-GDSM-10 approved NIPSCO's request to change from a semi-annual to annual filing. The Commission's November 21, 2018 Order in Cause No. 45012 approved NIPSCO's request for recovery of lost revenues through the GDSM Mechanism.

Transmission, Distribution and Storage System Improvement Charge Adjustment Factor ("TDSIC Mechanism"). Pursuant to the Commission's July 22, 2020 Order in Cause No. 45330, NIPSCO now files the TDSIC Mechanism in Cause No. 45330-TDSIC-XX.

(d) Pursuant to the Commission's September 19, 2018 Order in Cause No. 45007, NIPSCO has filed a semi-annual proceeding in Cause No. 45007-FMCA-XX to recover 80% of approved federally mandated costs through its Rider 290 – Federally Mandated Cost Adjustment Rider and Appendix G – FMCA Factors ("FMCA Mechanism"). Pursuant to the Commission's December 1, 2021 Order in Cause No. 45560, NIPSCO has also filed the FMCA Mechanism in Cause No. 45560-FMCA-XX. Pursuant to the Commission's December 28, 2022 Order in Cause No. 45703, NIPSCO now files the FMCA Mechanism in Cause No. 45703-FMCA-XX.

5. This Proceeding. On October 25, 2023, 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 gas 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 Sales Reconciliation Adjustment mechanism; (4) approving revised gas depreciation rates applicable to its gas plant in service; (5) approving necessary and appropriate accounting relief, including but not limited to approval of certain deferral mechanisms

for pension, other post-retirement benefits ("OPEB"), and line locate expenses; and (6) other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on October 25, 2023. On January 31, 2024, the OUCC and intervenors filed their respective cases-in-chief. NIPSCO filed its rebuttal testimony and evidence, and the OUCC, Industrial Group, and SDI filed cross-answering testimony, on February 28, 2024.

As discussed within NIPSCO's Verified Petition, and the testimony of various NIPSCO witnesses, this rate case filing was driven by several developments subsequent to the 45621 Rate Case Order. Since the 45621 Rate Case Order, NIPSCO's cost of providing service has increased. NIPSCO has made significant capital expenditures for additions, replacements, and improvements to its Utility Property to maintain safe and reliable service. Further, NIPSCO has incurred increasing operations and maintenance expenses to maintain safe and reliable service.

6. NIPSCO's Current Depreciation and Accrual Rates. NIPSCO's current gas depreciation rates are based on the depreciation study approved in the 45621 Rate Case Order. NIPSCO's current common and electric depreciation rates and last common and electric depreciation study were approved in the Commission's August 2, 2023 Order in Cause No. 45772.

B. Settlement Terms and Conditions

1. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement: The Settling Parties agree that NIPSCO's base rates will be designed to produce revenue at proposed rates of $1,114,923,631 as adjusted for the Rate Base Update Mechanism set forth in Paragraph B.9. This Revenue Requirement represents an increase of $120,948,338, which is a decrease of $40,948,669 (25.29%) from the amount NIPSCO requested in its case-in-chief ($161,897,007). Joint Exhibit A attached hereto represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending December 31, 2024.

(b) Net Operating Income: Subject to the Rate Base Update Mechanism set forth in Paragraph B.9., 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 $243,239,741.

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

(a) Original Cost Rate Base. NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this Agreement and the Rate Base Update Mechanism set forth in Paragraph B.9., the Settling Parties agree that NIPSCO should be authorized a fair return of $243,239,741 yielding an overall return for earnings test purposes of 6.98%, based upon: (a) a Net Original Cost Rate Base of $3,484,810,045; and (b) NIPSCO's forecasted capital structure, including an authorized return on equity ("ROE") of 9.75%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.75% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	% of Total	**Cost %**	**WACC %**
Common Equity	52.39%	9.75%	5.11%
Long-Term Debt	37.15%	4.94%	1.84%
Customer Deposits	0.60%	5.76%	0.03%
Deferred Income Taxes	13.41%	0.00%	0.00%
Post-Retirement Liability	0.04%	0.00%	0.00%
Prepaid Pension Asset	-3.60%	0.00%	0.00%
Post-1970 ITC	0.00%	7.75%	0.00%
Totals	**100.0%**		**6.98%**

The Settling Parties agree that fair return under the Agreement will be calculated based upon the actual capital structure and rate base as described in the Rate Base Update Mechanism set forth in Paragraph B.9 and that the actual capital structure will include NIPSCO's actual prepaid pension asset and post-retirement liability as proposed by NIPSCO.

3. Depreciation and Amortization Expense.

(a) Depreciation Expense. The Settling Parties agree to a $4,900,000 reduction to proposed depreciation expense with adjustments to originally proposed depreciation accrual rates to be determined by NIPSCO Witness Spanos related to non-meter and non-meter installations service lives or net salvage adjustments, resulting in pro forma Gas Plant Depreciation expense of $112,583,892.[5] The resulting depreciation accrual rates to which the Settling Parties agree are shown in Joint Exhibit B. NIPSCO will continue to use the depreciation rates applicable to its common plant as approved by the Commission in NIPSCO's last electric general rate proceeding in Cause No. 45772.

(b) Amortization Expense. The Settling Parties agree to a $4,361,479 reduction to amortization expense as follows: (1) Gas Rate Case Expense Amortization adjusted to $375,000, reflecting a 4-year amortization period with a cap of expenses of $1,500,000, for a reduction of $737,216 from NIPSCO's case-in-chief filing; and (2) 45621 Amortization adjusted to $3,624,263, reflecting two additional years of amortization now ending August 2028, for a reduction of $3,624,263. The Settling Parties agree to NIPSCO's proposed (1) 4-year amortization period for the TDSIC Regulatory Asset

---

5 Joint Exhibit B reflects an actual depreciation expense of $112,584,391, which is $499 higher than the pro forma Gas Plant Depreciation expense of $112,583,892. This reflects a difference between the actual depreciation adjustment made by NIPSCO Witness Spanos and the level of expense in the revenue requirement under the Agreement.

Amortization, (2) 4-year amortization period for the FMCA Regulatory Asset, and (3) 9-month amortization period for the Cause No. 44988 Regulatory Asset (rate case expense and then-deferred TDSIC balance). At the end of each item's agreed amortization period, NIPSCO agrees to file a compliance filing to take that amount out of base rates.

4. AMI Project. The Settling Parties agree to approval of NIPSCO's proposed AMI Project. The Settling Parties agree that NIPSCO will prepare proposed AMI Opt-Out Language to be included in its Gas Tariff to be reviewed and included in a 30-Day Filing. The Settling Parties agree NIPSCO will make an annual compliance filing to include the requests in the Testimony of OUCC Witness Jared J. Hoff (Public's Exhibit No. 10) regarding the status and update of the AMI Project, as follows:

- The number of gas AMI communication modules planned to be installed in the previous calendar year;
- The number of gas AMI communication modules actually installed in the previous calendar year;
- The number of gas AMI communication modules remaining to be installed;
- The current cost estimate for the installation of the gas AMI communication modules;
- The actual costs incurred in the previous calendar year for the gas AMI Upgrade Project, any changes from the project estimates, and the identified cause;
- The total costs incurred to date for the gas AMI Upgrade Project;

- The actual costs incurred in the previous calendar year for the AMI Network deployment, any changes from the project estimates, and the identified cause; and
- An explanation of any factors that have affected costs for the AMI Upgrade Project.

The foregoing annual compliance filings are to be made by the end of the first quarter of each year, and NIPSCO will report actual information based upon the prior calendar year and estimated information about the current calendar year. This obligation shall terminate after NIPSCO has completed its AMI Project and made a subsequent compliance filing.

5. <u>Operating Revenues</u>. The Settling Parties stipulate to NIPSCO's agreement to forego a reduction of $2,386,129 of overstated revenue presented in NIPSCO Witness Davis's rebuttal testimony, which had the effect of decreasing forecasted Retail Revenue and increasing the revenue deficiency at present rates.

6. <u>O&M Expenses</u>: The Settling Parties stipulate that NIPSCO's forecasted pro forma O&M Expenses should be decreased by $8,235,386, as follows: (a) Labor (Adjustment OM 1) – reduction of $341,910 from $71,905,040 to $71,563,130; (b) Uncollectible Expense (Adjustment OM 11) – reduction of $11,499 from $2,114,495 to $2,102,996; (c) Gas Operations Expense (Adjustment OM 2) – reduction of $1,945,844 from $45,853,342 to $43,907,498; and (d) Other reduction of $5,936,131.

7. Taxes Other Than Income Taxes: The Settling Parties stipulate that NIPSCO's forecasted pro forma Taxes Other than Income Taxes expense should be decreased by $28,761, as follows: (a) Payroll Taxes (Adjustment OTX-2) – reduction of $26,156 from $5,053,367 to $5,027,211; and (b) Public Utility Fee (Adjustment OTX-5) – reduction of $2,604 from $1,433,771 to $1,431,167.

8. Implementation. The Settling Parties agree the rate change will be implemented on a services rendered basis after NIPSCO's new tariff has been approved by the Commission's Energy Division.

9. Rate Base Update Mechanism. The Settling Parties agree that NIPSCO should be authorized to modify its base rates and charges for natural gas utility service in two steps as described herein. The Settling Parties agree to the following process for the implementation of rates in two steps:

(a) Step 1 Rates. The first change in rates will be based on the agreed revenue requirement as adjusted to reflect the actual original cost of NIPSCO's rate base, actual capital structure, and associated annualized depreciation and amortization expense as of June 30, 2024 ("Phase 1"). Following issuance of a Final Order in this Cause approving this Agreement, Phase 1 rates will go into effect on a services rendered basis after the new tariff has been approved by the Commission's Energy Division, on an interim subject to refund basis, pending the 60-day review process all other parties shall have to review and present any objections. NIPSCO will certify its actual total rate base, capital structure, and associated annualized depreciation and amortization expenses as of June 30, 2024, and implement base rates using the forecasted results of operation for the test year as found in the Order. If needed to resolve any objections, the Commission will conduct a hearing and rates will be trued up, retroactive to the date such rates were put into place.

(b) Step 2 Rates. NIPSCO will certify its actual total rate base, capital structure, and associated annualized depreciation and amortization expenses at test-year end (December 31, 2024). Step 2 rates will be based on the agreed revenue requirement as of December 31, 2024, as adjusted for this certification. Actual certified net original cost rate base to be reflected in Step 2 rates shall include the lesser of (a) NIPSCO's forecasted additions to test-year-end Total Utility Plant of $1,354,396,680, or (b) NIPSCO's actual additions to Total Utility Plant as of December 31, 2024. Step 2 rates will take effect on a services rendered basis after the new rates have been approved by the Commission’s Energy Division, on an interim-subject-to-refund basis, with other parties having a period of 60 days to review and present any objections. If needed to resolve any objections, the Commission will conduct a hearing, and rates will be trued up, retroactive to the date such rates were put into place. To the extent any additions to Utility Plant are excluded from net original cost rate base because NIPSCO’s total additions to Utility Plant in Service exceeds $1,354,396,680, NIPSCO shall include with its submission a list of the work orders which have been placed in service, but which are not being included in rate base in this Cause. For purposes of this Paragraph B.9., "certify" means NIPSCO has determined that it has substantially completed the amount of plant indicated in its certification and the corresponding plant additions have been placed in service and are used and useful in providing utility service as of the date of certification. NIPSCO will serve all Settling Parties with its certification.

(c) To the extent the actual revenue requirement resulting from either paragraph (a) or (b) of this section is different from $1,114,923,631 as provided in Paragraph B.1(a) herein, the difference shall be reflected by changing the rates set forth in NIPSCO Witness Sears' Attachment 2-S-A in an across-the-board fashion.

(d) As set forth in the Verified Rebuttal Testimony of Richard D. Weatherford (Petitioner's Exhibit No. 3-R), the forecasted additions to Utility Plant in Service ("UPIS") serve as a cap in calculating the actual rate base that is ultimately submitted as part of NIPSCO's Step 2 Compliance Filing. However, the forecasted additions to UPIS are only a cap for purposes of this proceeding (not a cap for purposes of a future general rate case or for purposes of NIPSCO's capital trackers).

(e) NIPSCO will exclude the net book value of technology costs to set up the billing and enrollment functionality for its Green Path Rider from its rate base at

Step 1 and Step 2 (cutoff as of June 30, 2024 and December 31, 2024) as established in this Cause.

10. Revenue Allocation. The Settling Parties stipulate to the allocation of the agreed $120,948,338 revenue increase between classes as shown below. The TDSIC allocators are as shown on Joint Exhibit C attached hereto.

	Margin Revenues at Current Rates	Revenue Increase	Percentage Increase on Margin
Rate 211	$376,460,321	$78,331,049	20.81%
Rate 215	$2,852,398	$593,506	20.81%
Rate 221	$121,103,007	$25,198,208	20.81%
Rate 225	$17,878,181	$3,719,958	20.81%
Rate 228 HP	$42,228,571	$12,039,229	28.51%
Rate 228 DP	$17,784,217	$1,066,388	6.00%
Rate 234	$69,452	-	0.00%
Rate 238	$6,043,060	-	0.00%
Total	$584,419,207	$120,948,338	20.70%

The Settling Parties agree that the revenue allocation for the agreed revenue requirement as included in the table set forth above, is solely for the purposes of settlement in this Cause and is without adoption or endorsement of any specified methodology. In its next gas rate case, NIPSCO will prepare alternative studies using Design Day demand and peak-and-average methodologies, and all parties reserve the right to take positions on cost of service without regard to the agreed allocation in this case.

11. Rate Design. The Settling Parties agree to monthly customer charges for residential and small general service (Rates 311, 315, 321) as follows:

Residential:	$16.50
Multi Family:	$20.75
General Service Small:	$67.00

The Settling Parties agree to increase monthly customer charges for Large Transportation and Balancing Service, Rate 328 HP and 328 DP to:

Rate 328 HP	$4,500
Rate 328 DP	$4,000

The Settling Parties agree a third volume block is being created for Large Transportation and Balancing Service, Rate 328 HP, for volumes over 500,000 therms per month with the following volumetric rates per block per therm:

1st Block	0-300,000 Therms	$0.047735
2nd Block	300,001-500,000 Therms	$0.010838
3rd Block	Everything over 500,000 Therms	$0.010189

12. Regulatory Mechanisms.

(a) Balancing Accounts. NIPSCO's proposed pension/OPEB and line locate balancing accounts are withdrawn.

(b) Weather Normalization Adjustment. NIPSCO's proposed Sales Reconciliation Adjustment is withdrawn and replaced by the annual Weather

Normalization Adjustment ("WNA") mechanism. The Settling Parties agree to NIPSCO's methodology of the WNA mechanism presented in the Verified Rebuttal Testimony of John D. Taylor (Petitioner's Exhibit No. 16-R), with the following changes:

(i) The billed amount for Rates 311, 315, 321, and/or 325 Customer (including Riders 351, 380, 381) shall be subject to the WNA for each customer's usage starting on October 1 through May 31. This is dependent on NIPSCO's ability to only apply the WNA to customer's usage starting on October 1 and ending on May 31. Inclusion of May in NIPSCO's WNA for purposes of this Agreement is in recognition of the distinctive characteristics of NIPSCO's service territory, including, but not limited to, the weather patterns unique to its service territory during May, particularly the lake effect weather during May.

(ii) NIPSCO will calculate the weather normalization revenue adjustment for each month of the period indicated above and will accumulate those to be filed in an annual WNA filing in June or July each year. The filing will have at least a 60-day timeline - 30 days for the OUCC and other interested parties to review and 30 days for the Commission to issue an order, which is similar to NIPSCO's GCA process. NIPSCO will provide workpapers to the OUCC monthly, to facilitate the OUCC's review of the filing when made, as it does for the OUCC in the GCA. NIPSCO will also make workpapers available to all intervenors in each proceeding, subject to the appropriate non-disclosure protections for any confidential information.

(iii) The WNA will be charged to customers over the same time period it was accumulated (starting on October 1 and ending on May 31) to ensure, to the extent practical, customers who use no gas in the summer months are not providing a subsidy.

(iv) The second year of the WNA filing and all subsequent years will include a reconciliation of the filed WNA revenue and actual WNA revenue from the prior winter period set out in the prior year filing, with that variance returned to or recovered from customers in the next winter period.

(v) If NIPSCO implements a new billing system, NIPSCO will evaluate the new system to determine its ability to calculate weather normalization on a real time basis and apply the WNA to customers' bills in real time as is generally the practice of other Indiana gas utilities. If NIPSCO implements a new billing system without the ability to calculate the WNA on a real time basis, NIPSCO shall, upon selecting such billing system, provide explanations to the OUCC and CAC as to why a billing system with that capability was not chosen.

(c) NIPSCO will continue to recover lost margins related to NIPSCO's 2024-2026 Gas Energy Efficiency Plan via the existing DSM tracking mechanism.

13. Tariff Changes.

(a) Bank Account Capacity Charge: The Settling Parties agree to a Bank Account Capacity Charge of $0.0600 per Therm of capacity per month.

(b) Universal Service Program ("USP") Rider: The Settling Parties agree that NIPSCO will fund 35% of the USP program expenses. NIPSCO's contribution to USP expenses will not exceed $650,000 in any program year, but the Company's administrative expenses are not included in the $650,000 contribution. The Settling Parties agree that NIPSCO will increase the discount for the three tiers used to determine the assistance amount for customers that are at or below 60% of state median income to 15% (Tier 1), 26% (Tier 2), and 32% (Tier 3).

14. Other Affordability Issues.

(a) INCAA Funding: NIPSCO will provide Indiana Community Action Association with $100,000 in both 2024 and 2025 to assist NIPSCO's low-income customers. NIPSCO's revenue deficiency in this Cause will not be adjusted to include the incremental costs of this contribution, and such contributions shall not be recoverable from ratepayers.

(b) Disconnection Policy: NIPSCO currently uses a policy to determine the relative risk of residential accounts and which accounts will be prioritized for disconnection or other collection activity after a bill becomes delinquent ("Disconnection Policy"). With regard to the Disconnection Policy, the Settling Parties agree that NIPSCO will change Dollar Threshold Levels for its Disconnection Policy as follows:

	NIPSCO Current Practice	**NIPSCO Revised Practice**
Good Risk	N/A	N/A
Low Risk	Arrears > $700	Arrears > $700
Medium Risk	Arrears > $120	Arrears > $240
High Risk	Arrears > $60	Arrears > $150

(c) Following issuance of a final order in this proceeding, NIPSCO will remove the following two criteria from its Disconnection Policy: (1) Prior NSF [Not Sufficient Funds] Checks; and (2) Bankruptcy.

(d) NIPSCO shall, through a third-party, conduct a review of policies and procedures for disconnecting and reconnecting customers for nonpayment, in consultation with CAC, the OUCC, and other interested stakeholders. NIPSCO will allow appropriate time for participants to provide verbal and written feedback on the equity impacts of those policies and procedures and will work in good faith to meaningfully address feedback and resolve concerns.

(e) NIPSCO will not perform residential gas disconnections for nonpayment on Fridays, Saturdays, Sundays, and Holidays.

(f) NIPSCO will not disconnect residential gas customers during the winter moratorium (as defined in Ind. Code § 8-1-2-121) if the customer can show they have an appointment to apply for the federally funded Energy Assistance Program ("EAP") with a local EAP intake office.

15. Other Issues.

(a) Threshold for Transport Service: As part of preparing cost of service for its next gas base rate case, NIPSCO will study operational and usage characteristics of potential gas transportation customers to determine if adjustments to the existing gas transportation rates or the creation of another gas transportation rate with a lower minimum volumetric threshold would be appropriate. This review will include, but will not be limited to, a review of the appropriate minimum daily volumetric threshold level for participation in Rate 338 and a comparison of NIPSCO's threshold levels to other similar Indiana utilities, including CenterPoint Energy Indiana. This may lead NIPSCO to ultimately propose something similar or something different than what is currently available.

(b) NIPSCO Telemetry Field Trial. NIPSCO will allow up to five (5) of Direct Energy's transportation customers to participate in NIPSCO's 2024 field trial of telemetry technology under mutually agreeable terms.

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. 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 a 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 Attorneys' 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 this 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 resolve disputes and avoid litigation with attendant unknowns, 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. The Settling Parties further agree that the respective cases-in-chief of NIPSCO, the OUCC, the Industrial Group, Direct Energy, CAC, and SDI may be admitted into the evidentiary record, and each of the Settling Parties waives cross-examination with respect thereto.

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 a Final Order approving this Agreement without any unacceptable modification 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 any such 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 confidential and privileged.

ACCEPTED AND AGREED this 20th of March, 2024.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

Thomas R. Harper
Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor

NIPSCO Industrial Group

Steel Dynamics, Inc.

Citizens Action Coalition of Indiana, Inc.

____

Kerwin L. Olson
Executive Director

Direct Energy Business Marketing

by ______________________

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2024

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)	$ 1,055,517,597		REV, Col A	$ 993,975,293	120,948,338	PF - 1 -S2 - S	$ 1,114,923,631
3	Pro forma Adjustments December 31, 2022		(70,781,929)	REV, Col B+C				
4	2023 Year-Over-Year Increase/(Decrease)		39,686,855	REV-S, Col E				
5	2024 Year-Over-Year Increase/(Decrease)		(39,546,474)	REV-S, Col G				
6	Ratemaking Adjustments December 31, 2024		9,099,244	REV, Col I				
7	Settlement Adjustments December 31, 2024		-	REV-S, Col K				
8	Total Operating Revenue	$ 1,055,517,597	$ (61,542,304)		$ 993,975,293	$ 120,948,338		$ 1,114,923,631
9	**Gas Costs (Trackable)**							
10	Fuel and Purchase Power Cost (Actual / Pro Forma)	$ 556,693,605		COGS, Col A	$ 400,343,545	-		$ 400,343,545
11	Pro forma Adjustments December 31, 2022		(114,094,280)	COGS, Col B+C				
12	2023 Year-Over-Year Increase/(Decrease)		18,351,607	COGS Col E				
13	2024 Year-Over-Year Increase/(Decrease)		(62,872,469)	COGS, Col G				
14	Ratemaking Adjustments December 31, 2024		2,265,081	COGS, Col I				
15	Total Gas Costs	$ 556,693,605	$ (156,350,060)		$ 400,343,545	$ -		$ 400,343,545
16	**Gross Margin**	$ 498,823,991	$ 94,807,756		$ 593,631,748	$ 120,948,338		$ 714,580,086
17	**Operations and Maintenance Expenses**							
18	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 248,884,633		O&M, Col A	$ 250,538,738	504,400	PF - 2 - S2 - S	$ 251,043,139
19	Pro forma Adjustments December 31, 2022		(6,733,284)	O&M, Col B				
20	2023 Year-Over-Year Increase/(Decrease)		11,631,700	O&M, Col D				
21	2024 Year-Over-Year Increase/(Decrease)		8,986,283	O&M, Col F				
22	Ratemaking Adjustments December 31, 2024		(6,294,463)	O&M-R, Col H				
23	Settlement Adjustments December 31, 2024		(5,936,131)	O&M-S, Col J				
24	Total Operations and Maintenance Expense	$ 248,884,633	$ 1,654,105		$ 250,538,738	$ 504,400		$ 251,043,139
25	**Depreciation Expense**							
26	Depreciation Expense (Actual / Pro Forma)	$ 75,110,862		DEPR, Col A	$ 116,647,848			$ 116,647,848
27	Pro forma Adjustments December 31, 2022		(485,698)	DEPR, Col B				
28	2023 Year-Over-Year Increase/(Decrease)		8,087,212	DEPR, Col D				
29	2024 Year-Over-Year Increase/(Decrease)		16,105,636	DEPR, Col F				
30	Ratemaking Adjustments December 31, 2024		22,729,836	DEPR, Col H				
31	Settlement Adjustments December 31, 2024		(4,900,000)	DEPR-S, Col J				
32	Total Depreciation Expense	$ 75,110,862	$ 41,536,986		$ 116,647,848	$ -		$ 116,647,848

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2024

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
33	**Amortization Expense**							
34	Amortization Expense (Actual / Pro Forma)	$ 10,239,228		AMTZ, Col A	$ 33,559,344			$ 33,559,344
35	Pro forma Adjustments December 31, 2022		4,321,930	AMTZ, Col B				
36	2023 Year-Over-Year Increase/(Decrease)		9,638,192	AMTZ, Col D				
37	2024 Year-Over-Year Increase/(Decrease)		4,564,844	AMTZ, Col F				
38	Ratemaking Adjustments December 31, 2024		9,201,629	AMTZ-R, Col H				
39	Settlement Adjustments December 31, 2024		(4,406,479)	AMTZ-S, Col J				
40	Total Amortization Expense	$ 10,239,228	$ 23,320,116		$ 33,559,344	$ -		$ 33,559,344
41	**Taxes**							
42	**Taxes Other than Income**							
43	Taxes Other than Income (Actual / Pro Forma)	$ 27,775,008		OTX, Col A	$ 24,110,580			$ 24,110,580
44	Pro forma Adjustments December 31, 2022		(8,126,834)	OTX, Col B				
45	2023 Year-Over-Year Increase/(Decrease)		2,210,193	OTX, Col D				
46	2024 Year-Over-Year Increase/(Decrease)		2,007,955	OTX, Col F				$ -
47	Ratemaking Adjustments December 31, 2024		244,258	OTX-R, Col H		177,504	PF - 3 - S2 - S	$ 177,504
48	Total Taxes Other Than Income	$ 27,775,008	$ (3,664,428)		$ 24,110,580	$ 177,504		$ 24,288,084
49	**Operating Income Before Income Taxes**	$ 136,814,260	$ 31,960,976		$ 168,775,236	$ 120,266,433		$ 289,041,670
50	**Income Taxes**							
51	Federal and State Taxes (Actual / Pro Forma)	$ 17,561,373	(1,670,909)	Attachment 3-C-S, ITX 1-S	$ 15,890,464	29,911,465	PF - 4 - S2 - S	$ 45,801,929
52	Total Taxes	$ 45,336,381	$ (5,335,337)		$ 40,001,044	$ 30,088,969		$ 70,090,013
53	**Total Operating Expenses including Income Taxes**	$ 379,571,104	$ 61,175,871		$ 440,746,975	$ 30,593,369		$ 471,340,345
54	**Required Net Operating Income**	$ 119,252,887	$ 33,631,885		$ 152,884,772	$ 90,354,969		$ 243,239,741

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, 2024

Line No.	Description				Revenue Deficiency
1	Net Original Cost Rate Base				$ 3,484,810,045
2	Rate of Return				6.98%
3	Net Operating Income				243,239,741
4	Pro forma Net Operating Income				152,884,772
5	Increase in Net Operating Income (NOI Shortfall)				90,354,969
6	Effective Incremental Revenuel NOl Conversion Factor				74.705%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)				$ 120,948,338
8	One	1.000000			
9	Less: Public Utility Fee	0.001468			
10	Less: Bad Debt	0.004170			
11	State Taxable Income		0.994362		
12	Taxable Adjusted Gross Income Tax	0.994362			
13	Adjusted Gross Income Tax Rate	0.049000			
14	Adjusted Gross Income Tax		0.048724		
15	Line 11 less line 14			0.945638	
16	One		1.000000		
17	Less: Federal Income Tax Rate		0.210000		
18	One Less Federal Income Tax Rate			0.790000	
19	Effective Incremental Revenue / NOl Conversion Factor				74.705%

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2024

Line No.	Description		As Of December 31, 2024	Attachment 3-B-S2 Reference
	Gas Rate Base			
1	Utility Plant	$	4,959,411,735	RB, Col I
2	Common Allocated		264,958,780	RB, Col I
3	**Total Gas Utility Plant**		5,224,370,516	RB, Col I
4	Utility Plant Accumulated Depreciation and Amortization		(1,706,665,078)	RB, Col I
5	Common Allocated Accumulated Depreciation and Amortization		(160,451,815)	RB, Col I
6	**Total Gas Accumulated Depreciation and Amortization**		(1,867,116,893)	RB, Col I
7	**Net Gas Utility Plant**	$	3,357,253,623	RB, Col I
8	Cause No. 44988 & 45621 Regulatory Assets		11,798,908	RB, Col I
9	TDSIC Regulatory Asset		14,874,792	RB, Col I
10	FMCA Regulatory Asset		8,503,778	RB, Col I
11	Materials & Supplies		17,337,093	RB, Col I
12	Gas Stored Underground - Current A/C 164 (13-mo avg)		70,092,430	RB, Col I
13	Gas Stored Underground - Non-Current A/C 117		4,949,422	RB, Col I
14	**Total Gas Rate Base**	**$**	**3,484,810,045**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure
As Of December 31, 2024

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 5,879,498,162	52.39%	9.75%	5.11%
2	Long-Term Debt	4,168,964,776	37.15%	4.94%	1.84%
3	Customer Deposits	67,265,050	0.60%	5.76%	0.03%
4	Deferred Income Taxes	1,505,117,107	13.41%	0.00%	0.00%
5	Post-Retirement Liability	4,449,551	0.04%	0.00%	0.00%
6	Prepaid Pension Asset	(403,801,782)	-3.60%	0.00%	0.00%
7	Post-1970 ITC	391,628	0.00%	7.75%	0.00%
8	Totals	**$ 11,221,884,492**	**100.00%**		**6.98%**

Cost of Investor Supplied Capital

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 5,879,498,162	58.51%	9.75%	5.70%
10	Long-Term Debt	4,168,964,776	41.49%	4.94%	2.05%
11	**Totals**	**$ 10,048,462,938**	**100.00%**		**7.75%**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2024

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2024 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
	DEPRECIABLE PLANT									
	UNDERGROUND STORAGE PLANT									
350.20	LEASEHOLDS	06-2042	75-R4 *	0	377,041.79	377,042	0	0	- ***	-
350.40	RIGHTS OF WAY	06-2042	75-R4 *	0	187,343.01	111,381	75,962	4,397	2.35	17.3
351.10	WELL STRUCTURES	06-2042	70-R4 *	(10)	18,848.51	17,741	2,992	181	0.96	16.5
351.20	COMPRESSOR STATION STRUCTURES	06-2042	70-R4 *	(10)	402,897.05	315,590	127,597	7,324	1.82	17.4
351.30	MEASURING AND REGULATING STATION STRUCTURES	06-2042	70-R4 *	(10)	108,989.10	119,888	0	0	- ***	-
351.40	OTHER STRUCTURES	06-2042	70-R4 *	(10)	6,392,614.27	3,130,434	3,901,442	229,031	3.58	17.0
352.00	WELLS	06-2042	65-S4 *	(10)	30,827,097.50	16,037,625	17,872,182	1,025,663	3.33	17.4
352.30	NONRECOVERABLE NATURAL GAS	06-2042	50-SQ *	0	5,414,970.23	5,009,090	405,880	23,193	0.43	17.5
353.00	LINES	06-2042	50-S1.5 *	(25)	33,965,054.66	22,501,232	19,955,086	1,167,118	3.44	17.1
354.00	COMPRESSOR STATION EQUIPMENT	06-2042	50-R3 *	(10)	5,235,333.04	3,254,502	2,504,364	145,156	2.77	17.3
355.00	MEASURING AND REGULATING STATION EQUIPMENT	06-2042	60-R2.5 *	(10)	3,534,546.32	2,285,969	1,602,032	96,607	2.73	16.6
356.00	PURIFICATION EQUIPMENT	06-2042	65-R4 *	(5)	14,843,529.22	9,723,531	5,862,175	335,834	2.26	17.5
357.00	OTHER EQUIPMENT	06-2042	30-S2.5 *	0	1,014,216.30	998,431	15,785	1,022	0.10	15.4
	TOTAL UNDERGROUND STORAGE PLANT				**102,322,481.00**	**63,882,456**	**52,325,497**	**3,035,526**	**2.97**	
	OTHER STORAGE PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	06-2031	65-R4 *	(10)	10,321,899.20	9,307,742	2,046,347	317,401	3.08	6.4
362.10	GAS HOLDERS	06-2031	55-S3 *	(10)	18,160,971.20	19,016,791	960,277	148,491	0.82	6.5
363.00	PURIFICATION EQUIPMENT	06-2031	55-S2.5 *	(10)	2,088,231.20	1,614,539	682,515	111,192	5.32	6.1
363.10	LIQUEFACTION EQUIPMENT	06-2031	50-S2 *	(10)	8,531,492.52	7,680,807	1,703,835	276,275	3.24	6.2
363.20	VAPORIZING EQUIPMENT	06-2031	50-R2 *	(10)	5,268,986.80	5,129,154	666,731	105,785	2.01	6.3
363.30	COMPRESSOR EQUIPMENT	06-2031	40-R2 *	(10)	3,066,102.96	2,256,194	1,116,519	179,155	5.84	6.2
363.40	MEASURING AND REGULATING EQUIPMENT	06-2031	55-R1.5 *	(10)	1,730,864.52	1,308,939	595,012	94,404	5.45	6.3
363.50	OTHER EQUIPMENT	06-2031	35-R2 *	(10)	3,199,735.18	2,040,409	1,479,300	240,776	7.52	6.1
	TOTAL OTHER STORAGE PLANT				**52,368,283.58**	**48,354,575**	**9,250,536**	**1,473,479**	**2.81**	
	TRANSMISSION PLANT									
365.20	LAND RIGHTS		75-R4	0	21,275,449.21	3,190,858	18,084,591	329,586	1.55	54.9
366.20	MEASURING AND REGULATING STATION STRUCTURES		60-R3	(5)	11,170,500.49	1,679,813	10,049,213	192,559	1.72	52.2
366.30	OTHER STRUCTURES		55-R4	(5)	2,247,576.86	250,557	2,109,399	44,178	1.97	47.7
367.00	MAINS		100-R3	(40)	1,050,465,783.18	134,842,260	1,335,809,836	14,520,405	1.38	92.0
369.00	MEASURING AND REGULATING STATION EQUIPMENT		60-R2	(35)	342,330,837.64	38,771,363	423,375,268	7,667,582	2.24	55.2
371.00	OTHER EQUIPMENT		30-R2.5	0	47,498.51	47,499	0	0	- ***	-
	TOTAL TRANSMISSION PLANT				**1,427,537,645.89**	**178,782,350**	**1,789,428,307**	**22,754,310**	**1.59**	
	DISTRIBUTION PLANT									
374.20	LAND RIGHTS		75-R4	0	3,633,836.47	521,934	3,111,902	48,251	1.33	64.5
375.00	STRUCTURES AND IMPROVEMENTS		70-R4	(15)	12,965,582.31	2,395,334	12,515,086	218,583	1.69	57.3
376.10	MAINS - STEEL		92-R2.5	(30)	394,101,076.30	153,506,360	358,825,039	4,854,058	1.23	73.9
376.20	MAINS - PLASTIC		92-R2.5	(30)	1,119,758,043.50	313,098,116	1,142,587,341	13,836,678	1.24	82.6
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		55-R1.5	(35)	80,713,398.27	26,186,574	82,776,514	1,790,487	2.22	46.2
380.10	SERVICES - STEEL		65-R2	(115)	75,054,110.27	55,887,686	105,478,651	3,352,050	4.47	31.5
380.20	SERVICES - PLASTIC		65-R2	(115)	879,561,553.65	502,414,453	1,388,642,887	26,314,264	2.99	52.8
381.00	METERS		21-L2.5	(5)	197,671,724.69	44,465,584	163,089,727	16,431,512	8.31	9.9
382.00	METER INSTALLATIONS		23-L1.5	(40)	230,249,593.15	137,896,179	184,453,251	11,657,642	5.06	15.8
383.00	HOUSE REGULATORS		60-R1.5	(40)	141,843,847.56	81,653,996	116,927,391	2,210,704	1.56	52.9
384.00	HOUSE REGULATOR INSTALLATIONS		55-R2.5	(10)	3,879,272.64	3,200,352	1,066,848	24,377	0.63	43.8
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		62-R2.5	(15)	76,257,656.10	28,798,261	58,898,044	1,307,238	1.71	45.1
386.00	OTHER PROPERTY ON CUSTOMER PREMISES		15-R3	0	40,914.56	35,479	5,436	385	0.94	14.1
	TOTAL DISTRIBUTION PLANT				**3,215,730,609.47**	**1,350,060,308**	**3,618,378,117**	**82,046,229**	**2.55**	
	GENERAL PLANT									
389.20	LAND RIGHTS		65-R4	0	2,166,283.25	277,435	1,888,848	42,653	1.97	44.3
390.00	STRUCTURES AND IMPROVEMENTS									
	GAS OPERATIONS CENTER	06-2044	50-S0 *	(10)	2,969,959.68	1,690,538	1,576,418	98,273	3.31	16.0
	SOUTH BEND OPERATIONS HEADQUARTERS	06-2042	50-S0 *	(10)	5,879,069.46	3,345,618	3,121,358	214,099	3.64	14.6

Joint Exhibit B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2024

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	CENTRAL GAS METER SHOP	06-2034	50-S0 *	(10)	2,175,690.02	1,512,172	881,087	101,548	4.67	8.7
	PERU OPERATIONS HEADQUARTERS	06-2038	50-S0 *	(10)	1,407,070.67	714,178	833,600	68,606	4.88	12.2
	FORT WAYNE OPERATIONS HEADQUARTERS	06-2040	50-S0 *	(10)	6,228,933.75	3,473,411	3,378,416	277,864	4.46	12.2
	OTHER MISCELLANEOUS STRUCTURES		50-S0	(10)	9,181,560.26	1,945,048	8,154,668	210,570	2.29	38.7
	TOTAL STRUCTURES AND IMPROVEMENTS				27,842,283.84	12,680,965	17,945,547	970,960	3.49	
391.10	OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	979,259.16	621,926	357,333	48,961	5.00	7.3
391.20	COMPUTER EQUIPMENT		7-SQ	0	801,180.68	629,500	171,681	114,454	14.29	1.5
392.40	TRANSPORTATION EQUIPMENT - TRUCKS > 13,000 #		15-L4	20	229,771.29	183,817	0	0	- ***	-
393.00	STORES EQUIPMENT		30-SQ	0	120,012.78	62,043	57,970	3,995	3.33	14.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	16,757,376.97	7,275,000	9,482,377	670,317	4.00	14.1
395.00	LABORATORY EQUIPMENT		20-SQ	0	1,725,512.26	1,018,000	707,512	86,312	5.00	8.2
396.00	POWER OPERATED EQUIPMENT		13-L2	15	869,209.94	738,828	0	0	- ***	-
397.00	COMMUNICATION EQUIPMENT		15-SQ	0	11,874,400.39	1,873,000	10,001,400	792,004	6.67	12.6
398.00	MISCELLANEOUS EQUIPMENT		20-SQ	0	324,197.87	181,900	142,298	16,204	5.00	8.8
	TOTAL GENERAL PLANT				**63,689,488.43**	**25,542,414**	**40,754,966**	**2,745,860**	**4.31**	
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION									
391.10	OFFICE FURNITURE AND EQUIPMENT					(80,504)		26,835 **		
391.20	COMPUTER EQUIPMENT					(572,869)		190,956 **		
393.00	STORES EQUIPMENT					(7,612)		2,537 **		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(687,826)		229,275 **		
395.00	LABORATORY EQUIPMENT					(96,682)		32,227 **		
397.00	COMMUNICATION EQUIPMENT					(159,977)		53,326 **		
398.00	MISCELLANEOUS EQUIPMENT					18,508		(6,169) **		
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION					**(1,586,962)**		**528,987**		
	TOTAL DEPRECIABLE PLANT				**4,861,648,508.37**	**1,665,035,141**	**5,510,137,423**	**112,584,391**	**2.32**	
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED									
301.00	ORGANIZATION				7,147.20	(36,462)				
302.00	FRANCHISES AND CONSENTS				56,860.68	41,766				
303.00	INTANGIBLE PLANT				51,239,974.45	42,114,290				
303.10	INTANGIBLE PLANT - CLOUD SOFTWARE				1,358,780.56	899,029				
350.10	LAND				83,338.02					
360.10	LAND				1,245,964.18					
365.10	LAND				39,692,485.72					
374.10	LAND				3,334,807.49					
388.00	ARO				28,374,694.80					
389.10	LAND				619,832.40					
	TOTAL NONDEPRECIABLE PLANT				**126,013,885.50**	**43,018,623**				
	TOTAL GAS PLANT IN SERVICE				**4,987,662,393.87**	**1,708,053,764**	**5,510,137,423**	**112,584,391**		

* INTERIM SURVIVOR CURVE USED. EACH LOCATION HAS A UNIQUE PROBABLE RETIREMENT DATE.

** 5-YEAR AMORTIZATION OF UNRECOVERED RESERVE RELATED TO IMPLEMENTATION OF AMORTIZATION ACCOUNTING.

*** ACCRUAL RATE TO BE BOOKED FOR NEW ADDITIONS RECORDED AS OF JANUARY 1, 2025 WILL BE:

ACCOUNT	RATE
350.20	10.53
351.30	11.58
371.00	3.33
392.40	5.33
396.00	6.54

NOTE: ADDITIONS RECORDED IN THE FOLLOWING ACCOUNTS AS OF JANUARY 1, 2025 WILL USE THE ANNUAL ACCRUAL RATES LISTED BELOW.

ACCOUNT	RATE	SURIVOR CURVE/ NET SALVAGE %
381.10	6.67	15-S2.5 / 0%
392.10	8.89	9-L1 / 20%
392.20	5.71	14-S4 / 20%
392.30	8.00	10-L0.5 / 20%

TDSIC Allocators

Class	Margin Revenues at Current Rates	COGS	Total Revenues (Margin + COGS)	Revenue Increase	Total Revenue	Percentage of Total per Class which will be the TDSIC Allocator
Rate 211	$ 376,460,321	$ 279,902,092	$ 656,362,412	$ 78,331,049	$ 734,693,461	66.58%
Rate 215	$ 2,852,398	$ 2,794,957	$ 5,647,355	$ 593,506	$ 6,240,861	0.57%
Rate 221/234	$ 121,172,459	$ 100,793,960	$ 221,966,419	$ 25,198,208	$ 247,164,627	22.40%
Rate 225	$ 17,878,181	$ 14,617,679	$ 32,495,861	$ 3,719,958	$ 36,215,819	3.28%
Rate 228 DP	$ 17,784,217		$ 17,784,217	$ 1,066,388	$ 18,850,605	1.71%
Rate 228 HP	$ 42,228,571		$ 42,228,571	$ 12,039,229	$ 54,267,799	4.92%
Rate 238	$ 6,043,060		$ 6,043,060	$ -	$ 6,043,060	0.55%
Total	$ 584,419,207	$ 398,108,688	$ 982,527,895	$ 120,948,338	$ 1,103,476,233	100.00%